2017

Q2 REPORT

For the period ended
June 30, 2017

encana

encana

news release

Encana delivers strong second quarter results; company expands margins, exceeds type curves, grows premium well inventory and updates guidance

Calgary, Alberta (July 21, 2017) **TSX, NYSE: ECA**

Encana's performance through the second quarter has put the company well ahead in the first year of its five-year plan. Driven by strong oil and condensate growth, an increasingly liquids-weighted portfolio and lower costs, Encana significantly expanded its non-GAAP corporate margin. Core asset growth is ahead of schedule and the company increased its type curves and premium return well inventory. Encana has increased total liquids production and lowered costs in its updated 2017 corporate guidance.

Highlights from the quarter include:

- Net earnings of $331 million compared to a loss of $601 million in the second quarter of 2016
- Cash from operating activities of $218 million and non-GAAP cash flow of $351 million, up 26 percent from the previous quarter
- Non-GAAP corporate margin of $12.19 per barrel of oil equivalent (BOE), up 25 percent from the previous quarter despite lower benchmark commodity prices
- Core asset production of 246,500 barrels of oil equivalent per day (BOE/d), up 9,200 BOE/d from the previous quarter; Encana now expects its core assets will deliver 25 to 30 percent production growth from the fourth quarter of 2016 to the fourth quarter of 2017
- Liquids production of 124,900 barrels per day (bbls/d), including oil and condensate production of 100,200 bbls/d, up 14 percent from the previous quarter
- Increased well productivity across its core assets and grew its premium return well inventory to over 11,000 locations
- Announced sale of Piceance natural gas assets
- By year-end 2017, Encana expects its net debt to adjusted EBITDA ratio will be approximately two times and that it will have total liquidity of over $5 billion

"Our results highlight our resilience and demonstrate that we can deliver quality corporate returns through the commodity cycle," said Doug Suttles, Encana President & CEO. "Our transition to a balanced production mix, strong oil and condensate growth and lower costs are driving corporate margin expansion. For the third consecutive year, we are significantly strengthening our balance sheet."

"Driven by innovation and operational excellence, we continue to expand our premium return well inventory," added Suttles. "Our updated guidance reflects our strong performance, efficiency and confidence. We are generating significant momentum and are well positioned for 2018 when we expect to grow within cash flow, even if commodity prices remain at today's levels."

Strong second quarter results: Outperforming plan and updating 2017 guidance
Encana generated cash from operating activities of $218 million in the second quarter of 2017. Non-GAAP cash flow was $351 million compared to $278 million in the previous quarter. The company delivered second quarter net earnings of $331 million, or $0.34 per share. Non-GAAP operating earnings were $180 million compared to $104 million in the previous quarter.

Encana's strong oil and condensate growth, increasingly liquids-weighted portfolio, lower costs and robust risk management strategy contributed to a non-GAAP corporate margin of $12.19 per BOE in the second quarter, up 25 percent from $9.72 per BOE in the first quarter. Year-to-date, the company's non-GAAP corporate margin has averaged $10.96 per BOE.

The company delivered second quarter total production of 316,000 BOE/d, including total liquids production of 124,900 bbls/d, of which 80 percent was oil and condensate. Encana’s second quarter liquids volumes accounted for approximately 40 percent of its total production mix, up from 35 percent in the first quarter. The company’s core assets contributed 246,500 BOE/d, representing almost 80 percent of total production. Natural gas production averaged 1,146 million cubic feet per day (MMcf/d).

Encana is outperforming its initial 2017 corporate guidance. Reflecting its efficiency, the company is maintaining its original capital investment guidance range while lowering expected costs and increasing expected production growth from its core assets from the fourth quarter of 2016 to the fourth quarter of 2017 to between 25 to 30 percent. Updated 2017 guidance can be found on Encana’s website at http://www.encana.com/investors/financial/corporate-guidance.html.

Innovation driving value: Boosting premium type curves and growing premium inventory
Encana’s ability to scale ideas and technology across its multi-basin portfolio is a powerful competitive advantage. Driven by cube development, optimized completions, improved targeting and lower costs, Encana outperformed its average initial production 180-day (IP180) type curves by between 20 to 45 percent. In addition, the company has grown its premium return well inventory to over 11,000 locations including the replacement of all premium wells drilled since October 2016.

In the Permian, Encana delivered a 20 percent increase in IP180 type curves and increased its premium return well inventory by 700 locations. The company has 45 cube wells on production and aims to create additional upside through advanced completions design and new benches.

In the Montney, Encana delivered a 25 percent increase in IP180 type curves and increased its premium return well inventory by 1,000 locations. The company expects to double oil and condensate production from the fourth quarter of 2016 to the fourth quarter of 2017 and has drilled 28 condensate-rich cube wells in the Tower North area.

In the Eagle Ford, Encana delivered a 45 percent increase in average IP180 type curves and grew oil and condensate production by 30 percent from the previous quarter. The company increased its premium return well inventory by 40 locations.

In the Duvernay, the company has replaced all of the 30 premium return well locations it has drilled since October 2016.

Driving further cost efficiencies: More than offsetting inflation
Encana continues to successfully manage inflation as it efficiently develops its core assets at scale. Through sophisticated planning, supply chain management and operating efficiencies, the company expects to hold like-for-like drilling and completion costs essentially flat year-over-year. On a per unit basis, combined second quarter operating costs (excluding long-term incentives) and transportation and processing costs were down $0.34 per BOE compared to the first quarter of 2017.

Highly resilient: Driving value through the commodity cycle and balance sheet strength
Operational improvements and productivity gains across the portfolio through the first half of 2017 strengthened Encana's resiliency. The company now expects it can deliver its five-year growth plan, announced in October 2016, in a flat $50 WTI oil price environment.

For the third consecutive year, Encana expects to significantly strengthen its balance sheet. The sale of its Piceance assets is expected to close in the third quarter of 2017. Transaction proceeds plus cash flow from anticipated strong operating performance means that by year-end 2017, Encana expects its net debt to adjusted EBITDA ratio will be approximately two times and that it will have total liquidity of over $5 billion. Encana has no debt maturities until 2019 and almost 75 percent of its long-term debt is not due until 2030 and beyond.

Commercial mindset: Managing risk and preserving optionality
Encana's multi-basin portfolio, short-cycle capital program and robust risk management strategy give the company significant flexibility and position it to effectively manage risk and protect value. Encana has protected over 75 percent of its expected oil, condensate and natural gas production for the remainder of 2017 and has limited its exposure to AECO natural gas and Midland oil regional pricing through 2020 through a combination of term financial basis hedging and physical transportation agreements.

As at June 30, 2017, Encana had hedged approximately 88,000 bbls/d of expected 2017 oil and condensate production for the balance of the year using a variety of structures at an average price of $49.73 per barrel (bbl). The company has hedged approximately 865 MMcf/d of expected 2017 natural gas production for the balance of the year using a variety of structures at an average price of $3.10 per thousand cubic feet (Mcf).

For 2018, the company has hedged approximately 31,000 bbls/d of expected oil and condensate production at an average price of $55.45 per bbl and approximately 650 MMcf/d of expected natural gas production at an average price of $3.07 per Mcf.

Dividend Declared
On July 20, 2017, the Board declared a dividend of $0.015 per share payable on September 29, 2017 to common shareholders of record as of September 15, 2017.

Second Quarter Highlights

Non-GAAP Cash Flow Reconciliation

(for the period ended June 30) ($ millions)	**Q2 2017**	Q2 2016
Cash from (used in) operating activities	**218**	83
Deduct (add back):		
Net change in other assets and liabilities	**(4)**	(5)
Net change in non-cash working capital	**(129)**	(94)
Current tax on sale of assets	**-**	-
Non-GAAP cash flow[1]	**351**	182

Non-GAAP Operating Earnings Reconciliation

	Q2 2017	Q2 2016
Net earnings (loss)	**331**	(601)
Before-tax (addition) deduction:		
Unrealized gain (loss) on risk management	**110**	(451)
Impairments	**-**	(484)
Non-operating foreign exchange gain (loss)	**63**	(61)
Gain (loss) on divestitures	**-**	(2)
	173	(998)
Income tax	**(22)**	308
After-tax (addition) deduction	**151**	(690)
Non-GAAP operating earnings [1]	**180**	89

[1] Non-GAAP cash flow and non-GAAP operating earnings (loss) are non-GAAP measures as defined in Note 1.

Production Summary			
(for the period ended June 30) (average)	**Q2 2017**	Q2 2016	% Δ
Liquids (Mbbls/d)	**124.9**	132.0	(5)
Natural gas (MMcf/d)	**1,146**	1,418	(19)
Total production (MBOE/d)	**316.0**	368.3	(14)

Liquids and Natural Gas Prices		
	Q2 2017	Q2 2016
Oil and NGLs ($/bbl)		
WTI	**48.29**	45.59
Encana realized liquids price[1]	**41.97**	38.47
Natural gas		
NYMEX ($/MMBtu)	**3.18**	1.95
Encana realized gas price[1] ($/Mcf)	**2.56**	1.86

[1] Prices include the impact of realized gains (losses) on risk management.

Second Quarter Conference Call

A conference call and webcast to discuss the 2017 second quarter results will be held for the investment community today (July 21, 2017) at 7 a.m. MT (9 a.m. ET). To participate, please dial (844) 707-0663 (toll-free in North America) or (703) 326-3003 (international) approximately 10 minutes prior to the conference call. The live audio webcast of the second quarter conference call, including slides, will also be available on Encana's website, www.encana.com, under Investors/Presentations & Events. The webcasts will be archived for approximately 90 days.

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 oil, natural gas liquids (NGLs) and natural gas. 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. 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

Certain measures in this news release 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 companies and should not be viewed as a substitute for measures reported under U.S. GAAP.

- **Non-GAAP 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 current tax on sale of assets. **Non-GAAP Corporate Margin** is a non-GAAP measure defined as Non-GAAP Cash Flow per BOE of production.
- **Non-GAAP 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 items may include, but are not limited to, unrealized gains/losses on risk management, impairments, restructuring charges, non-operating foreign exchange gains/losses, gains/losses on divestitures and gains on debt retirement. Income

taxes may include valuation allowances and the provision related to the pre-tax items listed, as well as income taxes related to divestitures and adjustments to normalize the effect of income taxes calculated using the estimated annual effective income tax rate.

- **Net Debt to Adjusted EBITDA** is a non-GAAP measure monitored by management as an indicator of the company's overall financial strength and as a measure considered comparable to peers in the industry. **Net Debt** is defined as long-term debt, including the current portion, less cash and cash equivalents. **Adjusted EBITDA** is defined as trailing 12-month net earnings (loss) before income taxes, DD&A, impairments, accretion of asset retirement obligation, interest, unrealized gains/losses on risk management, foreign exchange gains/losses, gains/losses on divestitures and other gains/losses.

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. 30-day initial production and other short-term rates are not necessarily indicative of long-term performance or of ultimate recovery.

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. Disclosure of estimated well locations include proved, probable, contingent and unbooked locations. Estimate of well locations and premium return inventory 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 36 percent of all locations specified in our core assets are booked as either reserves or resources, as prepared by internal qualified reserves evaluators using forecast prices and costs as of December 31, 2016. 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 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. Premium return well inventory are locations with expected after tax returns greater than 35 percent at $50/bbl WTI and $3/MMBtu NYMEX.

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: advancement of and expected growth and returns in Encana's five-year plan, including impact of various commodity prices; anticipated production, including growth from core assets, composition of commodity mix, cash flow and corporate margins; potential premium return locations, ability to develop, expected drilling and replacement of locations; expected consideration from transactions, use of proceeds, satisfaction of closing conditions and timing thereof; expected net debt and debt ratios; ability to access credit facilities and other sources of liquidity; anticipated costs, capital and operational efficiencies, including managing inflation; expectation of meeting or exceeding targets in Encana's corporate guidance; success of and benefits from technical innovation and cube development approach, including enhancements to well performance, type curves, number of wells and returns; performance relative to peers; anticipated hedging and outcomes of risk management program, including exposure to certain commodity prices, amount of hedged production and physical sales locations; and anticipated dividends.

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 results to differ materially from those expressed or implied. These assumptions include: future commodity prices and differentials; foreign exchange rates; Encana's ability to access its revolving credit facilities and shelf prospectuses; assumptions contained in Encana's corporate guidance and in the news release; data contained in key modeling statistics; availability of attractive hedges and enforceability of risk management program; effectiveness of Encana's drive to productivity and efficiencies; results from innovations; expectation that counterparties will fulfill their obligations under the gathering, midstream and marketing agreements; access to transportation and processing facilities where Encana operates; assumed tax, royalty and regulatory regimes; enforceability of transaction agreements; ability to satisfy closing conditions and regulatory approvals, successful closing of, and value of post-closing and other adjustments associated with announced sale of assets; 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: the ability to generate sufficient cash flow to meet Encana's obligations; risks inherent to completing transactions on a timely basis or at all and adjustments that may impact expected proceeds or value to Encana; commodity price volatility; ability to secure adequate product transportation and potential pipeline curtailments; variability and discretion of Encana's board of directors 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 and its impact on access to capital markets and other sources of liquidity; fluctuations in currency and interest rates; risks inherent in Encana's 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 Encana; impact to Encana as a result of disputes arising with its partners, including the suspension by its partners of certain of their obligations and the inability to dispose of assets or interests in certain arrangements; Encana's ability to acquire or find additional reserves; imprecision of reserves estimates and estimates of recoverable quantities of natural gas and liquids from 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 acquisitions or divestitures of certain assets or other transactions or receipt of amounts contemplated under the transaction agreements (such transactions may include third-party capital investments, farm-outs or partnerships, which Encana may refer to from time to time as "partnerships" or "joint ventures" and the funds received in respect thereof which Encana may refer to from time to time as "proceeds", "deferred purchase price" and/or "carry capital", regardless of the legal form) as a result of various conditions not being met; and other risks and uncertainties impacting Encana's business, as described in its most recent Annual Report on Form 10-K and as described from time to time in Encana's other periodic filings 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:

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SOURCE: Encana Corporation

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2017

or

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

Commission file number 1-15226

encana

ENCANA CORPORATION

(Exact name of registrant as specified in its charter)

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

Suite 4400, 500 Centre Street S.E., P.O. Box 2850, Calgary, Alberta, Canada, T2P 2S5
(Address of principal executive offices)

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [X] No [ ]

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

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Yes [ ] No [X]

Number of registrant's common shares outstanding as of July 19, 2017	973,095,555

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PART II

DEFINITIONS

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

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

“ASU” means Accounting Standards Update.

“bbl” or “bbls” means barrel or barrels.

“BOE” means barrels of oil equivalent.

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

“DD&A” means depreciation, depletion and amortization expenses.

“FASB” means Financial Accounting Standards Board.

“Mbbls/d” means thousand barrels per day.

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

“Mcf” means thousand cubic feet.

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

“MMBOE” means million barrels of oil equivalent.

“MMBtu” means million Btu.

“MMcf/d” means million cubic feet per day.

“NGL” or “NGLs” means natural gas liquids.

“NYMEX” means New York Mercantile Exchange.

“OPEC” means Organization of the Petroleum Exporting Countries.

“SEC” means United States Securities and Exchange Commission.

“U.S.”, “United States” or “USA” means United States of America.

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

“WTI” means West Texas Intermediate.

CONVERSIONS

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

CONVENTIONS

Unless otherwise specified, all dollar amounts are expressed in U.S. dollars, all references to “dollars”, “$” or “US$” are to U.S. dollars and all references to “C$” are to Canadian dollars. All amounts are provided on a before tax basis, unless otherwise stated. In addition, all information provided herein is presented on an after royalties basis.

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

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

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

FORWARD-LOOKING STATEMENTS AND RISK

This Quarterly Report on Form 10-Q contains certain forward-looking statements or information (collectively, "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements include: composition of the Company's core assets, including the allocation of capital and focus of development plans; growth in long-term shareholder value; statements with respect to the Company's strategic objectives including capital allocation strategy, focus of investment, growth of high margin liquids volumes, operating efficiencies, ability to reduce costs and ability to preserve balance sheet strength; the continued evolution of the Company to drive greater productivity and cost efficiencies; efficiencies resulting from the Company's multi-basin portfolio; balancing commodity portfolio; anticipated commodity prices; ability to accelerate activity levels; ability to optimize well and completion designs; anticipated drilling costs and cycle times; expected proceeds from announced divestitures, adjustments thereto, use of proceeds therefrom, satisfaction of regulatory approvals and closing conditions and timing of closing; anticipated proceeds and future benefits from various joint venture, partnership and other agreements; expected construction of compression and processing capacity; expansion of future midstream services; estimates of reserves and resources; success of and benefits from technical innovation and cube development approach, including enhancements to productivity and recovery; expected production and product types; statements regarding anticipated cash flow and leverage ratios; anticipated cash and cash equivalents; anticipated hedging and outcomes of risk management program; managing risk, including the impact of changes in laws and regulations; level of expenditures and impact of environmental legislation; 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; access to the Company's credit facilities; planned annualized dividend and the declaration and payment of future dividends, if any; the adequacy of the Company's provision for taxes and legal claims; successful resolution of certain tax items; the projections and expectation of meeting the targets contained in the Company's corporate guidance, including updates thereto; ability to manage cost inflation and expected cost structures, including expected operating, transportation and processing and administrative expenses; competitiveness and pace of growth of the Company's assets within North America and against its peers; outlook of oil and gas industry generally and impact of geopolitical environment, including potential supply and demand; returns from the Company's core assets; flexibility and source of funding of capital spending plans; expected future interest expense; the Company's commitments and obligations and adjustments thereto; potential future discounts, if any, in connection with the Company's dividend reinvestment program; statements with respect to future ceiling test impairments; and the possible impact and timing of accounting pronouncements, rule changes and standards.

Readers are cautioned against unduly relying on forward-looking statements which, by their nature, involve numerous assumptions, risks and uncertainties that may cause such statements not to occur, or results to differ materially from those expressed or implied. These assumptions include: future commodity prices and differentials; foreign exchange rates; the Company's ability to access its revolving credit facilities and shelf prospectuses; assumptions contained in the Company's corporate guidance and as specified herein; data contained in key modeling statistics; availability of attractive hedges and enforceability of risk management program; effectiveness of the Company's drive to productivity and efficiencies; results from innovations; the expectation that counterparties will fulfill their obligations under the gathering, midstream and marketing agreements; access to transportation and processing facilities where Encana operates; assumed tax, royalty and regulatory regimes; enforceability of transaction agreements; 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: the ability to generate sufficient cash flow to meet the Company's obligations; risks inherent to completing transactions on a timely basis or at all and adjustments that may impact the expected value to Encana; commodity price volatility; ability to secure adequate product transportation and potential pipeline curtailments; variability and discretion of Encana's board of directors (the "Board of Directors") to declare and pay dividends, if any; 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; risks inherent in the Company's 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; impact to the Company as a result of disputes arising with its partners, including the suspension by its partners of certain of their obligations and the inability to dispose of assets or interests in certain arrangements; the Company's ability to acquire or find additional reserves; imprecision of reserves estimates and estimates of recoverable quantities of natural gas and liquids from 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 acquisitions or divestitures of certain assets or other transactions or receipt of amounts contemplated under the transaction agreements (such transactions may include third-party capital investments, farm-outs or partnerships, which Encana may refer to from time to time as “partnerships” or “joint ventures” and the funds received in respect thereof which Encana may refer to from time to time as “proceeds”, “deferred purchase price” and/or “carry capital”, regardless of the legal form) as a result of various conditions not being met; and other risks described herein and in Item 1A. Risk Factors of the Annual Report on Form 10-K for the fiscal year ended December 31, 2016 (“2016 Annual Report on Form 10-K”) and risks and uncertainties impacting Encana's business as described from time to time in the Company's other periodic filings with the SEC.

Although the Company believes the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the assumptions, risks and uncertainties referenced above are not exhaustive. Forward-looking statements are made as of the date of this document and, except as required by law, the Company undertakes no obligation to update publicly or revise any forward-looking statements. The forward-looking statements contained in this Quarterly Report on Form 10-Q are expressly qualified by these cautionary statements.

The reader should read carefully the risk factors described herein and in Item 1A. Risk Factors of the 2016 Annual Report on Form 10-K for a description of certain risks that could, among other things, cause actual results to differ from these forward-looking statements.

PART I

Item 1. Financial Statements

Condensed Consolidated Statement of Earnings *(unaudited)*

(US$ millions, except per share amounts)		Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Revenues	*(Note 3)*				
Product revenues		**$ 728**	$ 578	**$ 1,466**	$ 1,097
Gains (losses) on risk management, net	*(Note 19)*	**129**	(330)	**467**	(207)
Market optimization		**204**	91	**390**	178
Other		**22**	25	**49**	49
Total Revenues		**1,083**	364	**2,372**	1,117
Operating Expenses	*(Note 3)*				
Production, mineral and other taxes		**24**	30	**53**	53
Transportation and processing	*(Note 19)*	**206**	244	**418**	513
Operating		**113**	135	**245**	301
Purchased product		**192**	79	**363**	152
Depreciation, depletion and amortization		**193**	230	**380**	491
Impairments	*(Note 8)*	**-**	484	**-**	1,396
Accretion of asset retirement obligation	*(Note 11)*	**10**	13	**21**	26
Administrative	*(Note 15)*	**24**	61	**82**	140
Total Operating Expenses		**762**	1,276	**1,562**	3,072
Operating Income (Loss)		**321**	(912)	**810**	(1,955)
Other (Income) Expenses					
Interest	*(Note 5)*	**79**	107	**167**	210
Foreign exchange (gain) loss, net	*(Notes 6, 19)*	**(58)**	23	**(84)**	(356)
(Gain) loss on divestitures, net		**-**	2	**1**	2
Other (gains) losses, net	*(Note 9)*	**(27)**	24	**(35)**	(63)
Total Other (Income) Expenses		**(6)**	156	**49**	(207)
Net Earnings (Loss) Before Income Tax		**327**	(1,068)	**761**	(1,748)
Income tax expense (recovery)	*(Note 7)*	**(4)**	(467)	**(1)**	(768)
Net Earnings (Loss)		**$ 331**	$ (601)	**$ 762**	$ (980)
Net Earnings (Loss) per Common Share					
Basic & Diluted	*(Note 12)*	**$ 0.34**	$ (0.71)	**$ 0.78**	$ (1.15)
Dividends Declared per Common Share	*(Note 12)*	**$ 0.015**	$ 0.015	**$ 0.03**	$ 0.03
Weighted Average Common Shares Outstanding (millions)					
Basic & Diluted	*(Note 12)*	**973.0**	849.9	**973.0**	849.9

Condensed Consolidated Statement of Comprehensive Income *(unaudited)*

(US$ millions)		Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Net Earnings (Loss)		**$ 331**	$ (601)	**$ 762**	$ (980)
Other Comprehensive Income (Loss), Net of Tax					
Foreign currency translation adjustment	*(Note 13)*	**(59)**	14	**(75)**	(256)
Pension and other post-employment benefit plans	*(Notes 13, 17)*	**-**	-	**(1)**	-
Other Comprehensive Income (Loss)		**(59)**	14	**(76)**	(256)
Comprehensive Income (Loss)		**$ 272**	$ (587)	**$ 686**	$ (1,236)

See accompanying Notes to Condensed Consolidated Financial Statements

Condensed Consolidated Balance Sheet *(unaudited)*

(US$ millions)		As at June 30, 2017	As at December 31, 2016
Assets			
Current Assets			
Cash and cash equivalents		**$ 395**	$ 834
Accounts receivable and accrued revenues		**603**	663
Risk management	*(Notes 18, 19)*	**145**	-
Income tax receivable		**627**	426
		1,770	1,923
Property, Plant and Equipment, at cost:	*(Note 8)*		
Oil and natural gas properties, based on full cost accounting			
Proved properties		**41,221**	39,610
Unproved properties		**4,796**	5,198
Other		**2,243**	2,194
Property, plant and equipment		**48,260**	47,002
Less: Accumulated depreciation, depletion and amortization		**(39,715)**	(38,863)
Property, plant and equipment, net	*(Note 3)*	**8,545**	8,139
Other Assets		**132**	138
Risk Management	*(Notes 18, 19)*	**135**	16
Deferred Income Taxes		**1,625**	1,658
Goodwill	*(Note 3)*	**2,802**	2,779
	(Note 3)	**$ 15,009**	$ 14,653
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 1,271**	$ 1,303
Income tax payable		**5**	5
Risk management	*(Notes 18, 19)*	**42**	254
		1,318	1,562
Long-Term Debt	*(Note 9)*	**4,198**	4,198
Other Liabilities and Provisions	*(Note 10)*	**2,061**	2,047
Risk Management	*(Notes 18, 19)*	**13**	35
Asset Retirement Obligation	*(Note 11)*	**604**	654
Deferred Income Taxes		**32**	31
		8,226	8,527
Commitments and Contingencies	*(Note 21)*		
Shareholders' Equity			
Share capital - authorized unlimited common shares			
2017 issued and outstanding: 973.0 million shares (2016: 973.0 million shares)	*(Note 12)*	**4,756**	4,756
Paid in surplus		**1,358**	1,358
Accumulated deficit		**(465)**	(1,198)
Accumulated other comprehensive income	*(Note 13)*	**1,134**	1,210
Total Shareholders' Equity		**6,783**	6,126
		$ 15,009	$ 14,653

See accompanying Notes to Condensed Consolidated Financial Statements

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

Six Months Ended June 30, 2017 (US$ millions)		Share Capital	Paid in Surplus	Accumulated Deficit	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance, December 31, 2016		**$ 4,756**	**$ 1,358**	**$ (1,198)**	**$ 1,210**	**$ 6,126**
Net Earnings (Loss)		**-**	**-**	**762**	**-**	**762**
Dividends on Common Shares	*(Note 12)*	**-**	**-**	**(29)**	**-**	**(29)**
Common Shares Issued Under Dividend Reinvestment Plan	*(Note 12)*	**-**	**-**	**-**	**-**	**-**
Other Comprehensive Income (Loss)	*(Note 13)*	**-**	**-**	**-**	**(76)**	**(76)**
Balance, June 30, 2017		**$ 4,756**	**$ 1,358**	**$ (465)**	**$ 1,134**	**$ 6,783**

Six Months Ended June 30, 2016 (US$ millions)		Share Capital	Paid in Surplus	Accumulated Deficit	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance, December 31, 2015		$ 3,621	$ 1,358	$ (202)	$ 1,390	$ 6,167
Net Earnings (Loss)		-	-	(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

See accompanying Notes to Condensed Consolidated Financial Statements

Condensed Consolidated Statement of Cash Flows *(unaudited)*

(US$ millions)		Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Operating Activities					
Net earnings (loss)		**$ 331**	$ (601)	**$ 762**	$ (980)
Depreciation, depletion and amortization		**193**	230	**380**	491
Impairments	*(Note 8)*	**-**	484	**-**	1,396
Accretion of asset retirement obligation	*(Note 11)*	**10**	13	**21**	26
Deferred income taxes	*(Note 7)*	**14**	(455)	**56**	(759)
Unrealized (gain) loss on risk management	*(Note 19)*	**(110)**	451	**(472)**	506
Unrealized foreign exchange (gain) loss	*(Note 6)*	**(63)**	73	**(99)**	(270)
Foreign exchange on settlements	*(Note 6)*	**7**	(53)	**9**	(85)
(Gain) loss on divestitures, net		**-**	2	**1**	2
Other		**(31)**	38	**(29)**	(43)
Net change in other assets and liabilities		**(4)**	(5)	**(16)**	(9)
Net change in non-cash working capital	*(Note 20)*	**(129)**	(94)	**(289)**	(35)
Cash From (Used in) Operating Activities		**218**	83	**324**	240
Investing Activities					
Capital expenditures	*(Note 3)*	**(415)**	(215)	**(814)**	(574)
Acquisitions	*(Note 4)*	**(2)**	(1)	**(48)**	(2)
Proceeds from divestitures	*(Note 4)*	**82**	-	**85**	6
Net change in investments and other		**24**	(56)	**79**	(44)
Cash From (Used in) Investing Activities		**(311)**	(272)	**(698)**	(614)
Financing Activities					
Net issuance (repayment) of revolving long-term debt		**-**	288	**-**	843
Repayment of long-term debt	*(Note 9)*	**-**	-	**-**	(400)
Dividends on common shares	*(Note 12)*	**(14)**	(11)	**(29)**	(24)
Capital lease payments and other financing arrangements	*(Note 10)*	**(24)**	(17)	**(40)**	(32)
Cash From (Used in) Financing Activities		**(38)**	260	**(69)**	387
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**3**	-	**4**	9
Increase (Decrease) in Cash and Cash Equivalents		**(128)**	71	**(439)**	22
Cash and Cash Equivalents, Beginning of Period		**523**	222	**834**	271
Cash and Cash Equivalents, End of Period		**$ 395**	$ 293	**$ 395**	$ 293
Cash, End of Period		**$ 112**	$ 31	**$ 112**	$ 31
Cash Equivalents, End of Period		**283**	262	**283**	262
Cash and Cash Equivalents, End of Period		**$ 395**	$ 293	**$ 395**	$ 293

See accompanying Notes to Condensed Consolidated Financial Statements

1. Basis of Presentation and Principles of Consolidation

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

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 oil and natural gas exploration and production joint ventures and partnerships are consolidated on a proportionate basis. Investments in non-controlled entities over which Encana has the ability to exercise significant influence are accounted for using the equity method.

The interim Condensed Consolidated Financial Statements are prepared in conformity with U.S. GAAP and the rules and regulations of the SEC. Pursuant to these rules and regulations, certain information and disclosures normally required under U.S. GAAP 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, 2016, which are included in Item 8 of Encana's 2016 Annual Report on Form 10-K.

These unaudited interim Condensed Consolidated Financial Statements reflect, in the opinion of Management, all normal and recurring adjustments, with the exception of an out-of-period adjustment as described in Note 6, which are 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

New Standards Issued Not Yet Adopted

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

As of January 1, 2018, Encana will be required to adopt ASU 2017-07, "Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost". The amendment requires the service cost component to be presented with the related employee compensation costs, while the other components of net benefit costs are required to be presented separately from the service cost component and outside the subtotal of income from operations. In addition, the amendment allows only the service cost to be eligible for capitalization. The amendment will be applied retrospectively and provides certain practical expedients for the presentation of net periodic pension costs and net periodic postretirement benefit cost, while the capitalization of the service cost component will be applied prospectively, at the date of adoption. Encana does not expect the amendment to have a material impact on the Company's Consolidated Financial Statements.

As of January 1, 2019, Encana will be required to adopt ASU 2016-02, “Leases” under Topic 842, which will replace Topic 840 “Leases”. The new standard will require lessees to recognize right-of-use assets and related lease liabilities for all leases, including leases classified as operating leases, on the Consolidated Balance Sheet. The dual classification model was retained for the purpose of subsequent measurement and presentation of leases in the Consolidated Statement of Earnings and Consolidated Statement of Cash Flows. The new standard also expands disclosures related to the amount, timing and uncertainty of cash flows arising from leases. The standard will be applied using a modified retrospective approach and provides for certain practical expedients at the date of adoption. Encana is currently identifying, gathering and analyzing contracts impacted by the adoption of the new standard, as well as evaluating the system requirements for implementation. Although Encana is not able to reasonably estimate the financial impact of ASU 2016-02 at this time, the Company anticipates there will be a material impact on the Company’s Consolidated Financial Statements resulting from the recognition of assets and liabilities related to operating lease activities.

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

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 oil, NGLs and natural gas and other related activities within the Canadian cost centre.

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

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

Corporate and Other mainly includes unrealized gains or losses recorded on derivative financial instruments. Once the instruments are settled, the realized gains and losses are recorded in the reporting segment to which the derivative instruments relate.

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

Segment and Geographic Information

	Canadian Operations		USA Operations		Market Optimization	
	2017	2016	**2017**	2016	**2017**	2016
Revenues						
Product revenues	**$ 264**	$ 196	**$ 464**	$ 382	**$ -**	$ -
Gains (losses) on risk management, net	**2**	55	**17**	71	**-**	1
Market optimization	**-**	-	**-**	-	**204**	91
Other	**1**	1	**4**	7	**-**	-
Total Revenues	**267**	252	**485**	460	**204**	92
Operating Expenses						
Production, mineral and other taxes	**5**	6	**19**	24	**-**	-
Transportation and processing	**133**	155	**51**	73	**22**	22
Operating	**22**	37	**84**	87	**3**	6
Purchased product	**-**	-	**-**	-	**192**	79
Depreciation, depletion and amortization	**53**	67	**123**	143	**-**	-
Impairments	**-**	226	**-**	258	**-**	-
Total Operating Expenses	**213**	491	**277**	585	**217**	107
Operating Income (Loss)	**$ 54**	$ (239)	**$ 208**	$ (125)	**$ (13)**	$ (15)

	Corporate & Other		Consolidated	
	2017	2016	**2017**	2016
Revenues				
Product revenues	**$ -**	$ -	**$ 728**	$ 578
Gains (losses) on risk management, net	**110**	(457)	**129**	(330)
Market optimization	**-**	-	**204**	91
Other	**17**	17	**22**	25
Total Revenues	**127**	(440)	**1,083**	364
Operating Expenses				
Production, mineral and other taxes	**-**	-	**24**	30
Transportation and processing	**-**	(6)	**206**	244
Operating	**4**	5	**113**	135
Purchased product	**-**	-	**192**	79
Depreciation, depletion and amortization	**17**	20	**193**	230
Impairments	**-**	-	**-**	484
Accretion of asset retirement obligation	**10**	13	**10**	13
Administrative	**24**	61	**24**	61
Total Operating Expenses	**55**	93	**762**	1,276
Operating Income (Loss)	**$ 72**	$ (533)	**321**	(912)
Other (Income) Expenses				
Interest			**79**	107
Foreign exchange (gain) loss, net			**(58)**	23
(Gain) loss on divestitures, net			**-**	2
Other (gains) losses, net			**(27)**	24
Total Other (Income) Expenses			**(6)**	156
Net Earnings (Loss) Before Income Tax			**327**	(1,068)
Income tax expense (recovery)			**(4)**	(467)
Net Earnings (Loss)			**$ 331**	$ (601)

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

Segment and Geographic Information

	Canadian Operations		USA Operations		Market Optimization	
	2017	2016	**2017**	2016	**2017**	2016
Revenues						
Product revenues	**$ 561**	$ 420	**$ 905**	$ 677	**$ -**	$ -
Gains (losses) on risk management, net	**(19)**	122	**14**	181	**-**	1
Market optimization	**-**	-	**-**	-	**390**	178
Other	**5**	4	**10**	11	**-**	-
Total Revenues	**547**	546	**929**	869	**390**	179
Operating Expenses						
Production, mineral and other taxes	**10**	12	**43**	41	**-**	-
Transportation and processing	**265**	304	**110**	171	**43**	43
Operating	**53**	77	**171**	200	**12**	14
Purchased product	**-**	-	**-**	-	**363**	152
Depreciation, depletion and amortization	**117**	149	**229**	302	**-**	-
Impairments	**-**	493	**-**	903	**-**	-
Total Operating Expenses	**445**	1,035	**553**	1,617	**418**	209
Operating Income (Loss)	**$ 102**	$ (489)	**$ 376**	$ (748)	**$ (28)**	$ (30)

	Corporate & Other		Consolidated	
	2017	2016	**2017**	2016
Revenues				
Product revenues	**$ -**	$ -	**$ 1,466**	$ 1,097
Gains (losses) on risk management, net	**472**	(511)	**467**	(207)
Market optimization	**-**	-	**390**	178
Other	**34**	34	**49**	49
Total Revenues	**506**	(477)	**2,372**	1,117
Operating Expenses				
Production, mineral and other taxes	**-**	-	**53**	53
Transportation and processing	**-**	(5)	**418**	513
Operating	**9**	10	**245**	301
Purchased product	**-**	-	**363**	152
Depreciation, depletion and amortization	**34**	40	**380**	491
Impairments	**-**	-	**-**	1,396
Accretion of asset retirement obligation	**21**	26	**21**	26
Administrative	**82**	140	**82**	140
Total Operating Expenses	**146**	211	**1,562**	3,072
Operating Income (Loss)	**$ 360**	$ (688)	**810**	(1,955)
Other (Income) Expenses				
Interest			**167**	210
Foreign exchange (gain) loss, net			**(84)**	(356)
(Gain) loss on divestitures, net			**1**	2
Other (gains) losses, net			**(35)**	(63)
Total Other (Income) Expenses			**49**	(207)
Net Earnings (Loss) Before Income Tax			**761**	(1,748)
Income tax expense (recovery)			**(1)**	(768)
Net Earnings (Loss)			**$ 762**	$ (980)

Intersegment Information

For the three months ended June 30	Marketing Sales 2017	Marketing Sales 2016	Market Optimization Upstream Eliminations 2017	Market Optimization Upstream Eliminations 2016	Total 2017	Total 2016
Revenues	**$ 951**	$ 713	**$ (747)**	$ (621)	**$ 204**	$ 92
Operating Expenses						
Transportation and processing	**61**	74	**(39)**	(52)	**22**	22
Operating	**3**	6	**-**	-	**3**	6
Purchased product	**900**	648	**(708)**	(569)	**192**	79
Operating Income (Loss)	**$ (13)**	$ (15)	**$ -**	$ -	**$ (13)**	$ (15)

For the six months ended June 30	Marketing Sales 2017	Marketing Sales 2016	Market Optimization Upstream Eliminations 2017	Market Optimization Upstream Eliminations 2016	Total 2017	Total 2016
Revenues	**$ 1,907**	$ 1,402	**$ (1,517)**	$ (1,223)	**$ 390**	$ 179
Operating Expenses						
Transportation and processing	**125**	154	**(82)**	(111)	**43**	43
Operating	**12**	14	**-**	-	**12**	14
Purchased product	**1,798**	1,263	**(1,435)**	(1,111)	**363**	152
Operating Income (Loss)	**$ (28)**	$ (29)	**$ -**	$ (1)	**$ (28)**	$ (30)

Capital Expenditures

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Canadian Operations	**$ 81**	$ 54	**$ 169**	$ 117
USA Operations	**333**	159	**644**	456
Corporate & Other	**1**	2	**1**	1
	$ 415	$ 215	**$ 814**	$ 574

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

	Goodwill As at June 30, 2017	Goodwill As at December 31, 2016	Property, Plant and Equipment As at June 30, 2017	Property, Plant and Equipment As at December 31, 2016	Total Assets As at June 30, 2017	Total Assets As at December 31, 2016
Canadian Operations	**$ 673**	$ 650	**$ 701**	$ 602	**$ 1,661**	$ 1,542
USA Operations	**2,129**	2,129	**6,337**	6,050	**9,803**	9,535
Market Optimization	**-**	-	**2**	2	**100**	105
Corporate & Other	**-**	-	**1,505**	1,485	**3,445**	3,471
	$ 2,802	$ 2,779	**$ 8,545**	$ 8,139	**$ 15,009**	$ 14,653

4. Acquisitions and Divestitures

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	**2017**	2016
Acquisitions				
Canadian Operations	**$ -**	$ -	**$ 31**	$ -
USA Operations	**2**	1	**17**	2
Total Acquisitions	**2**	1	**48**	2
Divestitures				
Canadian Operations	**(3)**	-	**(6)**	-
USA Operations	**(79)**	-	**(79)**	(6)
Total Divestitures	**(82)**	-	**(85)**	(6)
Net Acquisitions & (Divestitures)	**$ (80)**	$ 1	**$ (37)**	$ (4)

Acquisitions

For the six months ended June 30, 2017, acquisitions in the Canadian Operations and USA Operations were $31 million and $17 million, respectively, which primarily included land purchases with oil and liquids rich potential.

Divestitures

During the three and six months ended June 30, 2017, divestitures in the USA Operations were $79 million, which primarily included the sale of the Tuscaloosa Marine Shale assets in Mississippi and Louisiana. During the six months ended June 30, 2016, divestitures in the USA Operations were $6 million, which primarily included the sale of certain properties that did not complement Encana's existing portfolio of assets.

During the six months ended June 30, 2017, divestitures in the Canadian Operations were $6 million (2016 - nil), which primarily included 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.

5. Interest

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	**2017**	2016
Interest Expense on:				
Debt	**$ 67**	$ 76	**$ 133**	$ 157
The Bow office building	**15**	16	**31**	31
Capital leases	**5**	6	**10**	12
Other	**(8)**	9	**(7)**	10
	$ 79	$ 107	**$ 167**	$ 210

For the three and six months ended June 30, 2017, other primarily includes an interest recovery due to the successful resolution of certain tax items previously assessed by the tax authorities relating to prior taxation years.

6. Foreign Exchange (Gain) Loss, Net

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	**2017**	2016
Unrealized Foreign Exchange (Gain) Loss on:				
Translation of U.S. dollar financing debt issued from Canada	**$ (45)**	$ 59	**$ (78)**	$ (277)
Translation of U.S. dollar risk management contracts issued from Canada	**(28)**	-	**(32)**	6
Translation of intercompany notes	**10**	14	**11**	1
	(63)	73	**(99)**	(270)
Foreign Exchange on Settlements of:				
U.S. dollar financing debt issued from Canada	**7**	(41)	**7**	(72)
U.S. dollar risk management contracts issued from Canada	**2**	-	**1**	-
Intercompany notes	**-**	(12)	**2**	(13)
Other Monetary Revaluations	**(4)**	3	**5**	(1)
	$ (58)	$ 23	**$ (84)**	$ (356)

The unrealized foreign exchange (gain) loss on translation of U.S. dollar financing debt issued from Canada for the three and six months ended June 30, 2017 disclosed in the table above includes an out-of-period adjustment in respect of unrealized losses on a foreign-denominated capital lease obligation since December 2013. The cumulative impact from December 31, 2013 to June 30, 2017 recognized within foreign exchange (gain) loss in the Company's Condensed Consolidated Statement of Earnings for the three and six months ended June 30, 2017 was $68 million, before tax ($47 million, after tax). Encana has determined that the adjustment is not material to the Condensed Consolidated Financial Statements for the period ended June 30, 2017 or any prior periods. Accordingly, comparative periods presented in the Condensed Consolidated Financial Statements have not been restated.

7. Income Taxes

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	**2017**	2016
Current Tax				
Canada	**$ (20)**	$ (14)	**$ (62)**	$ (13)
United States	**1**	-	**1**	-
Other Countries	**1**	2	**4**	4
Total Current Tax Expense (Recovery)	**(18)**	(12)	**(57)**	(9)
Deferred Tax				
Canada	**2**	(262)	**20**	(358)
United States	**6**	(252)	**21**	(608)
Other Countries	**6**	59	**15**	207
Total Deferred Tax Expense (Recovery)	**14**	(455)	**56**	(759)
Income Tax Expense (Recovery)	**$ (4)**	$ (467)	**$ (1)**	$ (768)
Effective Tax Rate	**(1.2%)**	43.7%	**(0.1%)**	43.9%

Encana's interim income tax expense is determined using an estimated annual effective income tax rate applied to year-to-date net earnings before income tax plus the effect of legislative changes and amounts in respect of prior periods. The estimated annual effective income tax rate is impacted by expected annual earnings, income tax related to foreign operations, non-taxable capital gains and losses, tax differences on divestitures and transactions, and partnership tax allocations in excess of funding.

During the three and six months ended June 30, 2017, the current income tax recovery was primarily due to the successful resolution of certain tax items previously assessed by the tax authorities relating to prior taxation years. During the three and six months ended June 30, 2016, the deferred tax recovery was primarily due to the ceiling test impairments recognized in the Canadian and USA Operations as disclosed in Note 8.

These items resulted in an effective tax rate of (0.1) percent for the six months ended June 30, 2017, which is lower than the Canadian statutory rate of 27 percent. The effective tax rate for the six months ended June 30, 2016 exceeded the Canadian statutory tax rate of 27 percent primarily due to the impact of the foreign jurisdictional tax rates relative to the Canadian statutory tax rate applied to jurisdictional earnings.

8. Property, Plant and Equipment, Net

	As at June 30, 2017			As at December 31, 2016		
	Cost	**Accumulated DD&A**	**Net**	Cost	Accumulated DD&A	Net
Canadian Operations						
Proved properties	**$ 13,818**	**$ (13,463)**	**$ 355**	$ 13,159	$ (12,896)	$ 263
Unproved properties	**300**	**-**	**300**	285	-	285
Other	**46**	**-**	**46**	54	-	54
	14,164	**(13,463)**	**701**	13,498	(12,896)	602
USA Operations						
Proved properties	**27,342**	**(25,533)**	**1,809**	26,393	(25,300)	1,093
Unproved properties	**4,496**	**-**	**4,496**	4,913	-	4,913
Other	**32**	**-**	**32**	44	-	44
	31,870	**(25,533)**	**6,337**	31,350	(25,300)	6,050
Market Optimization	**7**	**(5)**	**2**	6	(4)	2
Corporate & Other	**2,219**	**(714)**	**1,505**	2,148	(663)	1,485
	$ 48,260	**$ (39,715)**	**$ 8,545**	$ 47,002	$ (38,863)	$ 8,139

Canadian Operations and USA Operations property, plant and equipment include internal costs directly related to exploration, development and construction activities of $77 million, which have been capitalized during the six months ended June 30, 2017 (2016 - $72 million). Included in Corporate and Other are $61 million ($58 million as of December 31, 2016) of international property costs, which have been fully impaired.

For the three and six months ended June 30, 2017, the Company did not recognize any ceiling test impairments in the Canadian or U.S. cost centres. For the three months ended June 30, 2016, the Company recognized before-tax ceiling test impairments of $226 million in the Canadian cost centre and $258 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 in the Canadian cost centre and $903 million in the U.S. cost centre. The impairments recognized in 2016 are included with accumulated DD&A in the table above and resulted primarily from the decline in the 12-month average trailing prices which reduced proved reserves volumes and values.

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

	Oil & NGLs		Natural Gas	
	WTI ($/bbl)	Edmonton Condensate [2] (C$/bbl)	Henry Hub ($/MMBtu)	AECO (C$/MMBtu)
12-Month Average Trailing Reserves Pricing [1]				
June 30, 2017	**48.95**	**64.27**	**3.01**	**2.76**
December 31, 2016	42.75	55.39	2.49	2.17
June 30, 2016	43.12	55.63	2.24	2.14

(1) All prices were held constant in all future years when estimating net revenues and reserves.
(2) Edmonton Condensate benchmark price has replaced the previously disclosed Edmonton Light Sweet benchmark price.

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, 2017, the total carrying value of assets under capital lease was $49 million ($51 million as at December 31, 2016), net of accumulated amortization of $666 million ($648 million as at December 31, 2016). 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, 2017, Corporate and Other property, plant and equipment and total assets include a carrying value of $1,224 million ($1,194 million as at December 31, 2016) related to The Bow office building, which is under a 25-year lease agreement. The Bow asset is being depreciated over the 60-year estimated life of the building. At the conclusion of the 25-year term, the remaining asset and corresponding liability are expected to be derecognized as disclosed in Note 10.

9. Long-Term Debt

	As at June 30, 2017	As at December 31, 2016
U.S. Dollar Denominated Debt		
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**	462
6.50% due February 1, 2038 [1]	**505**	505
5.15% due November 15, 2041 [1]	**244**	244
Total Principal	**4,211**	4,211
Increase in Value of Debt Acquired	**26**	26
Unamortized Debt Discounts and Issuance Costs	**(39)**	(39)
Current Portion of Long-Term Debt	**-**	-
	$ 4,198	$ 4,198

[1] Notes accepted for purchase in the March 2016 Tender Offers.

As at June 30, 2017, total long-term debt had a carrying value of $4,198 million and a fair value of $4,752 million (as at December 31, 2016 - carrying value of $4,198 million and a fair value of $4,553 million). The estimated fair value of long-term borrowings is categorized within Level 2 of the fair value hierarchy and has been determined based on market information of long-term debt with similar terms and maturity, or by discounting future payments of interest and principal at interest rates expected to be available to the Company at period end.

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

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

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

10. Other Liabilities and Provisions

	As at June 30, 2017	As at December 31, 2016
The Bow Office Building	$ 1,305	$ 1,266
Capital Lease Obligations	335	304
Unrecognized Tax Benefits	187	193
Pensions and Other Post-Employment Benefits	123	124
Long-Term Incentive Costs (See Note 16)	78	120
Other Derivative Contracts (See Notes 18, 19)	11	14
Other	22	26
	$ 2,061	$ 2,047

The Bow Office Building

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

	2017	2018	2019	2020	2021	Thereafter	Total
Expected Future Lease Payments	$ 37	$ 73	$ 74	$ 75	$ 75	$ 1,327	$ 1,661
Less: Amounts Representing Interest	32	62	62	62	61	834	1,113
Present Value of Expected Future Lease Payments	$ 5	$ 11	$ 12	$ 13	$ 14	$ 493	$ 548
Sublease Recoveries (undiscounted)	$ (18)	$ (36)	$ (36)	$ (37)	$ (37)	$ (653)	$ (817)

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.

	2017	2018	2019	2020	2021	Thereafter	Total
Expected Future Lease Payments	$ 49	$ 99	$ 99	$ 99	$ 87	$ 46	$ 479
Less: Amounts Representing Interest	11	20	15	10	4	7	67
Present Value of Expected Future Lease Payments	$ 38	$ 79	$ 84	$ 89	$ 83	$ 39	$ 412

11. Asset Retirement Obligation

	As at June 30, 2017	As at December 31, 2016
Asset Retirement Obligation, Beginning of Year	**$ 687**	$ 814
Liabilities Incurred and Acquired	**6**	18
Liabilities Settled and Divested	**(75)**	(107)
Change in Estimated Future Cash Outflows	**-**	(99)
Accretion Expense	**21**	51
Foreign Currency Translation	**11**	10
Asset Retirement Obligation, End of Period	**$ 650**	$ 687
Current Portion	**$ 46**	$ 33
Long-Term Portion	**604**	654
	$ 650	$ 687

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. No Class A Preferred Shares are outstanding.

Issued and Outstanding

	As at June 30, 2017		As at December 31, 2016	
	Number (millions)	Amount	Number (millions)	Amount
Common Shares Outstanding, Beginning of Year	**973.0**	**$ 4,756**	849.8	$ 3,621
Common Shares Issued	**-**	**-**	123.1	1,134
Common Shares Issued Under Dividend Reinvestment Plan	**-**	**-**	0.1	1
Common Shares Outstanding, End of Period	**973.0**	**$ 4,756**	973.0	$ 4,756

During the six months ended June 30, 2017, Encana issued 30,671 common shares totaling $0.3 million under the Company's dividend reinvestment plan ("DRIP"). During the twelve months ended December 31, 2016, Encana issued 121,249 common shares totaling $1 million under the DRIP.

Dividends

During the three months ended June 30, 2017, Encana paid dividends of $0.015 per common share totaling $14 million (2016 - $0.015 per common share totaling $12 million). During the six months ended June 30, 2017, Encana paid dividends of $0.03 per common share totaling $29 million (2016 - $0.03 per common share totaling $25 million).

For the three and six months ended June 30, 2017, the dividends paid included $0.1 million and $0.3 million, respectively, in common shares issued in lieu of cash dividends under the DRIP (for the three and six months ended June 30, 2016 - $0.3 million and $0.6 million, respectively).

On July 20, 2017, the Board of Directors declared a dividend of $0.015 per common share payable on September 29, 2017 to common shareholders of record as of September 15, 2017.

Earnings Per Common Share

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

(US$ millions, except per share amounts)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Net Earnings (Loss)	**$ 331**	$ (601)	**$ 762**	$ (980)
Number of Common Shares:				
Weighted average common shares outstanding - Basic	**973.0**	849.9	**973.0**	849.9
Effect of dilutive securities	**-**	-	**-**	-
Weighted average common shares outstanding - Diluted	**973.0**	849.9	**973.0**	849.9
Net Earnings (Loss) per Common Share				
Basic & Diluted	**$ 0.34**	$ (0.71)	**$ 0.78**	$ (1.15)

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, 2017 have associated Tandem Stock Appreciation Rights (“TSARs”) attached. In lieu of exercising the option, the associated TSARs give the option holder the right to receive a cash payment equal to the excess of the market price of Encana's common shares at the time of the exercise over the original grant price.

In addition, certain stock options granted are performance-based 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, outstanding TSARs are not considered 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, RSUs are not considered potentially dilutive securities.

13. Accumulated Other Comprehensive Income

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	**2017**	2016
Foreign Currency Translation Adjustment				
Balance, Beginning of Period	**$ 1,184**	$ 1,113	**$ 1,200**	$ 1,383
Change in Foreign Currency Translation Adjustment	**(59)**	14	**(75)**	(256)
Balance, End of Period	**$ 1,125**	$ 1,127	**$ 1,125**	$ 1,127
Pension and Other Post-Employment Benefit Plans				
Balance, Beginning of Period	**$ 9**	$ 7	**$ 10**	$ 7
Reclassification of Net Actuarial (Gains) and Losses to Net Earnings (See Note 17)	**-**	-	**(1)**	-
Income Taxes	**-**	-	**-**	-
Balance, End of Period	**$ 9**	$ 7	**$ 9**	$ 7
Total Accumulated Other Comprehensive Income	**$ 1,134**	$ 1,134	**$ 1,134**	$ 1,134

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, 2017, Encana had a capital lease obligation of $350 million ($299 million as at December 31, 2016) related to the PFC.

Veresen Midstream Limited Partnership

Veresen Midstream Limited Partnership ("VMLP") provides gathering, compression and processing services under various agreements related to the Company's development of liquids and natural gas production in the Montney play. As at June 30, 2017, VMLP provides approximately 623 MMcf/d of natural gas gathering and compression and 304 MMcf/d of natural gas processing under long-term service agreements with remaining terms ranging from up to 15 to 28 years and have various renewal terms providing up to a potential maximum of 10 years.

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

As a result of Encana's involvement with VMLP, the maximum total exposure, which represents the potential exposure to Encana in the event the assets under the agreements are deemed worthless, is estimated to be $1,988 million as at June 30, 2017. The estimate comprises the take or pay volume commitments and the potential payout of minimum costs. The take or pay volume commitments associated with certain gathering and processing assets are included in Note 21 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, 2017, accounts payable and accrued liabilities included $0.3 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. During 2016, Encana incurred total restructuring charges of $34 million, before tax, primarily related to severance costs, of which $1 million remains accrued as at June 30, 2017 and is expected to be paid in 2017.

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

	As at June 30, 2017	As at December 31, 2016
Outstanding Restructuring Accrual, Beginning of Year	**$ 7**	$ 13
Current Period Restructuring Expenses Incurred	**-**	34
Restructuring Costs Paid	**(6)**	(40)
Outstanding Restructuring Accrual, End of Period	**$ 1**	$ 7

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.

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

	As at June 30, 2017		As at June 30, 2016	
	US$ Share Units	**C$ Share Units**	US$ Share Units	C$ Share Units
Risk Free Interest Rate	**1.09%**	**1.09%**	0.54%	0.54%
Dividend Yield	**0.68%**	**0.70%**	0.77%	0.79%
Expected Volatility Rate [(1)]	**59.17%**	**54.94%**	53.96%	50.39%
Expected Term	**1.9 yrs**	**1.9 yrs**	1.7 yrs	2.0 yrs
Market Share Price	**US$8.80**	**C$11.41**	US$7.79	C$10.05

(1) Volatility was estimated using historical rates.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	**2017**	2016
Total Compensation Costs of Transactions Classified as Cash-Settled	**$ (41)**	$ 38	**$ (7)**	$ 46
Less: Total Share-Based Compensation Costs Capitalized	**11**	(9)	**-**	(10)
Total Share-Based Compensation Expense (Recovery)	**$ (30)**	$ 29	**$ (7)**	$ 36
Recognized on the Condensed Consolidated Statement of Earnings in:				
Operating	**$ (8)**	$ 11	**$ -**	$ 13
Administrative	**(22)**	18	**(7)**	23
	$ (30)	$ 29	**$ (7)**	$ 36

As at June 30, 2017, the liability for share-based payment transactions totaled $155 million ($208 million as at December 31, 2016), of which $77 million ($88 million as at December 31, 2016) is recognized in accounts payable and accrued liabilities and $78 million ($120 million as at December 31, 2016) is recognized in other liabilities and provisions in the Condensed Consolidated Balance Sheet.

	As at June 30, 2017	As at December 31, 2016
Liability for Cash-Settled Share-Based Payment Transactions:		
Unvested	**$ 128**	$ 171
Vested	**27**	37
	$ 155	$ 208

The following units were granted primarily in conjunction with the Company's February 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, 2017 (thousands of units)	
TSARs	850
SARs	349
PSUs	1,964
DSUs	140
RSUs	4,751

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	
	2017	2016	**2017**	2016	**2017**	2016
Net Defined Periodic Benefit Cost	**$ (1)**	$ (1)	**$ 5**	$ 7	**$ 4**	$ 6
Defined Contribution Plan Expense	**12**	14	**-**	-	**12**	14
Total Benefit Plans Expense	**$ 11**	$ 13	**$ 5**	$ 7	**$ 16**	$ 20

Of the total benefit plans expense, $12 million (2016 - $16 million) was included in operating expense and $4 million (2016 - $4 million) was included in administrative expense.

The net defined periodic benefit cost for the six months ended June 30 are as follows:

	Defined Benefits		OPEB		Total	
	2017	2016	**2017**	2016	**2017**	2016
Service Cost	**$ -**	$ 1	**$ 4**	$ 5	**$ 4**	$ 6
Interest Cost	**4**	4	**2**	2	**6**	6
Expected Return on Plan Assets	**(5)**	(6)	**-**	-	**(5)**	(6)
Amounts Reclassified from Accumulated Other Comprehensive Income:						
Amortization of net actuarial (gains) and losses [1]	**-**	-	**(1)**	-	**(1)**	-
Total Net Defined Periodic Benefit Cost	**$ (1)**	$ (1)	**$ 5**	$ 7	**$ 4**	$ 6

[1] Included in operating expense in the Condensed Consolidated Statement of Earnings.

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.

Recurring fair value measurements are performed for risk management assets and liabilities and other derivative contracts, 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 following tables. There have been no significant transfers between the hierarchy levels during the period.

Fair value changes and settlements for amounts related to risk management assets and liabilities are recognized in revenues, transportation and processing expense, and foreign exchange gains and losses according to their purpose.

As at June 30, 2017	Level 1 Quoted Prices in Active Markets	Level 2 Other Observable Inputs	Level 3 Significant Unobservable Inputs	Total Fair Value	Netting [1]	Carrying Amount
Risk Management Assets						
Commodity Derivatives:						
Current assets	**$ -**	**$ 128**	**$ 31**	**$ 159**	**$ (30)**	**$ 129**
Long-term assets	**-**	**141**	**-**	**141**	**(15)**	**126**
Foreign Currency Derivatives:						
Current assets	**-**	**16**	**-**	**16**	**-**	**16**
Long-term assets	**-**	**9**	**-**	**9**	**-**	**9**
Risk Management Liabilities						
Commodity Derivatives:						
Current liabilities	**$ -**	**$ 72**	**$ -**	**$ 72**	**$ (30)**	**$ 42**
Long-term liabilities	**-**	**28**	**-**	**28**	**(15)**	**13**
Other Derivative Contracts						
Current in accounts payable and accrued liabilities	**$ -**	**$ 5**	**$ -**	**$ 5**	**$ -**	**$ 5**
Long-term in other liabilities and provisions	**-**	**11**	**-**	**11**	**-**	**11**

[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.

As at December 31, 2016	Level 1 Quoted Prices in Active Markets	Level 2 Other Observable Inputs	Level 3 Significant Unobservable Inputs	Total Fair Value	Netting [(1)]	Carrying Amount
Risk Management Assets						
Commodity Derivatives:						
Current assets	$ -	$ 11	$ -	$ 11	$ (11)	$ -
Long-term assets	-	19	-	19	(3)	16
Risk Management Liabilities						
Commodity Derivatives:						
Current liabilities	$ -	$ 228	$ 36	$ 264	$ (11)	$ 253
Long-term liabilities	-	38	-	38	(3)	35
Foreign Currency Derivatives:						
Current liabilities	-	1	-	1	-	1
Other Derivative Contracts						
Current in accounts payable and accrued liabilities	$ -	$ 5	$ -	$ 5	$ -	$ 5
Long-term in other liabilities and provisions	-	14	-	14	-	14

(1) Netting to offset derivative assets and liabilities where the legal right and intention to offset exists, or where counterparty master netting arrangements contain provisions for net settlement.

The Company's Level 1 and Level 2 risk management assets and liabilities consist of commodity fixed price contracts, NYMEX three-way options, NYMEX costless collars, NYMEX call options, foreign currency swaps and basis swaps with terms to 2023. Level 2 also includes financial guarantee contracts 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.

Level 3 Fair Value Measurements

As at June 30, 2017, the Company's Level 3 risk management assets and liabilities consist of WTI three-way options and WTI costless collars with terms to 2017. The WTI three-way options are a combination of a sold call, bought put and a sold put. The WTI costless collars are a combination of a sold call and a bought put. These contracts allow the Company to participate in the upside of commodity prices to the ceiling of the call option and provide the Company with complete (collars) or partial (three-way) downside price protection through the put options. The fair values of the WTI three-way options and WTI costless collars are based on the income approach and are modelled using observable and unobservable inputs such as implied volatility. The unobservable inputs are obtained from third parties whenever possible and reviewed by the Company for reasonableness.

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

	Risk Management	
	2017	2016
Balance, Beginning of Year	**$ (36)**	$ 16
Total Gains (Losses)	**64**	(4)
Purchases, Sales, Issuances and Settlements:		
Settlements	**3**	(3)
Transfers Out of Level 3 [(1)]	**-**	(10)
Balance, End of Period	**$ 31**	$ (1)
Change in Unrealized Gains (Losses) Related to Assets and Liabilities Held at End of Period	**$ 59**	$ (7)

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

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

	Valuation Technique	Unobservable Input	**As at June 30, 2017**	As at December 31, 2016
Risk Management - WTI Options	Option Model	Implied Volatility	**17% - 48%**	18% - 64%

A 10 percent increase or decrease in implied volatility for the WTI options would cause a corresponding $1 million ($3 million as at December 31, 2016) 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, accounts payable and accrued liabilities, risk management assets and liabilities, other liabilities and provisions and long-term debt.

B) Risk Management Activities

Encana uses derivative financial instruments to manage its exposure to cash flow variability from commodity prices, electricity costs and fluctuating foreign currency exchange rates. The Company does not apply hedge accounting to any of its derivative financial instruments. As a result, gains and losses from changes in the fair value are recognized in net earnings.

Commodity Price Risk

Commodity price risk arises from the effect fluctuations in future commodity prices may have on future cash flows. To partially mitigate exposure to commodity price risk, the Company has entered into various derivative financial instruments. The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company's policy is to not use derivative financial instruments for speculative purposes.

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

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

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

Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign currency exchange rates that may affect the fair value or future cash flows of the Company's financial assets or liabilities. To partially mitigate the effect of foreign exchange fluctuations on future commodity revenues and expenses, the Company may enter into foreign currency derivative contracts. As at June 30, 2017, Encana had $620 million notional U.S. dollar denominated currency swaps at an average exchange rate of US$0.7421 to C$1. The notional contracts mature monthly throughout 2017 and 2018.

Risk Management Positions as at June 30, 2017

	Notional Volumes	Term	Average Price	Fair Value
Crude Oil and NGL Contracts				
Fixed Price Contracts				
WTI Fixed Price	33.0 Mbbls/d	2017	52.27 US$/bbl	**$ 33**
WTI Fixed Price	31.3 Mbbls/d	2018	55.45 US$/bbl	**80**
Butane Fixed Price	2.5 Mbbls/d	2017	36.12 US$/bbl	**2**
WTI Three-Way Options	25.0 Mbbls/d	2017		**18**
Sold call price			61.40 US$/bbl	
Bought put price			49.95 US$/bbl	
Sold put price			39.40 US$/bbl	
WTI Costless Collars	30.0 Mbbls/d	Q3 - Q4 2017		**13**
Sold call price			56.05 US$/bbl	
Bought put price			46.22 US$/bbl	
Basis Contracts (1)		2017 - 2020		**9**
Crude Oil and NGLs Fair Value Position				**155**
Natural Gas Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	405 MMcf/d	2017	3.13 US$/Mcf	**3**
NYMEX Fixed Price	650 MMcf/d	2018	3.07 US$/Mcf	**19**
NYMEX Three-Way Options	300 MMcf/d	2017		**(8)**
Sold call price			3.07 US$/Mcf	
Bought put price			2.75 US$/Mcf	
Sold put price			2.27 US$/Mcf	
NYMEX Costless Collars	160 MMcf/d	2017		**2**
Sold call price			3.57 US$/Mcf	
Bought put price			2.96 US$/Mcf	
NYMEX Call Options				
Sold call price	230 MMcf/d	2018	3.75 US$/Mcf	**(10)**
Sold call price	230 MMcf/d	2019	3.75 US$/Mcf	**(11)**
Basis Contracts (2)		2017 - 2023		**50**
Natural Gas Fair Value Position				**45**
Other Derivative Contracts				
Fair Value Position				**(16)**
Foreign Currency Contracts				
Fair Value Position (3)		2017-2018		**25**
Total Fair Value Position				**$ 209**

(1) Encana has entered into swaps to protect against widening Midland and Edmonton Condensate differentials to WTI.
(2) Encana has entered into swaps to protect against widening natural gas price differentials between benchmark and regional sales prices.
(3) Encana has entered into U.S. dollar denominated fixed-for-floating average currency swaps to protect against widening fluctuations between the Canadian and U.S. dollars.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	**2017**	2016
Realized Gains (Losses) on Risk Management				
Commodity and Other Derivatives:				
Revenues [1]	**$ 19**	$ 127	**$ (5)**	$ 304
Transportation and processing	**-**	2	**(4)**	(4)
Foreign Currency Derivatives:				
Foreign exchange	**(2)**	-	**(1)**	-
	$ 17	$ 129	**$ (10)**	$ 300
Unrealized Gains (Losses) on Risk Management				
Commodity and Other Derivatives:				
Revenues [2]	**$ 110**	$ (457)	**$ 472**	$ (511)
Transportation and processing	**-**	6	**-**	5
Foreign Currency Derivatives:				
Foreign exchange	**24**	-	**26**	-
	$ 134	$ (451)	**$ 498**	$ (506)
Total Realized and Unrealized Gains (Losses) on Risk Management, net				
Commodity and Other Derivatives:				
Revenues [1] [2]	**$ 129**	$ (330)	**$ 467**	$ (207)
Transportation and processing	**-**	8	**(4)**	1
Foreign Currency Derivatives:				
Foreign exchange	**22**	-	**25**	-
	$ 151	$ (322)	**$ 488**	$ (206)

(1) Includes realized gains of $1 million and $3 million for the three and six months ended June 30, 2017, respectively, (2016 - gains of $2 million and $3 million, respectively) related to other derivative contracts.

(2) Includes unrealized losses of $1 million for the three and six months ended June 30, 2017 (2016 – nil and nil, respectively) related to other derivative contracts.

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

	2017		2016
	Fair Value	**Total Unrealized Gain (Loss)**	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	**$ (292)**		
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Period	**488**	**$ 488**	$ (206)
Settlement of Other Derivative Contracts	**3**		
Fair Value of Contracts Realized During the Period	**10**	**10**	(300)
Fair Value of Contracts, End of Period	**$ 209**	**$ 498**	$ (506)

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.

Unrealized Risk Management Positions

		As at June 30, 2017		As at December 31, 2016
Risk Management Assets				
Current	**$**	**145**	$	-
Long-term		**135**		16
		280		16
Risk Management Liabilities				
Current		**42**		254
Long-term		**13**		35
		55		289
Other Derivative Contracts				
Current in accounts payable and accrued liabilities		**5**		5
Long-term in other liabilities and provisions		**11**		14
Net Risk Management Assets (Liabilities) and Other Derivative Contracts	**$**	**209**	$	(292)

C) Credit Risk

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. While exchange-traded contracts are subject to nominal credit risk due to the financial safeguards established by the New York Stock Exchange and Toronto Stock Exchange, over-the-counter traded contracts expose Encana to counterparty credit risk. This credit risk exposure is mitigated through the use of credit policies approved by the Board of Directors governing the Company's credit portfolio including credit practices that limit transactions according to counterparties' credit quality. Mitigation strategies may include master netting arrangements, requesting collateral and/or transacting credit derivatives. The Company executes commodity derivative financial instruments under master agreements that have netting provisions that provide for offsetting payables against receivables. As at June 30, 2017, the Company had no significant credit derivatives in place and held no collateral.

As at June 30, 2017, cash equivalents include high-grade, short-term securities, placed primarily with financial institutions and companies with strong investment grade ratings. Any foreign currency agreements entered into are with major financial institutions that have investment grade credit ratings.

A substantial portion of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. As at June 30, 2017, approximately 92 percent (90 percent as at December 31, 2016) of Encana's accounts receivable and financial derivative credit exposures were with investment grade counterparties.

As at June 30, 2017, 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, 2017, these counterparties accounted for 16 percent, 13 percent, 12 percent and 10 percent of the fair value of the outstanding in-the-money net risk management contracts. As at December 31, 2016, Encana had one counterparty whose net settlement position accounted for 84 percent of the fair value of the outstanding in-the-money net risk management contracts.

During 2015, 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 include 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 four to seven years with a fair value recognized of $16 million as at June 30, 2017 ($19 million as at December 31, 2016). The maximum potential amount of undiscounted future payments is $315 million as at June 30, 2017, and is considered unlikely.

20. Supplementary Information

Supplemental disclosures to the Condensed Consolidated Statement of Cash Flows are presented below:

A) Net Change in Non-Cash Working Capital

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	**2017**	2016
Operating Activities				
Accounts receivable and accrued revenues	**$ 33**	$ (19)	**$ 103**	$ 126
Accounts payable and accrued liabilities	**(37)**	(64)	**(171)**	(191)
Income tax receivable and payable	**(125)**	(11)	**(221)**	30
	$ (129)	$ (94)	**$ (289)**	$ (35)

B) Non-Cash Activities

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	**2017**	2016
Non-Cash Investing Activities				
Asset retirement obligation incurred (See Note 11)	**$ 3**	$ 1	**$ 6**	$ 4
Property, plant and equipment accruals	**34**	(66)	**78**	(53)
Capitalized long-term incentives (See Note 16)	**(11)**	9	**-**	10
Property additions/dispositions	**159**	54	**165**	55
Non-Cash Financing Activities				
Common shares issued under dividend reinvestment plan (See Note 12)	**$ -**	$ 1	**$ -**	$ 1

21. Commitments and Contingencies

Commitments

The following table outlines the Company's commitments as at June 30, 2017:

	Expected Future Payments						
(undiscounted)	2017	2018	2019	2020	2021	Thereafter	Total
Transportation and Processing	$ 257	$ 555	$ 623	$ 604	$ 480	$ 2,762	**$ 5,281**
Drilling and Field Services	129	69	34	19	7	-	**258**
Operating Leases	10	19	18	16	17	76	**156**
Total	$ 396	$ 643	$ 675	$ 639	$ 504	$ 2,838	**$ 5,695**

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 normal course of the Company's operations. Although the outcome of these claims cannot be predicted with certainty, the Company does not expect these matters to have a material adverse effect on Encana's financial position, cash flows or results of operations. Management's assessment of these matters may change in the future as certain of these matters are in early stages or are subject to a number of uncertainties. For material matters that the Company believes an unfavourable outcome is reasonably possible, the Company discloses the nature and a range of potential exposures. If an unfavourable outcome were to occur, there exists the possibility of a material impact on the

Company's consolidated net earnings or loss for the period in which the effect becomes reasonably estimable. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. Such accruals are based on the Company's information known about the matters, estimates of the outcomes of such matters and experience in handling similar matters.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The MD&A is intended to provide a narrative description of Encana's business from management's perspective. This MD&A should be read in conjunction with the unaudited interim Condensed Consolidated Financial Statements and accompanying notes for the period ended June 30, 2017 ("Consolidated Financial Statements"), which are included in Part I, Item 1 of this Quarterly Report on Form 10-Q and the audited Consolidated Financial Statements and accompanying notes and MD&A for the year ended December 31, 2016, which are included in Items 8 and 7, respectively, of the 2016 Annual Report on Form 10-K. Common industry terms and abbreviations are used throughout this MD&A and are defined in the Definitions, Conversions and Conventions sections of this Quarterly Report on Form 10-Q. This MD&A includes the following sections:

Executive Overview

Strategy

Encana is a leading North American energy producer that is focused on developing its multi-basin portfolio of oil, NGL and natural gas producing plays. Encana 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 exercising a disciplined capital allocation strategy by investing in a limited number of core assets, growing high margin liquids volumes, maximizing profitability through operating efficiencies and reducing costs, and preserving balance sheet strength.

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

Encana continually reviews and evaluates its strategy and changing market conditions. In 2017, Encana continues to focus on quality growth from high margin, scalable projects located in some of the best plays in North America, referred to as the "Core Assets", comprising Montney and Duvernay in Canada and Eagle Ford and Permian in the U.S. These world-class assets form a multi-basin portfolio enabling flexible and efficient investment of capital. The Company rapidly deploys successful ideas and practices across these assets, becoming more efficient as innovative and sustainable technical improvements are implemented.

For additional information on Encana's strategy, its reporting segments and the plays in which the Company operates, refer to Items 1 and 2 of the 2016 Annual Report on Form 10-K. In evaluating its operations, the Company reviews performance-based measures such as Non-GAAP Cash Flow and Corporate Margin, which are non-GAAP measures and do not have any standardized meaning under U.S. GAAP. These measures may not be similar to measures presented by other issuers and should not be viewed as a substitute for measures reported under U.S. GAAP. Further information regarding these measures, including reconciliations to the closest GAAP measure, can be found in the Non-GAAP Measures section of this MD&A.

Highlights

During the first six months of 2017, Encana focused on executing its 2017 capital plan, maintaining operational efficiencies achieved in 2016 and seeking new ways to reduce costs. Higher benchmark prices in the first six months of 2017 compared to 2016 contributed to increases in Encana's average realized oil, NGLs and natural gas prices which resulted in higher revenues. In the first six months of 2017, Encana's average realized oil, NGLs and natural gas prices increased by 40 percent, 62 percent and 71 percent, respectively, compared to 2016. Encana remains committed to building a business model that allows the Company to adapt to fluctuating commodity prices.

Significant Developments

- Announced an agreement with Caerus Oil and Gas LLC on June 9, 2017 to sell the Company's Piceance natural gas assets, which include approximately 550,000 net acres of leasehold and 3,100 operated wells in northwestern Colorado for total cash consideration of approximately $735 million. The transaction is expected to close in the third quarter of 2017 and is subject to satisfaction of normal closing conditions, regulatory approvals, closing and other adjustments. Based on an effective date of January 1, 2017, Encana expects to reduce its midstream commitments by approximately $430 million (undiscounted).

Financial Results

Three months ended June 30, 2017

- Reported net earnings of $331 million, including a before-tax amount for net gains on risk management of $129 million in revenues.
- Generated cash from operating activities of $218 million and Non-GAAP Cash Flow of $351 million.
- Achieved Corporate Margin of $12.19 per BOE.
- Recovered current taxes of approximately $18 million and interest of $13 million, as well as received interest income of $26 million primarily resulting from the successful resolution of certain tax items previously assessed.
- Paid dividends of $0.015 per common share.

Six months ended June 30, 2017

- Reported net earnings of $762 million, including a before-tax amount for net gains on risk management of $467 million in revenues.
- Generated cash from operating activities of $324 million and Non-GAAP Cash Flow of $629 million.
- Achieved Corporate Margin of $10.96 per BOE.
- Recovered current taxes of approximately $57 million and interest of $17 million, as well as received interest income of $33 million primarily resulting from the successful resolution of certain tax items previously assessed.
- Paid dividends of $0.03 per common share.
- Held cash and cash equivalents of $395 million and had available credit facilities of $4.5 billion for total liquidity of $4.9 billion at June 30, 2017.

Capital Investment

- Directed $393 million, or 95 percent, of total capital spending to the Core Assets in the second quarter of 2017 and $783 million, or 96 percent, during the first six months of 2017.
- Focused on highly efficient capital activity and short-cycle high margin projects providing flexibility to respond to fluctuations in commodity prices.

Production

Three months ended June 30, 2017

- Produced average oil and NGL volumes of 124.9 Mbbls/d which accounted for 40 percent of total production volumes. Average oil and plant condensate production volumes of 100.2 Mbbls/d were 80 percent of total liquids production volumes.
- Produced average natural gas volumes of 1,146 MMcf/d which accounted for 60 percent of total production volumes.
- Reported Core Assets production of 246.5 MBOE/d, or 78 percent of total production volumes.

Six months ended June 30, 2017

- Produced average oil and NGL volumes of 118.0 Mbbls/d which accounted for 37 percent of total production volumes. Average oil and plant condensate production volumes of 94.1 Mbbls/d were 80 percent of total liquids production volumes.
- Produced average natural gas volumes of 1,194 MMcf/d which accounted for 63 percent of total production volumes.
- Reported Core Assets production of 242.0 MBOE/d, or 76 percent of total production volumes.

Operating Expenses

- Continued to benefit from operational efficiencies achieved in 2016, which contributed to further cost savings improvements.
- Reduced transportation and processing expense in the second quarter and first six months of 2017 by $38 million, or 16 percent, and $95 million, or 19 percent, respectively, compared to 2016.
- Reduced operating expense, excluding long-term incentive costs, in the second quarter and first six months of 2017 by $3 million, or 2 percent, and $43 million, or 15 percent, respectively, compared to 2016.

2017 Outlook

Industry Outlook

The oil and gas industry is cyclical and commodity prices are inherently volatile. Oil prices during the second half of 2017 are expected to reflect global supply and demand dynamics as well as the geopolitical environment. At a meeting in May, OPEC decided to extend an agreement among members and certain non-OPEC countries to cut crude oil production until the end of the first quarter of 2018. The agreement, which was implemented in January 2017, has been generally supportive of oil prices in early 2017; however, production growth in other countries continues to partially offset the expected benefit of the OPEC agreement. In addition, rapid increases in U.S. crude oil production or the continuation of elevated levels of U.S. oil storage inventories could also negatively impact prices.

Natural gas prices were stronger in the first half of 2017 compared to 2016 as increases in exports and industrial demand coupled with lower natural gas production alleviated much of the oversupply. After declining in 2016, natural gas production in the contiguous U.S. is expected to grow as pipeline infrastructure additions in the U.S. Northeast alleviate bottlenecks in the region. Continued improvement in prices through 2018 depends on the timing of supply and demand growth; however, incremental natural gas production is expected to be sufficient to supply continued demand growth and support natural gas prices at relatively stronger levels than 2016.

Company Outlook

Encana has positioned itself to be flexible and to continue to achieve strong returns from the Core Assets through this evolving commodity price cycle. The Company released updated Corporate Guidance on July 21, 2017 to reflect the impact of divestitures and improved operational performance which included changes to liquids and natural gas production volumes, upstream operating expense, transportation and processing expense and production growth from the Core Assets compared to Corporate Guidance previously released in February 2017. The details of Encana's Corporate Guidance can be accessed on the Company's website at www.encana.com.

Encana enters into commodity derivative financial instruments on a portion of its expected oil, NGL and natural gas production volumes to reduce volatility and help sustain revenues during periods of lower prices. As of June 30, 2017, Encana's 2017 commodity price mitigation program covers over 75 percent of expected total production for the remainder of the year.

Capital Investment

Encana is on track to meet its full year capital investment guidance of $1.6 billion to $1.8 billion. During the first six months of 2017, the Company spent $814 million, of which 96 percent was invested in the Core Assets with 52 percent directed to Permian where the Company has drilled 64 net wells. Encana continually strives to improve well performance by lowering drilling and completion costs through innovative techniques such as the cube development model, characterized as a multi-well pad centralized development on a stacked pay resource. This approach, which is currently being applied in Permian and Montney, is helping to boost productivity and enhance recovery from reservoirs in those assets.

Production

During the first six months of 2017, average liquids production volumes of 118.0 Mbbls/d were below the updated full year guidance range of 127.0 Mbbls/d to 132.0 Mbbls/d as expected. The Company is on track to meet the updated full year liquids production guidance primarily due to growing Permian oil volumes and liquids volumes in Montney with the anticipated completion of new facilities in Montney. Average natural gas production volumes of 1,194 MMcf/d exceeded the updated full year 2017 guidance range of 1,075 MMcf/d to 1,125 MMcf/d; Encana expects to be within the updated full year 2017 guidance range after the Piceance asset sale closes in the third quarter of 2017.

Core Assets production of 242.0 MBOE/d was up slightly compared to the fourth quarter of 2016 and is expected to grow as Encana sees the anticipated benefit of its increased capital program with additional wells coming online and the anticipated completion of new facilities in Montney. Total liquids production accounted for 37 percent of the Company's total production volumes, with the Core Assets contributing 111.0 Mbbls/d or 94 percent.

Operating Expenses

To date, efficiency improvements and lower service costs have been maintained and the Company continues to benefit from transportation contract renegotiations completed in 2016. The Company reported operating costs for the first six months of 2017 which are on track to meet the updated full year 2017 guidance ranges. Transportation and processing expense was $6.53 per BOE, while upstream operating expense and administrative expense, excluding long-term incentive costs, were $3.79 per BOE and $1.56 per BOE, respectively. Encana continues to offset any inflationary pressures with additional efficiency gains.

Results of Operations

Selected Financial Information

($ millions)	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Product Revenues	**$ 728**	$ 578	**$ 1,466**	$ 1,097
Gains (Losses) on Risk Management, net	**129**	(330)	**467**	(207)
Market Optimization	**204**	91	**390**	178
Other	**22**	25	**49**	49
Total Revenues	**1,083**	364	**2,372**	1,117
Total Operating Expenses (1)	**762**	1,276	**1,562**	3,072
Operating Income (Loss)	**321**	(912)	**810**	(1,955)
Total Other (Income) Expenses	**(6)**	156	**49**	(207)
Net Earnings (Loss) Before Income Tax	**$ 327**	$ (1,068)	**$ 761**	$ (1,748)
Net Earnings (Loss)	**$ 331**	$ (601)	**$ 762**	$ (980)

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

Revenues

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

Benchmark Prices

(average for the period)	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Oil & NGLs				
WTI ($/bbl)	**$ 48.29**	$ 45.59	**$ 50.10**	$ 39.52
Edmonton Condensate (C$/bbl)	**64.59**	56.80	**66.87**	52.02
Natural Gas				
NYMEX ($/MMBtu)	**$ 3.18**	$ 1.95	**$ 3.25**	$ 2.02
AECO (C$/Mcf)	**2.77**	1.25	**2.86**	1.68
Algonquin City Gate ($/MMBtu)	**2.88**	2.44	**3.67**	2.86

Production Volumes and Realized Prices

	Three months ended June 30,				Six months ended June 30,			
	Production Volumes (1)		Realized Prices (2)		Production Volumes (1)		Realized Prices (2)	
	2017	2016	**2017**	2016	**2017**	2016	**2017**	2016
Oil (Mbbls/d, $/bbl)								
Canadian Operations	**0.4**	3.3	**$ 40.23**	$ 41.73	**0.4**	3.3	**$ 41.77**	$ 35.74
USA Operations	**77.0**	75.6	**46.14**	40.61	**72.0**	76.4	**47.75**	34.12
Total	**77.4**	78.9	**46.11**	40.65	**72.4**	79.7	**47.72**	34.19
NGLs – Plant Condensate (Mbbls/d, $/bbl)								
Canadian Operations	**20.5**	17.7	**46.94**	44.60	**19.6**	17.1	**48.53**	38.67
USA Operations	**2.3**	3.0	**41.07**	32.16	**2.1**	2.8	**41.86**	27.67
Total	**22.8**	20.7	**46.34**	42.82	**21.7**	19.9	**47.89**	37.14
NGLs – Other (Mbbls/d, $/bbl)								
Canadian Operations	**4.7**	9.4	**19.10**	9.42	**4.9**	9.9	**20.91**	7.48
USA Operations	**20.0**	23.0	**16.06**	11.46	**19.0**	21.9	**17.97**	10.26
Total	**24.7**	32.4	**16.65**	10.87	**23.9**	31.8	**18.57**	9.40
Total NGLs (Mbbls/d, $/bbl)								
Canadian Operations	**25.2**	27.1	**41.73**	32.38	**24.5**	27.0	**43.01**	27.21
USA Operations	**22.3**	26.0	**18.68**	13.82	**21.1**	24.7	**20.34**	12.21
Total	**47.5**	53.1	**30.93**	23.29	**45.6**	51.7	**32.54**	20.05
Total Oil & NGLs (Mbbls/d, $/bbl)								
Canadian Operations	**25.6**	30.4	**41.71**	33.40	**24.9**	30.3	**43.00**	28.13
USA Operations	**99.3**	101.6	**40.00**	33.76	**93.1**	101.1	**41.55**	28.77
Total	**124.9**	132.0	**40.35**	33.67	**118.0**	131.4	**41.86**	28.63
Natural Gas (MMcf/d, $/Mcf)								
Canadian Operations	**785**	971	**2.33**	1.18	**835**	1,018	**2.43**	1.43
USA Operations	**361**	447	**3.09**	1.74	**359**	448	**3.16**	1.81
Total	**1,146**	1,418	**2.57**	1.35	**1,194**	1,466	**2.65**	1.55
Total Production (MBOE/d, $/BOE)								
Canadian Operations	**156.6**	192.2	**18.52**	11.23	**164.1**	200.0	**18.89**	11.55
USA Operations	**159.4**	176.1	**31.92**	23.89	**152.8**	175.8	**32.71**	21.16
Total	**316.0**	368.3	**25.29**	17.29	**316.9**	375.8	**25.55**	16.05
Production Mix (%)								
Oil & Plant Condensate	**32**	27			**30**	27		
NGLs – Other	**8**	9			**7**	8		
Total Oil & NGLs	**40**	36			**37**	35		
Natural Gas	**60**	64			**63**	65		
Core Assets Production								
Oil (Mbbls/d)	**73.6**	67.2			**67.9**	66.8		
NGLs – Plant Condensate (Mbbls/d)	**22.4**	19.2			**21.1**	18.5		
NGLs – Other (Mbbls/d)	**22.8**	25.3			**22.0**	24.5		
Total NGLs (Mbbls/d)	**45.2**	44.5			**43.1**	43.0		
Total Oil & NGLs (Mbbls/d)	**118.8**	111.7			**111.0**	109.8		
Natural Gas (MMcf/d)	**768**	940			**786**	952		
Total Production (MBOE/d)	**246.5**	268.3			**242.0**	268.7		
% of Total Encana Production	**78**	73			**76**	72		

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

Product Revenues

($ millions)	Three months ended June 30, Oil	NGLs [1]	Natural Gas	Total	Six months ended June 30, Oil	NGLs [1]	Natural Gas	Total
2016 Product Revenues	**$ 292**	**$ 113**	**$ 173**	**$ 578**	**$ 495**	**$ 189**	**$ 413**	**$ 1,097**
Increase (decrease) due to:								
Sales prices	38	32	127	197	179	101	236	516
Production volumes	(5)	(10)	(32)	(47)	(49)	(21)	(77)	(147)
2017 Product Revenues	**$ 325**	**$ 135**	**$ 268**	**$ 728**	**$ 625**	**$ 269**	**$ 572**	**$ 1,466**

(1) Includes plant condensate.

Oil Revenues

Three months ended June 30, 2017 versus June 30, 2016

Oil revenues increased $33 million compared to the second quarter of 2016 primarily due to:

- Higher average realized oil prices of $5.46 per bbl, or 13 percent, increased revenues by $38 million. The increase reflected a higher WTI benchmark price which was up six percent. The increase was also due to higher utilization of pipelines to transport oil to more favourable markets to receive a higher net price, as well as improved regional pricing in the USA Operations;

partially offset by:

- Lower average oil production volumes of 1.5 Mbbls/d decreased revenues by $5 million. Lower volumes were primarily due to the sales of the DJ Basin (4.9 Mbbls/d) and Gordondale assets (2.4 Mbbls/d) in the third quarter of 2016, natural declines primarily in the USA Other Upstream Operations (1.6 Mbbls/d) and the sale of the Tuscaloosa Marine Shale assets in the second quarter of 2017 (1.3 Mbbls/d), partially offset by successful drilling programs in Permian (8.5 Mbbls/d) and Eagle Ford (1.1 Mbbls/d).

Six months ended June 30, 2017 versus June 30, 2016

Oil revenues increased $130 million compared to the first six months of 2016 primarily due to:

- Higher average realized oil prices of $13.53 per bbl, or 40 percent, increased revenues by $179 million. The increase reflected a higher WTI benchmark price which was up 27 percent. The increase was also due to higher utilization of pipelines to transport oil to more favourable markets to receive a higher net price, as well as improved regional pricing in the USA Operations;

partially offset by:

- Lower average oil production volumes of 7.3 Mbbls/d decreased revenues by $49 million. Lower volumes were primarily due to the sales of the DJ Basin (4.9 Mbbls/d) and Gordondale assets (2.4 Mbbls/d) in the third quarter of 2016, natural declines in Eagle Ford (4.1 Mbbls/d) and in the USA Other Upstream Operations (2.7 Mbbls/d), as well as the sale of the Tuscaloosa Marine Shale assets in the second quarter of 2017 (1.0 Mbbls/d), partially offset by a successful drilling program in Permian (8.1 Mbbls/d).

NGL Revenues

Three months ended June 30, 2017 versus June 30, 2016

NGL revenues increased $22 million compared to the second quarter of 2016 primarily due to:

- Higher average realized NGL prices of $7.64 per bbl, or 33 percent, increased revenues by $32 million. The increase reflected higher WTI and Edmonton Condensate benchmark prices which were up six percent and 14 percent, respectively. The increase was also due to a shift in the NGL production mix to higher value condensate compared to 2016;

partially offset by:

- Lower average NGL production volumes of 5.6 Mbbls/d decreased revenues by $10 million. Lower volumes were primarily due to the sales of the Gordondale (5.7 Mbbls/d) and DJ Basin assets (4.9 Mbbls/d) in the third quarter of 2016, partially offset by successful drilling programs in the Core Assets (6.6 Mbbls/d).

Six months ended June 30, 2017 versus June 30, 2016

NGL revenues increased $80 million compared to the first six months of 2016 primarily due to:

- Higher average realized NGL prices of $12.49 per bbl, or 62 percent, increased revenues by $101 million. The increase reflected higher WTI and Edmonton Condensate benchmark prices which were up 27 percent and 29 percent, respectively. The increase was also due to a shift in the NGL production mix to higher value condensate compared to 2016;

partially offset by:

- Lower average NGL production volumes of 6.1 Mbbls/d decreased revenues by $21 million. Lower volumes were primarily due to the sales of the Gordondale (5.7 Mbbls/d) and DJ Basin assets (4.9 Mbbls/d) in the third quarter of 2016, partially offset by successful drilling programs in the Core Assets (6.1 Mbbls/d).

Natural Gas Revenues

Three months ended June 30, 2017 versus June 30, 2016

Natural gas revenues increased $95 million compared to the second quarter of 2016 primarily due to:

- Higher average realized natural gas prices of $1.22 per Mcf, or 90 percent, increased revenues by $127 million. The increase reflected higher NYMEX, AECO and Algonquin City Gate benchmark prices which were up 63 percent, 122 percent and 18 percent, respectively;

partially offset by:

- Lower average natural gas production volumes of 272 MMcf/d decreased revenues by $32 million. Lower volumes were primarily due to the sales of the Gordondale (79 MMcf/d) and DJ Basin assets (47 MMcf/d) in the third quarter of 2016, increased downtime resulting from scheduled third-party plant maintenance in Montney (74 MMcf/d), natural declines in Other Upstream Operations (55 MMcf/d) and lower natural gas volumes in Montney due to natural declines and Encana’s focus on liquids rich wells in the play (25 MMcf/d).

Six months ended June 30, 2017 versus June 30, 2016

Natural gas revenues increased $159 million compared to the first six months of 2016 primarily due to:

- Higher average realized natural gas prices of $1.10 per Mcf, or 71 percent, increased revenues by $236 million. The increase reflected higher NYMEX, AECO and Algonquin City Gate benchmark prices which were up 61 percent, 70 percent and 28 percent, respectively;

partially offset by:

- Lower average natural gas production volumes of 272 MMcf/d decreased revenues by $77 million. Lower volumes were primarily due to the sales of the Gordondale (79 MMcf/d) and DJ Basin assets (47 MMcf/d) in the third quarter of 2016, lower natural gas volumes in Montney due to natural declines and Encana's focus on liquids rich wells in the play (60 MMcf/d), natural declines in Other Upstream Operations (49 MMcf/d) and increased downtime resulting from scheduled third-party plant maintenance in Montney (36 MMcf/d).

Gains (Losses) on Risk Management, Net

As a means of managing commodity price volatility, Encana enters into commodity derivative financial instruments on a portion of its expected oil, NGL and natural gas production volumes. The Company's commodity price mitigation program reduces volatility and helps sustain revenues during periods of lower prices. Further information on the Company's commodity price positions as at June 30, 2017 can be found in Note 19 to the Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q.

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

	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2017**	2016	**2017**	2016
Realized Gains (Losses) on Risk Management				
Commodity Price				
Oil	**$ 16**	$ 58	**$ 16**	$ 172
NGLs [1]	**2**	-	**1**	-
Natural Gas	**-**	66	**(25)**	128
Other [2]	**1**	3	**3**	4
Total	**19**	127	**(5)**	304
Unrealized Gains (Losses) on Risk Management	**110**	(457)	**472**	(511)
Total Gains (Losses) on Risk Management, Net	**$ 129**	$ (330)	**$ 467**	$ (207)

	Three months ended June 30,		Six months ended June 30,	
(Per-unit)	**2017**	2016	**2017**	2016
Realized Gains (Losses) on Risk Management				
Commodity Price				
Oil ($/bbl)	**$ 2.16**	$ 8.00	**$ 1.19**	$ 11.80
NGLs [1] ($/bbl)	**$ 0.73**	$ 0.05	**$ 0.19**	$ 0.02
Natural Gas ($/Mcf)	**$ (0.01)**	$ 0.51	**$ (0.12)**	$ 0.48
Total ($/BOE)	**$ 0.62**	$ 3.69	**$ (0.14)**	$ 4.38

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

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

Market Optimization Revenues

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

($ millions)	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Market Optimization	**$ 204**	$ 91	**$ 390**	$ 178

Three months ended June 30, 2017 versus June 30, 2016

Market Optimization revenues increased $113 million compared to the second quarter of 2016 primarily due to:

- Higher commodity prices ($73 million) and higher sales of third-party purchased volumes used for optimization activities ($40 million).

Six months ended June 30, 2017 versus June 30, 2016

Market Optimization revenues increased $212 million compared to the first six months of 2016 primarily due to:

- Higher commodity prices ($127 million) and higher sales of third-party purchased volumes used for optimization activities ($85 million).

Other Revenues

Other Revenues primarily includes amounts related to the sublease of office space in The Bow office building recorded in the Corporate and Other segment, as well as third party transportation and processing revenues with no associated volumes recorded in the Canadian and USA Operations segments. Further information on The Bow office sublease can be found in Note 10 to the Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q.

Operating Expenses

Production, Mineral and Other Taxes

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

($ millions)	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Canadian Operations	**$ 5**	$ 6	**$ 10**	$ 12
USA Operations	**19**	24	**43**	41
Total	**$ 24**	$ 30	**$ 53**	$ 53

($/BOE)	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Canadian Operations	**$ 0.39**	$ 0.36	**$ 0.34**	$ 0.33
USA Operations	**$ 1.29**	$ 1.48	**$ 1.55**	$ 1.27
Total	**$ 0.85**	$ 0.89	**$ 0.93**	$ 0.77

Three months ended June 30, 2017 versus June 30, 2016

Production, mineral and other taxes decreased $6 million compared to the second quarter of 2016 primarily due to:

- The recovery of certain production taxes in the USA Operations ($10 million) and the sales of the DJ Basin and Gordondale assets in the third quarter of 2016 ($2 million);

partially offset by:

- Higher commodity prices in the USA Operations and higher oil production volumes in Permian and Eagle Ford ($6 million).

Six months ended June 30, 2017 versus June 30, 2016

Production, mineral and other taxes were flat compared to the first six months of 2016 and were impacted by:

- Higher commodity prices in the USA Operations and higher oil production volumes in Permian ($14 million);

partially offset by:

- The recovery of certain production taxes in the USA Operations ($9 million) and the sales of the DJ Basin and Gordondale assets in the third quarter of 2016 ($4 million).

Transportation and Processing

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

($ millions)	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Canadian Operations	**$ 133**	$ 155	**$ 265**	$ 304
USA Operations	**51**	73	**110**	171
Upstream Transportation and Processing	**184**	228	**375**	475
Market Optimization	**22**	22	**43**	43
Corporate & Other	**-**	(6)	**-**	(5)
Total	**$ 206**	$ 244	**$ 418**	$ 513

($/BOE)	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Canadian Operations	**$ 9.30**	$ 8.85	**$ 8.91**	$ 8.34
USA Operations	**$ 3.54**	$ 4.56	**$ 3.97**	$ 5.34
Upstream Transportation and Processing	**$ 6.39**	$ 6.80	**$ 6.53**	$ 6.94

Three months ended June 30, 2017 versus June 30, 2016

Transportation and processing expense decreased $38 million compared to the second quarter of 2016 primarily due to:

- The sales of the Gordondale and DJ Basin assets in the third quarter of 2016 ($26 million), the renegotiation and expiration of certain transportation contracts ($14 million), and the lower U.S./Canadian dollar exchange rate ($7 million);

partially offset by:

- Higher volumes and prices in Permian ($6 million) and increased downstream processing costs in Montney due to Encana’s focus on liquids rich wells in the play ($3 million).

Six months ended June 30, 2017 versus June 30, 2016

Transportation and processing expense decreased $95 million compared to the first six months of 2016 primarily due to:

- The sales of the Gordondale and DJ Basin assets in the third quarter of 2016 ($48 million), the renegotiation and expiration of certain transportation contracts ($44 million) and lower gas gathering and processing fees in Montney, Duvernay and Other Upstream Operations ($17 million);

partially offset by:

- Higher volumes and prices in Permian ($12 million) and increased downstream processing costs in Montney and Duvernay due to Encana's focus on liquids rich wells in the plays ($8 million).

Operating

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

	Three months ended June 30,				Six months ended June 30,			
($ millions)		**2017**		2016		**2017**		2016
Canadian Operations	**$**	**22**	$	37	**$**	**53**	$	77
USA Operations		**84**		87		**171**		200
Upstream Operating Expense		**106**		124		**224**		277
Market Optimization		**3**		6		**12**		14
Corporate & Other		**4**		5		**9**		10
Total	**$**	**113**	$	135	**$**	**245**	$	301

	Three months ended June 30,				Six months ended June 30,			
($/BOE)		**2017**		2016		**2017**		2016
Canadian Operations	**$**	**1.52**	$	2.08	**$**	**1.73**	$	2.06
USA Operations	**$**	**5.60**	$	5.34	**$**	**5.99**	$	6.20
Upstream Operating Expense (1)	**$**	**3.58**	$	3.63	**$**	**3.78**	$	4.00

(1) Upstream Operating Expense per BOE for the second quarter and the first six months of 2017 includes a recovery of long-term incentive costs of $0.18/BOE and $0.01/BOE, respectively (2016 – long-term incentive costs of $0.27/BOE and $0.15/BOE, respectively).

Three months ended June 30, 2017 versus June 30, 2016

Operating expense decreased $22 million compared to the second quarter of 2016 primarily due to:

- Lower long-term incentive costs resulting from the decrease in Encana's share price in the second quarter of 2017 ($19 million), asset sales which primarily included the sales of the DJ Basin and Gordondale assets in the third quarter of 2016 ($12 million), lower salaries and benefits due to a lower headcount ($8 million) and cost-savings initiatives ($4 million);

partially offset by:

- Higher activity in Permian and Eagle Ford ($17 million).

Six months ended June 30, 2017 versus June 30, 2016

Operating expense decreased $56 million compared to the first six months of 2016 primarily due to:

- Asset sales which primarily included the sales of the DJ Basin and Gordondale assets in the third quarter of 2016 ($21 million), cost-saving initiatives ($20 million), lower salaries and benefits due to a lower headcount ($18 million) and lower long-term incentive costs resulting from the decrease in Encana's share price in the first six months of 2017 ($13 million);

partially offset by:

- Higher activity in Permian and Eagle Ford ($18 million).

Further information on Encana's long-term incentives can be found in Note 16 to the Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q.

Purchased Product

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

	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2017**	2016	**2017**	2016
Market Optimization	**$ 192**	$ 79	**$ 363**	$ 152

Three months ended June 30, 2017 versus June 30, 2016

Purchased product expense increased $113 million compared to the second quarter of 2016 primarily due to:

- Higher commodity prices ($70 million) and higher third-party volumes purchased for optimization activities ($43 million).

Six months ended June 30, 2017 versus June 30, 2016

Purchased product expense increased $211 million compared to the first six months of 2016 primarily due to:

- Higher commodity prices ($122 million) and higher third-party volumes purchased for optimization activities ($89 million).

Depreciation, Depletion & Amortization

Proved properties within each country cost centre are depleted using the unit-of-production method based on proved reserves as discussed in Note 1 to the Consolidated Financial Statements included in Item 8 of the 2016 Annual Report on Form 10-K. Depletion rates are impacted by impairments, acquisitions, divestitures and foreign exchange rates as well as fluctuations in 12-month average trailing prices which affect proved reserves volumes. For additional information on Critical Accounting Estimates, refer to the MD&A included in Item 7 of the 2016 Annual Report on Form 10-K. Corporate assets are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets.

	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2017**	2016	**2017**	2016
Canadian Operations	**$ 53**	$ 67	**$ 117**	$ 149
USA Operations	**123**	143	**229**	302
Upstream DD&A	**176**	210	**346**	451
Corporate & Other	**17**	20	**34**	40
Total	**$ 193**	$ 230	**$ 380**	$ 491

	Three months ended June 30,		Six months ended June 30,	
($/BOE)	**2017**	2016	**2017**	2016
Canadian Operations	**$ 3.72**	$ 3.87	**$ 3.92**	$ 4.10
USA Operations	**$ 8.47**	$ 8.90	**$ 8.29**	$ 9.44
Upstream DD&A	**$ 6.12**	$ 6.28	**$ 6.02**	$ 6.60

Three months ended June 30, 2017 versus June 30, 2016

DD&A decreased $37 million compared to the second quarter of 2016 primarily due to:

- Lower production volumes ($22 million) and depletion rates ($9 million) in the Canadian and USA Operations.

The depletion rate decreased $0.16 per BOE compared to the second quarter of 2016 primarily due to:

- Ceiling test impairments recognized in the first six months of 2016 in the Canadian and USA Operations and the sale of the DJ Basin assets in the third quarter of 2016.

Six months ended June 30, 2017 versus June 30, 2016

DD&A decreased $111 million compared to the first six months of 2016 primarily due to:

- Lower production volumes ($64 million) and depletion rates ($42 million) in the Canadian and USA Operations.

The depletion rate decreased $0.58 per BOE compared to the first six months of 2016 primarily due to:

- Ceiling test impairments recognized in the first six months of 2016 in the Canadian and USA Operations and the sale of the DJ Basin assets in the third quarter of 2016.

Impairments

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

	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2017**	2016	**2017**	2016
Canadian Operations	**$ -**	$ 226	**$ -**	$ 493
USA Operations	**-**	258	**-**	903
Total	**$ -**	$ 484	**$ -**	$ 1,396

Ceiling test impairments in the second quarter and first six months of 2016 were primarily due to the decline in the 12-month average trailing prices, which reduced the Canadian and USA Operations proved reserves volumes and values as calculated under SEC requirements.

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

	Oil & NGLs		**Natural Gas**	
	WTI ($/bbl)	Edmonton Condensate (2) (C$/bbl)	Henry Hub ($/MMBtu)	AECO (C$/MMBtu)
12-Month Average Trailing Reserves Pricing (1)				
June 30, 2017	**48.95**	**64.27**	**3.01**	**2.76**
December 31, 2016	42.75	55.39	2.49	2.17
June 30, 2016	43.12	55.63	2.24	2.14

(1) All prices were held constant in all future years when estimating net revenues and reserves.
(2) Edmonton Condensate benchmark price has replaced the previously disclosed Edmonton Light Sweet benchmark price.

The Company believes that the discounted after-tax future net cash flows from proved reserves required to be used in the ceiling test calculation are not indicative of the fair market value of Encana's oil and natural gas properties or the future net cash flows expected to be generated from such properties. The discounted after-tax future net cash flows do not consider the fair market value of unamortized unproved properties, or probable or possible liquids and natural gas reserves. In addition, there is no consideration given to the effect of future changes in commodity prices. Encana manages its business using estimates of reserves and resources based on forecast prices and costs. Additional information on the ceiling test calculation can be found in the Critical Accounting Estimates section of the MD&A included in Item 7 of the 2016 Annual Report on Form 10-K.

Administrative

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

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	**2017**	2016
Administrative ($ millions)	**$ 24**	$ 61	**$ 82**	$ 140
Administrative ($/BOE)	**$ 0.82**	$ 1.82	**$ 1.43**	$ 2.05

Administrative expense in the second quarter of 2017 decreased $37 million from 2016 primarily due to lower long-term incentive costs resulting from the decrease in Encana's share price in the second quarter of 2017 ($40 million). Administrative expense per BOE for the second quarter of 2017 includes a recovery of long-term incentive costs of $0.79/BOE compared to long-term incentive costs of $0.55/BOE in 2016.

Administrative expense in the first six months of 2017 decreased $58 million from 2016 primarily due to lower restructuring costs ($31 million) and lower long-term incentive costs resulting from the decrease in Encana's share price in the first six months of 2017 ($30 million). Administrative expense per BOE for the first six months of 2017 includes a recovery of long-term incentive costs of $0.13/BOE compared to long-term incentive costs and restructuring costs of $0.34/BOE and $0.46/BOE, respectively, in 2016.

During the first quarter of 2016, Encana completed workforce reductions announced in February 2016 to better align staffing levels and the organizational structure with its reduced capital spending program as a result of the low commodity price environment. Encana incurred restructuring costs of $31 million during the first six months of 2016. There were no restructuring costs in the first six months of 2017. Further information on restructuring costs can be found in Note 15 to the Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q.

Other (Income) Expenses

($ millions)	Three months ended June 30, **2017**	Three months ended June 30, 2016	Six months ended June 30, **2017**	Six months ended June 30, 2016
Interest	**$ 79**	$ 107	**$ 167**	$ 210
Foreign exchange (gain) loss, net	**(58)**	23	**(84)**	(356)
(Gain) loss on divestitures, net	**-**	2	**1**	2
Other (gains) losses, net	**(27)**	24	**(35)**	(63)
Total Other (Income) Expenses	**$ (6)**	$ 156	**$ 49**	$ (207)

Interest

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

Interest expense in the second quarter of 2017 decreased $28 million compared to 2016 primarily due to a recovery of other interest in the second quarter of 2017 compared to other interest expense in 2016 ($17 million) and lower interest on debt ($9 million).

Interest expense in the first six months of 2017 decreased $43 million compared to 2016 primarily due to lower interest on debt ($24 million) and a recovery of other interest in 2017 compared to other interest expense in 2016 ($17 million).

The recovery of other interest in the second quarter and first six months of 2017 is primarily due to the successful resolution of certain tax items previously assessed by the tax authorities relating to prior taxation years. Lower interest on debt in the second quarter and first six months of 2017 is primarily due to the early retirement of long-term debt in March 2016. Further information on the March 2016 debt retirement can be found in the Liquidity and Capital Resources section of this MD&A.

Foreign Exchange (Gain) Loss, Net

Foreign exchange gains and losses result from the impact of fluctuations in the Canadian to U.S. dollar exchange rate. In the second quarter and first six months of 2017, the average U.S./Canadian dollar foreign exchange rate was 0.744 and 0.750, respectively, compared to 0.776 and 0.752, respectively for 2016. The period end U.S./Canadian dollar foreign exchange rates as at June 30, 2017 and December 31, 2016 were 0.771 and 0.745, respectively.

In the second quarter of 2017, Encana recorded unrealized foreign exchange gains on the translation of U.S. dollar financing debt issued from Canada compared to foreign exchange losses in 2016 ($104 million), which includes an out-of-period adjustment of $68 million, before tax, in respect of cumulative unrealized losses on a foreign-denominated capital lease obligation since December 2013. Encana also recorded higher unrealized foreign exchange gains on the translation of U.S. dollar risk management contracts issued from Canada compared to 2016 ($28 million), partially offset by foreign exchange losses on the settlement of U.S. dollar financing debt issued from Canada compared to foreign exchange gains in the second quarter of 2016 ($48 million).

In the first six months of 2017, Encana recorded lower unrealized foreign exchange gains on the translation of U.S. dollar financing debt issued from Canada compared to 2016 ($199 million), which includes an out-of-period adjustment of $68 million as discussed above. Encana also recorded foreign exchange losses on the settlement of U.S. dollar financing debt issued from Canada compared to foreign exchange gains in the first six months of 2016 ($79 million), partially offset by unrealized foreign exchange gains on the translation of U.S. dollar risk management contracts issued from Canada compared to foreign exchange losses in the first six months of 2016 ($38 million).

Further information on the out-of-period adjustment can be found in Note 6 to the Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q.

Other (Gains) Losses, Net

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

Other gains in the second quarter and first six months of 2017 primarily includes interest received of $26 million and $33 million, respectively, resulting from the successful resolution of certain tax items previously assessed by the tax authorities relating to prior taxation years.

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

Income Tax

($ millions)	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Current Income Tax Expense (Recovery)	**$ (18)**	$ (12)	**$ (57)**	$ (9)
Deferred Income Tax Expense (Recovery)	**14**	(455)	**56**	(759)
Income Tax Expense (Recovery)	**$ (4)**	$ (467)	**$ (1)**	$ (768)
Effective Tax Rate	**(1.2%)**	43.7%	**(0.1%)**	43.9%

Income Tax Expense (Recovery)

Three months ended June 30, 2017 versus June 30, 2016

In the second quarter of 2017, Encana recorded a lower income tax recovery compared to 2016. The lower income tax recovery was primarily due to operating income in 2017 compared to an operating loss in 2016.

The current income tax recovery in the second quarter of 2017 was primarily due to the successful resolution of certain tax items previously assessed by the tax authorities relating to prior taxation years.

The deferred tax recovery in the second quarter of 2016 was primarily due to the recognition of ceiling test impairments.

Six months ended June 30, 2017 versus June 30, 2016

In the first six months of 2017, Encana recorded a lower income tax recovery compared to 2016. The lower income tax recovery was primarily due to operating income in 2017 compared to an operating loss in 2016 and lower foreign exchange gains.

The current income tax recovery in the first six months of 2017 was primarily due to the successful resolution of certain tax items previously assessed by the tax authorities relating to prior taxation years.

The deferred tax recovery in the first six months of 2016 was primarily due to the recognition of ceiling test impairments.

Effective Tax Rate

Encana's interim income tax expense is determined using the estimated annual effective income tax rate applied to year-to-date net earnings before income tax plus the effect of legislative changes and amounts in respect of prior periods. The estimated annual effective income tax rate is impacted by expected annual earnings, income tax related to foreign operations, non-taxable capital gains and losses, tax differences on divestitures and transactions, and partnership tax allocations in excess of funding. These items, along with the tax reassessments discussed above, resulted in an effective tax rate for the second quarter and first six months of 2017 that is lower than the Canadian statutory rate of 27 percent. The effective tax rate for the second quarter and first six months of 2016 exceeded the Canadian statutory tax rate of 27 percent primarily due to the impact of the foreign jurisdictional tax rates relative to the Canadian statutory tax rate applied to jurisdictional earnings.

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 for which the timing of resolution is uncertain. The Company believes that the provision for income taxes is adequate.

Liquidity and Capital Resources

Sources of Liquidity

The Company has the flexibility to access cash equivalents and a range of funding alternatives at competitive rates through committed revolving bank credit facilities as well as debt and equity capital markets. Encana closely monitors the accessibility of cost-effective credit and ensures that sufficient liquidity is in place to fund capital expenditures and dividend payments. In addition, the Company may use cash and cash equivalents, cash from operating activities, or proceeds from asset divestitures and share issuances to fund its operations and service debt repayments. At June 30, 2017, $158 million in cash and cash equivalents was held by U.S. subsidiaries. The cash held by U.S. subsidiaries is accessible and may be subject to additional Canadian income taxes and U.S. withholding taxes if repatriated.

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

	As at June 30,	
($ millions, except as indicated)	**2017**	2016
Cash and Cash Equivalents	**$ 395**	$ 293
Available Credit Facility – Encana (1)	**3,000**	1,507
Available Credit Facility – U.S. Subsidiary (1)	**1,500**	1,500
Total Liquidity	**4,895**	3,300
Long-Term Debt	**4,198**	5,690
Total Shareholders' Equity	**6,783**	4,907
Debt to Capitalization (%) (2)	**38**	54
Debt to Adjusted Capitalization (%) (3)	**22**	31

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

Encana is currently in compliance with, and expects that it will continue to be in compliance with, all financial covenants under the Credit Facilities. Management monitors Debt to Adjusted Capitalization, which is a non-GAAP measure defined in the Non-GAAP Measures section of this MD&A, as a proxy for Encana's financial covenant under the Credit Facilities, which requires debt to adjusted capitalization to be less than 60 percent. The definitions used in the covenant under the Credit Facilities adjust capitalization for cumulative historical ceiling test impairments that were recorded as at December 31, 2011 in conjunction with the Company's January 1, 2012 adoption of U.S. GAAP. As shown in the table above, Debt to Adjusted Capitalization as at June 30, 2017 decreased compared to 2016 as a result of Encana's efforts to strengthen its balance sheet through debt repayments. Additional information on financial covenants can be found in Note 13 to the Consolidated Financial Statements included in Item 8 of the 2016 Annual Report on Form 10-K.

Sources and Uses of Cash

In the second quarter and first six months of 2017, Encana primarily generated cash through operating activities. The following table summarizes the sources and uses of the Company's cash and cash equivalents.

		Three months ended June 30,		Six months ended June 30,	
($ millions)	Activity Type	**2017**	2016	**2017**	2016
Sources of Cash and Cash Equivalents					
Cash from operating activities	Operating	**$ 218**	$ 83	**$ 324**	$ 240
Proceeds from divestitures	Investing	**82**	-	**85**	6
Net issuance of revolving long-term debt	Financing	**-**	288	**-**	843
Other	Investing	**24**	-	**79**	-
		324	371	**488**	1,089
Uses of Cash and Cash Equivalents					
Capital expenditures	Investing	**415**	215	**814**	574
Acquisitions	Investing	**2**	1	**48**	2
Repayment of long-term debt	Financing	**-**	-	**-**	400
Dividends on common shares	Financing	**14**	11	**29**	24
Other	Investing/Financing	**24**	73	**40**	76
		455	300	**931**	1,076
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**3**	-	**4**	9
Increase (Decrease) in Cash and Cash Equivalents		**$ (128)**	$ 71	**$ (439)**	$ 22

Operating Activities

Cash from operating activities can be significantly impacted by fluctuations in commodity prices, operating costs, and changes in production volumes. In the first six months of 2017, cash from operating activities was primarily impacted by recovering commodity prices, the Company's efforts in maintaining cost efficiencies achieved in 2016, a current tax recovery and interest relating to the successful resolution of certain tax items previously assessed by the tax authorities and changes in non-cash working capital. Additional detail on changes in non-cash working capital can be found in Note 20 to the Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q. Encana expects it will continue to meet the payment terms of its suppliers.

Non-GAAP Cash Flow in the second quarter and first six months of 2017 was $351 million and $629 million, respectively. Non-GAAP Cash Flow was primarily impacted by the items affecting cash from operating activities which are discussed below and in the Results of Operations section of this MD&A. Non-GAAP Cash Flow excludes changes in non-cash working capital as disclosed in the Non-GAAP Measures section of this MD&A.

Three months ended June 30, 2017 versus June 30, 2016

Net cash from operating activities in the second quarter of 2017 increased $135 million from the second quarter of 2016 primarily due to:

- Higher realized commodity prices ($197 million), lower transportation and processing expense ($38 million), higher interest income recorded in other gains ($27 million) and lower interest on long-term debt and other ($26 million);

partially offset by:

- Lower realized gains on risk management included in revenues ($108 million), lower production volumes ($47 million) and changes in non-cash working capital ($35 million).

Six months ended June 30, 2017 versus June 30, 2016

Net cash from operating activities in the first six months of 2017 increased $84 million from the first six months of 2016 primarily due to:

- Higher realized commodity prices ($516 million), lower transportation and processing expense ($95 million), a higher current tax recovery ($48 million), lower interest on long-term debt and other ($41 million), lower operating expense, excluding non-cash long-term incentive costs ($38 million), higher interest income recorded in other gains ($35 million) and lower restructuring costs ($31 million);

partially offset by:

- Realized losses on risk management included in revenues in the first six months of 2017 compared to realized gains in 2016 ($309 million), lower production volumes ($147 million) and changes in non-cash working capital ($254 million).

Investing Activities

Net cash used in investing activities in the first six months of 2017 was $698 million primarily due to capital expenditures. Capital expenditures in the first six months of 2017 increased $240 million compared to 2016 due to an increase in the capital program for 2017. Capital expenditures in the Core Assets totaled $783 million, representing 96 percent of total capital expenditures, and increased $236 million compared to 2016, primarily in Permian ($109 million), Eagle Ford ($75 million) and Montney ($60 million). Capital expenditures exceeded cash from operating activities by $490 million and the difference was funded using cash on hand.

Divestitures in the first six months of 2017 were $85 million, which primarily included the sale of the Tuscaloosa Marine Shale assets in Mississippi and Louisiana, as well as the sale of certain properties that did not complement Encana's existing portfolio of assets.

Acquisitions in the first six months of 2017 were $48 million, which primarily included land purchases with oil and liquids rich potential.

Capital expenditures and acquisition and divestiture activity are summarized in Notes 3 and 4 to the Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q.

Financing Activities

Net cash used in financing activities in the first six months of 2017 was $69 million compared to net cash from financing activities of $387 million in 2016. The change was primarily due to a net issuance of revolving long-term debt ($843 million), partially offset by the repayment of long-term debt ($400 million), in the first six months of 2016.

Encana's long-term debt totaled $4,198 million at June 30, 2017 and December 31, 2016. There was no current portion outstanding at June 30, 2017 or December 31, 2016. At June 30, 2017, Encana has no long-term debt maturities until 2019 and over 73 percent of the Company's debt is not due until 2030 and beyond.

In March 2016, the Company completed tender offers (collectively, the "Tender Offers") for certain of the Company's outstanding senior notes (collectively, the "Notes") and accepted for purchase $489 million aggregate principal amount of Notes. The Company paid an aggregate amount of $406 million, including accrued and unpaid interest of $6 million and an early tender premium of $14 million, which resulted in the recognition of a net gain on the early debt retirement of $89 million, before tax. The Company used cash on hand and borrowings under the Credit Facilities to fund the Tender Offers. Further information on the Tender Offers can be found in Note 9 to the Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q.

The Company continues to have full access to the Credit Facilities, which remain committed through July 2020. The Credit Facilities provide financial flexibility and allow the Company to fund its operations, development activities or capital program. At June 30, 2017, Encana had no outstanding balance under the Credit Facilities.

Dividends

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

	Three months ended June 30,		Six months ended June 30,	
($ millions, except as indicated)	**2017**	2016	**2017**	2016
Dividend Payments	**$ 14**	$ 12	**$ 29**	$ 25
Dividend Payments ($/share)	**$ 0.015**	$ 0.015	**$ 0.03**	$ 0.03

On July 20, 2017, the Board of Directors declared a dividend of $0.015 per common share payable on September 29, 2017 to common shareholders of record as of September 15, 2017.

Off-Balance Sheet Arrangements

For information on off-balance sheet arrangements and transactions, refer to the Off-Balance Sheet Arrangements section of the MD&A included in Item 7 of the 2016 Annual Report on Form 10-K.

Commitments and Contingencies

For information on commitments and contingencies, refer to Note 21 to the Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q.

Non-GAAP Measures

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

Non-GAAP Cash Flow and Corporate Margin

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

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

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

	Three months ended June 30,		Six months ended June 30,	
($ millions, except as indicated)	**2017**	2016	**2017**	2016
Cash From (Used in) Operating Activities	**$ 218**	$ 83	**$ 324**	$ 240
(Add back) deduct:				
Net change in other assets and liabilities	**(4)**	(5)	**(16)**	(9)
Net change in non-cash working capital	**(129)**	(94)	**(289)**	(35)
Current tax on sale of assets	**-**	-	**-**	-
Non-GAAP Cash Flow	**$ 351**	$ 182	**$ 629**	$ 284
Production Volumes (MMBOE)	**28.8**	33.5	**57.4**	68.4
Corporate Margin ($/BOE)	**$ 12.19**	$ 5.43	**$ 10.96**	$ 4.15

Debt to Adjusted Capitalization

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

($ millions, except as indicated)	**June 30, 2017**	December 31, 2016
Debt	**$ 4,198**	$ 4,198
Total Shareholders' Equity	**6,783**	6,126
Equity Adjustment for Impairments at December 31, 2011	**7,746**	7,746
Adjusted Capitalization	**$ 18,727**	$ 18,070
Debt to Adjusted Capitalization	**22%**	23%

Item 3: Quantitative and Qualitative Disclosures About Market Risk

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

COMMODITY PRICE RISK

Commodity price risk arises from the effect fluctuations in future commodity prices, including oil, NGLs and natural gas may have on future revenues, expenses and cash flows. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to the Company's natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable as discussed in Item 1A. "Risk Factors" of the 2016 Annual Report on Form 10-K. To partially mitigate exposure to commodity price risk, the Company may enter into various derivative financial instruments including futures, forwards, swaps, options and costless collars. The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors and may vary from year to year. Both exchange traded and over-the-counter traded derivative instruments may be subject to margin-deposit requirements, and the Company may be required from time to time to deposit cash or provide letters of credit with exchange brokers or counterparties to satisfy these margin requirements. For additional information relating to the Company's derivative and financial instruments, see Note 19 under Part I, Item 1 of this Quarterly Report on Form 10-Q.

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

	June 30, 2017	
(US$ millions)	10% Price Increase	10% Price Decrease
Crude oil price	$ (107)	$ 112
NGL price	(1)	1
Natural gas price	(44)	35

FOREIGN EXCHANGE RISK

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

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

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

To partially mitigate the effect of foreign exchange fluctuations on future commodity revenues and expenses, the Company may enter into foreign currency derivative contracts. As at June 30, 2017, Encana had $620 million notional U.S. dollar denominated currency swaps at an average exchange rate of US$0.7421 to C$1. The notional contracts mature monthly throughout 2017 and 2018.

As at June 30, 2017, Encana had $4.2 billion in U.S. dollar long-term debt and $350 million in U.S. dollar capital leases issued from Canada that were subject to foreign exchange exposure.

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

	June 30, 2017	
(US$ millions)	10% Rate Increase	10% Rate Decrease
Foreign currency exchange	$ (411)	$ 502

INTEREST RATE RISK

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

As at June 30, 2017, the Company had no floating rate debt and there were no interest rate derivatives outstanding.

Item 4: Controls and Procedures

DISCLOSURE CONTROLS AND PROCEDURES

Encana's Chief Executive Officer and Chief Financial Officer performed an evaluation of the Company's disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended ("Exchange Act"). The Company's disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company in reports it files or submits under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the SEC, and to ensure that the information required to be disclosed by the Company in reports that it files or submits under the Exchange Act, is accumulated and communicated to the Company's management, including the principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures were effective as of June 30, 2017.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes in Encana's internal control over financial reporting during the second quarter of 2017 that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II

Item 1. Legal Proceedings

Please refer to Item 3 of the 2016 Annual Report on Form 10-K and Note 21 of Encana's Condensed Consolidated Financial Statements under Part I, Item 1 of this Quarterly Report on Form 10-Q.

Item 1A. Risk Factors

There have been no material changes from the risk factors disclosed in Item 1A. Risk Factors in the 2016 Annual Report on Form 10-K.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

Exhibit No	Description
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Schema Document.
101.CAL	XBRL Calculation Linkbase Document.
101.DEF	XBRL Definition Linkbase Document.
101.LAB	XBRL Label Linkbase Document.
101.PRE	XBRL Presentation Linkbase Document.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, hereunto duly authorized.

ENCANA CORPORATION

By: /s/ Sherri A. Brillon

Name: Sherri A. Brillon
Title: Executive Vice-President &
Chief Financial Officer

Dated: July 25, 2017

Encana Corporation

Interim Supplemental Information
(unaudited)

For the period ended June 30, 2017

U.S. Dollars / U.S. Protocol

Supplemental Financial Information *(unaudited)*

Financial Results

(US$ millions, except per share amounts)	2017 Year-to-date	2017 Q2	2017 Q1	2016 Year	2016 Q4	2016 Q3	2016 Q2 Year-to-date	2016 Q2	2016 Q1
Net Earnings (Loss)	**762**	**331**	431	(944)	(281)	317	(980)	(601)	(379)
Per share - Diluted [1]	**0.78**	**0.34**	0.44	(1.07)	(0.29)	0.37	(1.15)	(0.71)	(0.45)
Non-GAAP Operating Earnings (Loss) [2]	**284**	**180**	104	76	85	32	(41)	89	(130)
Per share - Diluted [1]	**0.29**	**0.18**	0.11	0.09	0.09	0.04	(0.05)	0.10	(0.15)
Non-GAAP Cash Flow [3]	**629**	**351**	278	838	302	252	284	182	102
Per share - Diluted [1]	**0.65**	**0.36**	0.29	0.95	0.31	0.29	0.33	0.21	0.12
Effective Tax Rate using Canadian Statutory Rate	**27.0%**			27.0%					
Foreign Exchange Rates (US$ per C$1)									
Average	**0.750**	**0.744**	0.755	0.755	0.750	0.766	0.752	0.776	0.728
Period end	**0.771**	**0.771**	0.751	0.745	0.745	0.762	0.769	0.769	0.771
Non-GAAP Operating Earnings Summary									
Net Earnings (Loss)	**762**	**331**	431	(944)	(281)	317	(980)	(601)	(379)
Before-tax (Addition) Deduction:									
Unrealized gain (loss) on risk management	**472**	**110**	362	(614)	(149)	41	(506)	(451)	(55)
Impairments	**-**	**-**	-	(1,396)	-	-	(1,396)	(484)	(912)
Restructuring charges	**-**	**-**	-	(34)	(1)	(2)	(31)	-	(31)
Non-operating foreign exchange gain (loss)	**97**	**63**	34	135	(104)	(44)	283	(61)	344
Gain (loss) on divestitures	**(1)**	**-**	(1)	390	(3)	395	(2)	(2)	-
Gain on debt retirement	**-**	**-**	-	89	-	-	89	-	89
	568	**173**	395	(1,430)	(257)	390	(1,563)	(998)	(565)
Income tax	**(90)**	**(22)**	(68)	410	(109)	(105)	624	308	316
After-tax (Addition) Deduction	**478**	**151**	327	(1,020)	(366)	285	(939)	(690)	(249)
Non-GAAP Operating Earnings (Loss) [2]	**284**	**180**	104	76	85	32	(41)	89	(130)
Non-GAAP Cash Flow Summary									
Cash From (Used in) Operating Activities	**324**	**218**	106	625	199	186	240	83	157
(Add back) Deduct:									
Net change in other assets and liabilities	**(16)**	**(4)**	(12)	(26)	(11)	(6)	(9)	(5)	(4)
Net change in non-cash working capital	**(289)**	**(129)**	(160)	(187)	(92)	(60)	(35)	(94)	59
Current tax on sale of assets	**-**	**-**	-	-	-	-	-	-	-
Non-GAAP Cash Flow [3]	**629**	**351**	278	838	302	252	284	182	102

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

(millions)	2017 Year-to-date	2017 Q2	2017 Q1	2016 Year	2016 Q4	2016 Q3	2016 Q2 Year-to-date	2016 Q2	2016 Q1
Weighted Average Common Shares Outstanding									
Basic	**973.0**	**973.0**	973.0	882.6	972.4	858.3	849.9	849.9	849.9
Diluted	**973.0**	**973.0**	973.0	882.6	972.4	858.3	849.9	849.9	849.9

(2) Non-GAAP 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 items may include, but are not limited to, unrealized gains/losses on risk management, impairments, restructuring charges, non-operating foreign exchange gains/losses, gains/losses on divestitures and gains on debt retirement. Income taxes may include valuation allowances and the provision related to the pre-tax items listed, as well as income taxes related to divestitures and adjustments to normalize the effect of income taxes calculated using the estimated annual effective income tax rate.

(3) Non-GAAP 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 current tax on sale of assets.

Financial Metrics

	2017 Year-to-date	2016 Year
Debt to Adjusted Capitalization	**22%**	23%
Corporate Margin ($/BOE)	**10.96**	6.49

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 of Financial Condition and Results of Operations.

Supplemental Operating Information *(unaudited)*

Production Volumes

	2017			2016					
(average)	**Year-to-date**	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Oil (Mbbls/d)	**72.4**	**77.4**	67.4	73.7	66.4	69.1	79.7	78.9	80.5
NGLs - Plant Condensate (Mbbls/d)	**21.7**	**22.8**	20.5	20.3	19.9	21.8	19.9	20.7	19.1
NGLs - Other (Mbbls/d)	**23.9**	**24.7**	23.0	28.1	22.6	26.1	31.8	32.4	31.2
Oil & NGLs (Mbbls/d)	**118.0**	**124.9**	110.9	122.1	108.9	117.0	131.4	132.0	130.8
Natural Gas (MMcf/d)	**1,194**	**1,146**	1,241	1,383	1,276	1,326	1,466	1,418	1,516
Total (MBOE/d)	**316.9**	**316.0**	317.9	352.7	321.5	338.0	375.8	368.3	383.4

Production Volumes

	2017			2016					
(average)	**Year-to-date**	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Oil (Mbbls/d)									
Canadian Operations	**0.4**	**0.4**	0.4	2.0	0.4	1.0	3.3	3.3	3.2
USA Operations	**72.0**	**77.0**	67.0	71.7	66.0	68.1	76.4	75.6	77.3
	72.4	**77.4**	67.4	73.7	66.4	69.1	79.7	78.9	80.5
NGLs - Plant Condensate (Mbbls/d)									
Canadian Operations	**19.6**	**20.5**	18.7	17.6	17.2	19.1	17.1	17.7	16.5
USA Operations	**2.1**	**2.3**	1.8	2.7	2.7	2.7	2.8	3.0	2.6
	21.7	**22.8**	20.5	20.3	19.9	21.8	19.9	20.7	19.1
NGLs - Other (Mbbls/d)									
Canadian Operations	**4.9**	**4.7**	5.0	7.6	4.3	6.1	9.9	9.4	10.5
USA Operations	**19.0**	**20.0**	18.0	20.5	18.3	20.0	21.9	23.0	20.7
	23.9	**24.7**	23.0	28.1	22.6	26.1	31.8	32.4	31.2
NGLs - Total (Mbbls/d)									
Canadian Operations	**24.5**	**25.2**	23.7	25.2	21.5	25.2	27.0	27.1	27.0
USA Operations	**21.1**	**22.3**	19.8	23.2	21.0	22.7	24.7	26.0	23.3
	45.6	**47.5**	43.5	48.4	42.5	47.9	51.7	53.1	50.3
Oil & NGLs (Mbbls/d)									
Canadian Operations	**24.9**	**25.6**	24.1	27.2	21.9	26.2	30.3	30.4	30.2
USA Operations	**93.1**	**99.3**	86.8	94.9	87.0	90.8	101.1	101.6	100.6
	118.0	**124.9**	110.9	122.1	108.9	117.0	131.4	132.0	130.8
Natural Gas (MMcf/d)									
Canadian Operations	**835**	**785**	885	966	905	924	1,018	971	1,066
USA Operations	**359**	**361**	356	417	371	402	448	447	450
	1,194	**1,146**	1,241	1,383	1,276	1,326	1,466	1,418	1,516
Total (MBOE/d)									
Canadian Operations	**164.1**	**156.6**	171.7	188.2	172.7	180.2	200.0	192.2	207.9
USA Operations	**152.8**	**159.4**	146.2	164.5	148.8	157.8	175.8	176.1	175.5
	316.9	**316.0**	317.9	352.7	321.5	338.0	375.8	368.3	383.4

Oil & NGLs Production Volumes

	2017				2016						
(average Mbbls/d)	**% of Total**	**Year-to-date**	**Q2**	Q1	% of Total	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Oil	**61**	**72.4**	**77.4**	67.4	61	73.7	66.4	69.1	79.7	78.9	80.5
NGLs - Plant Condensate	**19**	**21.7**	**22.8**	20.5	17	20.3	19.9	21.8	19.9	20.7	19.1
Oil & Plant Condensate	**80**	**94.1**	**100.2**	87.9	78	94.0	86.3	90.9	99.6	99.6	99.6
Butane	**5**	**6.5**	**6.7**	6.2	6	7.7	6.6	6.8	8.6	8.9	8.3
Propane	**8**	**9.4**	**9.7**	9.1	9	11.4	8.8	10.9	13.0	13.0	13.1
Ethane	**7**	**8.0**	**8.3**	7.7	7	9.0	7.2	8.4	10.2	10.5	9.8
NGLs - Other	**20**	**23.9**	**24.7**	23.0	22	28.1	22.6	26.1	31.8	32.4	31.2
Oil & NGLs	**100**	**118.0**	**124.9**	110.9	100	122.1	108.9	117.0	131.4	132.0	130.8

Supplemental Financial & Operating Information *(unaudited)*

Results of Operations

Revenues and Realized Gains (Losses) on Risk Management

	2017			2016					
(US$ millions)	**Year-to-date**	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Canadian Operations									
Revenues, excluding Realized Gains (Losses) on Risk Management [1]									
Oil	**3**	**1**	2	26	1	4	21	13	8
NGLs [2]	**191**	**97**	94	298	83	81	134	80	54
Natural Gas	**367**	**166**	201	628	204	159	265	103	162
	561	**264**	297	952	288	244	420	196	224
Realized Gains (Losses) on Risk Management									
Oil	**-**	**-**	-	45	4	12	29	8	21
NGLs [2]	**-**	**1**	(1)	-	-	-	-	-	-
Natural Gas	**(19)**	**1**	(20)	62	(19)	(12)	93	47	46
	(19)	**2**	(21)	107	(15)	-	122	55	67
USA Operations									
Revenues, excluding Realized Gains (Losses) on Risk Management [1]									
Oil	**622**	**324**	298	1,015	279	262	474	279	195
NGLs [2]	**78**	**38**	40	126	38	33	55	33	22
Natural Gas	**205**	**102**	103	350	100	102	148	70	78
	905	**464**	441	1,491	417	397	677	382	295
Realized Gains (Losses) on Risk Management									
Oil	**16**	**16**	-	226	25	58	143	50	93
NGLs [2]	**1**	**1**	-	-	-	-	-	-	-
Natural Gas	**(6)**	**(1)**	(5)	23	(8)	(4)	35	19	16
	11	**16**	(5)	249	17	54	178	69	109

(1) Excludes other revenues with no associated production volumes.

(2) Includes plant condensate.

Per-unit Results, Excluding the Impact of Realized Gains (Losses) on Risk Management [1]

	2017			2016					
(US$/BOE)	**Year-to-date**	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Total Canadian Operations Netback									
Price	**18.89**	**18.52**	19.23	13.82	18.05	14.74	11.55	11.23	11.84
Production, mineral and other taxes	**0.34**	**0.39**	0.30	0.33	0.39	0.28	0.33	0.36	0.29
Transportation and processing	**8.91**	**9.30**	8.56	8.35	8.52	8.23	8.34	8.85	7.87
Operating	**1.73**	**1.52**	1.91	2.16	2.27	2.29	2.06	2.08	2.06
Netback	**7.91**	**7.31**	8.46	2.98	6.87	3.94	0.82	(0.06)	1.62
Total USA Operations Netback									
Price	**32.71**	**31.92**	33.59	24.78	30.50	27.36	21.16	23.89	18.42
Production, mineral and other taxes	**1.55**	**1.29**	1.84	1.27	1.50	1.05	1.27	1.48	1.07
Transportation and processing	**3.97**	**3.54**	4.44	4.33	3.42	2.96	5.34	4.56	6.12
Operating	**5.99**	**5.60**	6.43	6.44	7.09	6.37	6.20	5.34	7.06
Netback	**21.20**	**21.49**	20.88	12.74	18.49	16.98	8.35	12.51	4.17
Total Operations Netback									
Price	**25.55**	**25.29**	25.82	18.93	23.81	20.64	16.05	17.29	14.85
Production, mineral and other taxes	**0.93**	**0.85**	1.01	0.77	0.91	0.64	0.77	0.89	0.65
Transportation and processing	**6.53**	**6.39**	6.67	6.48	6.16	5.77	6.94	6.80	7.07
Operating	**3.78**	**3.58**	3.99	4.16	4.50	4.19	4.00	3.63	4.35
Netback	**14.31**	**14.47**	14.15	7.52	12.24	10.04	4.34	5.97	2.78

(1) Netback is a common metric used in the oil and gas industry to measure operating performance on a per-unit basis and is considered a non-GAAP measure. The netbacks disclosed above do not meet the requirements outlined in National Instrument 51-101 and have been calculated on a BOE basis using product revenues, excluding the impact of realized gains and losses on risk management, less costs associated with delivering the product to market, including production, mineral and other taxes, transportation and processing expense and operating expense. For additional information regarding non-GAAP measures, including Netback reconciliations, see the Company's website.

Other Per-unit Results

	2017			2016					
(US$/BOE)	**Year-to-date**	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Operating Expense	**3.78**	**3.58**	3.99	4.16	4.50	4.19	4.00	3.63	4.35
Operating Expense, Excluding Long-Term Incentive Costs	**3.79**	**3.76**	3.82	3.87	4.07	3.75	3.85	3.36	4.31
Administrative Expense [1]	**1.43**	**0.82**	2.04	2.40	2.63	2.94	2.05	1.82	2.27
Administrative Expense, Excluding Long-Term Incentive and Restructuring Costs	**1.56**	**1.61**	1.50	1.47	1.63	1.80	1.25	1.27	1.23

(1) No restructuring costs have been incurred in 2017.

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Operating Statistics

Per-unit Prices, Excluding the Impact of Realized Gains (Losses) on Risk Management

	2017			2016					
(US$)	**Year-to-date**	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Oil Price ($/bbl)									
Canadian Operations	**41.77**	**40.23**	43.29	36.32	44.04	37.36	35.74	41.73	29.58
USA Operations	**47.75**	**46.14**	49.65	38.67	45.92	41.76	34.12	40.61	27.77
Total Operations	**47.72**	**46.11**	49.61	38.61	45.91	41.70	34.19	40.65	27.84
NGLs - Plant Condensate Price ($/bbl)									
Canadian Operations	**48.53**	**46.94**	50.29	40.97	46.41	40.16	38.67	44.60	32.32
USA Operations	**41.86**	**41.07**	42.87	32.48	38.88	35.83	27.67	32.16	22.45
Total Operations	**47.89**	**46.34**	49.63	39.84	45.39	39.63	37.14	42.82	31.00
NGLs - Other Price ($/bbl)									
Canadian Operations	**20.91**	**19.10**	22.62	12.13	21.65	20.41	7.48	9.42	5.74
USA Operations	**17.97**	**16.06**	20.11	12.53	17.26	13.11	10.26	11.46	8.93
Total Operations	**18.57**	**16.65**	20.66	12.42	18.10	14.80	9.40	10.87	7.86
Total NGLs Price ($/bbl)									
Canadian Operations	**43.01**	**41.73**	44.40	32.32	41.44	35.39	27.21	32.38	22.02
USA Operations	**20.34**	**18.68**	22.22	14.86	20.03	15.79	12.21	13.82	10.41
Total Operations	**32.54**	**30.93**	34.31	23.94	30.87	26.09	20.05	23.29	16.63
Oil & NGLs Price ($/bbl)									
Canadian Operations	**43.00**	**41.71**	44.38	32.61	41.48	35.47	28.13	33.40	22.82
USA Operations	**41.55**	**40.00**	43.36	32.84	39.67	35.26	28.77	33.76	23.74
Total Operations	**41.86**	**40.35**	43.59	32.79	40.04	35.31	28.63	33.67	23.53
Natural Gas Price ($/Mcf)									
Canadian Operations	**2.43**	**2.33**	2.52	1.77	2.44	1.87	1.43	1.18	1.66
USA Operations	**3.16**	**3.09**	3.23	2.29	2.93	2.78	1.81	1.74	1.88
Total Operations	**2.65**	**2.57**	2.72	1.93	2.58	2.15	1.55	1.35	1.73
Total Price ($/BOE)									
Canadian Operations	**18.89**	**18.52**	19.23	13.82	18.05	14.74	11.55	11.23	11.84
USA Operations	**32.71**	**31.92**	33.59	24.78	30.50	27.36	21.16	23.89	18.42
Total Operations	**25.55**	**25.29**	25.82	18.93	23.81	20.64	16.05	17.29	14.85

Per-unit Impact of Realized Gains (Losses) on Risk Management

	2017			2016					
(US$)	**Year-to-date**	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Oil ($/bbl)									
Canadian Operations [(1)]	**0.57**	**1.07**	0.08	62.45	123.11	132.29	48.40	25.04	72.40
USA Operations	**1.19**	**2.17**	0.05	8.64	4.25	9.32	10.25	7.26	13.17
Total Operations	**1.19**	**2.16**	0.05	10.07	4.87	11.09	11.80	8.00	15.54
NGLs - Plant Condensate ($/bbl)									
Canadian Operations	**0.12**	**1.10**	(0.98)	-	-	-	-	-	-
USA Operations	**-**	**-**	-	-	-	-	-	-	-
Total Operations	**0.11**	**0.99**	(0.89)	-	-	-	-	-	-
NGLs - Other ($/bbl)									
Canadian Operations	**-**	**-**	-	-	-	-	-	-	-
USA Operations	**0.33**	**0.62**	-	(0.09)	(0.30)	(0.23)	0.06	0.11	-
Total Operations	**0.26**	**0.50**	-	(0.07)	(0.24)	(0.18)	0.04	0.08	-
Total NGLs ($/bbl)									
Canadian Operations	**0.09**	**0.89**	(0.77)	-	-	-	-	-	-
USA Operations	**0.29**	**0.55**	-	(0.08)	(0.26)	(0.20)	0.05	0.10	-
Total Operations	**0.19**	**0.73**	(0.42)	(0.04)	(0.13)	(0.10)	0.02	0.05	-
Oil & NGLs ($/bbl)									
Canadian Operations	**0.10**	**0.90**	(0.76)	4.51	1.97	5.03	5.21	2.72	7.70
USA Operations	**0.99**	**1.81**	0.03	6.50	3.16	6.94	7.76	5.43	10.11
Total Operations	**0.80**	**1.62**	(0.14)	6.06	2.92	6.51	7.17	4.80	9.56
Natural Gas ($/Mcf)									
Canadian Operations	**(0.13)**	**-**	(0.24)	0.18	(0.22)	(0.14)	0.50	0.53	0.48
USA Operations	**(0.09)**	**(0.03)**	(0.16)	0.15	(0.25)	(0.11)	0.43	0.47	0.39
Total Operations	**(0.12)**	**(0.01)**	(0.22)	0.17	(0.23)	(0.13)	0.48	0.51	0.45
Total ($/BOE)									
Canadian Operations	**(0.63)**	**0.16**	(1.37)	1.55	(0.93)	-	3.35	3.12	3.56
USA Operations	**0.38**	**1.07**	(0.37)	4.13	1.23	3.72	5.56	4.32	6.79
Total Operations	**(0.14)**	**0.62**	(0.91)	2.76	0.07	1.74	4.38	3.69	5.04

(1) Calculated using the realized gains/losses on risk management divided by the discrete oil volumes, not total liquids volumes hedged under the risk management program, which include condensate volumes.

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Operating Statistics (continued)

Per-unit Results, Including the Impact of Realized Gains (Losses) on Risk Management

	2017			2016					
(US$)	**Year-to-date**	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Oil Price ($/bbl)									
Canadian Operations	**42.34**	**41.30**	43.37	98.77	167.15	169.65	84.14	66.77	101.98
USA Operations	**48.94**	**48.31**	49.70	47.31	50.17	51.08	44.37	47.87	40.94
Total Operations	**48.91**	**48.27**	49.66	48.68	50.78	52.79	45.99	48.65	43.38
NGLs - Plant Condensate Price ($/bbl)									
Canadian Operations	**48.65**	**48.04**	49.31	40.97	46.41	40.16	38.67	44.60	32.32
USA Operations	**41.86**	**41.07**	42.87	32.48	38.88	35.83	27.67	32.16	22.45
Total Operations	**48.00**	**47.33**	48.74	39.84	45.39	39.63	37.14	42.82	31.00
NGLs - Other Price ($/bbl)									
Canadian Operations	**20.91**	**19.10**	22.62	12.13	21.65	20.41	7.48	9.42	5.74
USA Operations	**18.30**	**16.68**	20.11	12.44	16.96	12.88	10.32	11.57	8.93
Total Operations	**18.83**	**17.15**	20.66	12.35	17.86	14.62	9.44	10.95	7.86
NGLs Price ($/bbl)									
Canadian Operations	**43.10**	**42.62**	43.63	32.32	41.44	35.39	27.21	32.38	22.02
USA Operations	**20.63**	**19.23**	22.22	14.78	19.77	15.59	12.26	13.92	10.41
Total Operations	**32.73**	**31.66**	33.89	23.90	30.74	25.99	20.07	23.34	16.63
Oil & NGLs Price ($/bbl)									
Canadian Operations	**43.10**	**42.61**	43.62	37.12	43.45	40.50	33.34	36.12	30.52
USA Operations	**42.54**	**41.81**	43.39	39.34	42.83	42.20	36.53	39.19	33.85
Total Operations	**42.66**	**41.97**	43.45	38.85	42.96	41.82	35.80	38.47	33.09
Natural Gas Price ($/Mcf)									
Canadian Operations	**2.30**	**2.33**	2.28	1.95	2.22	1.73	1.93	1.71	2.14
USA Operations	**3.07**	**3.06**	3.07	2.44	2.68	2.67	2.24	2.21	2.27
Total Operations	**2.53**	**2.56**	2.50	2.10	2.35	2.02	2.03	1.86	2.18
Total Price ($/BOE)									
Canadian Operations	**18.26**	**18.68**	17.86	15.37	17.12	14.74	14.90	14.35	15.40
USA Operations	**33.09**	**32.99**	33.22	28.91	31.73	31.08	26.72	28.21	25.21
Total Operations	**25.41**	**25.91**	24.91	21.69	23.88	22.38	20.43	20.98	19.89
Total Netback ($/BOE)									
Canadian Operations	**7.28**	**7.47**	7.09	4.53	5.94	3.94	4.17	3.06	5.18
USA Operations	**21.58**	**22.56**	20.51	16.87	19.72	20.70	13.91	16.83	10.96
Total Operations	**14.17**	**15.09**	13.24	10.28	12.31	11.78	8.72	9.66	7.82

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Results by Play

	2017			2016					
(average)	Year-to-date	Q2	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Oil Production (Mbbls/d)									
Canadian Operations									
Montney [1]	**0.2**	**0.2**	0.2	1.9	0.3	0.9	3.2	3.2	3.1
Duvernay	**0.1**	**0.1**	0.1	-	-	-	-	-	-
Other Upstream Operations [2]	**0.1**	**0.1**	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total Canadian Operations	**0.4**	**0.4**	0.4	2.0	0.4	1.0	3.3	3.3	3.2
USA Operations									
Eagle Ford	**30.3**	**34.3**	26.4	32.4	30.3	30.3	34.5	33.5	35.6
Permian	**37.3**	**39.0**	35.6	29.8	30.6	30.5	29.1	30.5	27.8
Other Upstream Operations [2]	**4.4**	**3.7**	5.0	9.5	5.1	7.3	12.8	11.6	13.9
Total USA Operations	**72.0**	**77.0**	67.0	71.7	66.0	68.1	76.4	75.6	77.3
Total Encana	**72.4**	**77.4**	67.4	73.7	66.4	69.1	79.7	78.9	80.5
Oil Production (Mbbls/d)									
Total Core Assets	**67.9**	**73.6**	62.3	64.1	61.2	61.7	66.8	67.2	66.5
% of Total Encana	**94%**	**95%**	92%	87%	92%	89%	84%	85%	83%
NGLs - Plant Condensate Production (Mbbls/d)									
Canadian Operations									
Montney [1]	**11.5**	**12.2**	10.9	10.4	10.3	11.3	10.0	10.0	10.0
Duvernay	**7.9**	**8.2**	7.6	7.1	6.8	7.8	7.0	7.5	6.4
Other Upstream Operations [2]	**0.2**	**0.1**	0.2	0.1	0.1	-	0.1	0.2	0.1
Total Canadian Operations	**19.6**	**20.5**	18.7	17.6	17.2	19.1	17.1	17.7	16.5
USA Operations									
Eagle Ford	**0.6**	**0.7**	0.5	0.6	0.7	0.7	0.5	0.7	0.4
Permian	**1.1**	**1.3**	1.0	1.1	1.4	1.1	1.0	1.0	0.9
Other Upstream Operations [2]	**0.4**	**0.3**	0.3	1.0	0.6	0.9	1.3	1.3	1.3
Total USA Operations	**2.1**	**2.3**	1.8	2.7	2.7	2.7	2.8	3.0	2.6
Total Encana	**21.7**	**22.8**	20.5	20.3	19.9	21.8	19.9	20.7	19.1
NGLs - Plant Condensate Production (Mbbls/d)									
Total Core Assets	**21.1**	**22.4**	20.0	19.2	19.2	20.9	18.5	19.2	17.7
% of Total Encana	**97%**	**98%**	98%	95%	96%	96%	93%	93%	93%

(1) Production volumes associated with the Gordondale assets were included in Montney until the divestiture of these assets on July 28, 2016.

(2) Other Upstream Operations includes production volumes from plays that are not part of the Company's current strategic focus. Canadian Other Upstream Operations primarily includes Wheatland; USA Other Upstream Operations primarily includes Piceance, DJ Basin, San Juan and Tuscaloosa Marine Shale ("TMS"). Production volumes associated with DJ Basin and TMS were included in Other Upstream Operations until the divestitures of these assets on July 29, 2016 and April 13, 2017, respectively.

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Results by Play (continued)

(average)	2017 Year-to-date	2017 Q2	2017 Q1	2016 Year	2016 Q4	2016 Q3	2016 Q2 Year-to-date	2016 Q2	2016 Q1
NGLs - Other Production (Mbbls/d)									
Canadian Operations									
Montney [1]	**3.5**	**3.4**	3.5	6.2	3.4	4.4	8.5	7.9	9.2
Duvernay	**1.2**	**1.2**	1.2	1.2	0.8	1.3	1.2	1.3	1.2
Other Upstream Operations [2]	**0.2**	**0.1**	0.3	0.2	0.1	0.4	0.2	0.2	0.1
Total Canadian Operations	**4.9**	**4.7**	5.0	7.6	4.3	6.1	9.9	9.4	10.5
USA Operations									
Eagle Ford	**6.7**	**7.2**	6.1	6.6	6.7	6.7	6.4	6.8	5.9
Permian	**10.6**	**11.0**	10.1	8.9	9.3	9.5	8.4	9.3	7.6
Other Upstream Operations [2]	**1.7**	**1.8**	1.8	5.0	2.3	3.8	7.1	6.9	7.2
Total USA Operations	**19.0**	**20.0**	18.0	20.5	18.3	20.0	21.9	23.0	20.7
Total Encana	**23.9**	**24.7**	23.0	28.1	22.6	26.1	31.8	32.4	31.2
NGLs - Other Production (Mbbls/d)									
Total Core Assets	**22.0**	**22.8**	20.9	22.9	20.2	21.9	24.5	25.3	23.9
% of Total Encana	**92%**	**92%**	91%	81%	89%	84%	77%	78%	77%
NGLs - Total Production (Mbbls/d)									
Canadian Operations									
Montney [1]	**15.0**	**15.6**	14.4	16.6	13.7	15.7	18.5	17.9	19.2
Duvernay	**9.1**	**9.4**	8.8	8.3	7.6	9.1	8.2	8.8	7.6
Other Upstream Operations [2]	**0.4**	**0.2**	0.5	0.3	0.2	0.4	0.3	0.4	0.2
Total Canadian Operations	**24.5**	**25.2**	23.7	25.2	21.5	25.2	27.0	27.1	27.0
USA Operations									
Eagle Ford	**7.3**	**7.9**	6.6	7.2	7.4	7.4	6.9	7.5	6.3
Permian	**11.7**	**12.3**	11.1	10.0	10.7	10.6	9.4	10.3	8.5
Other Upstream Operations [2]	**2.1**	**2.1**	2.1	6.0	2.9	4.7	8.4	8.2	8.5
Total USA Operations	**21.1**	**22.3**	19.8	23.2	21.0	22.7	24.7	26.0	23.3
Total Encana	**45.6**	**47.5**	43.5	48.4	42.5	47.9	51.7	53.1	50.3
NGLs - Total Production (Mbbls/d)									
Total Core Assets	**43.1**	**45.2**	40.9	42.1	39.4	42.8	43.0	44.5	41.6
% of Total Encana	**95%**	**95%**	94%	87%	93%	89%	83%	84%	83%

(1) Production volumes associated with the Gordondale assets were included in Montney until the divestiture of these assets on July 28, 2016.

(2) Other Upstream Operations includes production volumes from plays that are not part of the Company's current strategic focus. Canadian Other Upstream Operations primarily includes Wheatland; USA Other Upstream Operations primarily includes Piceance, DJ Basin, San Juan and TMS. Production volumes associated with DJ Basin and TMS were included in Other Upstream Operations until the divestitures of these assets on July 29, 2016 and April 13, 2017, respectively.

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Results by Play (continued)

(average)	**2017 Year-to-date**	**2017 Q2**	2017 Q1	2016 Year	2016 Q4	2016 Q3	2016 Q2 Year-to-date	2016 Q2	2016 Q1
Oil & NGLs Production (Mbbls/d)									
Canadian Operations									
Montney [(1)]	**15.2**	**15.8**	14.6	18.5	14.0	16.6	21.7	21.1	22.3
Duvernay	**9.2**	**9.5**	8.9	8.3	7.6	9.1	8.2	8.8	7.6
Other Upstream Operations [(2)]	**0.5**	**0.3**	0.6	0.4	0.3	0.5	0.4	0.5	0.3
Total Canadian Operations	**24.9**	**25.6**	24.1	27.2	21.9	26.2	30.3	30.4	30.2
USA Operations									
Eagle Ford	**37.6**	**42.2**	33.0	39.6	37.7	37.7	41.4	41.0	41.9
Permian	**49.0**	**51.3**	46.7	39.8	41.3	41.1	38.5	40.8	36.3
Other Upstream Operations [(2)]	**6.5**	**5.8**	7.1	15.5	8.0	12.0	21.2	19.8	22.4
Total USA Operations	**93.1**	**99.3**	86.8	94.9	87.0	90.8	101.1	101.6	100.6
Total Encana	**118.0**	**124.9**	110.9	122.1	108.9	117.0	131.4	132.0	130.8
Oil & NGLs Production (Mbbls/d)									
Total Core Assets	**111.0**	**118.8**	103.2	106.2	100.6	104.5	109.8	111.7	108.1
% of Total Encana	**94%**	**95%**	93%	87%	92%	89%	84%	85%	83%
Natural Gas Production (MMcf/d)									
Canadian Operations									
Montney [(1)]	**620**	**592**	648	735	667	669	803	781	826
Duvernay	**58**	**62**	55	54	51	61	52	57	48
Other Upstream Operations [(2)]	**157**	**131**	182	177	187	194	163	133	192
Total Canadian Operations	**835**	**785**	885	966	905	924	1,018	971	1,066
USA Operations									
Eagle Ford	**48**	**52**	43	48	48	50	48	50	46
Permian	**60**	**62**	58	50	53	50	49	52	46
Other Upstream Operations [(2)]	**251**	**247**	255	319	270	302	351	345	358
Total USA Operations	**359**	**361**	356	417	371	402	448	447	450
Total Encana	**1,194**	**1,146**	1,241	1,383	1,276	1,326	1,466	1,418	1,516
Natural Gas Production (MMcf/d)									
Total Core Assets	**786**	**768**	804	887	819	830	952	940	966
% of Total Encana	**66%**	**67%**	65%	64%	64%	63%	65%	66%	64%

(1) Production volumes associated with the Gordondale assets were included in Montney until the divestiture of these assets on July 28, 2016.

(2) Other Upstream Operations includes production volumes from plays that are not part of the Company's current strategic focus. Canadian Other Upstream Operations primarily includes Wheatland and natural gas volumes in Horn River and Deep Panuke; USA Other Upstream Operations primarily includes Piceance, DJ Basin, San Juan and TMS. Production volumes associated with DJ Basin and TMS were included in Other Upstream Operations until the divestitures of these assets on July 29, 2016 and April 13, 2017, respectively.

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Results by Play (continued)

(average)	2017 Year-to-date	2017 Q2	2017 Q1	2016 Year	2016 Q4	2016 Q3	2016 Q2 Year-to-date	2016 Q2	2016 Q1
Total Production (MBOE/d)									
Canadian Operations									
Montney [1]	118.6	114.4	122.7	141.0	125.1	128.1	155.6	151.2	159.9
Duvernay	18.9	19.7	18.1	17.3	16.2	19.2	16.9	18.3	15.6
Other Upstream Operations [2]	26.6	22.5	30.9	29.9	31.4	32.9	27.5	22.7	32.4
Total Canadian Operations	164.1	156.6	171.7	188.2	172.7	180.2	200.0	192.2	207.9
USA Operations									
Eagle Ford	45.5	50.8	40.2	47.6	45.6	46.0	49.5	49.4	49.6
Permian	59.0	61.6	56.3	48.3	50.2	49.5	46.7	49.4	44.0
Other Upstream Operations [2]	48.3	47.0	49.7	68.6	53.0	62.3	79.6	77.3	81.9
Total USA Operations	152.8	159.4	146.2	164.5	148.8	157.8	175.8	176.1	175.5
Total Encana	316.9	316.0	317.9	352.7	321.5	338.0	375.8	368.3	383.4
Total Production (MBOE/d)									
Total Core Assets	242.0	246.5	237.3	254.2	237.1	242.8	268.7	268.3	269.1
% of Total Encana	76%	78%	75%	72%	74%	72%	72%	73%	70%

(US$ millions)	2017 Year-to-date	2017 Q2	2017 Q1	2016 Year	2016 Q4	2016 Q3	2016 Q2 Year-to-date	2016 Q2	2016 Q1
Capital Expenditures									
Canadian Operations									
Montney	123	62	61	141	47	31	63	27	36
Duvernay	46	20	26	113	33	26	54	27	27
Other Upstream Operations [3]	-	(1)	1	2	3	(1)	-	-	-
Total Canadian Operations	169	81	88	256	83	56	117	54	63
USA Operations									
Eagle Ford	189	83	106	211	56	41	114	38	76
Permian	425	228	197	629	211	102	316	112	204
Other Upstream Operations [3]	30	22	8	33	1	6	26	9	17
Total USA Operations	644	333	311	873	268	149	456	159	297
Market Optimization	-	-	-	1	-	1	-	-	-
Corporate & Other	1	1	-	2	2	(1)	1	2	(1)
Capital Expenditures	814	415	399	1,132	353	205	574	215	359
Net Acquisitions & (Divestitures)	(37)	(80)	43	(1,052)	(8)	(1,040)	(4)	1	(5)
Net Capital Investment	777	335	442	80	345	(835)	570	216	354
Capital Expenditures									
Total Core Assets	783	393	390	1,094	347	200	547	204	343
% of Total Encana	96%	95%	98%	97%	98%	98%	95%	95%	96%

(1) Production volumes associated with the Gordondale assets were included in Montney until the divestiture of these assets on July 28, 2016.

(2) Other Upstream Operations includes total production volumes from plays that are not part of the Company's current strategic focus. Canadian Other Upstream Operations primarily includes Wheatland, Horn River and Deep Panuke; USA Other Upstream Operations primarily includes Piceance, DJ Basin, San Juan and TMS. Production volumes associated with DJ Basin and TMS were included in Other Upstream Operations until the divestitures of these assets on July 29, 2016 and April 13, 2017, respectively.

(3) Other Upstream Operations includes capital expenditures in plays that are not part of the Company's current strategic focus. Canadian Other Upstream Operations primarily includes Wheatland; USA Other Upstream Operations primarily includes Piceance, DJ Basin, San Juan and TMS.

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Results by Play (continued)

	2017			2016					
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2 Year-to-date	Q2	Q1
Drilling Activity (net wells drilled)									
Canadian Operations									
Montney	**41**	**20**	21	24	8	3	13	5	8
Duvernay	**9**	**2**	7	20	5	5	10	5	5
Total Canadian Operations	**50**	**22**	28	44	13	8	23	10	13
USA Operations									
Eagle Ford	**26**	**9**	17	28	7	6	15	7	8
Permian	**64**	**30**	34	88	25	18	45	14	31
Other Upstream Operations [1]	**4**	**2**	2	-	-	-	-	-	-
Total USA Operations	**94**	**41**	53	116	32	24	60	21	39
Total Encana	**144**	**63**	81	160	45	32	83	31	52

(1) Other Upstream Operations includes net wells drilled in plays that are not part of the Company's current strategic focus. USA Other Upstream Operations primarily includes San Juan.

Encana Corporation

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

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