2015 Q3 Report

For the period ended
September 30, 2015

encana

Encana lowers costs and grows high margin production in the third quarter

Calgary, Alberta (November 12, 2015) **TSX, NYSE: ECA**

Encana continued to grow high margin production in each of its core four assets during the third quarter and took further decisive steps to lower its cost structures, manage its balance sheet and focus its portfolio. Highlights include:

- liquids production up 10 percent from the second quarter and 35 percent year-over-year to 140,400 barrels per day (bbls/d), marking an eighth consecutive quarter of liquids growth
- production from the company's core four assets, the Permian, Eagle Ford, Duvernay and Montney, increased 12 percent over the second quarter to 249,300 barrels of oil equivalent per day (BOE/d)
- cash flow increased by $190 million from the second quarter to $371 million
- disciplined capital allocation with over 90 percent of capital invested in the company's core four assets
- reduced Permian horizontal drilling and completions costs by $2.0 million per well and Eagle Ford drilling and completion costs by $2.4 million per well since acquiring positions in both plays last year
- announced agreements in August and October to divest its Haynesville and DJ Basin assets for a total cash consideration of $1.75 billion before closing adjustments; proceeds will be used to further strengthen the balance sheet and provide greater financial flexibility
- under the agreement to sell its Haynesville natural gas assets (effective date of January 1, 2015), Encana will reduce its gathering and midstream commitments by $480 million on an undiscounted basis

"During the third quarter all aspects of our strategy came together to drive performance and deliver value," said Doug Suttles, President & CEO. "Disciplined capital allocation in our core four assets, combined with fast-paced operational innovation, delivered sustainable performance improvements and grew high-margin, high-return liquids volumes, which helped offset the quarter-over-quarter impact of lower liquids prices."

Total company production in the quarter averaged 398,300 BOE/d with Encana's core four assets, the Permian, Eagle Ford, Duvernay and Montney, contributing 249,300 BOE/d or 63 percent. Third quarter liquids production was 140,400 bbls/d, up 10 percent from the second quarter and 35 percent year-over-year, marking an eighth consecutive quarter of liquids growth. Natural gas volumes averaged 1,547 million cubic feet per day (MMcf/d).

"Decisive action across the organization is continuously strengthening our business," said Suttles. "We are capturing the benefits of an increasingly focused portfolio and disciplined capital program, as well as significant reductions in our cost structures, debt and interest expense. Encana is competitively positioned, delivering strong returns in today's price environment with tremendous torque to any uplift in oil prices."

Since launching its strategy two years ago, Encana has driven down corporate costs, such as interest and administrative expenses, by about $300 million per year. Excluding one-time interest payments on the early redemption of debt, interest expense has been reduced by $150 million per year over that time. These proactive cost reductions, combined with $2.8 billion in announced and completed divestitures and a C$1.44 billion bought deal offering in 2015, will strengthen the balance sheet and provide greater financial flexibility. Pending the closing of previously announced divestitures, by year-end 2015 Encana expects to have reduced debt by around $2.8 billion with no long-term debt maturities until 2019.

Encana remains on track to deliver its 2015 cash flow guidance of between $1.4 billion and $1.6 billion. The company generated third quarter cash flow of $371 million or $0.44 per share, up $190 million from the second quarter when Encana made a $165 million one-time outlay associated with the early redemption of long-term debt. This early debt redemption is expected to save Encana $200 million in gross interest expense.

In the third quarter, the company reported an operating loss of $24 million or $0.03 per share; and a net loss of $1.2 billion or $1.47 per share primarily due to a $1.1 billion non-cash, after-tax ceiling test impairment. Year-to-date, Encana has generated $1.0 billion in cash flow or $1.29 per share; an operating loss of $172 million or $0.21 per share; and a net loss of $4.6 billion or $5.59 per share, largely attributable to non-cash, after-tax ceiling test impairments of $3.6 billion.

"Innovation is part of our culture and crucial to value creation," added Suttles. "Our decision to invest in operational innovation, particularly in the Permian, has delivered rapid and sustainable performance improvements and invaluable technical insight. Our continuous testing of well spacing, completions design and simultaneous operations is driving down costs, delivering better wells and helping us quickly discover optimal well designs in each of our core four assets."

To carry operational momentum into 2016, Encana has chosen to accelerate activity in the Permian originally scheduled for 2016 into the fourth quarter of this year, increasing its 2015 investment in the play by $150 million. Encana expects to conclude the year around the upper end of its 2015 capital guidance range of $2.2 billion.

Operating highlights:

Permian: **Top tier operator after only 10 months in play**

- continued success in reducing drilling and completion costs, which are down $2.0 million per well in less than a year since entering the play
- drilled latest pace-setting well in the Wolfcamp with a cycle time of 14 days
- successful continuation of simultaneous operations with frac plugs drilled out on four wells simultaneously on the same pad
- ran six 24-hour frac crews simultaneously over 10 days on six multi-well pads
- drilled 17 net horizontal wells and 27 net vertical wells and brought 28 net horizontal wells and 30 net vertical wells on production
- third quarter production of 45,700 BOE/d, up 28 and 42 percent from the second and first quarters respectively
- expect to drill 36 net wells and bring 30 on production in the fourth quarter
- on track to deliver fourth quarter production of 50,000 BOE/d
- returns averaging more than 30 percent in 2015 based on October strip pricing

Eagle Ford: **A great asset continues to outperform**

- continued success in reducing drilling and completion costs, which are down $2.4 million per well since entering the play in June 2014
- completed upgrades to Patton Trust North facility, which when combined with the second quarter upgrades at Patton Trust South, increased gross production capacity by 30,000 bbls/d
- drilled 10 net wells and brought 29 net wells on production
- third quarter production of 54,000 BOE/d, up 18 and 29 percent from the second and first quarters respectively
- expect to drill 14 net wells and bring seven on production in the fourth quarter
- on track to deliver fourth quarter production of 57,000 BOE/d
- returns averaging more than 30 percent in 2015 based on October strip pricing

Duvernay: **Delivering compelling returns**

- repeated industry-leading drilling and completion costs of $10.4 million per well on the 15-22 multi-well pad
- brought the 15-31 compressor station online, increasing processing capacity by 10,000 bbls/d and 50 MMcf/d
- drilled two net wells and brought seven net wells on production
- third quarter production of 9,300 BOE/d, up 59 and 69 percent from the second and first quarters respectively
- expect to drill five net wells and bring six on production in the fourth quarter
- on track to deliver fourth quarter production of 17,000 BOE/d
- returns averaging more than 30 percent in 2015 (excluding joint venture carry) based on October strip pricing

Montney: **Capital efficiency and continued liquids growth**

- strong liquids production in the Tower area, with four wells each flowing at more than 500 bbls/d of condensate within the first 30 days
- brought nine net wells on production
- third quarter production of 140,400 BOE/d, up three percent from the second quarter and comprising 21,800 bbls/d of liquids and 711 MMcf/d of natural gas; third quarter natural gas production was impacted by ongoing third-party transportation restrictions
- expect to drill two net wells and bring seven on production in the fourth quarter
- on track to deliver fourth quarter production of 146,000 BOE/d
- the company continues to monitor ongoing third-party transportation restrictions to assess potential impact on fourth quarter natural gas production
- returns averaging more than 60 percent in 2015 (excluding third party capital) based on October strip pricing

Additional information on Encana's core four assets will be available in the company's updated corporate presentation later today. Encana's updated 2015 guidance is available for download from http://www.encana.com/investors/financial/corporate-guidance.html.

Encana updates its risk management program in the quarter

At September 30, 2015, Encana has hedged approximately 1,000 MMcf/d of expected October to December 2015 natural gas production using NYMEX fixed price contracts at an average price of $4.29 per thousand cubic feet (Mcf) and approximately 95 MMcf/d of expected 2016 natural gas production using fixed price contracts at an average price of $2.98 per Mcf. In addition, Encana has protection on approximately 300 MMcf/d of expected 2016 natural gas production hedged under three-way costless collars. The NYMEX three-way costless collars are a combination of a sold call, purchased put and a sold put with average prices of $3.43, $3.21 and $2.72 per Mcf, respectively. These contracts allow the company to participate in the upside of commodity prices to the ceiling of the call option and provide the company with partial downside price protection through the combination of the put options.

At September 30, 2015, Encana has hedged approximately 88.9 thousand barrels per day (Mbbls/d) of expected October to December 2015 oil production using WTI fixed price contracts at an average price of $58.09 per bbl and approximately 38.0 Mbbls/d of expected 2016 oil production at an average price of $62.83 per bbl. Encana also has protection on approximately 18.3 Mbbls/d of expected 2016 oil production hedged under three-way costless collars. The WTI three-way costless collars are a combination of a sold call, purchased put and a sold put with average prices of $63.03, $55.00 and $47.24 per bbl, respectively.

Dividend declared

On November 11, 2015, Encana's Board of Directors declared a dividend of $0.07 per share payable on December 31, 2015, to common shareholders of record as of December 15, 2015.

Third Quarter Highlights

Financial Summary		
(for the period ended September 30) ($ millions, except per share amounts)	**Q3 2015**	Q3 2014
Cash flow[1]	**371**	807
Per share diluted	**0.44**	1.09
Operating earnings (loss)[1]	**(24)**	281
Per share diluted	**(0.03)**	0.38
Earnings Reconciliation Summary		
Net earnings (loss) attributable to common shareholders	**(1,236)**	2,807
After-tax (addition) deduction:		
Unrealized hedging gain (loss)	**107**	160
Impairments	**(1,066)**	-
Restructuring charges	**(20)**	(5)
Non-operating foreign exchange gain (loss)	**(212)**	(218)
Gain (loss) on divestitures	**(2)**	2,399
Income tax adjustments	**(19)**	190
Operating earnings (loss)[1]	**(24)**	281
Per share diluted	**(0.03)**	0.38

[1] Cash flow and operating earnings (loss) are non-GAAP measures as defined in Note 1 on page 4.

Production Summary			
(for the period ended September 30) (After royalties)	**Q3 2015**	Q3 2014	% Δ
Natural gas (MMcf/d)	**1,547**	2,199	(30)
Liquids (Mbbls/d)	**140.4**	104.0	35
Total production (MBOE/d)	**398.3**	470.6	(15)

Natural Gas and Liquids Prices		
	Q3 2015	Q3 2014
Natural Gas		
NYMEX ($/MMBtu)	**2.77**	4.06
Encana realized gas price[1] ($/Mcf)	**3.71**	4.03
Oil and Natural Gas Liquids ($/bbl)		
WTI	**46.43**	97.17
Encana realized oil price[1]	**49.38**	90.22
Encana realized NGLs price	**19.57**	48.76

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

A conference call and webcast to discuss the third quarter 2015 results will be held for the investment community today at 7 a.m. MT (9 a.m. ET). To participate, please dial (877) 291-4570 (toll-free in North America) or (647) 788-4919 about 10 minutes prior to the conference call. An archived recording of the call will be available from 10 a.m. MT on November 12 until 9:59 p.m. MT on November 19, 2015 by dialing (800) 585-8367 or (416) 621-4642 and entering passcode 56244231. A live audio webcast of the conference call, including slides, will also be available on Encana's website, www.encana.com, under Invest In Us/Presentations & Events. The webcasts will be archived for 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 natural gas, oil and natural gas liquids (NGLs). By partnering with employees, community organizations and other businesses, Encana contributes to the strength and sustainability of the communities where it operates. Encana common shares trade on the Toronto and New York stock exchanges under the symbol ECA.

Important Information

Encana reports in U.S. dollars unless otherwise noted. Production, sales and reserves estimates are reported on an after-royalties basis, unless otherwise noted. Per share amounts for cash flow and earnings are on a diluted basis. The term liquids is used to represent oil, NGLs and condensate. The term liquids-rich is used to represent natural gas streams with associated liquids volumes. Certain production and financial information contained in this news release are presented in approximate figures. Unless otherwise specified or the context otherwise requires, reference to Encana or to the company includes reference to subsidiaries of and partnership interests held by Encana Corporation and its subsidiaries.

NOTE 1: Non-GAAP measures

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

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

These measures have been described and presented in this news release in order to provide shareholders and potential investors with additional information regarding Encana's liquidity and its ability to generate funds to finance its operations. The company believes that the discounted after-tax future net cash flows from proved reserves required to be used in the ceiling test calculation are not indicative of the fair market value of Encana's natural gas and oil properties or the future cash flows expected to be generated from such properties.

Rates of return for a particular play or well are on a before-tax basis and are based on specified commodity prices with local pricing offsets, capital costs associated with drilling, completing and equipping a well, the Company's field operating expenses and certain type curve assumptions.

ADVISORY REGARDING OIL AND GAS INFORMATION

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

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

The disclosure regarding drilling locations is based on internal estimates. The drilling locations which Encana will actually drill will ultimately depend upon the availability of capital, regulatory and partner approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors.

ADVISORY REGARDING FORWARD-LOOKING STATEMENTS

This news release contains certain forward-looking statements or information (collectively, "forward-looking statements" or "FLS") within the meaning of applicable securities legislation. FLS include, but are not limited to: expected proceeds, including cash consideration, from divestiture transactions, the use of proceeds therefrom, the expectation that the respective closing conditions will be satisfied, the timing of closing thereof and the expected impact on cash flow; the Company's expectation that it will reduce its gathering and midstream commitments as a result of certain divestitures; expected 2015 capital investment, including increased capital investment in the Permian; expected 2015 cash flow; expected total reduction in debt and savings in gross interest expense; expected production and number of wells; the ability to manage the balance sheet and continue to improve operational innovation to increase returns and margins; increase in available production capacity as a result of upgrades to certain facilities; and the expectation of meeting the targets in the Company's 2015 corporate guidance.

Readers are cautioned against unduly relying on FLS which, by their nature, involve numerous assumptions, risks and uncertainties that may cause such statements not to occur, or for results to differ materially from those expressed or implied. These assumptions include, but are not limited to: the ability to satisfy closing conditions, successful closing of, and the value of post-closing and other adjustments associated with divestiture transactions; the expectation that counterparties will successfully fulfill their obligations under gathering and midstream commitments; assumptions contained in Encana's 2015 corporate guidance and in this news release; the effectiveness of Encana's resource play hub model to drive productivity and efficiencies; 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 expectation.

Risks and uncertainties that may affect these business outcomes include, but are not limited to: risks inherent to closing announced divestitures and adjustments that may reduce the expected proceeds and value to Encana; the ability to generate sufficient cash flow to meet the Company's obligations; commodity price volatility; ability to secure adequate product transportation and potential pipeline curtailments; variability of dividends to be paid; timing and costs of well, facilities and pipeline construction; business interruption and casualty losses or unexpected technical difficulties; counterparty and credit risk associated with hedging contracts; risk and effect of a downgrade in credit rating, including access to capital markets; failure to achieve anticipated results from cost and efficiency initiatives; risks inherent in marketing operations; risks associated with technology; the Company's ability to acquire or find additional reserves; imprecision of reserves estimates and estimates of recoverable quantities of natural gas and liquids from resource plays and other sources not currently classified as proved, probable or possible reserves or economic contingent resources, including future net revenue estimates; risks associated with past and future divestitures of certain assets or other transactions or receive amounts contemplated under the transaction agreements (such transactions may include third-party capital investments, farm-outs or partnerships, which Encana may refer to from time to time as "partnerships" or "joint ventures" and the funds received in respect thereof which Encana may refer to from time to time as "proceeds", "deferred purchase price" and/or "carry capital", regardless of the legal form) as a result of various conditions not being met; and other risks and uncertainties impacting Encana's business, as described from time to time in its most recent MD&A, financial statements, Annual Information Form and Form 40-F, as filed on SEDAR and EDGAR.

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

Management's Discussion and Analysis

For the period ended September 30, 2015

(Prepared in U.S. Dollars)

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") for Encana Corporation ("Encana" or the "Company") should be read with the unaudited interim Condensed Consolidated Financial Statements for the period ended September 30, 2015 ("Interim Condensed Consolidated Financial Statements"), as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2014.

The Interim Condensed Consolidated Financial Statements and comparative information have been prepared in accordance with United States ("U.S.") generally accepted accounting principles ("U.S. GAAP") and in U.S. dollars, except where another currency has been indicated. References to C$ are to Canadian dollars. Encana's financial results are consolidated in Canadian dollars; however, the Company has adopted the U.S. dollar as its reporting currency to facilitate a more direct comparison to other North American oil and gas companies. Production volumes are presented on an after royalties basis consistent with U.S. oil and gas reporting standards and the disclosure of U.S. oil and gas companies. The term "liquids" is used to represent oil, natural gas liquids ("NGLs" or "NGL") and condensate. The term "liquids rich" is used to represent natural gas streams with associated liquids volumes. This document is dated November 11, 2015.

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

Certain measures in this document do not have any standardized meaning as prescribed by U.S. GAAP and, therefore, are considered non-GAAP measures. Non-GAAP measures are commonly used in the oil and gas industry and by Encana to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. Non-GAAP measures include: Cash Flow; Free Cash Flow; Operating Earnings (Loss); Upstream Operating Cash Flow, excluding Hedging; Operating Netback; Debt to Debt Adjusted Cash Flow; and Debt to Adjusted Capitalization. Further information regarding these measures can be found in the Non-GAAP Measures section of this MD&A, including reconciliations of Cash from Operating Activities to Cash Flow and Free Cash Flow, and of Net Earnings (Loss) Attributable to Common Shareholders to Operating Earnings (Loss).

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

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

Encana's Strategic Objectives

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

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

Encana hedges a portion of its expected natural gas and oil production volumes. The Company's hedging program reduces volatility and helps sustain Cash Flow and Operating Netbacks during periods of lower prices. Further information on the Company's commodity price positions as at September 30, 2015 can be found in the Results Overview section of this MD&A and in Note 21 to the Interim Condensed Consolidated Financial Statements.

Additional information on expected results can be found in Encana's 2015 Corporate Guidance on the Company's website www.encana.com.

Encana's Business

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

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

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

- **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 for transportation commitments, product type, delivery points and customer diversification. These activities are reflected in the Market Optimization segment. Market Optimization sells substantially all of the Company's upstream production to third party customers. Transactions between segments are based on market values and are eliminated on consolidation. Financial information is presented on an after eliminations basis within this MD&A.

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

Results Overview

Highlights

In the three months ended September 30, 2015, Encana reported:

- Cash Flow of $371 million and an Operating Loss of $24 million.
- Net Loss of $1,236 million, including an after-tax non-cash ceiling test impairment of $1,066 million.
- Average realized natural gas prices, including financial hedges, of $3.71 per Mcf. Average realized oil prices, including financial hedges, of $49.38 per bbl. Average realized NGL prices of $19.57 per bbl.
- Average natural gas production volumes of 1,547 MMcf/d and average oil and NGL production volumes of 140.4 Mbbls/d.
- Dividends paid of $0.07 per share.

In the nine months ended September 30, 2015, Encana reported:

- Cash Flow of $1,047 million and an Operating Loss of $172 million.
- Net Loss of $4,553 million, including after-tax non-cash ceiling test impairments of $3,616 million.
- Average realized natural gas prices, including financial hedges, of $4.04 per Mcf. Average realized oil prices, including financial hedges, of $49.64 per bbl. Average realized NGL prices of $21.78 per bbl.
- Average natural gas production volumes of 1,656 MMcf/d and average oil and NGL production volumes of 129.5 Mbbls/d.
- Dividends paid of $0.21 per share.
- Cash and cash equivalents of $352 million at period end.

Significant developments for the Company during the nine months ended September 30, 2015 included the following:

- Announced an agreement with GEP Haynesville, LLC ("GeoSouthern") on August 25, 2015, to sell the Company's Haynesville natural gas assets, which include approximately 112,000 net acres of leasehold, plus additional fee mineral lands located in northern Louisiana, for cash consideration of approximately $850 million. Based on the January 1, 2015 effective date of the transaction, Encana will also reduce its gathering and midstream commitments by approximately $480 million (undiscounted) through the transfer of current and future obligations and will transport and market GeoSouthern's Haynesville production on a fee for service basis for the next five years. The transaction is expected to close in the fourth quarter of 2015, with an effective date of January 1, 2015, and is subject to satisfaction of normal closing conditions and regulatory approvals. The Company expects to use the proceeds received to reduce debt.
- Completed a bought deal offering of 85,616,500 common shares of Encana and the over-allotment option of an additional 12,842,475 common shares of Encana at a price of C$14.60 per common share (the "Share Offering"). The Share Offering was completed during March 2015 for aggregate gross proceeds of approximately C$1.44 billion.
- Redeemed the Company's $700 million 5.90 percent notes due December 1, 2017 and its C$750 million 5.80 percent medium-term notes due January 18, 2018, in April 2015, using net proceeds from the Share Offering and cash on hand.
- Closed the sale of the Company's working interest in certain properties in central and southern Alberta to Ember Resources Inc. on January 15, 2015 for proceeds of approximately C$558 million, after closing adjustments.

- Closed the sale of certain natural gas gathering and compression assets in northeastern British Columbia to Veresen Midstream Limited Partnership (“VMLP”) on March 31, 2015 for cash consideration net to Encana of approximately C$453 million, after closing adjustments.

Subsequent Event

On October 8, 2015, Encana announced an agreement to sell its DJ Basin assets in Colorado, comprising 51,000 net acres, to a new entity jointly owned by the Canada Pension Plan Investment Board and The Broe Group for total consideration of approximately $900 million. The transaction is expected to close in the fourth quarter of 2015, with an effective date of April 1, 2015, and is subject to satisfaction of normal closing conditions, regulatory approvals and other adjustments.

Financial Results

($ millions, except as indicated)	Nine months ended September 30 2015	2014	2015 Q3	Q2	Q1	2014 Q4	Q3	Q2	Q1	2013 Q4
Cash Flow (1)	**$ 1,047**	$ 2,557	**$ 371**	$ 181	$ 495	$ 377	$ 807	$ 656	$ 1,094	$ 677
$ per share - diluted	**1.29**	3.45	**0.44**	0.22	0.65	0.51	1.09	0.89	1.48	0.91
Operating Earnings (Loss) (1), (2)	**(172)**	967	**(24)**	(167)	19	35	281	171	515	226
$ per share - diluted	**(0.21)**	1.30	**(0.03)**	(0.20)	0.03	0.05	0.38	0.23	0.70	0.31
Net Earnings (Loss) Attributable to Common Shareholders	**(4,553)**	3,194	**(1,236)**	(1,610)	(1,707)	198	2,807	271	116	(251)
$ per share - basic & diluted	**(5.59)**	4.31	**(1.47)**	(1.91)	(2.25)	0.27	3.79	0.37	0.16	(0.34)
Revenues, Net of Royalties	**3,391**	5,765	**1,312**	830	1,249	2,254	2,285	1,588	1,892	1,423
Realized Hedging Gain (Loss), before tax	**614**	(215)	**213**	161	240	124	28	(102)	(141)	174
Unrealized Hedging Gain (Loss), before tax	**(241)**	(45)	**173**	(278)	(136)	489	231	9	(285)	(301)
Upstream Operating Cash Flow	**1,712**	3,097	**531**	479	702	821	982	800	1,315	901
Upstream Operating Cash Flow, excluding Hedging (1)	**1,083**	3,305	**314**	315	454	694	952	898	1,455	728
Capital Investment	**1,952**	1,669	**473**	743	736	857	598	560	511	717
Net Acquisitions & (Divestitures) (3)	**(1,077)**	(1,379)	**(99)**	(140)	(838)	50	(2,007)	652	(24)	(72)
Free Cash Flow (1)	**(905)**	888	**(102)**	(562)	(241)	(480)	209	96	583	(40)
Ceiling Test Impairments, after tax	**(3,616)**	-	**(1,066)**	(1,328)	(1,222)	-	-	-	-	-
Gain (Loss) on Divestitures, after tax	**9**	2,534	**(2)**	1	10	(11)	2,399	135	-	-
Production Volumes										
Natural Gas (MMcf/d)	**1,656**	2,515	**1,547**	1,568	1,857	1,861	2,199	2,541	2,809	2,744
Oil & NGLs (Mbbls/d)										
Oil	**85.8**	42.9	**91.9**	86.2	79.2	68.8	62.1	34.2	32.1	33.0
NGLs	**43.7**	37.3	**48.5**	41.1	41.5	37.6	41.9	34.0	35.8	33.0
Total Oil & NGLs	**129.5**	80.2	**140.4**	127.3	120.7	106.4	104.0	68.2	67.9	66.0
Total Production (MBOE/d)	**405.6**	499.3	**398.3**	388.7	430.1	416.7	470.6	491.8	536.1	523.4
Production Mix (%)										
Natural Gas	**68**	84	**65**	67	72	74	78	86	87	87
Oil & NGLs	**32**	16	**35**	33	28	26	22	14	13	13

(1) A non-GAAP measure, which is defined in the Non-GAAP Measures section of this MD&A.
(2) In continued support of Encana's strategy, organizational structure changes were formalized in Q2 2015 and resulted in a revision to the Q1 2015 Operating Earnings to exclude restructuring charges incurred in the first quarter.
(3) Excludes the impact of the PrairieSky Royalty Ltd. divestiture and the Athlon Energy Inc. acquisition during 2014, as summarized in the Net Capital Investment section of this MD&A.

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

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

In the third quarter and first nine months of 2015, the Company recognized after-tax non-cash ceiling test impairments of $1,066 million and $3,616 million, respectively, in the U.S. cost centre. The non-cash ceiling test impairments primarily resulted from the decline in the 12-month average trailing commodity prices. Further declines in the 12-month average trailing commodity prices could reduce proved reserves volumes and values and result in the recognition of future ceiling test impairments. Future ceiling test impairments can also result from changes to reserves estimates, future development costs, capitalized costs and unproved property costs. Proceeds received from natural gas and oil property divestitures are generally deducted from the Company's capitalized costs and can reduce the likelihood of ceiling test impairments.

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

Three months ended September 30, 2015 versus September 30, 2014

Cash Flow of $371 million decreased $436 million in the three months ended September 30, 2015 and was impacted by the following significant items:

- Average realized natural gas prices, excluding financial hedges, were $2.60 per Mcf compared to $3.88 per Mcf in 2014 reflecting lower benchmark prices. Lower realized natural gas prices decreased revenues $180 million. Average realized liquids prices, excluding financial hedges, were $34.52 per bbl compared to $73.48 per bbl in 2014 reflecting lower benchmark prices. Lower realized liquids prices decreased revenues $396 million.
- Average natural gas production volumes of 1,547 MMcf/d decreased 652 MMcf/d from 2,199 MMcf/d in 2014 primarily due to divestitures, natural declines in Haynesville and Piceance and lower production from Deep Panuke, partially offset by successful drilling programs in Montney and Duvernay. Lower natural gas volumes decreased revenues $238 million. Average oil and NGL production volumes of 140.4 Mbbls/d increased 36.4 Mbbls/d from 104.0 Mbbls/d in 2014 primarily due to acquisitions and successful drilling programs in liquids rich plays, partially offset by divestitures. Higher oil and NGL volumes increased revenues $139 million.
- Realized financial hedging gains before tax were $213 million compared to $28 million in 2014.
- Transportation and processing expense decreased $51 million primarily due to the lower U.S./Canadian dollar exchange rate, divestitures and lower production from Deep Panuke, partially offset by higher volumes in Montney.
- Current tax was a recovery of $19 million compared to an expense of $244 million in 2014 as discussed in the Other Operating Results section of this MD&A. Cash Flow excludes cash tax on the sale of assets as discussed in the Non-GAAP measures section of this MD&A.

Operating Loss in the third quarter of 2015 was $24 million compared to Operating Earnings of $281 million in 2014 primarily due to the items discussed in the Cash Flow section. Operating Loss in the third quarter of 2015 was also impacted by higher foreign exchange losses on settlements and the revaluation of other monetary assets and liabilities, lower depreciation, depletion and amortization ("DD&A") and changes in deferred tax.

Net Loss Attributable to Common Shareholders in the third quarter of 2015 was $1,236 million compared to Net Earnings Attributable to Common Shareholders of $2,807 million in 2014 primarily due to a lower after-tax gain on divestitures, an after-tax non-cash ceiling test impairment and the items discussed in the Cash Flow and Operating Earnings sections. Net Loss in the third quarter of 2015 was also impacted by lower after-tax unrealized hedging gains and changes in deferred tax.

Nine months ended September 30, 2015 versus September 30, 2014

Cash Flow of $1,047 million decreased $1,510 million in the nine months ended September 30, 2015 and was impacted by the following significant items:

- Average realized natural gas prices, excluding financial hedges, were $2.87 per Mcf compared to $4.99 per Mcf in 2014 reflecting lower benchmark prices. Lower realized natural gas prices decreased revenues $911 million. Average realized liquids prices, excluding financial hedges, were $37.45 per bbl compared to $71.66 per bbl in 2014 reflecting lower benchmark prices. Lower realized liquids prices decreased revenues $812 million.
- Average natural gas production volumes of 1,656 MMcf/d decreased 859 MMcf/d from 2,515 MMcf/d in 2014 primarily due to divestitures, natural declines in Haynesville and Piceance and lower production from Deep Panuke, partially offset by successful drilling programs in Montney and Duvernay. Lower natural gas volumes decreased revenues $1,222 million. Average oil and NGL production volumes of 129.5 Mbbls/d increased 49.3 Mbbls/d from 80.2 Mbbls/d in 2014 primarily due to acquisitions and successful drilling programs in liquids rich plays, partially offset by divestitures. Higher oil and NGL volumes increased revenues $566 million.
- Realized financial hedging gains before tax were $614 million compared to losses of $215 million in 2014.
- Transportation and processing expense decreased $190 million primarily due to divestitures, the lower U.S./Canadian dollar exchange rate and lower production from Deep Panuke, partially offset by higher volumes in Montney.
- Interest expense increased $106 million primarily due to a one-time interest payment of approximately $165 million resulting from the April 2015 early debt redemptions, partially offset by lower interest on debt following these redemptions.
- Current tax was a recovery of $38 million compared to an expense of $241 million in 2014 as discussed in the Other Operating Results section of this MD&A. Cash Flow excludes cash tax on the sale of assets as discussed in the Non-GAAP measures section of this MD&A.

Operating Loss in the first nine months of 2015 was $172 million compared to Operating Earnings of $967 million in 2014 primarily due to the items discussed in the Cash Flow section. Operating Loss in the first nine months of 2015 was also impacted by higher foreign exchange losses on settlements and the revaluation of other monetary assets and liabilities, lower long-term compensation costs due to the decrease in the Encana share price, lower DD&A and changes in deferred tax.

Net Loss Attributable to Common Shareholders in the first nine months of 2015 was $4,553 million compared to Net Earnings Attributable to Common Shareholders of $3,194 million in 2014 primarily due to after-tax non-cash ceiling test impairments, a lower after-tax gain on divestitures and the items discussed in the Cash Flow and Operating Earnings sections. Net Loss in the first nine months of 2015 was also impacted by a higher after-tax non-operating foreign exchange loss, higher after-tax unrealized hedging losses and changes in deferred tax.

Prices and Foreign Exchange Rates

(average for the period)	Nine months ended September 30 2015	Nine months ended September 30 2014	2015 Q3	2015 Q2	2015 Q1	2014 Q4	2014 Q3	2014 Q2	2014 Q1	2013 Q4
Encana Realized Pricing										
Including Hedging										
Natural Gas ($/Mcf)	**$ 4.04**	$ 4.70	**$ 3.71**	$ 3.52	$ 4.78	$ 4.16	$ 4.03	$ 4.08	$ 5.82	$ 4.34
Oil & NGLs ($/bbl)										
Oil	**49.64**	89.09	**49.38**	53.08	46.17	80.38	90.22	89.55	86.34	85.39
NGLs	**21.78**	50.55	**19.57**	24.28	21.92	40.87	48.76	49.39	53.79	48.59
Total Oil & NGLs	**40.24**	71.18	**39.09**	43.78	37.83	66.40	73.50	69.53	69.19	67.01
Total ($/BOE)	**29.36**	35.12	**28.17**	28.53	31.24	35.55	35.06	30.75	39.22	31.23
Excluding Hedging										
Natural Gas ($/Mcf)	**2.87**	4.99	**2.60**	2.37	3.53	3.94	3.88	4.46	6.37	3.69
Oil & NGLs ($/bbl)										
Oil	**45.43**	89.99	**42.40**	53.15	40.53	66.38	90.18	92.93	86.43	82.54
NGLs	**21.78**	50.55	**19.57**	24.28	21.92	40.87	48.76	49.39	53.79	48.59
Total Oil & NGLs	**37.45**	71.66	**34.52**	43.83	34.13	57.35	73.48	71.23	69.23	65.58
Total ($/BOE)	**23.68**	36.64	**22.26**	23.90	24.82	32.25	34.36	32.93	42.12	27.63
Natural Gas Price Benchmarks										
NYMEX ($/MMBtu)	**2.80**	4.55	**2.77**	2.64	2.98	4.00	4.06	4.67	4.94	3.60
AECO (C$/Mcf)	**2.81**	4.55	**2.80**	2.67	2.95	4.01	4.22	4.68	4.76	3.15
Algonquin City Gate ($/MMBtu)	**5.31**	9.09	**2.37**	2.24	11.41	4.99	2.97	4.23	20.28	7.80
Basis Differential ($/MMBtu)										
AECO/NYMEX	**0.56**	0.38	**0.61**	0.50	0.57	0.44	0.16	0.40	0.60	0.59
Oil Price Benchmarks										
West Texas Intermediate (WTI) ($/bbl)	**51.00**	99.61	**46.43**	57.94	48.64	73.15	97.17	102.99	98.68	97.46
Edmonton Light Sweet (C$/bbl)	**58.63**	100.87	**56.23**	67.71	51.94	75.69	97.16	105.61	99.83	86.58
Foreign Exchange										
Average U.S./Canadian Dollar Exchange Rate	**0.794**	0.914	**0.764**	0.813	0.806	0.881	0.918	0.917	0.906	0.953

Encana's financial results are influenced by fluctuations in commodity prices, price differentials and the U.S./Canadian dollar exchange rate. In the third quarter and first nine months of 2015, Encana's average realized natural gas price, excluding hedging, reflected lower benchmark prices compared to 2014. Hedging activities contributed $1.11 per Mcf to Encana's average realized natural gas price in the third quarter of 2015 and $1.17 per Mcf in the first nine months of 2015. The average realized natural gas price for production from Deep Panuke was $9.40 per Mcf in the first nine months of 2015 compared to $8.71 per Mcf in 2014 and increased Encana's average realized natural gas price $0.29 per Mcf in the first nine months of 2015 compared to $0.37 per Mcf in 2014.

In the third quarter and first nine months of 2015, Encana's average realized oil and NGL prices, excluding hedging, reflected lower benchmark prices compared to 2014. Hedging activities contributed $6.98 per bbl to Encana's average realized oil price in the third quarter of 2015 and $4.21 per bbl in the first nine months of 2015.

Financial Hedge Agreements

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

During the third quarter of 2015, Encana entered into NYMEX and WTI three-way costless collars. The three-way costless collars are a combination of a sold call, purchased put and a sold put. These contracts allow the Company to participate in the upside of commodity prices to the ceiling of the call option and provide the Company with partial downside price protection through the combination of the put options.

The tables below summarize Encana's hedging contracts on expected future production as at September 30, 2015.

Natural Gas

	Term	Notional Volumes (MMcf/d)	Average Price ($/Mcf)
NYMEX Fixed Price Contracts	2015	1,000	4.29
NYMEX Fixed Price Contracts	2016	95	2.98
NYMEX Three-Way Costless Collars	2016	300	
Sold call price			3.43
Bought put price			3.21
Sold put price			2.72

Crude Oil

	Term	Notional Volumes (Mbbls/d)	Average Price ($/bbl)
WTI Fixed Price Contracts	2015	88.9	58.09
WTI Fixed Price Contracts	2016	38.0	62.83
WTI Fixed Price Swaptions (1)	2016	7.5	50.34
WTI Three-Way Costless Collars	2016	18.3	
Sold call price			63.03
Bought put price			55.00
Sold put price			47.24

(1) The WTI Fixed Price Swaptions give the counterparty the option to extend fourth quarter 2015 fixed price swaps to March 2016 at the same price.

The Company's hedging program helps sustain Cash Flow and Operating Netbacks during periods of lower prices. For additional information, see the Risk Management – Financial Risks section of this MD&A.

Foreign Exchange

As disclosed in the Prices and Foreign Exchange Rates table, the average U.S./Canadian dollar exchange rate decreased 0.154 in the third quarter of 2015 compared to the third quarter of 2014 and 0.120 in the first nine months of 2015 compared to the first nine months of 2014. The table below summarizes selected foreign exchange impacts on Encana's financial results when compared to the same periods in 2014.

	Three months ended September 30		Nine months ended September 30	
	$ millions	$/BOE	$ millions	$/BOE
Increase (Decrease) in:				
Capital Investment	**$ (49)**		**$ (121)**	
Transportation and Processing Expense	**(34)**	**$ (0.93)**	**(83)**	**$ (0.75)**
Operating Expense	**(12)**	**(0.34)**	**(31)**	**(0.28)**
Administrative Expense	**(7)**	**(0.19)**	**(23)**	**(0.20)**
Depreciation, Depletion and Amortization	**(27)**	**(0.76)**	**(65)**	**(0.59)**

Price Sensitivities

Natural gas and liquids prices fluctuate in response to changing market forces, creating varying impacts on Encana's financial results. The Company's potential exposure to commodity price fluctuations is summarized in the table below, which shows the estimated effects that certain price changes would have had on the Company's Cash Flow and Operating Earnings (Loss) for the third quarter of 2015. The price sensitivities below are based on business conditions, transactions and production volumes during the third quarter of 2015. Accordingly, these sensitivities may not be indicative of financial results for other periods, under other economic circumstances or with additional fluctuations in commodity prices.

		Impact On	
($ millions, except as indicated)	Price Change (1)	Cash Flow	Operating Earnings (Loss)
Increase or Decrease in:			
NYMEX Natural Gas Price	+/- $0.50/MMBtu	$ 20	$ 14
WTI Oil Price	+/- $10.00/bbl	50	33

(1) Assumes only one variable changes while all other variables are held constant.

Net Capital Investment

($ millions)	Three months ended September 30 2015	2014	Nine months ended September 30 2015	2014
Canadian Operations	**$ 76**	$ 293	**$ 341**	$ 924
USA Operations	**394**	305	**1,605**	737
Market Optimization	**1**	(2)	**1**	-
Corporate & Other	**2**	2	**5**	8
Capital Investment	**473**	598	**1,952**	1,669
Acquisitions	**-**	29	**38**	2,975
Divestitures	**(99)**	(2,036)	**(1,115)**	(4,354)
Net Acquisitions & (Divestitures)	**(99)**	(2,007)	**(1,077)**	(1,379)
Net Capital Investment	**$ 374**	$ (1,409)	**$ 875**	$ 290

Capital Investment by Play

($ millions)	Three months ended September 30 2015	2014	Nine months ended September 30 2015	2014
Canadian Operations				
Montney [1]	**$ 17**	$ 204	**$ 144**	$ 622
Duvernay	**58**	58	**185**	210
Other Upstream Operations				
Wheatland [2]	**-**	10	**4**	40
Bighorn	**-**	3	**-**	22
Deep Panuke	**-**	4	**3**	3
Other and emerging [1]	**1**	14	**5**	27
Total Canadian Operations	**$ 76**	$ 293	**$ 341**	$ 924
USA Operations				
Eagle Ford	**$ 142**	$ 113	**$ 514**	$ 125
Permian	**219**	-	**761**	-
DJ Basin	**17**	68	**161**	196
San Juan	**2**	89	**61**	191
Other Upstream Operations				
Piceance	**1**	3	**7**	29
Haynesville	**15**	1	**27**	34
Jonah	**-**	(2)	**-**	25
East Texas	**-**	(1)	**-**	9
Other and emerging	**(2)**	34	**74**	128
Total USA Operations	**$ 394**	$ 305	**$ 1,605**	$ 737
Capital Investment – Strategic Assets [1]	**$ 436**	$ 375	**$ 1,604**	$ 957

(1) Montney has been realigned to include certain capital investments which were previously reported in Other and emerging.
(2) Wheatland was previously presented as Clearwater.

Strategic assets include Montney, Duvernay, Eagle Ford and Permian. Other Upstream Operations includes capital investment from plays that are not part of the Company's current strategic focus as well as prospective plays that are under appraisal, including the Tuscaloosa Marine Shale ("TMS"), which is reported within Other and emerging in the USA Operations.

Capital investment associated with the Clearwater lands transferred to PrairieSky Royalty Ltd. ("PrairieSky") was included in Encana's Wheatland play until September 25, 2014, after which Encana no longer held an interest in PrairieSky.

Capital Investment

Capital investment during the first nine months of 2015 was $1,952 million (2014 – $1,669 million) which reflected disciplined capital spending focused on investment in the Company's strategic assets. During the first nine months of 2015, capital spending in Encana's strategic assets totaled $1,604 million (2014 – $957 million), representing approximately 82 percent (2014 – 57 percent) of capital investment.

Divestitures

Divestitures in the first nine months of 2015 were $935 million in the Canadian Operations and $127 million in the USA Operations, which primarily included the transactions discussed below, as well as the sale of land and properties that do not complement Encana's existing portfolio of assets.

The Canadian Operations included approximately C$558 million ($468 million), after closing adjustments, for the sale of the Company's working interest in certain assets included in Wheatland located in central and southern Alberta which comprised approximately 1.2 million net acres of land that contained over 6,800 producing wells. Encana retains a working interest in approximately 1.0 million net acres in Wheatland. In addition, the Canadian Operations included approximately C$453 million ($357 million), after closing adjustments, in cash consideration net to Encana for the sale of certain natural gas gathering and compression assets in northeastern British Columbia to VMLP. In conjunction with the sale, VMLP will undertake the expansion of future midstream services and will also provide natural gas gathering and processing in Montney to Encana and the Cutbank Ridge Partnership. Further information regarding VMLP can be found in Note 16 to the Interim Condensed Consolidated Financial Statements.

Divestitures in the first nine months of 2014 were $1,850 million in the Canadian Operations and $2,270 million in the USA Operations. The Canadian Operations primarily included approximately $1.7 billion, after closing adjustments, for the sale of the Company's Bighorn assets. The USA Operations primarily included approximately $1.6 billion, after closing adjustments, for the sale of the Jonah properties and approximately $497 million for the sale of certain properties in East Texas.

Amounts received from the divestiture transactions discussed above have been deducted from the respective Canadian and U.S. full cost pools, except for divestitures that resulted in a significant alteration between capitalized costs and proved reserves in the respective country cost centre. For divestitures that result in a gain or loss and constitute a business, goodwill is allocated to the divestiture. Accordingly, for the third quarter and first nine months of 2014, Encana recognized a gain of approximately $1,024 million, before tax, on the sale of the Company's Bighorn assets in the Canadian cost centre and allocated goodwill of $257 million. In addition, for the nine months ended September 30, 2014, Encana recognized a gain of approximately $212 million, before tax, on the sale of the Jonah properties in the U.S. cost centre and allocated goodwill of $68 million.

Acquisitions

Acquisitions in the first nine months of 2014 were $2,961 million in the USA Operations which primarily related to the acquisition of Eagle Ford.

2014 Capital Transactions

The significant acquisition and divestiture transactions below, which occurred during 2014, have impacted the Company's production volume and operating cash flow variances for the third quarter and first nine months of 2015. A comprehensive discussion of these transactions is included in the annual MD&A for the year ended December 31, 2014.

Transaction	Location	Closing Date
Canadian Operations		
Divestiture of Encana's remaining investment in PrairieSky [(1), (2)]	Alberta	September 26, 2014
Sale of Bighorn assets	Alberta	September 30, 2014
USA Operations		
Sale of Jonah properties	Wyoming	May 12, 2014
Sale of East Texas properties	Texas	June 19, 2014
Acquisition of properties in the Eagle Ford shale formation	Texas	June 20, 2014
Acquisition of Athlon Energy Inc. with assets in the Permian Basin [(1)]	Texas	November 13, 2014

(1) Transactions involved the disposition or acquisition of common shares and, therefore, were not part of the Company's net acquisition and divestiture activity for 2014.
(2) Encana completed the initial public offering of PrairieSky on May 29, 2014.

On September 26, 2014, Encana completed the secondary offering of 70.2 million common shares of PrairieSky at a price of C$36.50 per common share for aggregate gross proceeds of approximately C$2.6 billion. Following the completion of the secondary offering, Encana no longer held an interest in PrairieSky. As the sale of the investment in PrairieSky resulted in a significant alteration between capitalized costs and proved reserves in the Canadian cost centre, Encana recognized a gain on divestiture of approximately $2.1 billion, before tax. Further information on the PrairieSky transactions can be found in Note 15 to the Interim Condensed Consolidated Financial Statements.

Production Volumes

(average daily, after royalties)	Three months ended September 30 2015	2014	Nine months ended September 30 2015	2014
Natural Gas (MMcf/d)	**1,547**	2,199	**1,656**	2,515
Oil (Mbbls/d)	**91.9**	62.1	**85.8**	42.9
NGLs (Mbbls/d)	**48.5**	41.9	**43.7**	37.3
Total Oil & NGLs (Mbbls/d)	**140.4**	104.0	**129.5**	80.2
Total Production (MBOE/d)	**398.3**	470.6	**405.6**	499.3
Production Mix (%)				
Natural Gas	**65**	78	**68**	84
Oil & NGLs	**35**	22	**32**	16

Production Volumes by Play

	Three months ended September 30				Nine months ended September 30			
(average daily, after royalties)	Natural Gas (MMcf/d)		Oil & NGLs (Mbbls/d)		Natural Gas (MMcf/d)		Oil & NGLs (Mbbls/d)	
	2015	2014	**2015**	2014	**2015**	2014	**2015**	2014
Canadian Operations								
Montney [(1)]	**711**	644	**21.8**	20.8	**705**	623	**22.3**	16.9
Duvernay	**26**	15	**4.9**	2.6	**20**	11	**3.6**	1.9
Other Upstream Operations								
Wheatland [(2)]	**80**	291	**0.4**	9.9	**89**	307	**1.1**	10.9
Bighorn	**-**	162	**-**	8.7	**1**	212	**-**	10.6
Deep Panuke	**-**	186	**-**	-	**71**	227	**-**	-
Other and emerging [(1)]	**59**	76	**0.1**	0.3	**75**	88	**0.1**	-
Total Canadian Operations	**876**	1,374	**27.2**	42.3	**961**	1,468	**27.1**	40.3
USA Operations								
Eagle Ford	**48**	35	**46.0**	37.6	**40**	13	**40.6**	14.3
Permian	**54**	-	**36.7**	-	**42**	-	**31.0**	-
DJ Basin	**55**	38	**16.1**	11.8	**53**	40	**15.2**	10.8
San Juan	**15**	9	**6.8**	3.5	**14**	8	**6.7**	3.4
Other Upstream Operations								
Piceance	**311**	398	**3.5**	4.8	**326**	414	**3.6**	5.2
Haynesville	**177**	298	**-**	-	**203**	331	**-**	-
Jonah	**-**	-	**-**	0.2	**-**	134	**-**	2.4
East Texas	**-**	21	**-**	-	**-**	77	**-**	0.7
Other and emerging	**11**	26	**4.1**	3.8	**17**	30	**5.3**	3.1
Total USA Operations	**671**	825	**113.2**	61.7	**695**	1,047	**102.4**	39.9
Total Production Volumes	**1,547**	2,199	**140.4**	104.0	**1,656**	2,515	**129.5**	80.2
Total Production Volumes – Strategic Assets [(1)]	**839**	694	**109.4**	61.0	**807**	647	**97.5**	33.1

(1) Montney has been realigned to include certain production volumes which were previously reported in Other and emerging.
(2) Wheatland was previously presented as Clearwater.

Strategic assets include Montney, Duvernay, Eagle Ford and Permian. Other Upstream Operations includes production volumes from plays that are not part of the Company's current strategic focus as well as prospective plays that are under appraisal, including the TMS, which is reported within Other and emerging in the USA Operations.

The production volumes associated with the Clearwater lands transferred to PrairieSky were included in Encana's Wheatland play until September 25, 2014, after which Encana no longer held an interest in PrairieSky.

Natural Gas Production Volumes

In the third quarter of 2015, average natural gas production volumes of 1,547 MMcf/d decreased 652 MMcf/d from 2014. In the first nine months of 2015, average natural gas production volumes of 1,656 MMcf/d decreased 859 MMcf/d from 2014.

In the third quarter and first nine months of 2015, the Canadian Operations volumes were lower primarily due to shut-in production at Deep Panuke as a result of the implementation of a seasonal operating strategy during May 2015, the sale of certain assets included in Wheatland in January 2015, and the sale of the Bighorn assets in the third quarter of 2014, partially offset by successful drilling programs in Montney and Duvernay. In the first nine months of 2015, production volumes were also lower due to a higher water production rate at Deep Panuke.

In the third quarter of 2015, the USA Operations volumes were lower primarily due to natural declines in Haynesville and Piceance. In the first nine months of 2015, the USA Operations volumes were lower primarily due to natural declines in Haynesville and Piceance and the sales of the Jonah and East Texas properties in the second quarter of 2014.

Oil and NGL Production Volumes

In the third quarter of 2015, average oil and NGL production volumes of 140.4 Mbbls/d increased 36.4 Mbbls/d from 2014. In the first nine months of 2015, average oil and NGL production volumes of 129.5 Mbbls/d increased 49.3 Mbbls/d from 2014.

In the third quarter and first nine months of 2015, USA Operations volumes were higher primarily due to the acquisition of the Permian assets in the fourth quarter of 2014 and successful drilling programs mainly in the Permian and Eagle Ford. In the first nine months of 2015, production volumes were also higher due to the acquisition of Eagle Ford in the second quarter of 2014.

The Canadian Operations volumes were lower in the third quarter and first nine months of 2015 primarily due to the sales of the Bighorn assets and the Company's investment in PrairieSky in the third quarter of 2014, partially offset by successful drilling programs in Montney and Duvernay.

Results of Operations

Canadian Operations

Operating Cash Flow

($ millions)	Natural Gas 2015	Natural Gas 2014	Oil & NGLs 2015	Oil & NGLs 2014	Total (1) 2015	Total (1) 2014
	Three months ended September 30					
Revenues, Net of Royalties, excluding Hedging	**$ 199**	$ 480	**$ 75**	$ 251	**$ 282**	$ 740
Realized Financial Hedging Gain (Loss)	**104**	20	**5**	(1)	**109**	19
Revenues, Net of Royalties	**303**	500	**80**	250	**391**	759
Expenses						
Production and mineral taxes	**-**	1	**-**	3	**-**	4
Transportation and processing	**142**	186	**11**	16	**153**	202
Operating	**35**	66	**2**	8	**38**	76
Operating Cash Flow	**$ 126**	$ 247	**$ 67**	$ 223	**$ 200**	$ 477

Production Volumes

	Natural Gas (MMcf/d) 2015	Natural Gas (MMcf/d) 2014	Oil & NGLs (Mbbls/d) 2015	Oil & NGLs (Mbbls/d) 2014	Total (MBOE/d) 2015	Total (MBOE/d) 2014
	Three months ended September 30					
Production Volumes – After Royalties	**876**	1,374	**27.2**	42.3	**173.2**	271.4

Operating Netback [(2)]

	Natural Gas ($/Mcf) 2015	Natural Gas ($/Mcf) 2014	Oil & NGLs ($/bbl) 2015	Oil & NGLs ($/bbl) 2014	Total ($/BOE) 2015	Total ($/BOE) 2014
	Three months ended September 30					
Revenues, Net of Royalties, excluding Hedging	**$ 2.48**	$ 3.78	**$ 29.75**	$ 64.79	**$ 17.22**	$ 29.21
Realized Financial Hedging Gain (Loss)	**1.28**	0.16	**2.09**	(0.31)	**6.82**	0.78
Revenues, Net of Royalties	**3.76**	3.94	**31.84**	64.48	**24.04**	29.99
Expenses						
Production and mineral taxes	**-**	0.01	**(0.02)**	0.67	**0.01**	0.15
Transportation and processing	**1.77**	1.47	**3.95**	4.21	**9.55**	8.10
Operating	**0.44**	0.52	**1.22**	2.05	**2.42**	2.96
Operating Netback	**$ 1.55**	$ 1.94	**$ 26.69**	$ 57.55	**$ 12.06**	$ 18.78

(1) Also includes other revenues and expenses, such as third party processing, with no associated volumes.
(2) A Non-GAAP measure as defined in the Non-GAAP Measures section of this MD&A.

Three months ended September 30, 2015 versus September 30, 2014

Operating Cash Flow of $200 million decreased $277 million and was impacted by the following significant items:

- Lower natural gas prices reflected lower benchmark prices, which decreased revenues $107 million. Lower liquids prices reflected lower benchmark prices, which decreased revenues $86 million.
- Average natural gas production volumes of 876 MMcf/d were lower by 498 MMcf/d, which decreased revenues $174 million. Average oil and NGL production volumes of 27.2 Mbbls/d were lower by 15.1 Mbbls/d, which decreased revenues $90 million. Changes in production volumes are discussed in the Production Volumes section of this MD&A.
- Realized financial hedging gains were $109 million compared to $19 million in 2014.
- Transportation and processing expense decreased $49 million primarily due to the lower U.S./Canadian dollar exchange rate, the sale of the Bighorn assets in the third quarter of 2014, the sale of certain assets included in Wheatland in January 2015 and shut-in production at Deep Panuke as a result of the implementation of a seasonal operating strategy during May 2015, partially offset by higher volumes in Montney.
- Operating expense decreased $38 million primarily due to the sale of certain assets included in Wheatland in January 2015, the lower U.S./Canadian dollar exchange rate, the sale of the Bighorn assets in the third quarter of 2014 and lower long-term compensation costs due to the decrease in the Encana share price.

Operating Cash Flow

($ millions)	Natural Gas 2015	Natural Gas 2014	Oil & NGLs 2015	Oil & NGLs 2014	Total [1] 2015	Total [1] 2014
	Nine months ended September 30					
Revenues, Net of Royalties, excluding Hedging	**$ 788**	$ 2,066	**$ 243**	$ 723	**$ 1,044**	$ 2,811
Realized Financial Hedging Gain (Loss)	**364**	(99)	**2**	(6)	**366**	(105)
Revenues, Net of Royalties	**1,152**	1,967	**245**	717	**1,410**	2,706
Expenses						
Production and mineral taxes	**-**	3	**-**	10	**-**	13
Transportation and processing	**463**	596	**38**	46	**501**	642
Operating	**111**	222	**13**	18	**125**	246
Operating Cash Flow	**$ 578**	$ 1,146	**$ 194**	$ 643	**$ 784**	$ 1,805

Production Volumes

	Natural Gas (MMcf/d) 2015	Natural Gas (MMcf/d) 2014	Oil & NGLs (Mbbls/d) 2015	Oil & NGLs (Mbbls/d) 2014	Total (MBOE/d) 2015	Total (MBOE/d) 2014
	Nine months ended September 30					
Production Volumes – After Royalties	**961**	1,468	**27.1**	40.3	**187.2**	285.0

Operating Netback [2]

	Natural Gas ($/Mcf) 2015	Natural Gas ($/Mcf) 2014	Oil & NGLs ($/bbl) 2015	Oil & NGLs ($/bbl) 2014	Total ($/BOE) 2015	Total ($/BOE) 2014
	Nine months ended September 30					
Revenues, Net of Royalties, excluding Hedging	**$ 3.00**	$ 5.14	**$ 32.91**	$ 65.73	**$ 20.17**	$ 35.76
Realized Financial Hedging Gain (Loss)	**1.39**	(0.25)	**0.25**	(0.52)	**7.15**	(1.34)
Revenues, Net of Royalties	**4.39**	4.89	**33.16**	65.21	**27.32**	34.42
Expenses						
Production and mineral taxes	**-**	0.01	**0.01**	0.85	**0.01**	0.16
Transportation and processing	**1.76**	1.48	**5.07**	4.19	**9.79**	8.24
Operating	**0.42**	0.55	**1.81**	1.64	**2.43**	3.09
Operating Netback	**$ 2.21**	$ 2.85	**$ 26.27**	$ 58.53	**$ 15.09**	$ 22.93

(1) Also includes other revenues and expenses, such as third party processing, with no associated volumes.
(2) A Non-GAAP measure as defined in the Non-GAAP Measures section of this MD&A.

Nine months ended September 30, 2015 versus September 30, 2014

Operating Cash Flow of $784 million decreased $1,021 million and was impacted by the following significant items:

- Lower natural gas prices reflected lower benchmark prices, which decreased revenues $561 million. The average realized natural gas price for production from Deep Panuke was $9.40 per Mcf compared to $8.71 per Mcf in 2014 and increased the average realized natural gas price $0.50 per Mcf compared to $0.65 per Mcf in 2014. Lower liquids prices reflected lower benchmark prices, which decreased revenues $243 million.
- Average natural gas production volumes of 961 MMcf/d were lower by 507 MMcf/d, which decreased revenues $717 million. Average oil and NGL production volumes of 27.1 Mbbls/d were lower by 13.2 Mbbls/d, which decreased revenues $237 million. Changes in production volumes are discussed in the Production Volumes section of this MD&A.
- Realized financial hedging gains were $366 million compared to losses of $105 million in 2014.
- Transportation and processing expense decreased $141 million primarily due to the sale of the Bighorn assets in the third quarter of 2014, the lower U.S./Canadian dollar exchange rate, the sale of certain assets included in Wheatland in January 2015, and shut-in production at Deep Panuke as a result of the implementation of a seasonal operating strategy during May 2015 and a higher water production rate, partially offset by higher volumes in Montney.
- Operating expense decreased $121 million primarily due to the sale of certain assets included in Wheatland in January 2015, the lower U.S./Canadian dollar exchange rate, the sale of the Bighorn assets in the third quarter of 2014 and lower long-term compensation costs due to the decrease in the Encana share price.

Other Expenses

	Three months ended September 30		Nine months ended September 30	
($ millions, except as indicated)	**2015**	2014	**2015**	2014
Depreciation, depletion & amortization	**$ 64**	$ 166	**$ 237**	$ 503
Depletion rate ($/BOE)	**4.01**	6.61	**4.63**	6.44

DD&A decreased in the third quarter and first nine months of 2015 compared to 2014, primarily due to lower production volumes, the lower U.S./Canadian dollar exchange rate and a lower depletion rate. The depletion rate was impacted by the lower U.S./Canadian dollar exchange rate, and the sales of the Bighorn assets and the Company's investment in PrairieSky in the third quarter of 2014.

USA Operations

Operating Cash Flow

	Three months ended September 30					
	Natural Gas		Oil & NGLs		Total [1]	
($ millions)	**2015**	2014	**2015**	2014	**2015**	2014
Revenues, Net of Royalties, excluding Hedging	**$ 170**	$ 307	**$ 371**	$ 452	**$ 547**	$ 769
Realized Financial Hedging Gain (Loss)	**54**	10	**54**	1	**108**	11
Revenues, Net of Royalties	**224**	317	**425**	453	**655**	780
Expenses						
Production and mineral taxes	**6**	(10)	**21**	23	**27**	13
Transportation and processing	**152**	162	**3**	4	**155**	166
Operating	**39**	50	**103**	44	**142**	96
Operating Cash Flow	**$ 27**	$ 115	**$ 298**	$ 382	**$ 331**	$ 505

Production Volumes

	Three months ended September 30					
	Natural Gas (MMcf/d)		Oil & NGLs (Mbbls/d)		Total (MBOE/d)	
	2015	2014	**2015**	2014	**2015**	2014
Production Volumes – After Royalties	**671**	825	**113.2**	61.7	**225.1**	199.2

Operating Netback [2]

	Three months ended September 30					
	Natural Gas ($/Mcf)		Oil & NGLs ($/bbl)		Total ($/BOE)	
	2015	2014	**2015**	2014	**2015**	2014
Revenues, Net of Royalties, excluding Hedging	**$ 2.75**	$ 4.05	**$ 35.66**	$ 79.43	**$ 26.13**	$ 41.38
Realized Financial Hedging Gain (Loss)	**0.88**	0.12	**5.17**	0.25	**5.21**	0.58
Revenues, Net of Royalties	**3.63**	4.17	**40.83**	79.68	**31.34**	41.96
Expenses						
Production and mineral taxes	**0.11**	(0.14)	**1.95**	4.18	**1.30**	0.72
Transportation and processing	**2.47**	2.13	**0.31**	0.63	**7.52**	9.03
Operating	**0.62**	0.65	**9.95**	7.80	**6.85**	5.12
Operating Netback	**$ 0.43**	$ 1.53	**$ 28.62**	$ 67.07	**$ 15.67**	$ 27.09

(1) Also includes other revenues and expenses, such as third party processing, with no associated volumes.
(2) A Non-GAAP measure as defined in the Non-GAAP Measures section of this MD&A.

Three months ended September 30, 2015 versus September 30, 2014

Operating Cash Flow of $331 million decreased $174 million and was impacted by the following significant items:

- Lower natural gas prices reflected lower benchmark prices, which decreased revenues $73 million. Lower liquids prices reflected lower benchmark prices, which decreased revenues $310 million.
- Average natural gas production volumes of 671 MMcf/d were lower by 154 MMcf/d, which decreased revenues $64 million. Average oil and NGL production volumes of 113.2 Mbbls/d were higher by 51.5 Mbbls/d, which increased revenues $229 million. Changes in production volumes are discussed in the Production Volumes section of this MD&A.
- Realized financial hedging gains were $108 million compared to $11 million in 2014.
- Operating expense increased $46 million primarily due to the acquisition of the Permian assets in the fourth quarter of 2014 and successful drilling programs in the Permian and Eagle Ford.

Operating Cash Flow

	Nine months ended September 30					
	Natural Gas		Oil & NGLs		Total [(1)]	
($ millions)	**2015**	2014	**2015**	2014	**2015**	2014
Revenues, Net of Royalties, excluding Hedging	**$ 511**	$ 1,366	**$ 1,080**	$ 846	**$ 1,609**	$ 2,234
Realized Financial Hedging Gain (Loss)	**166**	(98)	**97**	(5)	**263**	(103)
Revenues, Net of Royalties	**677**	1,268	**1,177**	841	**1,872**	2,131
Expenses						
Production and mineral taxes	**15**	33	**57**	51	**72**	84
Transportation and processing	**445**	502	**9**	4	**454**	506
Operating	**134**	183	**282**	64	**418**	249
Operating Cash Flow	**$ 83**	$ 550	**$ 829**	$ 722	**$ 928**	$ 1,292

Production Volumes

	Nine months ended September 30					
	Natural Gas (MMcf/d)		Oil & NGLs (Mbbls/d)		Total (MBOE/d)	
	2015	2014	**2015**	2014	**2015**	2014
Production Volumes – After Royalties	**695**	1,047	**102.4**	39.9	**218.4**	214.3

Operating Netback [(2)]

	Nine months ended September 30					
	Natural Gas ($/Mcf)		Oil & NGLs ($/bbl)		Total ($/BOE)	
	2015	2014	**2015**	2014	**2015**	2014
Revenues, Net of Royalties, excluding Hedging	**$ 2.69**	$ 4.78	**$ 38.65**	$ 77.63	**$ 26.69**	$ 37.81
Realized Financial Hedging Gain (Loss)	**0.88**	(0.34)	**3.46**	(0.45)	**4.42**	(1.76)
Revenues, Net of Royalties	**3.57**	4.44	**42.11**	77.18	**31.11**	36.05
Expenses						
Production and mineral taxes	**0.08**	0.11	**2.01**	4.72	**1.20**	1.44
Transportation and processing	**2.35**	1.76	**0.32**	0.33	**7.62**	8.64
Operating	**0.71**	0.64	**10.09**	5.87	**6.98**	4.22
Operating Netback	**$ 0.43**	$ 1.93	**$ 29.69**	$ 66.26	**$ 15.31**	$ 21.75

(1) Also includes other revenues and expenses, such as third party processing, with no associated volumes.
(2) A Non-GAAP measure as defined in the Non-GAAP Measures section of this MD&A.

Nine months ended September 30, 2015 versus September 30, 2014

Operating Cash Flow of $928 million decreased $364 million and was impacted by the following significant items:

- Lower natural gas prices reflected lower benchmark prices, which decreased revenues $350 million. Lower liquids prices reflected lower benchmark prices, which decreased revenues $569 million.
- Average natural gas production volumes of 695 MMcf/d were lower by 352 MMcf/d, which decreased revenues $505 million. Average oil and NGL production volumes of 102.4 Mbbls/d were higher by 62.5 Mbbls/d, which increased revenues $803 million. Changes in production volumes are discussed in the Production Volumes section of this MD&A.
- Realized financial hedging gains were $263 million compared to losses of $103 million in 2014.
- Transportation and processing expense decreased $52 million primarily due to divestitures, which includes the sales of the Jonah and East Texas properties in the second quarter of 2014, partially offset by the acquisitions of Eagle Ford and the Permian assets in the second and fourth quarters of 2014, respectively.
- Operating expense increased $169 million primarily due to the acquisitions of Eagle Ford and the Permian assets in the second and fourth quarters of 2014, respectively, and successful drilling programs in these plays during 2015, partially offset by the sales of the Jonah and East Texas properties in the second quarter of 2014 and lower long-term compensation costs due to the decrease in the Encana share price.

Other Expenses

	Three months ended September 30		Nine months ended September 30	
($ millions, except as indicated)	**2015**	2014	**2015**	2014
Depreciation, depletion & amortization	**$ 265**	$ 279	**$ 902**	$ 694
Depletion rate ($/BOE)	**12.77**	15.22	**14.92**	11.86
Impairments	**1,671**	-	**5,668**	-

DD&A decreased in the third quarter of 2015 compared to 2014, primarily due to a lower depletion rate, partially offset by higher production volumes. The depletion rate was lower primarily due to the ceiling test impairments recognized in the first six months of 2015, partially offset by the acquisition of the Permian assets in the fourth quarter of 2014. DD&A increased in the first nine months of 2015 compared to 2014, primarily due to a higher depletion rate. The depletion rate was higher primarily due to the acquisitions of Eagle Ford and the Permian assets in the second and fourth quarters of 2014, respectively, partially offset by the ceiling test impairments recognized in the first six months of 2015 and a decrease in proved reserves as a result of the sale of the Jonah properties in the second quarter of 2014.

In the third quarter and first nine months of 2015, the USA Operations recognized before-tax non-cash ceiling test impairments of $1,671 million and $5,668 million, respectively. The impairments primarily resulted from the decline in the 12-month average trailing commodity prices, which reduced the USA Operations proved reserves volumes and values as calculated under SEC requirements.

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

	Natural Gas	**Oil & NGLs**
	Henry Hub ($/MMBtu)	WTI ($/bbl)
12-Month Average Trailing Reserves Pricing (1)		
September 30, 2015	**3.05**	**59.21**
December 31, 2014	4.34	94.99
September 30, 2014	4.24	99.08

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

Market Optimization

($ millions)	Three months ended September 30 2015		Three months ended September 30 2014		Nine months ended September 30 2015		Nine months ended September 30 2014	
Revenues	**$**	**66**	$	486	**$**	**293**	$	890
Expenses								
Operating		**4**		11		**28**		37
Purchased product		**60**		474		**260**		844
Depreciation, depletion and amortization		**-**		-		**-**		4
	$	**2**	$	1	**$**	**5**	$	5

Market Optimization revenues and purchased product expense relate to activities that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. Revenues and purchased product expense decreased in the third quarter and first nine months of 2015 compared to 2014 primarily due to lower commodity prices and lower third-party volumes resulting from transitional services related to the Company's divestiture activity.

Corporate and Other

($ millions)	Three months ended September 30 2015		Three months ended September 30 2014		Nine months ended September 30 2015		Nine months ended September 30 2014	
Revenues	**$**	**200**	$	260	**$**	**(184)**	$	38
Expenses								
Transportation and processing		**11**		2		**4**		1
Operating		**6**		7		**17**		25
Depreciation, depletion and amortization		**23**		31		**73**		93
	$	**160**	$	220	**$**	**(278)**	$	(81)

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

Corporate and Other results include revenues and operating expenses related to the sublease of office space in The Bow office building. Further information on The Bow office sublease can be found in Note 11 to the Interim Condensed Consolidated Financial Statements.

Other Operating Results

Expenses

($ millions)	Three months ended September 30 2015	Three months ended September 30 2014	Nine months ended September 30 2015	Nine months ended September 30 2014
Accretion of asset retirement obligation	**$ 11**	$ 13	**$ 34**	$ 39
Administrative	**61**	69	**217**	269
Interest	**105**	133	**508**	402
Foreign exchange (gain) loss, net	**348**	202	**918**	254
(Gain) loss on divestitures	**2**	(3,239)	**(14)**	(3,442)
Other	**(3)**	-	**2**	8
	$ 524	$ (2,822)	**$ 1,665**	$ (2,470)

Administrative expense in the first nine months of 2015 decreased from 2014 primarily due to lower long-term compensation costs due to the decrease in the Encana share price and the lower U.S./Canadian dollar exchange rate, partially offset by higher restructuring costs. During the second quarter of 2015, Encana revised its plans to align the organizational structure in continued support of the Company's strategy, which resulted in restructuring costs of $28 million and $58 million for the third quarter and first nine months of 2015, respectively. Restructuring costs attributable to work force reductions associated with the 2013 restructuring were nil and $1 million in the third quarter and first nine months of 2015, respectively, compared with $7 million and $29 million, respectively, for 2014.

Interest expense in the first nine months of 2015 increased from 2014 primarily due to a one-time interest payment of approximately $165 million resulting from the April 2015 early debt redemptions, partially offset by lower interest on debt following these redemptions.

Foreign exchange gains and losses result from the impact of the fluctuations in the Canadian to U.S. dollar exchange rate. In the third quarter of 2015 compared to 2014, the Company recorded higher foreign exchange losses on settlements, other monetary revaluations and the translation of U.S. dollar long-term debt issued from Canada, partially offset by foreign exchange gains on the translation of intercompany notes. In the first nine months of 2015 compared to 2014, Encana recorded higher foreign exchange losses on the translation of U.S. dollar long-term debt issued from Canada and on settlements.

Gain on divestitures in the first nine months of 2015 primarily includes a before tax gain on the sale of the Encana Place office building in Calgary. Gain on divestitures in the first nine months of 2014 primarily includes the before tax impact of the sales of Encana's investment in PrairieSky, the Bighorn assets and the Jonah properties, as discussed in the Net Capital Investment section of this MD&A.

Income Tax

($ millions)	Three months ended September 30		Nine months ended September 30	
	2015	2014	**2015**	2014
Current Income Tax (Recovery)	**$ (19)**	$ 244	**$ (38)**	$ 241
Deferred Income Tax (Recovery)	**(576)**	505	**(2,442)**	825
Income Tax Expense (Recovery)	**$ (595)**	$ 749	**$ (2,480)**	$ 1,066

The current income tax recovery of $38 million in the first nine months of 2015 was primarily due to amounts in respect of prior periods while the current income tax expense of $241 million in the first nine months of 2014 was primarily due to current taxes incurred on divestitures. Total income tax recovery in the first nine months of 2015 was primarily due to lower net earnings before tax. The net earnings variances are discussed in the Financial Results section of this MD&A.

Encana's interim income tax expense is determined using the estimated annual effective income tax rate applied to year-to-date net earnings before tax plus the effect of legislative changes, including the 2015 Alberta general corporate income tax rate increase, and amounts in respect of prior periods. The estimated annual effective income tax rate is impacted by expected annual earnings, statutory rate and other foreign differences, non-taxable capital gains and losses, tax differences on divestitures and transactions, and partnership tax allocations in excess of funding. The Company's effective tax rate for the first nine months of 2015 is higher than 2014 primarily as a result of changes in expected annual earnings and the gain on divestitures in 2014.

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

Liquidity and Capital Resources

($ millions)	Three months ended September 30 2015	Three months ended September 30 2014	Nine months ended September 30 2015	Nine months ended September 30 2014
Net Cash From (Used In)				
Operating activities	**$ 453**	$ 696	**$ 1,233**	$ 2,406
Investing activities	**(544)**	3,805	**(957)**	1,870
Financing activities	**(36)**	(95)	**(238)**	231
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency	**(17)**	(90)	**(24)**	(99)
Increase (Decrease) in Cash and Cash Equivalents	**$ (144)**	$ 4,316	**$ 14**	$ 4,408
Cash and Cash Equivalents, End of Period	**$ 352**	$ 6,974	**$ 352**	$ 6,974

Operating Activities

Net cash from operating activities in the third quarter of 2015 of $453 million decreased $243 million from 2014 primarily as a result of the Cash Flow variances discussed in the Financial Results section of this MD&A. In the third quarter of 2015, the net change in non-cash working capital was a surplus of $100 million compared to $155 million in 2014.

Net cash from operating activities in the first nine months of 2015 of $1,233 million decreased $1,173 million from 2014 primarily as a result of the Cash Flow variances discussed in the Financial Results section of this MD&A. In the first nine months of 2015, the net change in non-cash working capital was a surplus of $204 million compared to $132 million in 2014.

The Company had a working capital surplus of $277 million at September 30, 2015 compared to $455 million at December 31, 2014. The decrease in working capital is primarily due to a decrease in accounts receivable and accrued revenues and risk management assets, partially offset by a decrease in accounts payable and accrued liabilities. At September 30, 2015, working capital included cash and cash equivalents of $352 million compared to $338 million at December 31, 2014. Encana expects it will continue to meet the payment terms of its suppliers.

Investing Activities

Net cash used in investing activities in the first nine months of 2015 was $957 million compared to net cash from investing activities of $1,870 million in 2014. The change was primarily due to lower proceeds from divestitures and the sale of the Company's investment in PrairieSky in 2014, partially offset by the acquisition of Eagle Ford in 2014. Further information on acquisitions and divestitures can be found in the Net Capital Investment section of this MD&A.

Financing Activities

Net cash used in financing activities in the first nine months of 2015 was $238 million compared to net cash from financing activities of $231 million in 2014. The change was primarily due to the sale of a noncontrolling interest in PrairieSky in the second quarter of 2014, partially offset by proceeds from the issuance of common shares pursuant to the Share Offering in the first quarter of 2015.

Credit Facilities

The following table outlines the Company's committed revolving bank credit facilities at September 30, 2015:

($ billions)	Capacity	Unused	Maturity Date
Committed Revolving Bank Credit Facilities			
Encana Credit Facility (1)	**3.0**	**1.6**	**July 2020**
U.S. Subsidiary Credit Facility	**1.5**	**1.5**	**July 2020**

(1) At September 30, 2015, $1.4 billion fully supported the U.S. Commercial Paper program, as discussed in the Long-Term Debt section below.

Encana is currently in compliance with, and expects that it will continue to be in compliance with, all financial covenants under its credit facility agreements. Management monitors Debt to Adjusted Capitalization as a proxy for Encana's financial covenant under its credit facility agreements which require debt to adjusted capitalization to be less than 60 percent. The definitions used in the covenant under the credit facilities adjust capitalization for cumulative historical ceiling test impairments that were recorded as at December 31, 2011 in conjunction with the Company's January 1, 2012 adoption of U.S. GAAP. Debt to Adjusted Capitalization was 30 percent at September 30, 2015 and December 31, 2014.

Long-Term Debt

Encana's long-term debt, excluding the current portion, totaled $6,128 million at September 30, 2015 and $7,340 million at December 31, 2014. There was no current portion of long-term debt outstanding at September 30, 2015 or December 31, 2014.

On April 6, 2015, the Company used the net proceeds from the Share Offering and cash on hand to complete the redemption of its $700 million 5.90 percent notes due December 1, 2017 and its C$750 million 5.80 percent medium-term notes due January 18, 2018. The note redemptions required an aggregate one-time early interest payment of approximately $165 million and is expected to save Encana a gross amount of approximately $205 million in future interest expense, based on foreign exchange and treasury rates at the time of the redemptions.

During the first quarter of 2015, Encana implemented a U.S. Commercial Paper ("U.S. CP") program which is fully supported by the Company's revolving credit facility. At September 30, 2015, Encana had an outstanding balance of $1,414 million which reflected U.S. CP issuances that had an average term of 28 days and a weighted average interest rate of 0.64 percent. Management expects these amounts will continue to be supported by the revolving credit facility that has no repayment requirements within the next year. At December 31, 2014, Encana had an outstanding balance of $1,277 million under the Company's revolving credit facility, which reflected principal obligations related to LIBOR loans maturing at various dates with a weighted average interest rate of 1.62 percent. During the first quarter of 2015, Encana repaid the outstanding balance relating to LIBOR loans using proceeds from the U.S. CP program and cash on hand.

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

Shelf Prospectus

On June 27, 2014, Encana filed a short form base shelf prospectus, whereby the Company may issue from time to time up to $6.0 billion, or the equivalent in foreign currencies, of debt securities, common shares, preferred shares, subscription receipts, warrants and units in Canada and/or the U.S. On March 5, 2015, the Company filed a prospectus supplement to the base shelf prospectus for the issuance of 85,616,500 common shares of Encana and granted an over-allotment option for up to an additional 12,842,475 common shares of Encana at a price of C$14.60 per common share, pursuant to an underwriting agreement. The Share Offering of 98,458,975 common shares of Encana was completed during March 2015 for aggregate gross proceeds of approximately C$1.44 billion ($1.13 billion). After deducting underwriter's fees and costs of the Share Offering, the net proceeds received were approximately C$1.39 billion ($1.09 billion). At September 30, 2015, $4.9 billion, or the equivalent in foreign currencies, remained accessible under the shelf prospectus, the availability of which is dependent upon market conditions. The shelf prospectus expires in July 2016.

Outstanding Share Data

(millions)	December 31, 2014	September 30, 2015	November 6, 2015
Common Shares Outstanding	**741.2**	**845.7**	**845.7**
Stock Options with TSARs attached [(1)]			
Outstanding	**21.3**	**19.7**	**19.0**
Exercisable	**10.0**	**10.9**	**10.4**

(1) A Tandem Stock Appreciation Right ("TSAR") gives the option holder the right to receive a cash payment equal to the excess of the market price of Encana's common shares at the time of exercise over the original grant price.

During the first quarter of 2015, Encana issued common shares pursuant to the Share Offering as discussed above.

During the first nine months of 2015, Encana issued 6,115,535 common shares under the Company's dividend reinvestment plan ("DRIP") compared with 164,840 common shares in 2014. The number of common shares issued under the DRIP increased in the first nine months of 2015 primarily as a result of Encana's February 25, 2015 announcement that, effective with the dividend payable on March 31, 2015, any future dividends in conjunction with the DRIP will be issued from its treasury with a two percent discount to the average market price of the common shares unless otherwise announced by the Company via news release.

Dividends

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

	Three months ended September 30		Nine months ended September 30	
($ millions, except as indicated)	**2015**	2014	**2015**	2014
Dividend Payments	**$ 59**	$ 52	**$ 166**	$ 156
Dividend Payments ($/share)	**0.07**	0.07	**0.21**	0.21

The dividends paid in the third quarter and first nine months of 2015 included $21 million and $53 million, respectively, in common shares issued in lieu of cash dividends under the DRIP compared to $1 million and $4 million, respectively, for 2014. Common shares issued in the Share Offering were not eligible to receive the dividend that was paid during the first quarter of 2015.

On November 11, 2015, the Board declared a dividend of $0.07 per share payable on December 31, 2015 to common shareholders of record as of December 15, 2015.

Capital Structure

The Company's capital structure consists of total shareholders' equity plus long-term debt, including the current portion. The Company's objectives when managing its capital structure are to maintain financial flexibility to preserve Encana's access to capital markets and its ability to meet financial obligations and finance internally generated growth, as well as potential acquisitions. Encana has a long-standing practice of maintaining capital discipline and managing and adjusting its capital structure according to market conditions to maintain flexibility while achieving the Company's objectives.

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

	September 30, 2015	December 31, 2014
Debt to Debt Adjusted Cash Flow	**3.1x**	2.1x
Debt to Adjusted Capitalization	**30%**	30%

Commitments and Contingencies

Commitments

The following table outlines the Company's commitments at September 30, 2015:

	Expected Future Payments						
($ millions, undiscounted)	2015	2016	2017	2018	2019	Thereafter	Total
Transportation and Processing	$ 210	$ 795	$ 778	$ 790	$ 672	$ 3,037	$ 6,282
Drilling and Field Services	62	151	107	54	18	22	414
Operating Leases	9	29	24	23	11	23	119
Commitments	$ 281	$ 975	$ 909	$ 867	$ 701	$ 3,082	$ 6,815

Included in Transportation and Processing in the table above are certain commitments associated with midstream service agreements with VMLP. Additional information can be found in Note 16 to the Interim Condensed Consolidated Financial Statements. Encana also has significant development commitments with joint venture partners, a portion of which may be satisfied by the Drilling and Field Services commitments included in the table above.

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

Announced divestiture transactions can reduce certain commitments and obligations disclosed above. The Company expects to fund its 2015 commitments and obligations from Cash Flow and cash and cash equivalents.

Contingencies

Encana is involved in various legal claims and actions arising in the course of the Company's operations. Although the outcome of these claims cannot be predicted with certainty, the Company does not expect these matters to have a material adverse effect on Encana's financial position, cash flows or results of operations. If an unfavourable outcome were to occur, there exists the possibility of a material adverse impact on the Company's consolidated net earnings or loss in the period in which the outcome is determined. Accruals for litigation and claims are recognized if the Company determines that the loss is probable and the amount can be reasonably estimated. The Company believes it has made adequate provision for such legal claims.

Risk Management

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

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

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

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

Financial Risks

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

Financial risks include, but are not limited to:

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

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

To partially mitigate commodity price risk, the Company may enter into transactions that fix, set a floor or combine to set floors and caps on price exposures. To help protect against regional price differentials, Encana executes transactions to manage the price differentials between its production areas and various sales points. Further information, including the details of Encana's financial instruments as at September 30, 2015, is disclosed in Note 21 to the Interim Condensed Consolidated Financial Statements.

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

The Company manages liquidity risk using cash and debt management programs. The Company has access to cash equivalents and a range of funding alternatives at competitive rates through committed revolving bank credit facilities as well as debt and equity capital markets. Encana closely monitors the Company's ability to access cost-effective credit and ensures that sufficient liquidity is in place to fund capital expenditures and dividend payments. The Company minimizes its liquidity risk by managing its capital structure which may include adjusting capital spending, adjusting dividends paid to shareholders, issuing new shares, issuing new debt or repaying existing debt.

Operational Risks

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

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

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

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

In June 2015, the Alberta Government convened a panel to undertake a review of the province's oil and gas royalty structure. The panel is currently consulting with industry, the public and stakeholders and is expected to report back to the Alberta Government by the end of 2015. Encana is monitoring the work of the panel and is actively engaged in the consultations. The Company will assess the impact of possible changes to the royalty structure on its operations as information becomes available.

Environmental, Regulatory, Reputational and Safety Risks

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

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

In the state of Colorado, several cities have passed local ordinances limiting or banning certain oil and gas activities, including hydraulic fracturing. These local rule-making initiatives have not significantly impacted the Company's operations or development plans in the state to date. Encana continues to work with state and local governments, academics and industry leaders to respond to hydraulic fracturing related concerns in Colorado. The Company recognizes that additional hydraulic fracturing ballot and/or local rule-making limiting or restricting oil and gas development activities are a possibility in the future and will continue to monitor and respond to these developments in 2015.

The U.S. federal government has noted climate change action as a priority for the current administration. On January 14, 2015, the Environmental Protection Agency ("EPA") outlined a series of steps to address methane and volatile organic compound emissions from the oil and gas industry, including a new goal to reduce oil and gas methane emissions by 40 to 45 percent from 2012 levels by 2025. The reductions will be achieved through regulatory and voluntary measures released on August 18, 2015 for public comment. Encana continues to monitor these developments, provide comment as appropriate and assess the potential impact on its business. The EPA is expected to release the final rule and guidance in 2016.

On June 25, 2015 the Alberta Government announced that it was renewing and updating the Specified Gas Emitters Regulation (the "Regulation"), which governs carbon emissions and was set to expire on June 30, 2015. The Regulation requires any facility that emits 100,000 tonnes or more of greenhouse gases per year to reduce their emissions intensity. The renewed Regulation increases the reduction target from 12 percent to 20 percent by 2017 and increases the cost of carbon from C$15 per tonne to C$30 per tonne by 2017 for those facilities that are unable to meet the specified reduction targets. Encana does not own or operate any facilities which exceed the 100,000 tonne threshold and, as a result, is not currently subject to the Regulation.

Various levels of government within Canada have enhanced focus on climate change policy during 2015. Encana continues to monitor developments and engage in the consultations as appropriate.

A comprehensive discussion of Encana's risk management is provided in the Company's annual MD&A for the year ended December 31, 2014.

Controls and Procedures

Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over the Company's financial reporting, which is a process designed by, or designed under the supervision of the Chief Executive Officer and Chief Financial Officer, and effected by the Board, Management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP.

Encana previously limited the scope and design and subsequent evaluation of internal controls over financial reporting to exclude the controls, policies and procedures of Athlon Energy Inc., acquired through a business combination on November 13, 2014. During the second quarter of 2015, the Company completed the evaluation and integration of the controls, policies and procedures of Athlon Energy Inc. and no material weaknesses or significant deficiencies were noted during the integration. There have been no changes to the Company's internal control over financial reporting during the three months ended September 30, 2015 that have materially affected, or are reasonably likely to materially affect, the effectiveness of the internal control over financial reporting.

Limitations of the Effectiveness of Controls

The Company's control system was designed to provide reasonable assurance to Management regarding the preparation and presentation of the Consolidated Financial Statements. Control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation and should not be expected to prevent all errors or fraud. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Accounting Policies and Estimates

Critical Accounting Estimates

Refer to the annual MD&A for the year ended December 31, 2014 for a comprehensive discussion of Encana's Critical Accounting Policies and Estimates.

Recent Accounting Pronouncements

Changes in Accounting Policies and Practices

On January 1, 2015, Encana adopted Accounting Standard Update ("ASU") 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity* as issued by the Financial Accounting Standards Board ("FASB"). The update amends the criteria and expands the disclosures for reporting discontinued operations. Under the new criteria, only disposals representing a strategic shift in operations would qualify as a discontinued operation. The amendments have been applied prospectively and have not had a material impact on the Company's Interim Condensed Consolidated Financial Statements.

New Standards Issued Not Yet Adopted

As of January 1, 2016, Encana will be required to adopt the following pronouncements issued by the FASB:

- ASU 2014-12, *Compensation – Stock Compensation: Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved After the Requisite Service Period*. The update requires that a performance target that affects vesting and could be achieved after the requisite service period be treated as a performance condition. The amendments will be applied prospectively and are not expected to have a material impact on the Company's Consolidated Financial Statements.
- ASU 2015-02, *Amendments to the Consolidation Analysis*. The update requires limited partnerships and similar entities to be evaluated under the variable interest and voting interest models, eliminate the presumption that a general partner should consolidate a limited partnership, and simplify the identification of variable interests and related effect on the primary beneficiary criterion when fees are paid to a decision maker. The amendments can be applied using either a full retrospective approach or a modified retrospective approach at the date of adoption. Encana is currently assessing the potential impact of the amendments on the Company's Consolidated Financial Statements.
- ASU 2015-03, *Simplifying the Presentation of Debt Issuance Costs*. The update requires debt issuance costs to be presented on the balance sheet as a deduction from the carrying amount of the related liability. Previously, debt issuance costs were presented as a deferred charge within assets. In August 2015, the FASB issued ASU 2015-15, *Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements.* The update further clarifies that regardless of whether there are outstanding borrowings, debt issuance costs arising from credit arrangements can be presented as an asset and subsequently amortized ratably over the term of the arrangement. These amendments will be applied retrospectively. As at September 30, 2015, $31 million of debt issuance costs were presented in Other Assets on the Company's Interim Condensed Consolidated Balance Sheet ($39 million as at December 31, 2014).

As of January 1, 2018, Encana will be required to adopt ASU 2014-09, *Revenue from Contracts with Customers* under Topic 606, which was the result of a joint project by the FASB and International Accounting Standards Board. The new standard replaces 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, but permits early adoption using the original effective date of January 1, 2017. The standard can be applied using one of two retrospective application methods at the date of adoption. Encana is currently assessing the potential impact of the standard on the Company's Consolidated Financial Statements.

Non-GAAP Measures

Certain measures in this document do not have any standardized meaning as prescribed by U.S. GAAP and, therefore, are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures are commonly used in the oil and gas industry and by Encana to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. Non-GAAP measures include: Cash Flow; Free Cash Flow; Operating Earnings (Loss); Upstream Operating Cash Flow, excluding Hedging; Operating Netback; Debt to Debt Adjusted Cash Flow; and Debt to Adjusted Capitalization. Management's use of these measures is discussed further below.

Cash Flow and Free Cash Flow

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

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

	Nine months ended September 30		2015			2014				2013
($ millions)	**2015**	2014	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Cash From (Used in) Operating Activities	**$1,233**	$2,406	**$ 453**	$ 298	$ 482	$ 261	$ 696	$ 767	$ 943	$ 462
(Add back) deduct:										
Net change in other assets and liabilities	**(18)**	(28)	**(18)**	7	(7)	(15)	(11)	(8)	(9)	(21)
Net change in non-cash working capital	**204**	132	**100**	110	(6)	(141)	155	119	(142)	(183)
Cash tax on sale of assets	**-**	(255)	**-**	-	-	40	(255)	-	-	(11)
Cash Flow	**$1,047**	$2,557	**$ 371**	$ 181	$ 495	$ 377	$ 807	$ 656	$1,094	$ 677
Deduct:										
Capital investment	**1,952**	1,669	**473**	743	736	857	598	560	511	717
Free Cash Flow	**$ (905)**	$ 888	**$ (102)**	$ (562)	$ (241)	$ (480)	$ 209	$ 96	$ 583	$ (40)

Operating Earnings

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

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

	Nine months ended September 30		2015			2014				2013
($ millions)	**2015**	2014	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Net Earnings (Loss) Attributable to Common Shareholders	**$ (4,553)**	$3,194	**$ (1,236)**	$ (1,610)	$ (1,707)	$ 198	$2,807	$ 271	$ 116	$ (251)
After-tax (addition) / deduction:										
Unrealized hedging gain (loss)	**(178)**	(35)	**107**	(187)	(98)	341	160	8	(203)	(209)
Impairments	**(3,616)**	-	**(1,066)**	(1,328)	(1,222)	-	-	-	-	-
Restructuring charges [(1)]	**(40)**	(20)	**(20)**	(10)	(10)	(4)	(5)	(5)	(10)	(64)
Non-operating foreign exchange gain (loss)	**(606)**	(256)	**(212)**	114	(508)	(151)	(218)	156	(194)	(124)
Gain (loss) on divestitures	**9**	2,534	**(2)**	1	10	(11)	2,399	135	-	-
Income tax adjustments	**50**	4	**(19)**	(33)	102	(12)	190	(194)	8	(80)
Operating Earnings (Loss) [(1)]	**$ (172)**	$ 967	**$ (24)**	$ (167)	$ 19	$ 35	$ 281	$ 171	$ 515	$ 226

(1) In continued support of Encana's strategy, organizational structure changes were formalized in Q2 2015 and resulted in a revision to the Q1 2015 Operating Earnings to exclude restructuring charges incurred in the first quarter.

Upstream Operating Cash Flow, excluding Hedging

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

	Nine months ended September 30		2015			2014				2013
($ millions)	**2015**	2014	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Upstream Operating Cash Flow										
Canadian Operations	**$ 784**	$1,805	**$ 200**	$ 171	$ 413	$ 341	$ 477	$ 447	$ 881	$ 526
USA Operations	**928**	1,292	**331**	308	289	480	505	353	434	375
	$1,712	$3,097	**$ 531**	$ 479	$ 702	$ 821	$ 982	$ 800	$1,315	$ 901
(Add back) deduct:										
Realized Hedging Gain (Loss)										
Canadian Operations	**$ 366**	$ (105)	**$ 109**	$ 101	$ 156	$ 49	$ 19	$ (49)	$ (75)	$ 90
USA Operations	**263**	(103)	**108**	63	92	78	11	(49)	(65)	83
	$ 629	$ (208)	**$ 217**	$ 164	$ 248	$ 127	$ 30	$ (98)	$ (140)	$ 173
Upstream Operating Cash Flow, excluding Hedging										
Canadian Operations	**$ 418**	$1,910	**$ 91**	$ 70	$ 257	$ 292	$ 458	$ 496	$ 956	$ 436
USA Operations	**665**	1,395	**223**	245	197	402	494	402	499	292
	$1,083	$3,305	**$ 314**	$ 315	$ 454	$ 694	$ 952	$ 898	$1,455	$ 728

Operating Netback

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

Debt to Debt Adjusted Cash Flow

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

($ millions)		**September 30, 2015**		December 31, 2014
Debt	**$**	**6,128**	$	7,340
Cash Flow		**1,424**		2,934
Interest Expense, after tax		**561**		486
Debt Adjusted Cash Flow	**$**	**1,985**	$	3,420
Debt to Debt Adjusted Cash Flow		**3.1x**		2.1x

Debt to Adjusted Capitalization

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

($ millions)		**September 30, 2015**		December 31, 2014
Debt	**$**	**6,128**	$	7,340
Total Shareholders' Equity		**6,719**		9,685
Equity Adjustment for Impairments at December 31, 2011		**7,746**		7,746
Adjusted Capitalization	**$**	**20,593**	$	24,771
Debt to Adjusted Capitalization		**30%**		30%

Advisory

Forward-Looking Statements

This document contains certain forward-looking statements or information (collectively, "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements include, but are not limited to:

- anticipated cash flow
- anticipated cash and cash equivalents
- anticipated dividends
- the expected proceeds from the Haynesville and DJ Basin transactions, the value to Encana and the use of proceeds therefrom, the timing of the closings and the expectation that closing conditions will be satisfied
- the anticipated benefits to Encana of entering into ancillary gathering, midstream and marketing arrangements with GeoSouthern
- the projections and expectation of meeting the targets contained in the Company's 2015 corporate guidance
- anticipated oil, natural gas and NGLs prices
- expected future interest expense savings
- anticipated future cost and operating efficiencies
- the Company's expectation to fund its 2015 commitments and obligations from Cash Flow and cash and cash equivalents
- managing risk, including the possible impact of changes to the royalty structure
- flexibility of capital spending plans
- estimates of reserves and resources
- expected production
- 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
- statements with respect to future ceiling test impairments
- the continued evolution of the Company's resource play hub model to drive greater productivity and cost efficiencies
- anticipated revenues and operating expenses
- statements with respect to its strategic objectives
- the adequacy of the Company's provision for taxes and legal claims
- the possible impact of environmental legislation and/or regulations
- anticipated proceeds and future benefits from various joint venture, partnership and other agreements
- the possible impact and timing of accounting pronouncements, rule changes and standards

Readers are cautioned upon unduly relying on forward-looking statements as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, these statements involve numerous assumptions, known and unknown risks and uncertainties and other factors, which can contribute to the possibility that such statements will not occur or which may cause the actual performance and financial results of the Company to differ materially from those expressed or implied by such statements. These assumptions include, but are not limited to:

- achieving average production for 2015 of between 1.60 Bcf/d and 1.70 Bcf/d of natural gas and 130 Mbbls/d to 150 Mbbls/d of liquids
- commodity prices for natural gas and liquids based on NYMEX of $3.00 per MMBtu, AECO of C$2.62 per GJ and WTI of $50 per bbl through the remainder of 2015
- U.S./Canadian dollar exchange rate of 0.80
- a weighted average number of outstanding shares of approximately 821 million
- availability of attractive hedge contracts
- effectiveness of the Company's resource play hub model to drive productivity and efficiencies
- results from innovations
- the expectation that GeoSouthern will successfully fulfill its obligations under the ancillary gathering, midstream and marketing agreements
- the ability to satisfy closing conditions, the successful closing of, and the value of post-closing and other adjustments associated with the Haynesville and DJ Basin assets
- 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 the operations and development of our business include, but are not limited to: the ability to generate sufficient cash flow to meet the Company's obligations; risks inherent to closing announced divestitures and adjustments that may reduce the expected proceeds and value to Encana; commodity price volatility; ability to secure adequate product transportation and potential pipeline curtailments; variability of dividends to be paid; 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 access to capital markets; fluctuations in currency and interest rates; assumptions based upon the Company's 2015 corporate guidance; failure to achieve anticipated results from cost and efficiency initiatives; risks inherent in marketing operations; risks associated with technology; the Company's ability to acquire or find additional reserves; imprecision of reserves estimates and estimates of recoverable quantities of natural gas and liquids from resource plays and other sources not currently classified as proved, probable or possible reserves or economic contingent resources, including future net revenue estimates; risks associated with past and future divestitures of certain assets or other transactions or receive amounts contemplated under the transaction agreements (such transactions may include third-party capital investments, farm-outs or partnerships, which Encana may refer to from time to time as "partnerships" or "joint ventures" and the funds received in respect thereof which Encana may refer to from time to time as "proceeds", "deferred purchase price" and/or "carry capital", regardless of the legal form) as a result of various conditions not being met; and other risks and uncertainties impacting Encana's business as described from time to time in Encana's annual MD&A, financial statements, Annual Information Form and Form 40-F, as filed on SEDAR and EDGAR.

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

Encana is required to disclose events and circumstances that occurred during the period to which this MD&A relates that are reasonably likely to cause actual results to differ materially from material forward-looking statements for a period that is not yet complete that Encana has previously disclosed to the public and the expected differences thereto. Such disclosure can be found in Encana's news release dated November 12, 2015, which is available on Encana's website at www.encana.com, on SEDAR at www.sedar.com and EDGAR at www.sec.gov.

Oil and Gas Information

National Instrument 51-101 ("NI 51-101") of the Canadian Securities Administrators imposes oil and gas disclosure standards for Canadian public companies engaged in oil and gas activities. The Canadian protocol disclosure is contained in Appendix A and under "Narrative Description of the Business" in the Company's Annual Information Form ("AIF"). Encana obtained an exemption dated January 4, 2011 from certain requirements of NI 51-101 to permit it to provide certain disclosure prepared in accordance with U.S. disclosure requirements, in addition to the Canadian protocol disclosure. The Company's U.S. protocol disclosure is included in Note 26 (unaudited) to the Company's Consolidated Financial Statements for the year ended December 31, 2014 and in Appendix D of the AIF.

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

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

Natural Gas, Oil and NGLs Conversions

The conversion of natural gas volumes to BOE is on the basis of six thousand cubic feet to one barrel. BOE is based on a generic energy equivalency conversion method primarily applicable at the burner tip and does not represent economic value equivalency at the wellhead. Readers are cautioned that BOE may be misleading, particularly if used in isolation.

Play and Resource Play

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

Additional Information

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

Encana Corporation

Interim Condensed Consolidated Financial Statements
(unaudited)

For the period ended September 30, 2015

(U.S. Dollars)

Condensed Consolidated Statement of Earnings *(unaudited)*

($ millions, except per share amounts)		Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Revenues, Net of Royalties	*(Note 3)*	**$ 1,312**	$ 2,285	**$ 3,391**	$ 5,765
Expenses	*(Note 3)*				
Production and mineral taxes		**27**	17	**72**	97
Transportation and processing		**319**	370	**959**	1,149
Operating		**190**	190	**588**	557
Purchased product		**60**	474	**260**	844
Depreciation, depletion and amortization		**352**	476	**1,212**	1,294
Impairments	*(Note 9)*	**1,671**	-	**5,668**	-
Accretion of asset retirement obligation	*(Note 12)*	**11**	13	**34**	39
Administrative	*(Note 17)*	**61**	69	**217**	269
Interest	*(Note 6)*	**105**	133	**508**	402
Foreign exchange (gain) loss, net	*(Note 7)*	**348**	202	**918**	254
(Gain) loss on divestitures	*(Notes 5, 15)*	**2**	(3,239)	**(14)**	(3,442)
Other		**(3)**	-	**2**	8
		3,143	(1,295)	**10,424**	1,471
Net Earnings (Loss) Before Income Tax		**(1,831)**	3,580	**(7,033)**	4,294
Income tax expense (recovery)	*(Note 8)*	**(595)**	749	**(2,480)**	1,066
Net Earnings (Loss)		**(1,236)**	2,831	**(4,553)**	3,228
Net earnings attributable to noncontrolling interest	*(Note 15)*	**-**	(24)	**-**	(34)
Net Earnings (Loss) Attributable to Common Shareholders		**$ (1,236)**	$ 2,807	**$ (4,553)**	$ 3,194
Net Earnings (Loss) per Common Share					
Basic & Diluted	*(Note 13)*	**$ (1.47)**	$ 3.79	**$ (5.59)**	$ 4.31

Condensed Consolidated Statement of Comprehensive Income *(unaudited)*

($ millions)		Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Net Earnings (Loss)		**$ (1,236)**	$ 2,831	**$ (4,553)**	$ 3,228
Other Comprehensive Income (Loss), Net of Tax					
Foreign currency translation adjustment	*(Note 14)*	**175**	(58)	**600**	(36)
Pension and other post-employment benefit plans	*(Notes 14, 19)*	**1**	-	**2**	-
Other Comprehensive Income (Loss)		**176**	(58)	**602**	(36)
Comprehensive Income (Loss)		**(1,060)**	2,773	**(3,951)**	3,192
Comprehensive Income Attributable to Noncontrolling Interest	*(Note 15)*	**-**	(24)	**-**	(34)
Comprehensive Income (Loss) Attributable to Common Shareholders		**$ (1,060)**	$ 2,749	**$ (3,951)**	$ 3,158

See accompanying Notes to Condensed Consolidated Financial Statements

Condensed Consolidated Balance Sheet *(unaudited)*

($ millions)		As at September 30, 2015	As at December 31, 2014
Assets			
Current Assets			
Cash and cash equivalents		$ 352	$ 338
Accounts receivable and accrued revenues		705	1,307
Risk management	*(Note 21)*	427	707
Income tax receivable		353	509
Deferred income taxes		34	-
		1,871	2,861
Property, Plant and Equipment, at cost:	*(Note 9)*		
Natural gas and oil properties, based on full cost accounting			
Proved properties		41,453	42,615
Unproved properties		5,734	6,133
Other		2,292	2,711
Property, plant and equipment		49,479	51,459
Less: Accumulated depreciation, depletion and amortization		(37,997)	(33,444)
Property, plant and equipment, net	*(Note 3)*	11,482	18,015
Cash in Reserve		1	73
Other Assets		310	394
Risk Management	*(Note 21)*	51	65
Deferred Income Taxes		767	296
Goodwill	*(Notes 3, 4, 5, 15)*	2,812	2,917
	(Note 3)	$ 17,294	$ 24,621
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable and accrued liabilities		$ 1,535	$ 2,243
Income tax payable		4	15
Risk management	*(Note 21)*	10	20
Deferred income taxes		45	128
		1,594	2,406
Long-Term Debt	*(Note 10)*	6,128	7,340
Other Liabilities and Provisions	*(Note 11)*	2,067	2,484
Risk Management	*(Note 21)*	9	7
Asset Retirement Obligation	*(Note 12)*	757	870
Deferred Income Taxes		20	1,829
		10,575	14,936
Commitments and Contingencies	*(Note 22)*		
Shareholders' Equity			
Share capital - authorized unlimited common shares, without par value			
2015 issued and outstanding: 845.7 million shares (2014: 741.2 million shares)	*(Note 13)*	3,601	2,450
Paid in surplus	*(Note 15)*	1,358	1,358
Retained earnings		469	5,188
Accumulated other comprehensive income	*(Note 14)*	1,291	689
Total Shareholders' Equity		6,719	9,685
		$ 17,294	$ 24,621

See accompanying Notes to Condensed Consolidated Financial Statements

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

Nine Months Ended September 30, 2015 ($ millions)		Share Capital	Paid in Surplus	Retained Earnings	Accumulated Other Comprehensive Income	Non-Controlling Interest	Total Shareholders' Equity
Balance, December 31, 2014		**$ 2,450**	**$ 1,358**	**$ 5,188**	**$ 689**	**$ -**	**$ 9,685**
Net Earnings (Loss)		**-**	**-**	**(4,553)**	**-**	**-**	**(4,553)**
Dividends on Common Shares	*(Note 13)*	**-**	**-**	**(166)**	**-**	**-**	**(166)**
Common Shares Issued	*(Note 13)*	**1,098**	**-**	**-**	**-**	**-**	**1,098**
Common Shares Issued Under Dividend Reinvestment Plan	*(Note 13)*	**53**	**-**	**-**	**-**	**-**	**53**
Other Comprehensive Income	*(Note 14)*	**-**	**-**	**-**	**602**	**-**	**602**
Balance, September 30, 2015		**$ 3,601**	**$ 1,358**	**$ 469**	**$ 1,291**	**$ -**	**$ 6,719**

Nine Months Ended September 30, 2014 ($ millions)		Share Capital	Paid in Surplus	Retained Earnings	Accumulated Other Comprehensive Income	Non-Controlling Interest	Total Shareholders' Equity
Balance, December 31, 2013		$ 2,445	$ 15	$ 2,003	$ 684	$ -	$ 5,147
Share-Based Compensation	*(Note 18)*	-	(1)	-	-	-	(1)
Net Earnings		-	-	3,194	-	34	3,228
Dividends on Common Shares	*(Note 13)*	-	-	(156)	-	-	(156)
Common Shares Issued Under Dividend Reinvestment Plan	*(Note 13)*	4	-	-	-	-	4
Other Comprehensive Income (Loss)	*(Note 14)*	-	-	-	(36)	-	(36)
Sale of Noncontrolling Interest	*(Note 15)*	-	1,346	-	-	117	1,463
Distributions to Noncontrolling Interest Owners	*(Note 15)*	-	-	-	-	(18)	(18)
Sale of Investment in PrairieSky	*(Note 15)*	-	-	-	-	(133)	(133)
Balance, September 30, 2014		$ 2,449	$ 1,360	$ 5,041	$ 648	$ -	$ 9,498

See accompanying Notes to Condensed Consolidated Financial Statements

Condensed Consolidated Statement of Cash Flows *(unaudited)*

($ millions)		Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Operating Activities					
Net earnings (loss)		**$ (1,236)**	$ 2,831	**$ (4,553)**	$ 3,228
Depreciation, depletion and amortization		**352**	476	**1,212**	1,294
Impairments	*(Note 9)*	**1,671**	-	**5,668**	-
Accretion of asset retirement obligation	*(Note 12)*	**11**	13	**34**	39
Deferred income taxes	*(Note 8)*	**(576)**	505	**(2,442)**	825
Unrealized (gain) loss on risk management	*(Note 21)*	**(173)**	(231)	**241**	45
Unrealized foreign exchange (gain) loss	*(Note 7)*	**241**	247	**555**	266
Foreign exchange on settlements	*(Note 7)*	**102**	1	**337**	28
(Gain) loss on divestitures	*(Notes 5, 15)*	**2**	(3,239)	**(14)**	(3,442)
Other		**(23)**	(51)	**9**	19
Net change in other assets and liabilities		**(18)**	(11)	**(18)**	(28)
Net change in non-cash working capital		**100**	155	**204**	132
Cash From (Used in) Operating Activities		**453**	696	**1,233**	2,406
Investing Activities					
Capital expenditures	*(Note 3)*	**(473)**	(598)	**(1,952)**	(1,669)
Acquisitions	*(Note 5)*	**-**	(29)	**(38)**	(2,975)
Proceeds from divestitures	*(Note 5)*	**99**	2,036	**1,115**	4,354
Proceeds from sale of investment in PrairieSky	*(Notes 5, 15)*	**-**	2,172	**-**	2,172
Cash in reserve		**-**	111	**72**	(101)
Net change in investments and other		**(170)**	113	**(154)**	89
Cash From (Used in) Investing Activities		**(544)**	3,805	**(957)**	1,870
Financing Activities					
Net issuance (repayment) of revolving long-term debt		**17**	-	**137**	-
Repayment of long-term debt	*(Note 10)*	**-**	-	**(1,302)**	(1,002)
Issuance of common shares	*(Note 13)*	**-**	-	**1,088**	-
Dividends on common shares	*(Note 13)*	**(38)**	(51)	**(113)**	(152)
Proceeds from sale of noncontrolling interest	*(Note 15)*	**-**	(8)	**-**	1,463
Distributions to noncontrolling interest owners	*(Note 15)*	**-**	(18)	**-**	(18)
Capital lease payments and other financing arrangements	*(Note 11)*	**(15)**	(18)	**(48)**	(60)
Cash From (Used in) Financing Activities		**(36)**	(95)	**(238)**	231
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**(17)**	(90)	**(24)**	(99)
Increase (Decrease) in Cash and Cash Equivalents		**(144)**	4,316	**14**	4,408
Cash and Cash Equivalents, Beginning of Period		**496**	2,658	**338**	2,566
Cash and Cash Equivalents, End of Period		**$ 352**	$ 6,974	**$ 352**	$ 6,974
Cash, End of Period		**$ 90**	$ 172	**$ 90**	$ 172
Cash Equivalents, End of Period		**262**	6,802	**262**	6,802
Cash and Cash Equivalents, End of Period		**$ 352**	$ 6,974	**$ 352**	$ 6,974

See accompanying Notes to Condensed Consolidated Financial Statements

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

1. Basis of Presentation and Principles of Consolidation

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

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

The interim Condensed Consolidated Financial Statements include the accounts of Encana and entities in which it holds a controlling interest. The noncontrolling interest represented the third party equity ownership in a former consolidated subsidiary, PrairieSky Royalty Ltd. ("PrairieSky"), as presented in the Condensed Consolidated Statement of Changes in Shareholders' Equity. See Note 15 for further details regarding the noncontrolling interest. All intercompany balances and transactions are eliminated on consolidation. Undivided interests in natural gas and oil exploration and production joint ventures and partnerships are consolidated on a proportionate basis. Investments in non-controlled entities over which Encana has the ability to exercise significant influence are accounted for using the equity method.

The interim Condensed Consolidated Financial Statements have been prepared following the same accounting policies and methods of computation as the annual audited Consolidated Financial Statements for the year ended December 31, 2014, except as noted below in Note 2. The disclosures provided below are incremental to those included with the annual audited Consolidated Financial Statements. Certain information and disclosures normally required to be included in the notes to the annual audited Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, the interim Condensed Consolidated Financial Statements should be read in conjunction with the annual audited Consolidated Financial Statements and the notes thereto for the year ended December 31, 2014.

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

2. Recent Accounting Pronouncements

Changes in Accounting Policies and Practices

On January 1, 2015, Encana adopted Accounting Standards Update ("ASU") 2014-08, "Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity" as issued by the Financial Accounting Standards Board ("FASB"). The update amends the criteria and expands the disclosures for reporting discontinued operations. Under the new criteria, only disposals representing a strategic shift in operations would qualify as a discontinued operation. The amendments have been applied prospectively and have not had a material impact on the Company's interim Condensed Consolidated Financial Statements.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

2. Recent Accounting Pronouncements (continued)

New Standards Issued Not Yet Adopted

As of January 1, 2016, Encana will be required to adopt the following pronouncements issued by the FASB:

- ASU 2014-12, "Compensation - Stock Compensation: Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved After the Requisite Service Period". The update requires that a performance target that affects vesting and could be achieved after the requisite service period be treated as a performance condition. The amendments will be applied prospectively and are not expected to have a material impact on the Company's Consolidated Financial Statements.

- ASU 2015-02, "Amendments to the Consolidation Analysis". The update requires limited partnerships and similar entities to be evaluated under the variable interest and voting interest models, eliminate the presumption that a general partner should consolidate a limited partnership, and simplify the identification of variable interests and related effect on the primary beneficiary criterion when fees are paid to a decision maker. The amendments can be applied using either a full retrospective approach or a modified retrospective approach at the date of adoption. Encana is currently assessing the potential impact of the amendments on the Company's Consolidated Financial Statements.

- ASU 2015-03, "Simplifying the Presentation of Debt Issuance Costs". The update requires debt issuance costs to be presented on the balance sheet as a deduction from the carrying amount of the related liability. Previously, debt issuance costs were presented as a deferred charge within assets. In August 2015, the FASB issued ASU 2015-15, "Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements". The update further clarifies that regardless of whether there are outstanding borrowings, debt issuance costs arising from credit arrangements can be presented as an asset and subsequently amortized ratably over the term of the arrangement. These amendments will be applied retrospectively. As at September 30, 2015, $31 million of debt issuance costs were presented in Other Assets on the Company's interim Condensed Consolidated Balance Sheet ($39 million as at December 31, 2014).

As of January 1, 2018, Encana will be required to adopt ASU 2014-09, "Revenue from Contracts with Customers" under Topic 606, which was the result of a joint project by the FASB and International Accounting Standards Board. The new standard replaces 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, but permits early adoption using the original effective date of January 1, 2017. The standard can be applied using one of two retrospective application methods at the date of adoption. Encana is currently assessing the potential impact of the standard on the Company's Consolidated Financial Statements.

3. Segmented Information

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

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

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

- **Market Optimization** is primarily responsible for the sale of the Company's proprietary production. These results are reported in the Canadian and USA Operations. Market optimization activities include third party purchases and sales of product to provide operational flexibility 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.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. Segmented Information (continued)

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

Segment and Geographic Information

	Canadian Operations		USA Operations		Market Optimization	
	2015	2014	**2015**	2014	**2015**	2014
Revenues, Net of Royalties	**$ 391**	$ 759	**$ 655**	$ 780	**$ 66**	$ 486
Expenses						
Production and mineral taxes	**-**	4	**27**	13	**-**	-
Transportation and processing	**153**	202	**155**	166	**-**	-
Operating	**38**	76	**142**	96	**4**	11
Purchased product	**-**	-	**-**	-	**60**	474
	200	477	**331**	505	**2**	1
Depreciation, depletion and amortization	**64**	166	**265**	279	**-**	-
Impairments	**-**	-	**1,671**	-	**-**	-
	$ 136	$ 311	**$ (1,605)**	$ 226	**$ 2**	$ 1

	Corporate & Other		Consolidated	
	2015	2014	**2015**	2014
Revenues, Net of Royalties	**$ 200**	$ 260	**$ 1,312**	$ 2,285
Expenses				
Production and mineral taxes	**-**	-	**27**	17
Transportation and processing	**11**	2	**319**	370
Operating	**6**	7	**190**	190
Purchased product	**-**	-	**60**	474
	183	251	**716**	1,234
Depreciation, depletion and amortization	**23**	31	**352**	476
Impairments	**-**	-	**1,671**	-
	$ 160	$ 220	**(1,307)**	758
Accretion of asset retirement obligation			**11**	13
Administrative			**61**	69
Interest			**105**	133
Foreign exchange (gain) loss, net			**348**	202
(Gain) loss on divestitures			**2**	(3,239)
Other			**(3)**	-
			524	(2,822)
Net Earnings (Loss) Before Income Tax			**(1,831)**	3,580
Income tax expense (recovery)			**(595)**	749
Net Earnings (Loss)			**(1,236)**	2,831
Net earnings attributable to noncontrolling interest			**-**	(24)
Net Earnings (Loss) Attributable to Common Shareholders			**$ (1,236)**	$ 2,807

Intersegment Information

	Market Optimization					
	Marketing Sales		Upstream Eliminations		Total	
	2015	2014	**2015**	2014	**2015**	2014
Revenues, Net of Royalties	**$ 1,063**	$ 1,732	**$ (997)**	$ (1,246)	**$ 66**	$ 486
Expenses						
Transportation and processing	**77**	108	**(77)**	(108)	**-**	-
Operating	**4**	15	**-**	(4)	**4**	11
Purchased product	**980**	1,600	**(920)**	(1,126)	**60**	474
Operating Cash Flow	**$ 2**	$ 9	**$ -**	$ (8)	**$ 2**	$ 1

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. Segmented Information (continued)

Results of Operations (For the nine months ended September 30)

Segment and Geographic Information

	Canadian Operations		USA Operations		Market Optimization	
	2015	2014	**2015**	2014	**2015**	2014
Revenues, Net of Royalties	**$ 1,410**	$ 2,706	**$ 1,872**	$ 2,131	**$ 293**	$ 890
Expenses						
Production and mineral taxes	**-**	13	**72**	84	**-**	-
Transportation and processing	**501**	642	**454**	506	**-**	-
Operating	**125**	246	**418**	249	**28**	37
Purchased product	**-**	-	**-**	-	**260**	844
	784	1,805	**928**	1,292	**5**	9
Depreciation, depletion and amortization	**237**	503	**902**	694	**-**	4
Impairments	**-**	-	**5,668**	-	**-**	-
	$ 547	$ 1,302	**$ (5,642)**	$ 598	**$ 5**	$ 5

	Corporate & Other		Consolidated	
	2015	2014	**2015**	2014
Revenues, Net of Royalties	**$ (184)**	$ 38	**$ 3,391**	$ 5,765
Expenses				
Production and mineral taxes	**-**	-	**72**	97
Transportation and processing	**4**	1	**959**	1,149
Operating	**17**	25	**588**	557
Purchased product	**-**	-	**260**	844
	(205)	12	**1,512**	3,118
Depreciation, depletion and amortization	**73**	93	**1,212**	1,294
Impairments	**-**	-	**5,668**	-
	$ (278)	$ (81)	**(5,368)**	1,824
Accretion of asset retirement obligation			**34**	39
Administrative			**217**	269
Interest			**508**	402
Foreign exchange (gain) loss, net			**918**	254
(Gain) loss on divestitures			**(14)**	(3,442)
Other			**2**	8
			1,665	(2,470)
Net Earnings (Loss) Before Income Tax			**(7,033)**	4,294
Income tax expense (recovery)			**(2,480)**	1,066
Net Earnings (Loss)			**(4,553)**	3,228
Net earnings attributable to noncontrolling interest			**-**	(34)
Net Earnings (Loss) Attributable to Common Shareholders			**$ (4,553)**	$ 3,194

Intersegment Information

	Market Optimization					
	Marketing Sales		Upstream Eliminations		Total	
	2015	2014	**2015**	2014	**2015**	2014
Revenues, Net of Royalties	**$ 3,345**	$ 5,740	**$ (3,052)**	$ (4,850)	**$ 293**	$ 890
Expenses						
Transportation and processing	**261**	358	**(261)**	(358)	**-**	-
Operating	**28**	59	**-**	(22)	**28**	37
Purchased product	**3,051**	5,303	**(2,791)**	(4,459)	**260**	844
Operating Cash Flow	**$ 5**	$ 20	**$ -**	$ (11)	**$ 5**	$ 9

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. Segmented Information (continued)

Capital Expenditures

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Canadian Operations	**$ 76**	$ 293	**$ 341**	$ 924
USA Operations	**394**	305	**1,605**	737
Market Optimization	**1**	(2)	**1**	-
Corporate & Other	**2**	2	**5**	8
	$ 473	$ 598	**$ 1,952**	$ 1,669

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

	Goodwill As at September 30, 2015	Goodwill As at December 31, 2014	Property, Plant and Equipment As at September 30, 2015	Property, Plant and Equipment As at December 31, 2014	Total Assets As at September 30, 2015	Total Assets As at December 31, 2014
Canadian Operations	**$ 683**	$ 788	**$ 1,184**	$ 2,338	**$ 2,177**	$ 3,632
USA Operations	**2,129**	2,129	**8,725**	13,817	**11,351**	16,800
Market Optimization	**-**	-	**1**	1	**57**	181
Corporate & Other	**-**	-	**1,572**	1,859	**3,709**	4,008
	$ 2,812	$ 2,917	**$ 11,482**	$ 18,015	**$ 17,294**	$ 24,621

4. Business Combinations

Eagle Ford Acquisition

On June 20, 2014, Encana completed the acquisition of properties located in the Eagle Ford shale formation for approximately $2.9 billion, after closing adjustments. The acquisition included an interest in certain producing properties and undeveloped lands in the Karnes, Wilson and Atascosa counties of south Texas. Encana funded the acquisition with cash on hand. Transaction costs of approximately $9 million were included in other expenses.

Athlon Energy Inc. Acquisition

On November 13, 2014, Encana completed the acquisition of all of the issued and outstanding shares of common stock of Athlon Energy Inc. (“Athlon”) for $5.93 billion, or $58.50 per share. In addition, Encana assumed Athlon’s $1.15 billion senior notes and repaid and terminated Athlon’s credit facility with indebtedness outstanding of $335 million. Encana funded the acquisition of Athlon with cash on hand. Transaction costs of approximately $31 million were included in other expenses. Following completion of the acquisition, Athlon’s $1.15 billion senior notes were redeemed in accordance with the provisions of the governing indentures. Athlon's operations focused on the acquisition and development of oil and gas properties located in the Permian Basin in Texas.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

4. Business Combinations (continued)

Purchase Price Allocations

The transactions were accounted for under the acquisition method, which requires that the assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date. The purchase price allocations, representing consideration paid and the fair values of the assets acquired and liabilities assumed as of the acquisition date, are shown in the table below.

Purchase Price Allocation	Eagle Ford (1)	Athlon (2, 3)
Assets Acquired:		
Cash	$ -	$ 2
Accounts receivable and other current assets	4	133
Risk management	-	80
Proved properties	2,873	2,124
Unproved properties	78	5,338
Other property, plant and equipment	-	2
Other assets	-	2
Goodwill	-	1,724
Liabilities Assumed:		
Accounts payable and accrued liabilities	-	(195)
Long-term debt, including revolving credit facility	-	(1,497)
Asset retirement obligation	(32)	(25)
Deferred income taxes	-	(1,724)
Total Purchase Price	$ 2,923	$ 5,964

(1) The purchase price allocation for Eagle Ford is finalized.

(2) The purchase price allocation for Athlon is preliminary. There were no changes during the nine months ended September 30, 2015.

(3) The purchase price includes cash consideration paid for issued and outstanding shares of common stock of Athlon of $58.50 per share totaling $5.93 billion, as well as payments to terminate certain employment agreements with Athlon's management and payments for certain other existing obligations of Athlon.

The Company used the income approach valuation technique for the fair value of assets acquired and liabilities assumed. The carrying amounts of cash, accounts receivable and other current assets, and accounts payable and accrued liabilities approximate their fair values due to the short-term maturity of the instruments. The fair values of the risk management assets and long-term debt, including the revolving credit facility, are categorized within Level 2 of the fair value hierarchy and were determined using quoted prices and rates from an available pricing source. The fair values of the proved and unproved properties, other property, plant and equipment, other assets, goodwill, and asset retirement obligation are categorized within Level 3 and were determined using relevant market assumptions, including discount rates, future commodity prices and costs, timing of development activities, projections of oil and gas reserves, and estimates to abandon and reclaim producing wells.

Goodwill arose from the Athlon acquisition primarily from the requirement to recognize deferred taxes on the difference between the fair value of the assets acquired and liabilities assumed and the respective carry-over tax basis. Goodwill is not amortized and is not deductible for tax purposes.

Pro Forma Financial Information

The following unaudited pro forma financial information combines the historical financial results of Encana with Eagle Ford and Athlon, and has been prepared assuming the acquisitions occurred on January 1, 2014. The pro forma information is not intended to reflect the actual results of operations that would have occurred if the business combinations had been completed at the date indicated. In addition, the pro forma information does not project Encana's results of operations for any future period. The Company's consolidated results for the nine months ended September 30, 2015 include the results from Eagle Ford and Athlon.

Nine Months Ended September 30, 2014 ($ millions, except per share amounts)	Eagle Ford	Athlon
Revenues, Net of Royalties	$ 6,506	$ 6,188
Net Earnings Attributable to Common Shareholders	$ 3,445	$ 3,258
Net Earnings per Common Share		
Basic & Diluted	$ 4.65	$ 4.40

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. Acquisitions and Divestitures

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Acquisitions				
Canadian Operations	**$ -**	$ 12	**$ 1**	$ 14
USA Operations	**-**	17	**3**	2,961
Corporate & Other	**-**	-	**34**	-
Total Acquisitions	**-**	29	**38**	2,975
Divestitures				
Canadian Operations	**(56)**	(1,729)	**(935)**	(1,850)
USA Operations	**(43)**	(100)	**(127)**	(2,270)
Market Optimization	**-**	(205)	**-**	(205)
Corporate & Other	**-**	(2)	**(53)**	(29)
Total Divestitures	**(99)**	(2,036)	**(1,115)**	(4,354)
Net Acquisitions & (Divestitures)	**$ (99)**	$ (2,007)	**$ (1,077)**	$ (1,379)

Acquisitions

During the nine months ended September 30, 2014, acquisitions primarily included the purchase of certain properties in the Eagle Ford shale formation in south Texas as described in Note 4.

Divestitures

For the three and nine months ended September 30, 2015, divestitures in the Canadian Operations were $56 million and $935 million, respectively. Divestitures primarily reflect the sale of certain assets included in Wheatland located in central and southern Alberta for proceeds of approximately C$558 million ($468 million), after closing adjustments, the sale of certain natural gas gathering and compression assets in the Montney area of northeastern British Columbia for proceeds of approximately C$453 million ($357 million), after closing adjustments, and the sale of land and properties that do not complement Encana's existing portfolio of assets. During the three and nine months ended September 30, 2014, divestitures in the Canadian Operations were $1,729 million and $1,850 million, respectively, which primarily included the sale of the Company's Bighorn assets in west central Alberta.

For the three and nine months ended September 30, 2015, divestitures in the USA Operations were $43 million and $127 million, respectively, which primarily included the sale of land and properties that do not complement Encana's existing portfolio of assets. During the three and nine months ended September 30, 2014, divestitures in the USA Operations were $100 million and $2,270 million, respectively. During the nine months ended September 30, 2014, divestitures primarily included the sale of the Jonah properties for proceeds of approximately $1,639 million and the sale of certain properties in East Texas for proceeds of approximately $497 million.

Encana recognizes gains or losses on divestitures that result in a significant alteration between capitalized costs and proved reserves in a country cost centre. For divestitures that result in a gain or loss and constitute a business, goodwill is allocated to the divestiture. Accordingly, for the three and nine months ended September 30, 2014, Encana recognized a gain of approximately $1,024 million, before tax, on the sale of the Company's Bighorn assets in the Canadian cost centre and allocated goodwill of $257 million. In addition, for the nine months ended September 30, 2014, Encana recognized a gain of approximately $212 million, before tax, on the sale of the Jonah properties in the U.S. cost centre and allocated goodwill of $68 million.

Amounts received from the divestiture transactions have been deducted from the respective Canadian and U.S. full cost pools, except for the sale of the Bighorn assets and the Jonah properties as noted above and the sale of the investment in PrairieSky as noted below.

For the nine months ended September 30, 2015, Corporate and Other acquisitions and divestitures primarily includes the purchase and subsequent sale of the Encana Place office building located in Calgary, which resulted in a gain on divestiture of approximately $12 million.

Divestiture of Investment in PrairieSky

On September 26, 2014, Encana completed the secondary offering of 70.2 million common shares of PrairieSky at a price of C$36.50 per common share for aggregate gross proceeds of approximately C$2.6 billion. As the sale of the investment in PrairieSky resulted in a significant alteration between capitalized costs and proved reserves in the Canadian cost centre, Encana recognized a gain on divestiture of approximately $2.1 billion, before tax. See Note 15 for further details regarding the PrairieSky transactions.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

6. Interest

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	**2015**	2014
Interest Expense on:				
Debt	**$ 77**	$ 95	**$ 420**	$ 303
The Bow office building	**15**	19	**49**	57
Capital leases	**7**	9	**22**	28
Other	**6**	10	**17**	14
	$ 105	$ 133	**$ 508**	$ 402

Interest Expense on Debt for the nine months ended September 30, 2015 includes a one-time interest payment of approximately $165 million resulting from the April 2015 early redemption of the Company's $700 million 5.90 percent notes due December 1, 2017 and C$750 million 5.80 percent medium-term notes due January 18, 2018 as discussed in Note 10.

7. Foreign Exchange (Gain) Loss, Net

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	**2015**	2014
Unrealized Foreign Exchange (Gain) Loss on:				
Translation of U.S. dollar debt issued from Canada	**$ 297**	$ 256	**$ 638**	$ 276
Translation of U.S. dollar risk management contracts issued from Canada	**(27)**	(9)	**(56)**	(10)
Translation of intercompany notes	**(29)**	-	**(27)**	-
	241	247	**555**	266
Foreign Exchange on Settlements	**102**	1	**337**	28
Other Monetary Revaluations	**5**	(46)	**26**	(40)
	$ 348	$ 202	**$ 918**	$ 254

Foreign Exchange on Settlements includes foreign exchange on intercompany transactions and foreign exchange on settlement of long-term debt previously reported in Other Monetary Revaluations.

8. Income Taxes

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	**2015**	2014
Current Tax				
Canada	**$ 1**	$ 267	**$ (24)**	$ 247
United States	**(22)**	(26)	**(19)**	(19)
Other countries	**2**	3	**5**	13
Total Current Tax Expense (Recovery)	**(19)**	244	**(38)**	241
Deferred Tax				
Canada	**(138)**	470	**(616)**	698
United States	**(471)**	36	**(2,110)**	107
Other countries	**33**	(1)	**284**	20
Total Deferred Tax Expense (Recovery)	**(576)**	505	**(2,442)**	825
	$ (595)	$ 749	**$ (2,480)**	$ 1,066

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, including the 2015 Alberta general corporate income tax rate increase, and amounts in respect of prior periods. The estimated annual effective income tax rate is impacted by the expected annual earnings, statutory rate and other foreign differences, non-taxable capital gains and losses, tax differences on divestitures and transactions, and partnership tax allocations in excess of funding.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

9. Property, Plant and Equipment, Net

	As at September 30, 2015			As at December 31, 2014		
	Cost	Accumulated DD&A [1]	Net	Cost	Accumulated DD&A [1]	Net
Canadian Operations						
Proved properties	$ 15,286	$ (14,574)	$ 712	$ 18,271	$ (16,566)	$ 1,705
Unproved properties	380	-	380	478	-	478
Other	92	-	92	155	-	155
	15,758	(14,574)	1,184	18,904	(16,566)	2,338
USA Operations						
Proved properties	26,111	(22,829)	3,282	24,279	(16,260)	8,019
Unproved properties	5,354	-	5,354	5,655	-	5,655
Other	89	-	89	143	-	143
	31,554	(22,829)	8,725	30,077	(16,260)	13,817
Market Optimization	7	(6)	1	8	(7)	1
Corporate & Other	2,160	(588)	1,572	2,470	(611)	1,859
	$ 49,479	$ (37,997)	$ 11,482	$ 51,459	$ (33,444)	$ 18,015

(1) Depreciation, depletion and amortization.

Canadian Operations and USA Operations property, plant and equipment include internal costs directly related to exploration, development and construction activities of $170 million which have been capitalized during the nine months ended September 30, 2015 (2014 - $255 million). Included in Corporate and Other are $56 million ($65 million as at December 31, 2014) of international property costs, which have been fully impaired.

For the three and nine months ended September 30, 2015, the Company recognized before-tax ceiling test impairments of $1,671 million and $5,668 million, respectively (2014 - nil) in the U.S. cost centre, which are included within accumulated DD&A in the table above. The impairments resulted primarily from the decline in the 12-month average trailing commodity prices which reduced proved reserves volumes and values. There were no ceiling test impairments in the Canadian cost centre for the three and nine months ended September 30, 2015 (2014 - nil).

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

	Natural Gas		Oil & NGLs	
	Henry Hub ($/MMBtu)	AECO (C$/MMBtu)	WTI ($/bbl)	Edmonton Light Sweet (C$/bbl)
12-Month Average Trailing Reserves Pricing				
September 30, 2015	**3.05**	**3.02**	**59.21**	**65.69**
December 31, 2014	4.34	4.63	94.99	96.40
September 30, 2014	4.24	4.49	99.08	96.92

Capital Lease Arrangements

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

In December 2013, Encana commenced commercial operations at its Deep Panuke facility located offshore Nova Scotia at which time the Company recorded a capital lease asset and a corresponding capital lease obligation related to the Production Field Centre ("PFC"). Variable interests related to the PFC are described in Note 16.

As at September 30, 2015, the total carrying value of assets under capital lease was $402 million ($547 million as at December 31, 2014). Liabilities for the capital lease arrangements are included in other liabilities and provisions in the Condensed Consolidated Balance Sheet and are disclosed in Note 11.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

9. Property, Plant and Equipment, Net (continued)

Other Arrangement

As at September 30, 2015, Corporate and Other property, plant and equipment and total assets include a carrying value of $1,223 million ($1,431 million as at December 31, 2014) 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 11.

10. Long-Term Debt

	C$ Principal Amount	As at September 30, 2015	As at December 31, 2014
Canadian Dollar Denominated Debt			
5.80% due January 18, 2018	$ -	$ -	$ 647
U.S. Dollar Denominated Debt			
Revolving credit and term loan borrowings		1,414	1,277
U.S. Unsecured Notes			
5.90% due December 1, 2017		-	700
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		500	500
6.50% due February 1, 2038		800	800
5.15% due November 15, 2041		400	400
		6,114	6,677
Total Principal		6,114	7,324
Increase in Value of Debt Acquired		28	34
Debt Discounts		(14)	(18)
Current Portion of Long-Term Debt		-	-
		$ 6,128	$ 7,340

Long-term debt is accounted for at amortized cost using the effective interest method of amortization. As at September 30, 2015, total long-term debt had a carrying value of $6,128 million and a fair value of $5,870 million (as at December 31, 2014 - carrying value of $7,340 million and a fair value of $7,788 million). The estimated fair value of long-term borrowings is categorized within Level 2 of the fair value hierarchy and has been determined based on market information, or by discounting future payments of interest and principal at interest rates expected to be available to the Company at period end.

On March 5, 2015, Encana provided notice to note holders that it would redeem the Company's $700 million 5.90 percent notes due December 1, 2017 and C$750 million 5.80 percent medium-term notes due January 18, 2018. On April 6, 2015, the Company used net proceeds from the common shares issued, as disclosed in Note 13, and cash on hand to complete the note redemptions. In conjunction with the early note redemptions, the Company incurred a one-time interest payment of approximately $165 million as discussed in Note 6.

On February 28, 2014, Encana announced a cash tender offer and consent solicitation for any and all of the Company’s outstanding $1,000 million 5.80 percent notes with a maturity date of May 1, 2014. The Company paid $1,004.59 for each $1,000 principal amount of the notes plus accrued and unpaid interest up to, but not including, the settlement date and a consent payment equal to $2.50 per $1,000 principal amount of the notes.

On March 28, 2014, the tender offer and consent solicitation expired and on March 31, 2014, Encana paid the consenting note holders an aggregate of approximately $792 million in cash reflecting a $768 million principal debt repayment, $2 million for the consent payment and $22 million of accrued and unpaid interest.

On April 28, 2014, pursuant to the Notice of Redemption issued on March 28, 2014, the Company redeemed the remaining principal amount of the 5.80 percent notes not tendered in the tender offer. Encana paid approximately $239 million in cash reflecting a $232 million principal debt repayment and $7 million of accrued and unpaid interest.

(All amounts in $ millions unless otherwise specified)

11. Other Liabilities and Provisions

	As at September 30, 2015	As at December 31, 2014
The Bow Office Building (See Note 9)	**$ 1,281**	$ 1,486
Capital Lease Obligations (See Note 9)	**378**	473
Unrecognized Tax Benefits	**184**	279
Pensions and Other Post-Employment Benefits	**158**	144
Long-Term Incentives (See Note 18)	**23**	70
Other	**43**	32
	$ 2,067	$ 2,484

The Bow Office Building

As described in Note 9, Encana has recognized the accumulated costs for The Bow office building, which is under a 25-year lease agreement. At the conclusion of the 25-year term, the remaining asset and corresponding liability are expected to be derecognized. Encana has also subleased part of The Bow office space to a subsidiary of Cenovus Energy Inc. ("Cenovus"). The total undiscounted future payments related to the lease agreement and the total undiscounted future amounts expected to be recovered from the Cenovus sublease are outlined below.

(undiscounted)	2015	2016	2017	2018	2019	Thereafter	Total
Expected Future Lease Payments	$ 17	$ 70	$ 71	$ 71	$ 72	$ 1,431	**$ 1,732**
Sublease Recoveries	$ (9)	$ (34)	$ (35)	$ (35)	$ (35)	$ (703)	**$ (851)**

Capital Lease Obligations

As described in Note 9, the Company has several lease arrangements that are accounted for as capital leases, including an office building, equipment and an offshore production platform. Variable interests related to the PFC are described in Note 16.

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

	2015	2016	2017	2018	2019	Thereafter	Total
Expected Future Lease Payments	$ 24	$ 98	$ 99	$ 99	$ 99	$ 232	**$ 651**
Less Amounts Representing Interest	11	44	40	36	32	56	**219**
Present Value of Expected Future Lease Payments	$ 13	$ 54	$ 59	$ 63	$ 67	$ 176	**$ 432**

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

12. Asset Retirement Obligation

	As at September 30, 2015	As at December 31, 2014
Asset Retirement Obligation, Beginning of Year	**$ 913**	$ 966
Liabilities Incurred and Acquired (See Note 4)	**15**	85
Liabilities Settled and Divested	**(125)**	(188)
Change in Estimated Future Cash Outflows	**-**	35
Accretion Expense	**34**	52
Foreign Currency Translation	**(50)**	(37)
Asset Retirement Obligation, End of Period	**$ 787**	$ 913
Current Portion	**$ 30**	$ 43
Long-Term Portion	**757**	870
	$ 787	$ 913

13. 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.

Issued and Outstanding

	As at September 30, 2015		As at December 31, 2014	
	Number (millions)	Amount	Number (millions)	Amount
Common Shares Outstanding, Beginning of Year	**741.2**	**$ 2,450**	740.9	$ 2,445
Common Shares Issued	**98.4**	**1,098**	-	-
Common Shares Issued Under Dividend Reinvestment Plan	**6.1**	**53**	0.3	5
Common Shares Outstanding, End of Period	**845.7**	**$ 3,601**	741.2	$ 2,450

On March 5, 2015, Encana filed a prospectus supplement (the "Share Offering") to the Company's base shelf prospectus for the issuance of 85,616,500 common shares and granted an over-allotment option for up to an additional 12,842,475 common shares at a price of C$14.60 per common share, pursuant to an underwriting agreement. The aggregate gross proceeds from the Share Offering were approximately C$1.44 billion ($1.13 billion). After deducting underwriter's fees and costs of the Share Offering, the net proceeds received were approximately C$1.39 billion ($1.09 billion).

During the nine months ended September 30, 2015, Encana issued 6,115,535 common shares totaling $53 million under the Company's dividend reinvestment plan ("DRIP"). During the twelve months ended December 31, 2014, Encana issued 240,839 common shares totaling $5 million under the DRIP.

Dividends

During the three months ended September 30, 2015, Encana paid dividends of $0.07 per common share totaling $59 million (2014 - $0.07 per common share totaling $52 million). During the nine months ended September 30, 2015, Encana paid dividends of $0.21 per common share totaling $166 million (2014 - $0.21 per common share totaling $156 million). Common shares issued as part of the Share Offering as described above were not eligible to receive the dividend paid on March 31, 2015.

For the three and nine months ended September 30, 2015, the dividends paid included $21 million and $53 million, respectively, in common shares issued in lieu of cash dividends under the DRIP (for the three and nine months ended September 30, 2014 - $1 million and $4 million, respectively).

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

13. Share Capital (continued)

Earnings Per Common Share

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions, except per share amounts)	**2015**	2014	**2015**	2014
Net Earnings (Loss) Attributable to Common Shareholders	**$ (1,236)**	$ 2,807	**$ (4,553)**	$ 3,194
Number of Common Shares:				
Weighted average common shares outstanding - Basic	**843.1**	741.1	**814.0**	741.0
Effect of dilutive securities	**-**	-	**-**	-
Weighted average common shares outstanding - Diluted	**843.1**	741.1	**814.0**	741.0
Net Earnings (Loss) per Common Share				
Basic	**$ (1.47)**	$ 3.79	**$ (5.59)**	$ 4.31
Diluted	**$ (1.47)**	$ 3.79	**$ (5.59)**	$ 4.31

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 September 30, 2015 have associated Tandem Stock Appreciation Rights ("TSARs") attached. In lieu of exercising the option, the associated TSARs give the option holder the right to receive a cash payment equal to the excess of the market price of Encana's common shares at the time of the exercise over the original grant price.

In addition, certain stock options granted are performance-based whereby vesting is also subject to Encana attaining prescribed performance relative to predetermined key measures. Historically, most holders of options with TSARs have elected to exercise their stock options as a Stock Appreciation Right ("SAR") in exchange for a cash payment. As a result, Encana does not consider outstanding TSARs to be potentially dilutive securities.

Encana Restricted Share Units ("RSUs")

Encana has a share-based compensation plan whereby eligible employees are granted RSUs. An RSU is a conditional grant to receive an Encana common share, or the cash equivalent, as determined by Encana, upon vesting of the RSUs and in accordance with the terms of the RSU Plan and Grant Agreement. The Company intends to settle vested RSUs in cash on the vesting date. As a result, Encana does not consider RSUs to be potentially dilutive securities.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

14. Accumulated Other Comprehensive Income

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Foreign Currency Translation Adjustment				
Balance, Beginning of Period	**$ 1,140**	$ 715	**$ 715**	$ 693
Current Period Change in Foreign Currency Translation Adjustment	**175**	(58)	**600**	(36)
Balance, End of Period	**$ 1,315**	$ 657	**$ 1,315**	$ 657
Pension and Other Post-Employment Benefit Plans				
Balance, Beginning of Period	**$ (25)**	$ (9)	**$ (26)**	$ (9)
Reclassification of Net Actuarial (Gains) and Losses to Net Earnings (See Note 19)	**1**	-	**2**	-
Income Taxes	**-**	-	**-**	-
Balance, End of Period	**$ (24)**	$ (9)	**$ (24)**	$ (9)
Total Accumulated Other Comprehensive Income	**$ 1,291**	$ 648	**$ 1,291**	$ 648

15. Noncontrolling Interest

Initial Public Offering of Common Shares of PrairieSky

On May 29, 2014, Encana completed an initial public offering ("IPO") of 52.0 million common shares of PrairieSky at a price of C$28.00 per common share for gross proceeds of approximately C$1.46 billion. On June 3, 2014, the over-allotment option granted to the underwriters to purchase up to an additional 7.8 million common shares was exercised in full for gross proceeds of approximately C$218.4 million. Encana received aggregate gross proceeds from the IPO of approximately C$1.67 billion ($1.54 billion). Subsequent to the IPO, Encana owned 70.2 million common shares of PrairieSky, representing a 54 percent ownership interest. Accordingly, Encana consolidated 100 percent of the financial position and results of operations of PrairieSky and recognized a noncontrolling interest for the third party ownership.

The noncontrolling interest in the former consolidated subsidiary, PrairieSky, was reflected as a separate component in the Condensed Consolidated Statement of Changes in Shareholders' Equity for the nine months ended September 30, 2014. Encana recorded $117 million of the proceeds from the IPO as a noncontrolling interest and the remainder of the proceeds of $1,427 million, less transaction costs of $81 million, was recognized as paid in surplus as at September 30, 2014.

Secondary Public Offering of Common Shares of PrairieSky

On September 26, 2014, Encana completed the secondary offering of 70.2 million common shares of PrairieSky at a price of C$36.50 per common share, for aggregate gross proceeds to Encana of approximately C$2.6 billion. Following the completion of the secondary offering, Encana no longer held an interest in PrairieSky. As discussed in Note 5, the PrairieSky divestiture resulted in a significant alteration between capitalized costs and proved reserves in the Canadian cost centre. Accordingly, Encana recognized a gain on the divestiture of approximately $2,095 million, which is included in the (gain) loss on divestitures in the Company's Condensed Consolidated Statement of Earnings. In conjunction with the divestiture, Encana derecognized the carrying amount of the net assets of $258 million, including goodwill of $39 million, and the noncontrolling interest of $133 million.

Distributions to Noncontrolling Interest Owners

During the period from May 29, 2014 to September 25, 2014, PrairieSky paid dividends of C$0.3174 per common share totaling $38 million, of which $18 million was attributable to the noncontrolling interest as presented in the Condensed Consolidated Statement of Changes in Shareholders' Equity and Condensed Consolidated Statement of Cash Flows.

Net Earnings Attributable to Noncontrolling Interest

During the period from May 29, 2014 to September 25, 2014, the Company held a noncontrolling interest in PrairieSky. Accordingly, Encana consolidated 100 percent of the financial position and results of operations of PrairieSky and recognized a noncontrolling interest for third party ownership. For the three and nine months ended September 30, 2014, net earnings and comprehensive income of $24 million and $34 million, respectively, were attributable to the noncontrolling interest as presented in the Condensed Consolidated Statement of Earnings and Condensed Consolidated Statement of Comprehensive Income.

16. 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 as described in Note 9. 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 September 30, 2015, Encana's capital lease obligation of $364 million ($462 million as at December 31, 2014) is related to the PFC.

Veresen Midstream Limited Partnership

On March 31, 2015, Encana, along with the Cutbank Ridge Partnership ("CRP"), entered into natural gas gathering and compression agreements with Veresen Midstream Limited Partnership ("VMLP"), under an initial term of 30 years with two potential five-year renewal terms. As part of the agreement, VMLP agreed to undertake future expansion of midstream services if required by Encana and the CRP in support of the anticipated future development of the Montney play. In addition, VMLP provides to Encana and the CRP natural gas gathering and processing under agreements that were contributed to VMLP by its partner Veresen Inc., and have remaining terms of 17 years and up to a potential maximum of 10 one-year renewal terms.

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

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 $1,169 million as at September 30, 2015. 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 22 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 September 30, 2015, accounts payable and accrued liabilities included $1 million related to the take or pay commitment.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

17. Restructuring Charges

In November 2013, Encana announced its plans to align the organizational structure in support of the Company's strategy. Since the announcement, total restructuring charges primarily related to severance costs of $125 million, before tax, have been incurred, of which $2 million remains accrued as at September 30, 2015. For the nine months ended September 30, 2015, $1 million in restructuring charges were incurred (2014 - $29 million).

During the second quarter of 2015, Encana revised its plans to align the organizational structure in continued support of the Company's strategy. Additional transition and severance costs are expected to total approximately $59 million before tax. For the nine months ended September 30, 2015, costs of $58 million were incurred, of which $12 million remains accrued. The remaining transition and severance costs of approximately $1 million are expected to be incurred during the remainder of 2015.

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

18. Compensation Plans

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

Encana accounts for TSARs, Performance TSARs, SARs, Performance SARs, PSUs and RSUs held by Encana employees as cash-settled share-based payment transactions and, accordingly, accrues compensation costs over the vesting period based on the fair value of the rights determined using the Black-Scholes-Merton and other fair value models.

As at September 30, 2015, the following weighted average assumptions were used to determine the fair value of the share units held by Encana employees:

	Encana US$ Share Units	Encana C$ Share Units
Risk Free Interest Rate	0.51%	0.51%
Dividend Yield	4.35%	4.11%
Expected Volatility Rate	34.80%	32.43%
Expected Term	1.6 yrs	1.6 yrs
Market Share Price	US$6.44	C$8.59

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

18. Compensation Plans (continued)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	**2015**	2014
Compensation Costs of Transactions Classified as Cash-Settled	**$ (31)**	$ (14)	**$ (24)**	$ 115
Compensation Costs of Transactions Classified as Equity-Settled [1]	**-**	-	**-**	(1)
Total Share-Based Compensation Costs	**(31)**	(14)	**(24)**	114
Less: Total Share-Based Compensation Costs Capitalized	**11**	5	**9**	(41)
Total Share-Based Compensation Expense	**$ (20)**	$ (9)	**$ (15)**	$ 73
Recognized on the Condensed Consolidated Statement of Earnings in:				
Operating expense	**$ (7)**	$ (5)	**$ (6)**	$ 31
Administrative expense	**(13)**	(4)	**(9)**	42
	$ (20)	$ (9)	**$ (15)**	$ 73

(1) RSUs may be settled in cash or equity as determined by Encana. The Company's decision to cash settle RSUs was made subsequent to the original grant date.

As at September 30, 2015, the liability for share-based payment transactions totaled $59 million ($99 million as at December 31, 2014), of which $36 million ($29 million as at December 31, 2014) is recognized in accounts payable and accrued liabilities in the Condensed Consolidated Balance Sheet.

	As at September 30, 2015	As at December 31, 2014
Liability for Cash-Settled Share-Based Payment Transactions:		
Unvested	**$ 52**	$ 78
Vested	**7**	21
	$ 59	$ 99

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

Nine Months Ended September 30, 2015 (thousands of units)	
TSARs	1,934
SARs	1,444
PSUs	2,370
DSUs	172
RSUs	6,807

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

19. 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 nine months ended September 30 as follows:

	Pension Benefits		OPEB		Total	
	2015	2014	**2015**	2014	**2015**	2014
Defined Benefit Plan Expense	**$ 1**	$ -	**$ 11**	$ 9	**$ 12**	$ 9
Defined Contribution Plan Expense	**23**	26	**-**	-	**23**	26
Total Benefit Plans Expense	**$ 24**	$ 26	**$ 11**	$ 9	**$ 35**	$ 35

Of the total benefit plans expense, $28 million (2014 - $27 million) was included in operating expense and $7 million (2014 - $8 million) was included in administrative expense.

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

	Pension Benefits		OPEB		Total	
	2015	2014	**2015**	2014	**2015**	2014
Current Service Costs	**$ 2**	$ 2	**$ 8**	$ 6	**$ 10**	$ 8
Interest Cost	**7**	9	**3**	3	**10**	12
Expected Return On Plan Assets	**(10)**	(11)	**-**	-	**(10)**	(11)
Amounts Reclassified From Accumulated Other Comprehensive Income:						
Amortization of net actuarial (gains) and losses	**2**	-	**-**	-	**2**	-
Total Defined Benefit Plan Expense	**$ 1**	$ -	**$ 11**	$ 9	**$ 12**	$ 9

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

	Pension Benefits		OPEB		Total	
	2015	2014	**2015**	2014	**2015**	2014
Total Amounts Recognized in Other Comprehensive (Income) Loss, Before Tax	**$ (2)**	$ -	**$ -**	$ -	**$ (2)**	$ -
Total Amounts Recognized in Other Comprehensive (Income) Loss, After Tax	**$ (2)**	$ -	**$ -**	$ -	**$ (2)**	$ -

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

20. Fair Value Measurements

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, and accounts payable and accrued liabilities approximate their carrying amounts due to the short-term maturity of those instruments. The fair value of cash in reserve approximates its carrying amount due to the nature of the instrument held.

Recurring fair value measurements are performed for risk management assets and liabilities and are discussed further in Note 21. These items are carried at fair value in the Condensed Consolidated Balance Sheet and are classified within the three levels of the fair value hierarchy in the tables below. There have been no transfers between the hierarchy levels during the period.

As at September 30, 2015	Level 1 Quoted Prices in Active Markets	Level 2 Other Observable Inputs	Level 3 Significant Unobservable Inputs	Total Fair Value	Netting [1]	Carrying Amount
Risk Management						
Risk Management Assets						
Current	**$ -**	**$ 436**	**$ 13**	**$ 449**	**$ (22)**	**$ 427**
Long-term	**-**	**52**	**3**	**55**	**(4)**	**51**
Risk Management Liabilities						
Current	**-**	**22**	**10**	**32**	**(22)**	**10**
Long-term	**-**	**4**	**9**	**13**	**(4)**	**9**

As at December 31, 2014	Level 1 Quoted Prices in Active Markets	Level 2 Other Observable Inputs	Level 3 Significant Unobservable Inputs	Total Fair Value	Netting [1]	Carrying Amount
Risk Management						
Risk Management Assets						
Current	$ -	$ 718	$ -	$ 718	$ (11)	$ 707
Long-term	-	67	-	67	(2)	65
Risk Management Liabilities						
Current	6	14	11	31	(11)	20
Long-term	-	2	7	9	(2)	7

[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.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

20. Fair Value Measurements (continued)

The Company's Level 1 and Level 2 risk management assets and liabilities consist of commodity fixed price contracts, NYMEX three-way costless collars, WTI fixed price swaptions and basis swaps with terms as disclosed in Note 21. 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 September 30, 2015, the Company’s Level 3 risk management assets and liabilities consist of power purchase contracts with terms to 2017 and WTI three-way costless collars with terms to 2016. The fair values of the power purchase contracts are based on the income approach and are modelled internally using observable and unobservable inputs such as forward power prices in less active markets. The WTI three-way costless collars are a combination of a sold call, purchased put and a sold put. These contracts allow the Company to participate in the upside of commodity prices to the ceiling of the call option and provide the Company with partial downside price protection through the combination of the put options. The fair values of the WTI three-way 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.

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

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

	Risk Management	
	2015	2014
Balance, Beginning of Year	**$ (18)**	$ (7)
Total Gains (Losses)	**(12)**	(5)
Purchases and Settlements:		
Purchases	**16**	-
Settlements	**11**	5
Transfers in and out of Level 3	**-**	-
Balance, End of Period	**$ (3)**	$ (7)
Change in unrealized gains (losses) related to assets and liabilities held at end of period	**$ 7**	$ (2)

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

	Valuation Technique	Unobservable Input	**As at September 30, 2015**	As at December 31, 2014
Risk Management - Power	Discounted Cash Flow	Forward prices ($/Megawatt Hour)	**$36.17 - $42.00**	$40.70 - $48.50
Risk Management - WTI Three-Way Costless Collars	Option Model	Implied Volatility	**31% - 42%**	-

A 10 percent increase or decrease in estimated forward power prices would cause a corresponding $4 million ($5 million as at December 31, 2014) increase or decrease to net risk management assets and liabilities. A 10 percent increase or decrease in implied volatility for the WTI three-way costless collars would cause a corresponding $3 million increase or decrease to net risk management assets and liabilities (nil as at December 31, 2014).

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

21. Financial Instruments and Risk Management

A) Financial Instruments

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

B) Risk Management Assets and Liabilities

Risk management assets and liabilities arise from the use of derivative financial instruments and are measured at fair value. See Note 20 for a discussion of fair value measurements.

Unrealized Risk Management Position	As at September 30, 2015	As at December 31, 2014
Risk Management Assets		
Current	$ 427	$ 707
Long-term	51	65
	478	772
Risk Management Liabilities		
Current	10	20
Long-term	9	7
	19	27
Net Risk Management Assets	$ 459	$ 745

Commodity Price Positions as at September 30, 2015

	Notional Volumes		Term	Average Price		Fair Value
Natural Gas Contracts						
Fixed Price Contracts						
NYMEX Fixed Price	1,000	MMcf/d	2015	4.29	US$/Mcf	$ 156
NYMEX Fixed Price	95	MMcf/d	2016	2.98	US$/Mcf	6
NYMEX Three-Way Costless Collars	300	MMcf/d	2016			21
Sold call price				3.43	US$/Mcf	
Bought put price				3.21	US$/Mcf	
Sold put price				2.72	US$/Mcf	
Basis Contracts [1]			2015-2018			23
Other Financial Positions						-
Natural Gas Fair Value Position						206
Crude Oil Contracts						
Fixed Price Contracts						
WTI Fixed Price	88.9	Mbbls/d	2015	58.09	US$/bbl	101
WTI Fixed Price	38.0	Mbbls/d	2016	62.83	US$/bbl	187
WTI Fixed Price Swaptions [2]	7.5	Mbbls/d	2016	50.34	US$/bbl	(7)
WTI Three-Way Costless Collars	18.3	Mbbls/d	2016			16
Sold call price				63.03	US$/bbl	
Bought put price				55.00	US$/bbl	
Sold put price				47.24	US$/bbl	
Basis Contracts [3]			2015-2017			(25)
Crude Oil Fair Value Position						272
Power Purchase Contracts						
Fair Value Position						(19)
Total Fair Value Position						$ 459

(1) Encana has entered into swaps to protect against widening natural gas price differentials between benchmark and regional sales prices. These basis swaps are priced using differentials determined as a percentage of NYMEX.

(2) The WTI Fixed Price Swaptions give the counterparty the option to extend fourth quarter 2015 fixed price swaps to March 2016 at the same price.

(3) Encana has entered into swaps to protect against widening Brent and Midland differentials to WTI. These basis swaps are priced using fixed price differentials.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

21. Financial Instruments and Risk Management (continued)

B) Risk Management Assets and Liabilities (continued)

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

	Realized Gain (Loss)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	**2015**	2014
Revenues, Net of Royalties	**$ 217**	$ 29	**$ 626**	$ (210)
Transportation and Processing	**(4)**	(1)	**(12)**	(5)
Gain (Loss) on Risk Management	**$ 213**	$ 28	**$ 614**	$ (215)

	Unrealized Gain (Loss)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	**2015**	2014
Revenues, Net of Royalties	**$ 184**	$ 233	**$ (237)**	$ (44)
Transportation and Processing	**(11)**	(2)	**(4)**	(1)
Gain (Loss) on Risk Management	**$ 173**	$ 231	**$ (241)**	$ (45)

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

	2015		2014
	Fair Value	**Total Unrealized Gain (Loss)**	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	**$ 745**		
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Period	**373**	**$ 373**	$ (260)
Foreign Exchange Translation Adjustment on Canadian Dollar Contracts	**2**		
Settlement of Athlon Crude Oil Contracts from Business Combination	**(47)**		
Fair Value of Contracts Realized During the Period	**(614)**	**(614)**	215
Fair Value of Contracts, End of Period	**$ 459**	**$ (241)**	$ (45)

C) Risks Associated with Financial Assets and Liabilities

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

Commodity Price Risk

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

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

Crude Oil - To partially mitigate crude oil commodity price risk, the Company uses contracts such as WTI-based fixed price contracts, WTI-based options, swaptions and costless collars. Encana also enters into basis swaps to manage against widening price differentials between North American and world prices.

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

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

21. Financial Instruments and Risk Management (continued)

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

Commodity Price Risk (continued)

The table below summarizes the sensitivity of the fair value of the Company's risk management positions to fluctuations in commodity prices, with all other variables held constant. The Company has used a 10 percent variability to assess the potential impact of commodity price changes. Fluctuations in commodity prices could have resulted in unrealized gains (losses) impacting pre-tax net earnings for the nine months ended September 30 as follows:

	2015		2014	
	10% Price Increase	**10% Price Decrease**	10% Price Increase	10% Price Decrease
Natural Gas Price	**$ (40)**	**$ 37**	$ (197)	$ 197
Crude Oil Price	**(128)**	**122**	(24)	24
Power Price	**4**	**(4)**	7	(7)

Credit Risk

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. This credit risk exposure is mitigated through the use of Board-approved credit policies governing the Company's credit portfolio including credit practices that limit transactions according to counterparties' credit quality. Mitigation strategies may include master netting arrangements, requesting collateral and/or transacting credit derivatives. The Company executes commodity derivative financial instruments under master agreements that have netting provisions that provide for offsetting payables against receivables. As at September 30, 2015, the Company had no significant credit derivatives in place and no significant collateral balances were posted or received.

As at September 30, 2015, cash equivalents include high-grade, short-term securities, placed primarily with financial institutions and companies with strong investment grade ratings. Any foreign currency agreements entered into are with major financial institutions in Canada and the U.S. or with counterparties having investment grade credit ratings.

A substantial portion of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. As at September 30, 2015, approximately 93 percent (94 percent as at December 31, 2014) of Encana's accounts receivable and financial derivative credit exposures were with investment grade counterparties.

As at September 30, 2015, Encana had two counterparties (three counterparties as at December 31, 2014) 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 September 30, 2015, these counterparties accounted for 10 percent and 10 percent (16 percent, 16 percent and 15 percent as at December 31, 2014) of the fair value of the outstanding in-the-money net risk management contracts.

Liquidity Risk

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

The Company has access to cash equivalents and a range of funding alternatives at competitive rates through committed revolving bank credit facilities and debt and equity capital markets. As at September 30, 2015, the Company had committed revolving bank credit facilities totaling $4.5 billion which include $3.0 billion on a revolving bank credit facility for Encana and $1.5 billion on a revolving bank credit facility for a U.S. subsidiary, the latter of which remains unused. The facilities remain committed through July 2020. Of the $3.0 billion revolving bank credit facility, $1.4 billion fully supported the U.S. Commercial Paper Program and $1.6 billion remained unused.

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

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

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

21. Financial Instruments and Risk Management (continued)

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

Liquidity Risk (continued)

The Company minimizes its liquidity risk by managing its capital structure. The Company's capital structure consists of shareholders' equity plus long-term debt, including the current portion. The Company's objectives when managing its capital structure are to maintain financial flexibility to preserve Encana's access to capital markets and its ability to meet financial obligations and to finance internally generated growth as well as potential acquisitions. To manage the capital structure, the Company may adjust capital spending, adjust dividends paid to shareholders, issue new shares, issue new debt or repay existing debt.

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

	Less Than 1 Year	1 - 3 Years	4 - 5 Years	6 - 9 Years	Thereafter	Total
Accounts Payable and Accrued Liabilities	$ 1,535	$ -	$ -	$ -	$ -	**$ 1,535**
Risk Management Liabilities	10	9	-	-	-	**19**
Long-Term Debt [(1)]	306	612	2,483	1,599	6,192	**11,192**

(1) Principal and interest.

Included in Encana's long-term debt obligations of $11,192 million at September 30, 2015 are $1,414 million in principal obligations for revolving credit and term loan borrowings related to U.S. Commercial Paper. These amounts are fully supported and Management expects they will continue to be supported by revolving credit facilities that have no repayment requirements within the next year. The revolving credit facilities are fully revolving for a period of up to five years. Based on the current maturity dates of the credit facilities, these amounts are included in cash outflows for the period disclosed as 4 - 5 Years. Further information on Long-Term Debt is contained in Note 10.

Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of the Company's financial assets or liabilities. As Encana operates primarily in North America, fluctuations in the exchange rate between the U.S. and Canadian dollars can have a significant effect on the Company's reported results. Encana's financial results are consolidated in Canadian dollars; however, the Company reports its results in U.S. dollars as most of its revenue is closely tied to the U.S. dollar and to facilitate a more direct comparison to other North American oil and gas companies. As the effects of foreign exchange fluctuations are embedded in the Company's results, the total effect of foreign exchange fluctuations is not separately identifiable.

As at September 30, 2015, Encana had $6.1 billion in U.S. dollar debt issued from Canada that was subject to foreign exchange exposure. As at December 31, 2014, Encana had $6.7 billion in debt that was subject to foreign exchange exposure and $0.6 billion that was not subject to foreign exchange exposure. To mitigate the exposure to the fluctuating U.S./Canadian dollar exchange rate, Encana may enter into foreign exchange derivatives. There were no foreign exchange derivatives outstanding as at September 30, 2015.

Encana's foreign exchange (gain) loss primarily includes foreign exchange gains and losses on the translation and settlement of U.S. dollar denominated debt issued from Canada, unrealized foreign exchange gains and losses on the translation of U.S. dollar denominated risk management assets and liabilities held in Canada, foreign exchange gains and losses on the translation and settlement of foreign denominated intercompany balances and foreign exchange gains and losses on U.S. dollar denominated cash and short-term investments held in Canada. A $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in a $47 million change in foreign exchange (gain) loss as at September 30, 2015 (2014 - $27 million).

Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect the fair value or future cash flows from the Company's financial assets or liabilities. The Company 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. There were no interest rate derivatives outstanding as at September 30, 2015.

As at September 30, 2015, the Company had floating rate debt of $1,414 million. Accordingly, the sensitivity in net earnings for each one percent change in interest rates on floating rate debt was $10 million (2014 - nil).

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

22. Commitments and Contingencies

Commitments

The following table outlines the Company's commitments as at September 30, 2015:

	Expected Future Payments						
(undiscounted)	2015	2016	2017	2018	2019	Thereafter	Total
Transportation and Processing	$ 210	$ 795	$ 778	$ 790	$ 672	$ 3,037	**$ 6,282**
Drilling and Field Services	62	151	107	54	18	22	**414**
Operating Leases	9	29	24	23	11	23	**119**
Total	$ 281	$ 975	$ 909	$ 867	$ 701	$ 3,082	**$ 6,815**

Included within transportation and processing in the table above are certain commitments associated with midstream service agreements with VMLP as described in Note 16. Announced divestiture transactions can reduce certain commitments disclosed above.

Contingencies

Encana is involved in various legal claims and actions arising in the course of the Company's operations. Although the outcome of these claims cannot be predicted with certainty, the Company does not expect these matters to have a material adverse effect on Encana's financial position, cash flows or results of operations. If an unfavourable outcome were to occur, there exists the possibility of a material adverse impact on the Company's consolidated net earnings or loss in the period in which the outcome is determined. Accruals for litigation and claims are recognized if the Company determines that the loss is probable and the amount can be reasonably estimated. The Company believes it has made adequate provision for such legal claims.

23. Subsequent Event

On October 8, 2015, Encana announced an agreement to sell its DJ Basin assets in Colorado, for total consideration of approximately $900 million. The transaction is expected to close in the fourth quarter of 2015, with an effective date of April 1, 2015, and is subject to satisfaction of normal closing conditions, regulatory approvals and other adjustments.

encana

Encana Corporation

Interim Supplemental Information
(unaudited)

For the period ended September 30, 2015

U.S. Dollars / U.S. Protocol

Supplemental Financial Information *(unaudited)*

Financial Results

	2015				2014					
($ millions, except per share amounts)	**Year-to-date**	**Q3**	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Cash Flow (1)	**1,047**	**371**	181	495	2,934	377	2,557	807	656	1,094
Per share - Diluted (4)	**1.29**	**0.44**	0.22	0.65	3.96	0.51	3.45	1.09	0.89	1.48
Operating Earnings (Loss) (2,3)	**(172)**	**(24)**	(167)	19	1,002	35	967	281	171	515
Per share - Diluted (4)	**(0.21)**	**(0.03)**	(0.20)	0.03	1.35	0.05	1.30	0.38	0.23	0.70
Net Earnings (Loss) Attributable to Common Shareholders	**(4,553)**	**(1,236)**	(1,610)	(1,707)	3,392	198	3,194	2,807	271	116
Per share - Diluted (4)	**(5.59)**	**(1.47)**	(1.91)	(2.25)	4.58	0.27	4.31	3.79	0.37	0.16
Effective Tax Rate using Canadian Statutory Rate	**26.4%**				25.7%					
Foreign Exchange Rates (US$ per C$1)										
Average	**0.794**	**0.764**	0.813	0.806	0.905	0.881	0.914	0.918	0.917	0.906
Period end	**0.747**	**0.747**	0.802	0.789	0.862	0.862	0.892	0.892	0.937	0.905
Cash Flow Summary										
Cash From (Used in) Operating Activities	**1,233**	**453**	298	482	2,667	261	2,406	696	767	943
Deduct (Add back):										
Net change in other assets and liabilities	**(18)**	**(18)**	7	(7)	(43)	(15)	(28)	(11)	(8)	(9)
Net change in non-cash working capital	**204**	**100**	110	(6)	(9)	(141)	132	155	119	(142)
Cash tax on sale of assets	**-**	**-**	-	-	(215)	40	(255)	(255)	-	-
Cash Flow (1)	**1,047**	**371**	181	495	2,934	377	2,557	807	656	1,094
Operating Earnings Summary										
Net Earnings (Loss) Attributable to Common Shareholders	**(4,553)**	**(1,236)**	(1,610)	(1,707)	3,392	198	3,194	2,807	271	116
After-tax (addition) deduction:										
Unrealized hedging gain (loss)	**(178)**	**107**	(187)	(98)	306	341	(35)	160	8	(203)
Impairments	**(3,616)**	**(1,066)**	(1,328)	(1,222)	-	-	-	-	-	-
Restructuring charges (3)	**(40)**	**(20)**	(10)	(10)	(24)	(4)	(20)	(5)	(5)	(10)
Non-operating foreign exchange gain (loss)	**(606)**	**(212)**	114	(508)	(407)	(151)	(256)	(218)	156	(194)
Gain (loss) on divestitures	**9**	**(2)**	1	10	2,523	(11)	2,534	2,399	135	-
Income tax adjustments	**50**	**(19)**	(33)	102	(8)	(12)	4	190	(194)	8
Operating Earnings (Loss) (2,3)	**(172)**	**(24)**	(167)	19	1,002	35	967	281	171	515

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

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

(3) In continued support of Encana's strategy, organizational structure changes were formalized in Q2 2015 and resulted in a revision to the Q1 2015 Operating Earnings to exclude restructuring charges incurred in the first quarter.

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

	2015				2014					
(millions)	**Year-to-date**	**Q3**	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Weighted Average Common Shares Outstanding										
Basic	**814.0**	**843.1**	841.2	757.8	741.0	741.1	741.0	741.1	741.0	741.0
Diluted	**814.0**	**843.1**	841.2	757.8	741.0	741.1	741.0	741.1	741.0	741.0

Supplemental Financial & Operating Information *(unaudited)*

Financial Metrics

	2015 Year-to-date	2014 Year
Debt to Debt Adjusted Cash Flow	**3.1x**	2.1x
Debt to Adjusted Capitalization	**30%**	30%

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

Net Capital Investment

	2015				2014					
($ millions)	**Year-to-date**	**Q3**	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Capital Investment										
Canadian Operations	**341**	**76**	114	151	1,226	302	924	293	350	281
USA Operations	**1,605**	**394**	628	583	1,285	548	737	305	206	226
Market Optimization	**1**	**1**	-	-	-	-	-	(2)	1	1
Corporate & Other	**5**	**2**	1	2	15	7	8	2	3	3
Capital Investment	**1,952**	**473**	743	736	2,526	857	1,669	598	560	511
Net Acquisitions & (Divestitures)	**(1,077)**	**(99)**	(140)	(838)	(1,329)	50	(1,379)	(2,007)	652	(24)
Net Capital Investment	**875**	**374**	603	(102)	1,197	907	290	(1,409)	1,212	487

Capital Investment

	2015				2014					
($ millions)	**Year-to-date**	**Q3**	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Capital Investment										
Montney [1]	**144**	**17**	48	79	781	159	622	204	210	208
Duvernay	**185**	**58**	57	70	328	118	210	58	81	71
Eagle Ford	**514**	**142**	175	197	274	149	125	113	12	-
Permian	**761**	**219**	325	217	117	117	-	-	-	-
DJ Basin	**161**	**17**	56	88	277	81	196	68	69	59
San Juan	**61**	**2**	23	36	287	96	191	89	50	52
	1,826	**455**	684	687	2,064	720	1,344	532	422	390
Other Upstream Operations [1, 2]	**120**	**15**	58	47	447	130	317	66	134	117
Market Optimization	**1**	**1**	-	-	-	-	-	(2)	1	1
Corporate & Other	**5**	**2**	1	2	15	7	8	2	3	3
Capital Investment	**1,952**	**473**	743	736	2,526	857	1,669	598	560	511

(1) Montney has been realigned to include certain capital investments which were previously reported in Other Upstream Operations.

(2) Other Upstream Operations includes capital investment for Encana's base production properties as well as capital investment for prospective plays which are under appraisal, including the Tuscaloosa Marine Shale ("TMS").

Supplemental Financial & Operating Information *(unaudited)*

Production Volumes - After Royalties

	2015				2014					
(average)	**Year-to-date**	**Q3**	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Natural Gas (MMcf/d)	**1,656**	**1,547**	1,568	1,857	2,350	1,861	2,515	2,199	2,541	2,809
Oil (Mbbls/d)	**85.8**	**91.9**	86.2	79.2	49.4	68.8	42.9	62.1	34.2	32.1
NGLs (Mbbls/d)	**43.7**	**48.5**	41.1	41.5	37.4	37.6	37.3	41.9	34.0	35.8
Oil & NGLs (Mbbls/d)	**129.5**	**140.4**	127.3	120.7	86.8	106.4	80.2	104.0	68.2	67.9
Total (MBOE/d)	**405.6**	**398.3**	388.7	430.1	478.5	416.7	499.3	470.6	491.8	536.1

Production Volumes - After Royalties

	2015				2014					
(average)	**Year-to-date**	**Q3**	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Natural Gas (MMcf/d)										
Canadian Operations	**961**	**876**	881	1,128	1,378	1,111	1,468	1,374	1,463	1,568
USA Operations	**695**	**671**	687	729	972	750	1,047	825	1,078	1,241
	1,656	**1,547**	1,568	1,857	2,350	1,861	2,515	2,199	2,541	2,809
Oil (Mbbls/d)										
Canadian Operations	**6.1**	**5.3**	6.5	6.6	13.6	9.4	15.0	14.7	13.9	16.4
USA Operations	**79.7**	**86.6**	79.7	72.6	35.8	59.4	27.9	47.4	20.3	15.7
	85.8	**91.9**	86.2	79.2	49.4	68.8	42.9	62.1	34.2	32.1
NGLs (Mbbls/d)										
Canadian Operations	**21.0**	**21.9**	19.8	21.2	23.6	18.8	25.3	27.6	23.5	24.6
USA Operations	**22.7**	**26.6**	21.3	20.3	13.8	18.8	12.0	14.3	10.5	11.2
	43.7	**48.5**	41.1	41.5	37.4	37.6	37.3	41.9	34.0	35.8
Oil & NGLs (Mbbls/d)										
Canadian Operations	**27.1**	**27.2**	26.3	27.8	37.2	28.2	40.3	42.3	37.4	41.0
USA Operations	**102.4**	**113.2**	101.0	92.9	49.6	78.2	39.9	61.7	30.8	26.9
	129.5	**140.4**	127.3	120.7	86.8	106.4	80.2	104.0	68.2	67.9
Total (MBOE/d)										
Canadian Operations	**187.2**	**173.2**	173.2	215.8	266.9	213.4	285.0	271.4	281.4	302.4
USA Operations	**218.4**	**225.1**	215.5	214.3	211.6	203.3	214.3	199.2	210.4	233.7
	405.6	**398.3**	388.7	430.1	478.5	416.7	499.3	470.6	491.8	536.1

Oil & NGLs Production Volumes - After Royalties

	2015		2014	
(average Mbbls/d)	**Year-to-date**	**% of Total**	Year	% of Total
Oil	**85.8**	**66**	49.4	57
Plant Condensate	**14.9**	**12**	12.0	14
Butane	**7.1**	**5**	6.8	8
Propane	**11.9**	**9**	10.2	11
Ethane	**9.8**	**8**	8.4	10
	129.5	**100**	86.8	100

Supplemental Financial & Operating Information *(unaudited)*

Results of Operations

Product and Operational Information, Including the Impact of Realized Financial Hedging

	2015				2014					
($ millions)	**Year-to-date**	**Q3**	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Natural Gas - Canadian Operations										
Revenues, Net of Royalties, excluding Hedging	**788**	**199**	193	396	2,468	402	2,066	480	569	1,017
Realized Financial Hedging Gain (Loss)	**364**	**104**	106	154	(74)	25	(99)	20	(44)	(75)
Expenses										
Production and mineral taxes	**-**	**-**	-	-	5	2	3	1	-	2
Transportation and processing	**463**	**142**	158	163	773	177	596	186	209	201
Operating	**111**	**35**	40	36	279	57	222	66	72	84
Operating Cash Flow	**578**	**126**	101	351	1,337	191	1,146	247	244	655
Natural Gas - USA Operations										
Revenues, Net of Royalties, excluding Hedging	**511**	**170**	146	195	1,640	274	1,366	307	463	596
Realized Financial Hedging Gain (Loss)	**166**	**54**	58	54	(85)	13	(98)	10	(43)	(65)
Expenses										
Production and mineral taxes	**15**	**6**	5	4	44	11	33	(10)	14	29
Transportation and processing	**445**	**152**	142	151	651	149	502	162	177	163
Operating	**134**	**39**	46	49	235	52	183	50	65	68
Operating Cash Flow	**83**	**27**	11	45	625	75	550	115	164	271
Natural Gas - Total Operations										
Revenues, Net of Royalties, excluding Hedging	**1,299**	**369**	339	591	4,108	676	3,432	787	1,032	1,613
Realized Financial Hedging Gain (Loss)	**530**	**158**	164	208	(159)	38	(197)	30	(87)	(140)
Expenses										
Production and mineral taxes	**15**	**6**	5	4	49	13	36	(9)	14	31
Transportation and processing	**908**	**294**	300	314	1,424	326	1,098	348	386	364
Operating	**245**	**74**	86	85	514	109	405	116	137	152
Operating Cash Flow	**661**	**153**	112	396	1,962	266	1,696	362	408	926
Oil & NGLs - Canadian Operations										
Revenues, Net of Royalties, excluding Hedging	**243**	**75**	91	77	872	149	723	251	227	245
Realized Financial Hedging Gain (Loss)	**2**	**5**	(5)	2	18	24	(6)	(1)	(5)	-
Expenses										
Production and mineral taxes	**-**	**-**	-	-	10	-	10	3	4	3
Transportation and processing	**38**	**11**	13	14	62	16	46	16	16	14
Operating	**13**	**2**	5	6	28	10	18	8	4	6
Operating Cash Flow	**194**	**67**	68	59	790	147	643	223	198	222
Oil & NGLs - USA Operations										
Revenues, Net of Royalties, excluding Hedging	**1,080**	**371**	414	295	1,258	412	846	452	215	179
Realized Financial Hedging Gain (Loss)	**97**	**54**	5	38	60	65	(5)	1	(6)	-
Expenses										
Production and mineral taxes	**57**	**21**	21	15	74	23	51	23	15	13
Transportation and processing	**9**	**3**	2	4	7	3	4	4	-	-
Operating	**282**	**103**	104	75	115	51	64	44	12	8
Operating Cash Flow	**829**	**298**	292	239	1,122	400	722	382	182	158
Oil & NGLs - Total Operations										
Revenues, Net of Royalties, excluding Hedging	**1,323**	**446**	505	372	2,130	561	1,569	703	442	424
Realized Financial Hedging Gain (Loss)	**99**	**59**	-	40	78	89	(11)	-	(11)	-
Expenses										
Production and mineral taxes	**57**	**21**	21	15	84	23	61	26	19	16
Transportation and processing	**47**	**14**	15	18	69	19	50	20	16	14
Operating	**295**	**105**	109	81	143	61	82	52	16	14
Operating Cash Flow	**1,023**	**365**	360	298	1,912	547	1,365	605	380	380

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Operating Statistics - After Royalties

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

	2015				2014					
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Natural Gas - Canadian Operations ($/Mcf)										
Price [(1)]	**3.00**	**2.48**	2.39	3.89	4.89	3.93	5.14	3.78	4.27	7.17
Production and mineral taxes	**-**	**-**	-	-	0.01	0.01	0.01	0.01	-	0.01
Transportation and processing	**1.76**	**1.77**	1.97	1.60	1.53	1.73	1.48	1.47	1.57	1.42
Operating	**0.42**	**0.44**	0.49	0.35	0.55	0.55	0.55	0.52	0.55	0.59
Netback	**0.82**	**0.27**	(0.07)	1.94	2.80	1.64	3.10	1.78	2.15	5.15
Natural Gas - USA Operations ($/Mcf)										
Price	**2.69**	**2.75**	2.33	2.97	4.62	3.95	4.78	4.05	4.72	5.34
Production and mineral taxes	**0.08**	**0.11**	0.08	0.06	0.12	0.17	0.11	(0.14)	0.15	0.26
Transportation and processing	**2.35**	**2.47**	2.27	2.30	1.83	2.16	1.76	2.13	1.80	1.46
Operating	**0.71**	**0.62**	0.74	0.75	0.66	0.75	0.64	0.65	0.67	0.61
Netback	**(0.45)**	**(0.45)**	(0.76)	(0.14)	2.01	0.87	2.27	1.41	2.10	3.01
Natural Gas - Total Operations ($/Mcf)										
Price [(2)]	**2.87**	**2.60**	2.37	3.53	4.78	3.94	4.99	3.88	4.46	6.37
Production and mineral taxes	**0.04**	**0.05**	0.04	0.02	0.06	0.08	0.05	(0.05)	0.06	0.12
Transportation and processing	**2.01**	**2.07**	2.10	1.88	1.66	1.90	1.60	1.72	1.67	1.44
Operating	**0.54**	**0.52**	0.60	0.51	0.60	0.63	0.59	0.57	0.60	0.60
Netback	**0.28**	**(0.04)**	(0.37)	1.12	2.46	1.33	2.75	1.64	2.13	4.21
Oil & NGLs - Canadian Operations ($/bbl)										
Price	**32.91**	**29.75**	38.57	30.65	64.16	57.50	65.73	64.79	66.13	66.36
Production and mineral taxes	**0.01**	**(0.02)**	-	0.04	0.71	0.10	0.85	0.67	1.12	0.80
Transportation and processing	**5.07**	**3.95**	5.46	5.82	4.52	5.92	4.19	4.21	4.60	3.80
Operating	**1.81**	**1.22**	1.91	2.31	2.09	4.00	1.64	2.05	1.06	1.75
Netback	**26.02**	**24.60**	31.20	22.48	56.84	47.48	59.05	57.86	59.35	60.01
Oil & NGLs - USA Operations ($/bbl)										
Price	**38.65**	**35.66**	45.21	35.18	69.54	57.30	77.63	79.43	77.46	73.61
Production and mineral taxes	**2.01**	**1.95**	2.26	1.80	4.10	3.16	4.72	4.18	5.19	5.46
Transportation and processing	**0.32**	**0.31**	0.24	0.43	0.39	0.49	0.33	0.63	-	-
Operating	**10.09**	**9.95**	11.28	8.96	6.36	7.11	5.87	7.80	4.29	3.16
Netback	**26.23**	**23.45**	31.43	23.99	58.69	46.54	66.71	66.82	67.98	64.99
Oil & NGLs - Total Operations ($/bbl)										
Price	**37.45**	**34.52**	43.83	34.13	67.24	57.35	71.66	73.48	71.23	69.23
Production and mineral taxes	**1.59**	**1.57**	1.79	1.40	2.65	2.35	2.78	2.75	2.95	2.65
Transportation and processing	**1.32**	**1.02**	1.32	1.67	2.16	1.93	2.27	2.09	2.53	2.30
Operating	**8.36**	**8.25**	9.35	7.43	4.54	6.29	3.74	5.46	2.51	2.31
Netback	**26.18**	**23.68**	31.37	23.63	57.89	46.78	62.87	63.18	63.24	61.97
Total - Canadian Operations ($/BOE)										
Price	**20.17**	**17.22**	18.05	24.30	34.21	28.06	35.76	29.21	31.02	46.20
Production and mineral taxes	**0.01**	**0.01**	-	0.02	0.15	0.09	0.16	0.15	0.16	0.18
Transportation and processing	**9.79**	**9.55**	10.85	9.12	8.55	9.79	8.24	8.10	8.76	7.87
Operating	**2.43**	**2.42**	2.80	2.14	3.14	3.39	3.09	2.96	2.98	3.29
Netback	**7.94**	**5.24**	4.40	13.02	22.37	14.79	24.27	18.00	19.12	34.86
Total - USA Operations ($/BOE)										
Price	**26.69**	**26.13**	28.61	25.34	37.53	36.64	37.81	41.38	35.48	36.82
Production and mineral taxes	**1.20**	**1.30**	1.33	0.97	1.53	1.84	1.44	0.72	1.51	1.99
Transportation and processing	**7.62**	**7.52**	7.34	8.02	8.52	8.17	8.64	9.03	9.23	7.75
Operating	**6.98**	**6.85**	7.66	6.44	4.53	5.51	4.22	5.12	4.05	3.60
Netback	**10.89**	**10.46**	12.28	9.91	22.95	21.12	23.51	26.51	20.69	23.48
Total Operations Netback ($/BOE)										
Price	**23.68**	**22.26**	23.90	24.82	35.67	32.25	36.64	34.36	32.93	42.12
Production and mineral taxes	**0.65**	**0.74**	0.73	0.49	0.76	0.94	0.71	0.39	0.74	0.97
Transportation and processing	**8.62**	**8.41**	8.91	8.57	8.54	9.00	8.41	8.50	8.96	7.82
Operating [(3)]	**4.89**	**4.93**	5.50	4.27	3.76	4.43	3.57	3.87	3.44	3.43
Netback	**9.52**	**8.18**	8.76	11.49	22.61	17.88	23.95	21.60	19.79	29.90

(1) Canadian Operations price reflects Deep Panuke price for 2015 year-to-date of $9.40/Mcf on natural gas production volumes of 71 MMcf/d. Excluding the impact of the Deep Panuke operations, the natural gas price for 2015 year-to-date is $2.50/Mcf.

(2) Excluding the impact of the Deep Panuke operations, the natural gas price for 2015 year-to-date is $2.58/Mcf.

(3) 2015 year-to-date operating expense includes a recovery of costs related to long-term incentives of $0.04/BOE (2014 year-to-date - costs of $0.18/BOE).

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Operating Statistics - After Royalties (continued)

Impact of Realized Financial Hedging

	2015				2014					
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Natural Gas ($/Mcf)										
Canadian Operations	**1.39**	**1.28**	1.32	1.52	(0.15)	0.24	(0.25)	0.16	(0.33)	(0.53)
USA Operations	**0.88**	**0.88**	0.93	0.82	(0.24)	0.19	(0.34)	0.12	(0.44)	(0.58)
Total Operations	**1.17**	**1.11**	1.15	1.25	(0.19)	0.22	(0.29)	0.15	(0.38)	(0.55)
Oil & NGLs ($/bbl)										
Canadian Operations	**0.25**	**2.09**	(2.21)	0.78	1.36	9.35	(0.52)	(0.31)	(1.22)	(0.09)
USA Operations	**3.46**	**5.17**	0.52	4.58	3.29	8.94	(0.45)	0.25	(2.28)	0.04
Total Operations	**2.79**	**4.57**	(0.05)	3.70	2.46	9.05	(0.48)	0.02	(1.70)	(0.04)
Total ($/BOE)										
Canadian Operations	**7.15**	**6.82**	6.39	8.04	(0.57)	2.49	(1.34)	0.78	(1.89)	(2.77)
USA Operations	**4.42**	**5.21**	3.22	4.78	(0.33)	4.15	(1.76)	0.58	(2.57)	(3.07)
Total Operations	**5.68**	**5.91**	4.63	6.42	(0.46)	3.30	(1.52)	0.70	(2.18)	(2.90)

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

	2015				2014					
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Natural Gas Price ($/Mcf)										
Canadian Operations	**4.39**	**3.76**	3.71	5.41	4.74	4.17	4.89	3.94	3.94	6.64
USA Operations	**3.57**	**3.63**	3.26	3.79	4.38	4.14	4.44	4.17	4.28	4.76
Total Operations	**4.04**	**3.71**	3.52	4.78	4.59	4.16	4.70	4.03	4.08	5.82
Natural Gas Netback ($/Mcf)										
Canadian Operations	**2.21**	**1.55**	1.25	3.46	2.65	1.88	2.85	1.94	1.82	4.62
USA Operations	**0.43**	**0.43**	0.17	0.68	1.77	1.06	1.93	1.53	1.66	2.43
Total Operations	**1.45**	**1.07**	0.78	2.37	2.27	1.55	2.46	1.79	1.75	3.66
Oil & NGLs Price ($/bbl)										
Canadian Operations	**33.16**	**31.84**	36.36	31.43	65.52	66.85	65.21	64.48	64.91	66.27
USA Operations	**42.11**	**40.83**	45.73	39.76	72.83	66.24	77.18	79.68	75.18	73.65
Total Operations	**40.24**	**39.09**	43.78	37.83	69.70	66.40	71.18	73.50	69.53	69.19
Oil & NGLs Netback ($/bbl)										
Canadian Operations	**26.27**	**26.69**	28.99	23.26	58.20	56.83	58.53	57.55	58.13	59.92
USA Operations	**29.69**	**28.62**	31.95	28.57	61.98	55.48	66.26	67.07	65.70	65.03
Total Operations	**28.97**	**28.25**	31.32	27.33	60.35	55.83	62.39	63.20	61.54	61.93
Total Price ($/BOE)										
Canadian Operations	**27.32**	**24.04**	24.44	32.34	33.64	30.55	34.42	29.99	29.13	43.43
USA Operations	**31.11**	**31.34**	31.83	30.12	37.20	40.79	36.05	41.96	32.91	33.75
Total Operations	**29.36**	**28.17**	28.53	31.24	35.21	35.55	35.12	35.06	30.75	39.22
Total Netback ($/BOE)										
Canadian Operations	**15.09**	**12.06**	10.79	21.06	21.80	17.28	22.93	18.78	17.23	32.09
USA Operations	**15.31**	**15.67**	15.50	14.69	22.62	25.27	21.75	27.09	18.12	20.41
Total Operations	**15.20**	**14.09**	13.39	17.91	22.15	21.18	22.43	22.30	17.61	27.00

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Results by Play

(after royalties)	2015 Year-to-date	2015 Q3	2015 Q2	2015 Q1	2014 Year	2014 Q4	2014 Q3 Year-to-date	2014 Q3	2014 Q2	2014 Q1
Natural Gas Production (MMcf/d)										
Canadian Operations										
Montney [1]	**705**	**711**	685	717	639	687	623	644	604	620
Duvernay	**20**	**26**	17	16	11	12	11	15	9	8
Other Upstream Operations [2]										
Wheatland [3]	**89**	**80**	76	111	292	249	307	291	305	324
Bighorn	**1**	**-**	-	4	158	(3)	212	162	230	246
Deep Panuke	**71**	**-**	32	182	190	79	227	186	243	253
Other and emerging [1]	**75**	**59**	71	98	88	87	88	76	72	117
Total Canadian Operations	**961**	**876**	881	1,128	1,378	1,111	1,468	1,374	1,463	1,568
USA Operations										
Eagle Ford	**40**	**48**	36	36	19	35	13	35	5	-
Permian	**42**	**54**	38	34	5	20	-	-	-	-
DJ Basin	**53**	**55**	55	49	43	49	40	38	43	40
San Juan	**14**	**15**	15	13	8	8	8	9	7	7
Other Upstream Operations [2]										
Piceance	**326**	**311**	324	343	402	367	414	398	407	436
Haynesville	**203**	**177**	204	230	311	252	331	298	365	331
Jonah	**-**	**-**	-	-	100	-	134	-	124	282
East Texas	**-**	**-**	-	-	57	-	77	21	97	113
Other and emerging	**17**	**11**	15	24	27	19	30	26	30	32
Total USA Operations	**695**	**671**	687	729	972	750	1,047	825	1,078	1,241
Oil & NGLs Production (Mbbls/d)										
Canadian Operations										
Montney [1]	**22.3**	**21.8**	21.6	23.3	18.9	24.8	16.9	20.8	13.3	16.2
Duvernay	**3.6**	**4.9**	3.0	2.8	2.1	2.5	1.9	2.6	1.8	1.4
Other Upstream Operations [2]										
Wheatland [3]	**1.1**	**0.4**	1.2	1.7	8.6	2.0	10.9	9.9	11.3	11.3
Bighorn	**-**	**-**	-	-	7.5	(1.5)	10.6	8.7	11.0	12.1
Other and emerging [1]	**0.1**	**0.1**	0.5	-	0.1	0.4	-	0.3	-	-
Total Canadian Operations	**27.1**	**27.2**	26.3	27.8	37.2	28.2	40.3	42.3	37.4	41.0
USA Operations										
Eagle Ford	**40.6**	**46.0**	39.8	36.0	19.8	36.1	14.3	37.6	5.0	-
Permian	**31.0**	**36.7**	29.5	26.7	3.5	13.8	-	-	-	-
DJ Basin	**15.2**	**16.1**	15.3	14.3	11.6	14.0	10.8	11.8	10.1	10.5
San Juan	**6.7**	**6.8**	6.4	6.7	3.9	5.6	3.4	3.5	3.9	2.7
Other Upstream Operations [2]										
Piceance	**3.6**	**3.5**	3.7	3.7	5.0	4.3	5.2	4.8	5.3	5.4
Jonah	**-**	**-**	-	-	1.8	-	2.4	0.2	2.5	4.7
East Texas	**-**	**-**	-	-	0.5	-	0.7	-	1.0	1.2
Other and emerging	**5.3**	**4.1**	6.3	5.5	3.5	4.4	3.1	3.8	3.0	2.4
Total USA Operations	**102.4**	**113.2**	101.0	92.9	49.6	78.2	39.9	61.7	30.8	26.9

(1) Montney has been realigned to include certain production volumes which were previously reported in Other and emerging.

(2) Other Upstream Operations includes results from plays that are not part of the Company's current strategic focus as well as prospective plays which are under appraisal, including the TMS which is reported in Other and emerging in the USA Operations.

(3) Wheatland was previously presented as Clearwater.

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Results by Play (continued)

	2015				2014					
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3 Year-to-date	Q3	Q2	Q1
Drilling Activity (net wells drilled)										
Canadian Operations										
Montney	**14**	**-**	6	8	79	14	65	15	23	27
Duvernay	**9**	**2**	1	6	24	5	19	7	6	6
Other Upstream Operations [1]										
Wheatland [2]	**105**	**34**	-	71	174	84	90	24	-	66
Bighorn	**-**	**-**	-	-	1	-	1	1	-	-
Other and emerging	**-**	**-**	-	-	1	-	1	1	-	-
Total Canadian Operations	**128**	**36**	7	85	279	103	176	48	29	99
USA Operations										
Eagle Ford	**51**	**10**	14	27	35	21	14	14	-	-
Permian	**142**	**44**	52	46	28	28	-	-	-	-
DJ Basin	**15**	**-**	2	13	64	15	49	17	14	18
San Juan	**1**	**-**	-	1	43	19	24	15	5	4
Other Upstream Operations [1]										
Piceance	**-**	**-**	-	-	1	-	1	-	-	1
Haynesville	**2**	**2**	-	-	-	-	-	-	-	-
Jonah	**-**	**-**	-	-	18	-	18	-	6	12
East Texas	**-**	**-**	-	-	-	-	-	-	-	-
Other and emerging	**3**	**-**	-	3	15	5	10	4	4	2
Total USA Operations	**214**	**56**	68	90	204	88	116	50	29	37

(1) Other Upstream Operations includes net wells drilled in plays that are not part of the Company's current strategic focus as well as prospective plays which are under appraisal, including the TMS which is reported in Other and emerging in the USA Operations.

(2) Wheatland was previously presented as Clearwater.

Encana Corporation

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