news release

Encana reports strong performance in 2014, reduces 2015 capital

Calgary, Alberta (February 25, 2015) **TSX, NYSE: ECA**

Encana reported strong results from a transformative 2014 in which the company restructured its organization, transformed its portfolio and delivered solid operational results. The company delivered on all of its strategic targets and achieved enduring efficiency improvements throughout the business. Highlights include:

- Average annual liquids production of 86,800 barrels per day (bbls/d) up 61 percent from 2013
- Fourth quarter liquids production averaged 106,400 bbls/d, up 61 percent year-over-year
- Two-thirds of fourth quarter 2014 upstream operating cash flow, including hedging, derived from liquids production
- Successful base production optimization reduced base decline from 34 percent to 29 percent
- Seamless operational transition into the Eagle Ford and Permian Basin with immediate capital efficiencies
- $150 million in operating and administrative cost savings
- The best safety record in company history based on total recordable injury frequency rate

"The transformation of Encana occurred at a pace that exceeded even our own expectations and our accomplishments in 2014 shouldn't be overshadowed by today's low commodity price environment," said Doug Suttles, Encana President & CEO. "We resized the company, focused our capital investment on our most strategic assets and enhanced operational performance. Consistent with our strategy to grow higher margin production, we successfully transitioned to a more liquids-weighted portfolio which helped to deliver a marked increase in year-over-year cash flow."

Encana's strategic focus on growing value was evident in the first year of its new strategy through the 14 percent increase in year-over-year cash flow to approximately $2.9 billion, or $3.96 per share. This cash flow growth was delivered within the context of approximately seven percent lower total production and substantially similar oil and gas prices compared to 2013. The company met its 2014 production targets while spending approximately eight percent less capital than indicated in the mid-year Guidance. Full-year operating earnings of around $1.0 billion, or $1.35 per share, were up 25 percent from last year. Net earnings attributable to common shareholders were approximately $3.4 billion or $4.58 per share.

For the fourth quarter of 2014, Encana reported cash flow of approximately $377 million, or $0.51 per share, and operating earnings of $35 million, or $0.05 per share, compared with cash flow of $677 million or $0.91 per share and operating earnings of $226 million or $0.31 per share in the fourth quarter of 2013. The year-over-year decline in cash flow was largely due to higher current taxes and one-time outlays associated with the completion of the acquisition of Athlon Energy Inc. ("Athlon"), including the early repayment of Athlon's long-term debt. Upstream operating cash flow, excluding realized hedging, totaled $694 million in the fourth quarter of 2014 compared with $728 million a year earlier. Propelled by successful drilling programs and strong production results from the Eagle Ford and Permian, the two strategic assets acquired in 2014, Encana averaged fourth quarter liquids volumes of 106,400 bbls/d, reflecting a 61 percent year-over-year increase.

To maintain a solid balance sheet and help strengthen liquidity through a low price environment, Encana is reducing its previously announced 2015 capital investment by approximately $700 million to between $2.0 billion and $2.2 billion. The company's 2015 capital program is now based on assumptions of $50 per barrel (bbl) WTI oil prices and NYMEX natural gas prices of $3 per million British thermal units (MMBtu). Encana expects total 2015 cash flow of between $1.4 billion and $1.6 billion. The company intends to fully fund its 2015 capital program and dividend with anticipated cash flow combined with net proceeds of around $800 million from the previously announced divestitures of certain Clearwater assets and Montney midstream infrastructure.

"We're responding decisively and prudently to the current low commodity price environment," said Suttles. "We will continue to execute our strategy at a pace that makes sense and continue our relentless efforts to realize enduring efficiencies in all aspects of our business. Our priority is to maintain our solid balance sheet and financial flexibility while preserving the long-term value of our portfolio by investing in our most strategic assets."

Encana's updated 2015 guidance can be downloaded from the company's website at http://www.encana.com/investors/financial/corporate-guidance.html.

Operating highlights

More than 80 percent of Encana's 2015 capital investment will be focused on the company's four most strategic assets, all of which are expected to deliver substantial growth.

Permian Basin: Upon closing its acquisition of Athlon in the fourth quarter of 2014, Encana successfully integrated the Athlon team and maintained uninterrupted operations through the transition. By year-end, the company had drilled seven net horizontal and 21 net vertical wells and reduced well tie-in times from 15 to five days. Encana exited 2014 with an oil production rate of 18,000 bbls/d and total production of 31,000 barrels of oil equivalent per day (BOE/d). Encana now plans to invest approximately $700 million to run four to six horizontal rigs and four to six vertical rigs in 2015. The company anticipates drilling around 55 net horizontal wells and 110 net vertical wells. Projected volumes are expected to average at least 45,000 BOE/d in 2015.

Eagle Ford: Encana closed the acquisition of its Eagle Ford acreage during the second quarter of 2014. In its first full quarter of operations, the company achieved a nine percent reduction in drilling costs through optimization of well design and reduced cycle times. Fourth-quarter production in the play was approximately 36,000 bbls/d of liquids and 35 million cubic feet per day (MMcf/d) of natural gas. Encana drilled 35 net wells in the play in 2014 and plans to drill approximately 60 net wells in 2015. The company now plans to invest approximately $550 million to run two to three rigs in 2015. Total production in 2015 is expected to grow to over 50,000 BOE/d.

Montney: Annualized liquids production increased by 87 percent from 2013 to approximately 19,000 bbls/d, while annual natural gas production was approximately 514 MMcf/d. Fourth-quarter production was 24,600 bbls/d of liquids and 570 MMcf/d of natural gas. During the fourth quarter, Encana announced an agreement to sell midstream infrastructure in northeastern British Columbia to Veresen Midstream Limited Partnership. The transaction, expected to close in the first quarter of 2015, helps Encana to unlock value from midstream assets while ensuring reliable takeaway capacity in the Montney under an innovative fee-for-service arrangement. Encana drilled 79 net wells in the play in 2014 and plans to drill around 25 net wells in 2015 while running approximately three rigs. The company now expects a net investment of approximately $245 million. The Cutbank Ridge Partnership expects to invest an additional $325 million, representing a total gross investment of $570 million. Expected net production for 2015 is approximately 124,000 BOE/d.

Duvernay: The Duvernay team continued to reduce drilling and completion costs in 2014. Encana achieved an average cost of $12.4 million per well on the 4-4 pad, which is 17 percent lower than the 2014 target of $15 million and 50 percent lower than the 2013 average. Annualized liquids production grew more than 200 percent in 2014 to approximately 2,100 bbls/d. During the fourth quarter, Encana and its joint venture participant signed a long-term rich gas premium agreement with Aux Sable Canada LP to increase market takeaway capacity in the play. Encana drilled 24 net wells in the Duvernay last year. The company now plans to run two to three rigs in 2015 and drill around 15 net wells. Encana now expects a net investment of approximately $230 million. An additional $660 million of joint venture capital is expected to be invested in the play, representing a gross investment of $890 million. Expected net production for 2015 is approximately 10,000 BOE/d.

Encana updates its risk management program

As of February 24, 2015, Encana has hedged approximately 1,044 MMcf/d of expected February to December 2015 natural gas production using NYMEX fixed price contracts at an average price of $4.29 per thousand cubic feet (Mcf). In addition, Encana has hedged approximately 55,000 bbls/d of expected February to December 2015 oil production using WTI fixed price contracts at an average price of $62.18 per bbl and approximately 1,200 bbls/d of expected 2016 oil production at an average price of $92.35 per bbl. The company's hedging program helps sustain cash flow and operating netbacks during periods of lower prices.

Dividend declared

On February 25, 2015, the Board declared a dividend of $0.07 per share payable on March 31, 2015 to common shareholders of record as of March 13, 2015.

For the dividend payable on March 31, 2015, Encana's Board of Directors has determined that all common shares distributed to participating shareholders pursuant to the company's dividend reinvestment plan (DRIP) will be issued from Encana's treasury at a two percent discount to the average market price of the common shares (as defined in the DRIP). Previously, common shares distributed to participating shareholders pursuant to the DRIP were issued from Encana's treasury without a discount to the average market price. Any future dividends of common shares distributed to shareholders participating in the DRIP will be issued from Encana's treasury with a two percent discount to the average market price unless otherwise announced by Encana by way of news release. Any Encana shareholders who may be interested in enrolling in the DRIP should review the information available at http://www.encana.com/investors/shareholder/dividend-reinvestment-plan.html.

Financial Summary				
(for the period ended December 31) ($ millions, except per share amounts)	**Q4 2014**	Q4 2013	**2014**	2013
Cash flow[1]	**377**	677	**2,934**	2,581
Per share diluted	**0.51**	0.91	**3.96**	3.50
Operating earnings[1]	**35**	226	**1,002**	802
Per share diluted	**0.05**	0.31	**1.35**	1.09
Earnings Reconciliation Summary				
Net earnings (loss) attributable to common shareholders	**198**	(251)	**3,392**	236
After tax (addition) deduction:				
Unrealized hedging gain (loss)	**341**	(209)	**306**	(232)
Impairments	**-**	-	**-**	(16)
Non-operating foreign exchange gain (loss)	**(151)**	(124)	**(407)**	(282)
Income tax adjustments	**(12)**	(80)	**(8)**	28
Restructuring charges	**(4)**	(64)	**(24)**	(64)
Gain (loss) on divestitures	**(11)**	-	**2,523**	-
Operating earnings[1]	**35**	226	**1,002**	802
Per share diluted	**0.05**	0.31	**1.35**	1.09

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

Production Summary						
(for the period ended December 31) (After royalties)	**Q4 2014**	Q4 2013	% Δ	**2014**	2013	% Δ
Natural gas (MMcf/d)	**1,861**	2,744	-32	**2,350**	2,777	-15
Oil and NGLs (Mbbls/d)	**106.4**	66.0	61	**86.8**	53.9	61

Natural Gas and Oil & NGLs Prices				
	Q4 2014	Q4 2013	**2014**	2013
Natural gas				
NYMEX ($/MMBtu)	4.00	3.60	4.41	3.65
Encana realized natural gas price[1] ($/Mcf)	**4.16**	4.34	**4.59**	4.09
Oil and NGLs ($/bbl)				
WTI	73.15	97.46	93.00	97.97
Encana realized liquids price[1]	**66.40**	67.01	**69.70**	67.75

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

Reserves Quantities

2014 Proved Reserves Estimates - United States SEC Protocols (After Royalties) [1]			
Using constant prices and costs; simplified table.	**Natural Gas (Bcf)**	**Oil & NGLs (MMbbls)**	**Total (MMBOE)**
December 31, 2013	**7,852**	**220.8**	**1,529.5**
Revisions and improved recovery	(261)	0.5	**(43.0)**
Extensions and discoveries	879	57.2	**203.7**
Purchase of reserves in place	240	201.1	**241.1**
Sale of reserves in place	(2,358)	(86.2)	**(479.2)**
Production	(858)	(31.7)	**(174.7)**
December 31, 2014	**5,494**	**361.7**	**1,277.4**

[1] Numbers may not add due to rounding.

Using SEC constant price assumptions, Encana's strategic transition to a more balanced commodity portfolio resulted in an increase in proved oil and NGLs reserves after royalties to approximately 362 million barrels (MMbbls) for year-end 2014, representing an increase of 141 MMbbls from 2013 primarily due to the purchase of reserves in place of approximately 201 MMbbls, partially offset by the sale of reserves in place of approximately 86 MMbbls. Extensions and discoveries after revisions of approximately 58 MMbbls replaced 182 percent of production during the year.

Encana's 2014 proved natural gas reserves after royalties of approximately 5.5 trillion cubic feet (Tcf) decreased 2.4 Tcf from 2013 primarily due to the sale of reserves in place of approximately 2.4 Tcf resulting from the company's strategic transition to a more balanced commodity portfolio. Gas extensions and discoveries after revisions resulted in the addition of approximately 0.6 Tcf which replaced 72 percent of production during the year.

2014 Proved Reserves Estimates - Canadian Protocols (After Royalties) [1]			
Using forecast prices and costs; simplified table.	**Natural Gas (Bcf)**	**Oil & NGLs (MMbbls)**	**Total (MMBOE)**
December 31, 2013	**8,576**	**234.9**	**1,664.2**
Extensions & discoveries	847	49.7	**190.8**
Revisions	(852)	(4.6)	**(146.6)**
Acquisitions	237	198.1	**237.5**
Divestitures	(2,427)	(89.9)	**(494.3)**
Production	(858)	(31.7)	**(174.6)**
December 31, 2014	**5,522**	**356.5**	**1,276.9**

[1] Numbers may not add due to rounding.

Using forecast price assumptions, Encana's strategic transition to a more balanced commodity portfolio resulted in an increase in proved oil and NGLs reserves after royalties to approximately 356 MMbbls for year-end 2014, representing an increase of 122 MMbbls from 2013 primarily due to acquisitions of approximately 198 MMbbls, partially offset by dispositions of approximately 90 MMbbls. Extensions and discoveries after revisions of approximately 45 MMbbls replaced 142 percent of production during the year.

Encana's 2014 proved natural gas reserves after royalties of approximately 5.5 Tcf decreased 3.1 Tcf from 2013 primarily due to dispositions of approximately 2.4 Tcf resulting from the Company's strategic transition to a more balanced commodity portfolio. Gas extensions and discoveries after revisions were essentially zero.

Reserves and Resources (MMBOE, After Royalties)						
	Estimated Reserves			Estimated Economic Contingent Resources		
Using forecast prices and costs	1P Proved	2P Proved + Probable	3P Proved + Probable + Possible	1C Low Estimate	2C Best Estimate	3C High Estimate
Total As at Dec. 31 2014	1,277	2,349	2,763	5,094	7,672	10,356
Total As at Dec. 31 2013	1,664	2,458	2,935	4,940	8,549	12,338

For information on reserves reporting protocols see Note 2.

Conference call information
Encana will host a conference call today Wednesday, February 25, 2015 starting at 7:00 a.m. MT (9:00 a.m. ET). To participate, please dial (877) 291-4570 (toll-free in North America) or (647) 788-4919 approximately 10 minutes prior to the conference call. An archived recording of the call will be available from approximately 10 a.m. MT (12 p.m. ET) on February 25 until 9:59 p.m. MT (11:59 p.m. ET) on March 4, 2015 by dialing (800) 585-8367 or (416) 621-4642 and entering passcode 56241851. A live audio webcast, including slides, of the conference call will also be available via Encana's website, www.encana.com, under Investors/Presentations & Events. The webcasts will be archived for approximately 90 days.

Media are invited to participate in the call in a listen-only mode.

The unaudited interim Condensed Consolidated Financial Statements for the period ended December 31, 2014 are available at www.encana.com.

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

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

NOTE 1: Non-GAAP measures

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

- Cash flow is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities, net change in non-cash working capital and cash tax on sale of assets. Upstream operating cash flow is defined as revenues, net of royalties, including realized hedging gains/losses less production and mineral taxes, transportation and processing and operating expenses for each of the respective Canadian and USA operations. Operating cash flow for a specific asset is defined as revenues, net of royalties, less production and mineral taxes, transportation and processing and operating expenses.

- Operating earnings is a non-GAAP measure defined as net earnings 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.

NOTE 2: Reserves reporting information

Encana's disclosure of reserves data is in accordance with Canadian securities regulatory requirements. Encana's 2014 disclosure includes proved and probable reserves quantities before and after royalties employing forecast prices and costs in accordance with Canadian protocols. Reserves disclosure employing U.S. protocols uses SEC constant prices and costs on proved reserves on an after-royalties basis. Reserves disclosure under both Canadian and U.S. protocols will be available in the Annual Information Form, which the company anticipates filing in March.

For all Canadian protocol reserves and economic contingent resources estimates highlighted in this news release, Encana has used Henry Hub forecast prices of $3.31 per MMBtu for 2015, $3.75 per MMBtu for 2016, $4.00 per MMBtu for 2017, $4.25 per MMBtu for 2018, $4.50 per MMBtu for 2019, then increasing to $5.68 per MMBtu by 2024 and escalating 2 percent per year thereafter. Encana has used WTI forecast prices of $62.50 per bbl for 2015, $75.00 per bbl for 2016, $80.00 per bbl for 2017, $85.00 per bbl for 2018, $90.00 per bbl for 2019, then increasing to $104.57 per bbl by 2024 and escalating 2 percent per year thereafter.

RESERVES METRICS DEFINITIONS

Proved reserves added in 2014 included both developed and undeveloped quantities. Additions to and removals from Encana's PUD bookings were consistent with Encana's revised strategy. The company estimates that 100 percent of its PUDs will be developed within the next five years. Many performance measures exist; all measures have limitations and historical measures are not necessarily indicative of future performance.

ADVISORY REGARDING RESERVES & OTHER RESOURCES INFORMATION - Reserves are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data, the use of established technology, and specified economic conditions, which are generally accepted as being reasonable. Proved reserves are those reserves which can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

The estimates of economic contingent resources contained in this news release are based on definitions contained in the Canadian Oil and Gas Evaluation Handbook. Contingent resources do not constitute, and should not be confused with, reserves. Contingent resources are defined as those quantities of petroleum estimated, on a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Economic contingent resources are those contingent resources that are currently economically recoverable. In examining economic viability, the same fiscal conditions have been applied as in the estimation of reserves. There is a range of uncertainty of estimated recoverable volumes. A low estimate is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate, which under probabilistic methodology reflects a 90 percent confidence level. A best estimate is considered to be a realistic estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate, which under probabilistic methodology reflects a 50 percent confidence level. A high estimate is considered to be an optimistic estimate. It is unlikely that the actual remaining quantities recovered will exceed the high estimate, which under probabilistic methodology reflects a 10 percent confidence level.

There is no certainty that it will be commercially viable to produce any portion of the volumes currently classified as economic contingent resources. The primary contingencies which currently prevent the classification of Encana's disclosed economic contingent resources as reserves include the lack of a reasonable expectation that all internal and external approvals will be forthcoming and the lack of a documented intent to develop the resources within a reasonable time frame. Other commercial considerations that may preclude the classification of contingent resources as reserves include factors such as legal, environmental, political and regulatory matters or a lack of markets.

The estimates of various classes of reserves (proved, probable, possible) and of contingent resources (low, best, high) in this news release represent arithmetic sums of multiple estimates of such classes for different properties, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of reserves and contingent resources and appreciate the differing probabilities of recovery associated with each class.

Encana uses the term resource play. 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.

The practice of preparing production and reserve quantities data under Canadian disclosure requirements (National Instrument 51-101) differs from the disclosure under U.S. protocols prepared in accordance with the requirements of the SEC. The primary differences between the two reporting requirements include:

a. the Canadian standards require disclosure of proved and probable reserves, while the U.S. standards require disclosure of only proved reserves;

b. the Canadian standards require the use of forecast prices in the estimation of reserves, while the U.S. standards require the use of 12-month average historical prices which are held constant;

c. the Canadian standards require disclosure of reserves on a gross (before royalties) and net (after royalties) basis, while the U.S standards require disclosure on a net (after royalties) basis;

d. the Canadian standards require disclosure of production on a gross (before royalties) basis, while the U.S. standards require disclosure on a net (after royalties) basis;

e. the Canadian standards require that reserves and other data be reported on a more granular product type basis than required by the U.S. standards; and

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

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

In this news release, certain oil and NGLs volumes have been converted to cubic feet equivalent (cfe) on the basis of one barrel to six thousand cubic feet (Mcf). Cfe may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the well head. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

ADVISORY REGARDING FORWARD-LOOKING STATEMENTS - In the interests of providing Encana shareholders and potential investors with information regarding Encana, including management's assessment of Encana's and its subsidiaries' future plans and operations, certain statements contained in this news release are forward-looking statements or information within the meaning of applicable securities legislation, collectively referred to herein as "forward-looking statements." Forward-looking statements in this news release include, but are not limited to:

- achieving the company's focus of developing its strong portfolio of resource plays producing natural gas, oil and NGLs
- the company's plan to continue to execute on its long-term strategy through 2016 and beyond, realize efficiencies and maximize profitability through focused capital allocation and operational excellence
- anticipated positioning to be more competitive and resilient
- anticipated cost reductions including capital and operating cost targets for 2015 and beyond, and the ability to preserve balance sheet strength
- maintaining a balanced portfolio
- the company’s plan to focus capital investment in its four most strategic assets (including in the Permian, Eagle Ford, Montney and Duvernay areas) and the expected growth from these areas in 2015
- anticipated 2015 capital investment
- anticipated 2015 cash flow
- anticipated flexibility to make capital adjustments
- expected proceeds from divestitures
- anticipated drilling and production and number of wells and the success thereof (including in the Permian, Eagle Ford, Montney and Duvernay areas)
- expected third-party investment
- expected hedging activities

- anticipated oil, natural gas and NGLs prices
- anticipated oil, natural gas and NGLs production in 2015 and beyond
- anticipated dividends
- potential future discounts to market price in connection with the company's DRIP
- estimated reserves and economic contingent resources, including estimates of PUDs and the expected period within which to convert PUDs to proved developed reserves
- the expectation of meeting the targets in the company's 2015 corporate guidance

Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These assumptions, risks and uncertainties include, among other things:

- volatility of, and assumptions regarding natural gas and liquids prices, including substantial or extended decline of the same and their adverse effect on the company's operations and financial condition and the value and amount of its reserves
- assumptions based upon the company's current guidance
- the company’s ability to realize capital and operating efficiencies as anticipated
- risks and uncertainties associated with announced but not completed transactions including the risk that the transactions may not be completed on a timely basis or at all
- fluctuations in currency and interest rates
- risk that the company may not conclude divestitures of certain assets or other transactions or receive amounts contemplated under the transaction agreements (such transactions may include third-party capital investments, farm-outs or partnerships, which Encana may refer to from time to time as "partnerships" or "joint ventures" and the funds received in respect thereof which Encana may refer to from time to time as "proceeds", "deferred purchase price" and/or "carry capital", regardless of the legal form) as a result of various conditions not being met
- product supply and demand; market competition
- risks inherent in the company's and its subsidiaries' marketing operations, including credit risks
- imprecision of reserves estimates and estimates of recoverable quantities of natural gas 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
- marketing margins; potential disruption or unexpected technical difficulties in developing new facilities
- unexpected cost increases or technical difficulties in constructing or modifying processing facilities
- risks associated with technology
- the company's ability to acquire or find additional reserves
- hedging activities resulting in realized and unrealized losses
- business interruption and casualty losses
- risk of the company not operating all of its properties and assets
- counterparty risk
- risk of downgrade in credit rating and its adverse effects
- liability for indemnification obligations to third parties
- variability of dividends to be paid
- its ability to generate sufficient cash flow from operations to meet its current and future obligations
- its ability to access external sources of debt and equity capital
- the timing and the costs of well and pipeline construction
- the company's ability to secure adequate product transportation
- changes in royalty, tax, environmental, greenhouse gas, carbon, accounting and other laws or regulations or the interpretations of such laws or regulations
- political and economic conditions in the countries in which the company operates
- terrorist threats
- risks associated with existing and potential future lawsuits and regulatory actions made against the company
- risk arising from price basis differential
- risk arising from inability to enter into attractive hedges to protect the company's capital program
- and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by Encana

Although Encana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. In addition, assumptions relating to such forward-looking statements generally include Encana's current expectations and projections made in light of, and generally consistent with, its historical experience and its perception of historical trends, including the conversion of resources into reserves and production as well as expectations regarding rates of advancement and innovation, generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in this news release.

Assumptions with respect to forward-looking information regarding expanding Encana's oil and NGLs production and extraction volumes are based on existing expansion of natural gas processing facilities in areas where Encana operates and the continued expansion and development of oil and NGL production from existing properties within its asset portfolio.

Forward-looking information respecting anticipated 2015 cash flow for Encana is based upon, among other things, achieving average production for 2015 of between 1.60 Bcf/d and 1.70 Bcf/d of natural gas and 130,000 bbls/d to 150,000 bbls/d of liquids, commodity prices for natural gas and liquids based on NYMEX $3.00 per MMBtu and WTI of $50 per bbl, an estimated U.S./Canadian dollar exchange rate of $0.80 and a weighted average number of outstanding shares for Encana of approximately 741 million.

Furthermore, the forward-looking statements contained in this news release are made as of the date hereof and, except as required by law, Encana undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this news release are expressly qualified by this cautionary statement.

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

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SOURCE: Encana Corporation

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 audited Consolidated Financial Statements for the year ended December 31, 2014 ("Consolidated Financial Statements"), as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2013.

The 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 March 3, 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; 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 Attributable to Common Shareholders to Operating Earnings.

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 ("Bcf"); trillion cubic feet ("Tcf"); barrel ("bbl"); thousand barrels ("Mbbls") per day ("Mbbls/d"); million barrels ("MMbbls"); barrels of oil equivalent ("BOE") per day ("BOE/d"); thousand barrels of oil equivalent ("MBOE") per day ("MBOE/d"); million barrels of oil equivalent ("MMBOE"); million British thermal units ("MMBtu").

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

Encana's Strategic Objectives

Encana is a leading North American energy producer that is focused on developing its strong portfolio of resource plays producing natural gas, oil and NGLs. Encana is committed to growing long-term shareholder value through a disciplined focus on generating profitable growth. The Company is pursuing the key business objectives of balancing its commodity portfolio, focusing capital investments in 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, which utilizes highly integrated production facilities, is used to develop resources by drilling multiple wells from central pad sites. Ongoing cost reductions 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 December 31, 2014 can be found in the Results Overview section of this MD&A and in Note 23 to the 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 year ended December 31, 2014, Encana reported:

- Cash Flow of $2,934 million, Operating Earnings of $1,002 million and Net Earnings Attributable to Common Shareholders of $3,392 million.
- Average realized natural gas prices, including financial hedges, of $4.59 per Mcf. Average realized oil prices, including financial hedges, of $86.03 per bbl. Average realized NGL prices of $48.09 per bbl.
- Average natural gas production volumes of 2,350 MMcf/d and average oil and NGL production volumes of 86.8 Mbbls/d.
- Gain on divestitures of approximately $3.4 billion, before tax, primarily related to the sale of Encana's investment in PrairieSky Royalty Ltd. ("PrairieSky"), the Company's Bighorn assets and Jonah properties.
- Dividends paid of $0.28 per share.
- Long-term debt repayments and redemptions totaling approximately $2.5 billion, funded using cash on hand and proceeds of $1.3 billion drawn on the Company's revolving credit facility.
- Cash and cash equivalents of $338 million at year end.

Significant developments for the Company during the year ended December 31, 2014 included the following:

- Completed the acquisition of all issued and outstanding shares of common stock of Athlon Energy Inc. ("Athlon") for $5.93 billion, or $58.50 per share, on November 13, 2014. As part of the acquisition, Encana also 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 with cash on hand. On December 16, 2014, Encana completed the redemption of Athlon's senior notes. Athlon's operations focused on the acquisition and development of oil and gas properties located in the Permian Basin in Texas.
- Completed the secondary offering of 70.2 million common shares of PrairieSky on September 26, 2014 at a price of C$36.50 per common share for aggregate gross proceeds of approximately C$2.6 billion and recognized a gain on divestiture of approximately $2.1 billion, before tax. Following the completion of the secondary offering, Encana no longer holds an interest in PrairieSky.

  During the second quarter of 2014, Encana completed the initial public offering of 59.8 million common shares of PrairieSky at a price of C$28.00 per common share for aggregate gross proceeds of approximately C$1.67 billion. Subsequent to the initial public offering, Encana owned 70.2 million common shares of PrairieSky, representing a 54 percent ownership interest.
- Completed the acquisition of certain properties in the Eagle Ford shale formation in south Texas ("Eagle Ford") on June 20, 2014 for approximately $2.9 billion, after closing adjustments. The transaction had an effective date of April 1, 2014.
- Closed the sale of the Company's Bighorn assets located in west central Alberta on September 30, 2014 for approximately $1.7 billion, after closing adjustments, and recognized a gain on divestiture of approximately $1.0 billion, before tax. The transaction had an effective date of May 1, 2014.
- Closed the sale of the Jonah properties in Wyoming on May 12, 2014 for proceeds of approximately $1.6 billion, after closing adjustments, and recognized a gain on divestiture of approximately $209 million, before tax.
- Closed the majority of the sale of certain properties in East Texas on June 19, 2014 for proceeds of approximately $425 million and closed the balance of the transaction on September 30, 2014 for proceeds of approximately $70 million.

- Completed a cash tender offer and consent solicitation for the Company's $1.0 billion 5.80 percent notes with a maturity date of May 1, 2014 and the redemption of all notes not tendered in the tender offer.
- Announced an agreement with Ember Resources Inc. to sell certain Clearwater assets located in central and southern Alberta on October 8, 2014. The sale includes the Company's working interest in approximately 1.2 million net acres of land and over 6,800 producing wells. Encana retains a working interest in approximately 1.1 million net acres in Clearwater. The sale closed on January 15, 2015 and proceeds of approximately C$556 million, after closing adjustments, were received.
- Announced an agreement with Veresen Midstream Limited Partnership on December 22, 2014 to sell certain natural gas gathering and compression assets in northeastern British Columbia for approximately C$412 million in cash consideration net to Encana. The transaction is expected to close in the first quarter of 2015, subject to regulatory approval and the satisfaction of normal closing conditions.

As a result of the execution of the strategy announced in November 2013, the Company's results for the year ended December 31, 2014 reflected the following:

- Acquired properties in Eagle Ford and the Permian Basin, which provide significant oil reserves to the Company.
- Divested natural gas-weighted properties in Jonah, East Texas and Bighorn.
- Completed the initial public offering and secondary offering of common shares of PrairieSky, providing a source of funding for subsequent acquisition transactions.
- Focused capital spending on seven growth assets, totaling approximately $2.2 billion, or 86 percent of total capital investment.
- Reported oil and NGL production volumes of 86.8 Mbbls/d, an increase of 61 percent from 2013. Average oil and NGL production volumes were 18 percent of total production in 2014 compared to 10 percent in 2013.
- Achieved total operating and administrative cost savings of approximately $150 million attributable to workforce reductions and operating efficiencies, of which approximately $45 million is reflected in operating expense, $35 million in administrative expense and $70 million in capital costs.

Financial Results

($ millions, except as indicated)	2014 Annual	2014 Q4	2014 Q3	2014 Q2	2014 Q1	2013 Annual	2013 Q4	2013 Q3	2013 Q2	2013 Q1	2012 Annual
Cash Flow (1)	**$ 2,934**	**$ 377**	**$ 807**	**$ 656**	**$ 1,094**	$ 2,581	$ 677	$ 660	$ 665	$ 579	$ 3,537
$ per share - diluted	**3.96**	**0.51**	**1.09**	**0.89**	**1.48**	3.50	0.91	0.89	0.90	0.79	4.80
Operating Earnings (1)	**1,002**	**35**	**281**	**171**	**515**	802	226	150	247	179	997
$ per share - diluted	**1.35**	**0.05**	**0.38**	**0.23**	**0.70**	1.09	0.31	0.20	0.34	0.24	1.35
Net Earnings (Loss) Attributable to Common Shareholders	**3,392**	**198**	**2,807**	**271**	**116**	236	(251)	188	730	(431)	(2,794)
$ per share - basic & diluted	**4.58**	**0.27**	**3.79**	**0.37**	**0.16**	0.32	(0.34)	0.25	0.99	(0.59)	(3.79)
Revenues, Net of Royalties	**8,019**	**2,254**	**2,285**	**1,588**	**1,892**	5,858	1,423	1,392	1,984	1,059	5,160
Realized Hedging Gain (Loss), before tax	**(91)**	**124**	**28**	**(102)**	**(141)**	544	174	175	52	143	2,161
Unrealized Hedging Gain (Loss), before tax	**444**	**489**	**231**	**9**	**(285)**	(345)	(301)	(128)	469	(385)	(1,465)
Upstream Operating Cash Flow	**3,918**	**821**	**982**	**800**	**1,315**	3,192	901	794	788	709	4,084
Upstream Operating Cash Flow Excluding Realized Hedging (1)	**3,999**	**694**	**952**	**898**	**1,455**	2,652	728	622	737	565	1,931
Capital Investment	**2,526**	**857**	**598**	**560**	**511**	2,712	717	641	639	715	3,476
Net Acquisitions & (Divestitures) (2)	**(1,329)**	**50**	**(2,007)**	**652**	**(24)**	(521)	(72)	(51)	(312)	(86)	(3,664)
Free Cash Flow (1)	**408**	**(480)**	**209**	**96**	**583**	(131)	(40)	19	26	(136)	61
Ceiling Test Impairments, after tax	**-**	**-**	**-**	**-**	**-**	-	-	-	-	-	(3,179)
Gain (Loss) on Divestitures, after tax	**2,523**	**(11)**	**2,399**	**135**	**-**	-	-	-	-	-	-
Total Assets	**24,621**					17,648					18,700
Total Debt	**7,340**					7,124					7,675
Cash & Cash Equivalents	**338**					2,566					3,179
Production Volumes											
Natural Gas (MMcf/d)	**2,350**	**1,861**	**2,199**	**2,541**	**2,809**	2,777	2,744	2,723	2,766	2,877	2,981
Oil & NGLs (Mbbls/d)											
Oil	**49.4**	**68.8**	**62.1**	**34.2**	**32.1**	25.8	33.0	27.2	22.9	20.0	17.6
NGLs	**37.4**	**37.6**	**41.9**	**34.0**	**35.8**	28.1	33.0	31.0	24.7	23.5	13.4
Total Oil & NGLs	**86.8**	**106.4**	**104.0**	**68.2**	**67.9**	53.9	66.0	58.2	47.6	43.5	31.0
Total Production (MBOE/d)	**478.5**	**416.7**	**470.6**	**491.8**	**536.1**	516.7	523.4	512.1	508.6	523.0	527.9
Production Mix (%)											
Natural Gas	**82**	**74**	**78**	**86**	**87**	90	87	89	91	92	94
Oil & NGLs	**18**	**26**	**22**	**14**	**13**	10	13	11	9	8	6

(1) A non-GAAP measure, which is defined under the Non-GAAP Measures section of this MD&A.
(2) Excluding the impact of the PrairieSky divestiture and Athlon acquisition as discussed 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, non-cash 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 Critical Accounting Estimates section of this MD&A. Quarterly net earnings are also impacted by acquisition and divestiture transactions, which are 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 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. The Company's after-tax non-cash ceiling test impairment in 2012 primarily resulted from the decline in the 12-month average trailing natural gas prices.

In the last half of 2014, commodity prices have generally declined. Further declines in the 12-month average trailing commodity prices could reduce proved reserves 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 oil and gas divestitures are generally deducted from the Company's capitalized costs and can reduce the risk of ceiling test impairments.

Q4 2014 versus Q4 2013

Cash Flow of $377 million decreased $300 million in the three months ended December 31, 2014 primarily due to the following significant items:

- Average realized natural gas prices, excluding financial hedges, were $3.94 per Mcf compared to $3.69 per Mcf in 2013 reflecting higher benchmark prices for AECO and NYMEX. Higher realized natural gas prices increased revenues $44 million. Average realized liquids prices, excluding financial hedges, were $57.35 per bbl compared to $65.58 per bbl in 2013 reflecting lower benchmark prices. Lower realized liquids prices decreased revenues $105 million.
- Average natural gas production volumes of 1,861 MMcf/d decreased 883 MMcf/d from 2,744 MMcf/d in 2013 primarily due to divestitures resulting from the Company's strategic transition to a more balanced commodity portfolio and natural declines. Lower natural gas volumes decreased revenues $303 million. Average oil and NGL production volumes of 106.4 Mbbls/d increased 40.4 Mbbls/d from 66.0 Mbbls/d in 2013 primarily due to acquisitions and successful drilling programs in oil and liquids rich natural gas plays, partially offset by divestitures and the sale of the Company's investment in PrairieSky. Higher oil and NGL volumes increased revenues $267 million.
- Realized financial hedging gains before tax were $124 million compared to $174 million in 2013.
- Transportation and processing expense decreased $49 million primarily due to divestitures and the lower U.S./Canadian dollar exchange rate, partially offset by higher liquids volumes processed.
- Administrative expense decreased $109 million primarily due to lower restructuring charges of $68 million. The decrease also reflects lower non-cash long-term compensation costs resulting from the decrease in the Encana share price.
- Interest expense increased $113 million primarily due to a one-time outlay associated with the early redemption of senior notes assumed in conjunction with the acquisition of Athlon.
- Other expense increased $56 million primarily due to transaction costs of $31 million associated with the acquisition of Athlon. The increase also reflects non-cash reclamation charges relating to non-producing assets.
- Current tax expense was $2 million compared to a recovery of $25 million in 2013. Cash Flow excludes cash tax on the sale of assets as discussed in the Non-GAAP Measures section of this MD&A.

Operating Earnings of $35 million decreased $191 million primarily due to the items discussed in the Cash Flow section. Operating Earnings for the fourth quarter of 2014 were also impacted by higher depreciation, depletion and amortization ("DD&A"), a foreign exchange gain on the revaluation of other monetary assets, lower long-term compensation costs and deferred tax. Operating Earnings excludes restructuring charges as described in the Non-GAAP Measures section of this MD&A.

Net Earnings Attributable to Common Shareholders of $198 million increased $449 million primarily due to unrealized hedging gains and the items discussed in the Cash Flow and Operating Earnings sections. Net Earnings Attributable to Common Shareholders for the fourth quarter of 2014 were also impacted by deferred tax.

2014 versus 2013

Cash Flow of $2,934 million increased $353 million in the year ended December 31, 2014 primarily due to the following significant items:

- Average realized natural gas prices, excluding financial hedges, were $4.78 per Mcf compared to $3.57 per Mcf in 2013 reflecting higher benchmark prices, including the impact of higher realized prices from Deep Panuke production. Higher realized natural gas prices increased revenues $1,067 million. Average realized liquids prices, excluding financial hedges, were $67.24 per bbl compared to $67.30 per bbl in 2013 reflecting lower WTI prices. Lower realized liquids prices decreased revenues $23 million.
- Average natural gas production volumes of 2,350 MMcf/d decreased 427 MMcf/d from 2,777 MMcf/d in 2013 primarily due to divestitures resulting from the Company's strategic transition to a more balanced commodity portfolio and natural declines, partially offset by production from Deep Panuke. Lower natural gas volumes decreased revenues $602 million. Average oil and NGL production volumes of 86.8 Mbbls/d increased 32.9 Mbbls/d from 53.9 Mbbls/d in 2013 primarily due to acquisitions and successful drilling programs in oil and liquids rich natural gas plays, partially offset by divestitures and the sale of the Company's investment in PrairieSky. Higher oil and NGL volumes increased revenues $829 million.
- Realized financial hedging losses before tax were $91 million compared to gains of $544 million in 2013.
- Operating expense decreased $124 million primarily due to lower salaries and benefits related to workforce reductions resulting from the 2013 restructuring, divestitures and the lower U.S./Canadian dollar exchange rate, partially offset by acquisitions. The decrease also reflects lower non-cash long-term compensation costs resulting from the decrease in the Encana share price.
- Administrative expense decreased $112 million primarily due to lower restructuring charges of $52 million and the lower U.S./Canadian dollar exchange rate. The decrease also reflects lower non-cash long-term compensation costs resulting from the decrease in the Encana share price.
- Interest expense increased $91 million primarily due to a one-time outlay associated with the early redemption of senior notes assumed in conjunction with the acquisition of Athlon.
- Other expense increased $70 million primarily due to transaction costs of $40 million associated with the acquisitions of Athlon and Eagle Ford. The increase also reflects non-cash reclamation charges relating to non-producing assets.
- Current tax expense was $243 million compared to a recovery of $191 million in 2013 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 Earnings of $1,002 million increased $200 million primarily due to the items discussed in the Cash Flow section. Operating Earnings for 2014 were also impacted by a higher foreign exchange gain on the revaluation of other monetary assets and higher DD&A. Operating Earnings excludes restructuring charges as described in the Non-GAAP Measures section of this MD&A.

Net Earnings Attributable to Common Shareholders of $3,392 million increased $3,156 million primarily due to gains on divestitures as well as the items discussed in the Cash Flow and Operating Earnings sections. Net Earnings Attributable to Common Shareholders for 2014 were also impacted by unrealized hedging gains, a higher after-tax non-operating foreign exchange loss and deferred tax.

2013 versus 2012

Cash Flow of $2,581 million decreased $956 million in the year ended December 31, 2013 primarily due to the following significant items:

- Average realized natural gas prices, excluding financial hedges, were $3.57 per Mcf compared to $2.83 per Mcf in 2012 reflecting higher benchmark prices which increased revenues $790 million. Average realized liquids prices, excluding hedges, were $67.30 per bbl compared to $75.12 per bbl in 2012 which decreased revenues $168 million.
- Average natural gas production volumes of 2,777 MMcf/d decreased 204 MMcf/d from 2,981 MMcf/d in 2012 primarily due to the Company's capital investment focus in oil and liquids rich natural gas plays, a reduced capital investment program and natural declines, partially offset by shut-in production volumes in 2012, successful drilling programs and production from the Deep Panuke offshore natural gas facility in 2013. Lower natural gas volumes decreased revenues $208 million. Average oil and NGL production volumes of 53.9 Mbbls/d increased 22.9 Mbbls/d from 31.0 Mbbls/d in 2012 primarily due to successful drilling programs in oil and liquids rich natural gas plays, the extraction of additional liquids volumes processed through third party facilities and additional NGL volumes resulting from new and renegotiated gathering and processing agreements. Higher oil and NGL volumes increased revenues $640 million.
- Realized financial hedging gains before tax were $544 million compared to $2,161 million in 2012.
- Transportation and processing expense increased $245 million primarily due to costs related to higher production volumes processed through third party facilities, additional NGL volumes resulting from new and renegotiated gathering and processing agreements, costs related to the Deep Panuke offshore natural gas facility and higher firm processing costs.
- Operating expense increased $65 million primarily due to an increased focus on emerging oil and liquids rich natural gas plays.
- Administrative expense increased primarily due to restructuring charges as discussed in the Other Operating Results section of this MD&A.

Operating Earnings of $802 million decreased $195 million primarily due to the items discussed in the Cash Flow section, partially offset by lower DD&A and lower deferred tax. Operating Earnings excludes restructuring charges as described in the Non-GAAP Measures section of this MD&A.

Net Earnings were $236 million compared to a Net Loss of $2,794 million in 2012 primarily due to the inclusion of after-tax non-cash ceiling test impairments of $3,179 million in the 2012 comparative, partially offset by the items discussed in the Cash Flow and Operating Earnings sections. Net Earnings for 2013 were also impacted by lower unrealized hedging losses of $770 million after tax, partially offset by an after-tax non-operating foreign exchange loss and higher administrative expense as a result of restructuring charges.

Prices and Foreign Exchange Rates

	2014					2013					2012
(average for the period)	**Annual**	**Q4**	**Q3**	**Q2**	**Q1**	Annual	Q4	Q3	Q2	Q1	Annual
Encana Realized Pricing											
Including Hedging											
Natural Gas ($/Mcf)	**$ 4.59**	**$ 4.16**	**$ 4.03**	**$ 4.08**	**$ 5.82**	$ 4.09	$ 4.34	$ 4.00	$ 4.17	$ 3.86	$ 4.82
Oil & NGLs ($/bbl)											
Oil	**86.03**	**80.38**	**90.22**	**89.55**	**86.34**	88.19	85.39	90.42	88.27	89.71	84.06
NGLs	**48.09**	**40.87**	**48.76**	**49.39**	**53.79**	48.95	48.59	46.35	49.63	52.24	63.37
Total Oil & NGLs	**69.70**	**66.40**	**73.50**	**69.53**	**69.19**	67.75	67.01	66.95	68.25	69.45	75.12
Total ($/BOE)	**35.21**	**35.55**	**35.06**	**30.75**	**39.22**	29.05	31.23	28.85	29.08	27.00	31.62
Excluding Hedging											
Natural Gas ($/Mcf)	**4.78**	**3.94**	**3.88**	**4.46**	**6.37**	3.57	3.69	3.26	3.99	3.35	2.83
Oil & NGLs ($/bbl)											
Oil	**81.71**	**66.38**	**90.18**	**92.93**	**86.43**	87.25	82.54	96.09	85.89	84.46	84.06
NGLs	**48.09**	**40.87**	**48.76**	**49.39**	**53.79**	48.95	48.59	46.35	49.63	52.24	63.37
Total Oil & NGLs	**67.24**	**57.35**	**73.48**	**71.23**	**69.23**	67.30	65.58	69.60	67.10	67.04	75.12
Total ($/BOE)	**35.67**	**32.25**	**34.36**	**32.93**	**42.12**	26.20	27.63	25.23	27.99	23.97	20.40
Natural Gas Price Benchmarks											
NYMEX ($/MMBtu)	**4.41**	**4.00**	**4.06**	**4.67**	**4.94**	3.65	3.60	3.58	4.09	3.34	2.79
AECO (C$/Mcf)	**4.42**	**4.01**	**4.22**	**4.68**	**4.76**	3.16	3.15	2.82	3.59	3.08	2.40
Algonquin City Gate ($/MMBtu) (1)	**8.06**	**4.99**	**2.97**	**4.23**	**20.28**	6.97	7.80	3.98	4.63	11.56	3.94
Basis Differential ($/MMBtu)											
AECO/NYMEX	**0.39**	**0.44**	**0.16**	**0.40**	**0.60**	0.57	0.59	0.89	0.56	0.27	0.38
Oil Price Benchmarks											
West Texas Intermediate (WTI) ($/bbl)	**93.00**	**73.15**	**97.17**	**102.99**	**98.68**	97.97	97.46	105.81	94.17	94.36	94.21
Edmonton Light Sweet (C$/bbl)	**94.57**	**75.69**	**97.16**	**105.61**	**99.83**	93.11	86.58	103.65	92.67	87.43	87.02
Foreign Exchange											
Average U.S./Canadian Dollar Exchange Rate	**0.905**	**0.881**	**0.918**	**0.917**	**0.906**	0.971	0.953	0.963	0.977	0.992	1.000

(1) The Algonquin City Gate benchmark reflects the daily average price for sales of production from Atlantic Canada. Encana's operations at Deep Panuke in Atlantic Canada commenced in Q4 2013.

Encana's financial results are influenced by fluctuations in commodity prices, price differentials and the U.S./Canadian dollar exchange rate. In 2014, Encana's average realized natural gas price, excluding hedging, reflected higher benchmark prices compared to 2013. Hedging activities reduced Encana's average realized natural gas price $0.19 per Mcf in 2014. Realized natural gas prices for production from Deep Panuke were $8.34 per Mcf in 2014, which increased Encana's average realized natural gas price $0.31 per Mcf in 2014. The Deep Panuke offshore natural gas facility commenced commercial operations in December 2013.

In 2014, Encana's average realized oil price, excluding hedging, reflected generally lower benchmark prices compared to 2013. Hedging activities contributed $4.32 per bbl to Encana's average realized oil price in 2014.

In 2013, Encana's average realized natural gas price, excluding hedging, reflected higher benchmark prices compared to 2012. Hedging activities contributed $0.52 per Mcf to the average realized natural gas price in 2013. Encana's average realized oil price, excluding hedging for 2013, reflected higher benchmark prices. Hedging activities contributed $0.94 per bbl to the average realized oil price in 2013. The Company's 2013 NGLs price reflected a lower proportion of higher value condensate included in the total NGL product mix.

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 curves of 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.

At December 31, 2014, Encana has hedged approximately 1,062 MMcf/d of expected 2015 natural gas production using NYMEX fixed price contracts at an average price of $4.29 per Mcf. In addition, Encana has hedged approximately 12.3 Mbbls/d of expected 2015 oil production using WTI fixed price contracts at an average price of $92.88 per bbl and approximately 1.2 Mbbls/d of expected 2016 oil production at an average price of $92.35 per bbl. At February 24, 2015, Encana has hedged approximately 1,044 MMcf/d of expected February to December 2015 natural gas production using NYMEX fixed price contracts at an average price of $4.29 per Mcf. In addition, Encana has hedged approximately 55.3 Mbbls/d of expected February to December 2015 oil production using WTI fixed price contracts at an average price of $62.18 per bbl and approximately 1.2 Mbbls/d of expected 2016 oil production at an average price of $92.35 per bbl.

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 0.066 in 2014 compared to 2013 and 0.029 in 2013 compared to 2012. The table below summarizes selected foreign exchange impacts on Encana's financial results when compared to the same periods in the prior years.

	2014		2013		2012	
	$ millions	**$/BOE**	$ millions	$/BOE	$ millions	$/BOE
Increase (Decrease) in:						
Capital Investment	**$ (100)**		$ (45)		$ (18)	
Transportation and Processing Expense	**(51)**	**$ (0.29)**	(17)	$ (0.09)	(5)	$ (0.03)
Operating Expense	**(25)**	**(0.14)**	(10)	(0.05)	(3)	(0.02)
Administrative Expense	**(23)**	**(0.13)**	(12)	(0.06)	(3)	(0.02)
Depreciation, Depletion and Amortization	**(41)**	**(0.23)**	(23)	(0.10)	(8)	(0.04)

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 for 2014. The price sensitivities below are based on business conditions, transactions and production volumes during 2014. 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
Increase or Decrease in:			
NYMEX Natural Gas Price	+/- $0.50/Mcf	$ 4	$ 4
WTI Oil Price	+/- $10.00/bbl	121	83

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

Reserves Quantities

Since its formation in 2002, Encana has retained independent qualified reserves evaluators ("IQREs") to evaluate and prepare reports on 100 percent of the Company's natural gas, oil and NGL reserves annually. The Company has a Reserves Committee composed of independent Board of Directors ("Board") members that reviews the qualifications and appointment of the IQREs. The Reserves Committee also reviews the procedures for providing information to the IQREs. All booked reserves are based upon annual evaluations by the IQREs.

As required by Canadian regulatory standards, Encana's disclosure of reserves data is in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). Encana's 2014 Canadian protocol disclosure includes proved reserves quantities before and after royalties employing forecast prices and costs and is available in Encana's Annual Information Form ("AIF"). Canadian standards require reconciliations in this section to include barrels of oil equivalent. The natural gas volumes have been converted to barrels of oil equivalent on the basis of six Mcf to one bbl based on an energy equivalency conversion method primarily applicable at the burner tip. This energy equivalency conversion method does not represent value equivalency, as the current price of oil and NGLs compared to natural gas is significantly higher.

Supplementary oil and gas information, including proved reserves on an after royalties basis, is provided in accordance with U.S. disclosure requirements in Note 26 to the December 31, 2014 Consolidated Financial Statements. As Encana follows U.S. GAAP full cost accounting for oil and gas activities, the U.S. protocol reserves estimates are key inputs to the Company's depletion and ceiling test impairment calculations.

The Canadian standards require the use of forecast prices in the estimation of reserves and the disclosure of before and after royalties volumes. The U.S. standards require the use of 12-month average trailing prices in the estimation of reserves and the disclosure of after royalties volumes. The following sections provide Encana's Canadian protocol and U.S. protocol reserves quantities.

Canadian Protocol Reserves Quantities

Proved Reserves by Country (1)
(Forecast Prices and Costs; Before Royalties)

	Natural Gas (Bcf)			Oil & NGLs (MMbbls)		
(as at December 31)	**2014**	2013	2012	**2014**	2013	2012
Canada	**3,752**	5,031	6,730	**97.2**	141.1	126.3
United States	**2,712**	4,887	6,660	**357.6**	136.2	156.2
Total	**6,463**	9,918	13,390	**454.7**	277.3	282.5

(1) Numbers may not add due to rounding.

Proved Reserves Reconciliation (1)
(Forecast Prices and Costs; Before Royalties)

	Natural Gas (Bcf)			Oil & NGLs (MMbbls)			
	Canada	United States	Total	Canada	United States	Total	**Total** (MMBOE)
December 31, 2013	5,031	4,887	9,918	141.1	136.2	277.3	1,930.3
Extensions and improved recovery	391	594	986	27.3	30.0	57.3	221.6
Discoveries	28	-	28	4.7	-	4.7	9.4
Technical revisions	(171)	(662)	(833)	(5.7)	(0.1)	(5.7)	(144.6)
Economic factors	(58)	(69)	(127)	(0.5)	(1.4)	(1.9)	(23.1)
Acquisitions	7	300	307	0.1	257.7	257.8	309.0
Dispositions	(932)	(1,903)	(2,835)	(56.6)	(42.4)	(99.0)	(571.5)
Production	(544)	(436)	(980)	(13.2)	(22.5)	(35.7)	(199.0)
December 31, 2014	3,752	2,712	6,463	97.2	357.6	454.7	1,532.0

(1) Numbers may not add due to rounding.

Encana's 2014 proved natural gas reserves before royalties of approximately 6.5 Tcf decreased 3.5 Tcf from 2013 primarily due to dispositions of approximately 2.8 Tcf resulting from the Company's strategic transition to a more balanced commodity portfolio. Extensions and improved recovery and discoveries of approximately 1.0 Tcf were mostly offset by negative technical revisions of approximately 0.8 Tcf primarily due to revised development plans. Extensions and improved recovery and discoveries replaced 103 percent of production before royalties during the year.

Encana's 2014 proved oil and NGL reserves before royalties of approximately 454.7 MMbbls increased 177.4 MMbbls from 2013 primarily due to acquisitions of approximately 257.8 MMbbls, partially offset by dispositions of approximately 99.0 MMbbls resulting from the Company's strategic transition to a more balanced commodity portfolio. Extensions and improved recovery and discoveries of approximately 62.0 MMbbls replaced 174 percent of production before royalties during the year.

Proved Reserves by Country (1)
(Forecast Prices and Costs; After Royalties)

	Natural Gas (Bcf)			Oil & NGLs (MMbbls)		
(as at December 31)	**2014**	2013	2012	**2014**	2013	2012
Canada	**3,252**	4,550	6,207	**76.2**	122.2	113.1
United States	**2,270**	4,026	5,410	**280.3**	112.7	127.3
Total	**5,522**	8,576	11,617	**356.5**	234.9	240.4

(1) Numbers may not add due to rounding.

Proved Reserves Reconciliation [1]
(Forecast Prices and Costs; After Royalties)

	Natural Gas (Bcf)			Oil & NGLs (MMbbls)			
	Canada	United States	Total	Canada	United States	Total	Total (MMBOE)
December 31, 2013	4,550	4,026	8,576	122.2	112.7	234.9	1,664.2
Extensions and discoveries	371	475	847	25.4	24.4	49.7	190.8
Revisions [2]	(233)	(619)	(852)	(2.8)	(1.8)	(4.6)	(146.6)
Acquisitions	6	231	237	0.1	198.0	198.1	237.5
Dispositions	(938)	(1,488)	(2,427)	(55.1)	(34.8)	(89.9)	(494.3)
Production	(503)	(355)	(858)	(13.6)	(18.1)	(31.7)	(174.6)
December 31, 2014	3,252	2,270	5,522	76.2	280.3	356.5	1,276.9

(1) Numbers may not add due to rounding.
(2) Includes economic factors.

Encana's 2014 proved natural gas reserves after royalties of approximately 5.5 Tcf decreased 3.1 Tcf from 2013 primarily due to dispositions of approximately 2.4 Tcf resulting from the Company's strategic transition to a more balanced commodity portfolio. Negative revisions of approximately 0.9 Tcf were mainly due to revised development plans and were offset by extensions and discoveries of approximately 0.8 Tcf. Extensions and discoveries replaced 99 percent of production after royalties during the year.

Encana's 2014 proved oil and NGL reserves after royalties of approximately 356.5 MMbbls increased 121.6 MMbbls from 2013 primarily due to acquisitions of approximately 198.1 MMbbls, partially offset by dispositions of approximately 89.9 MMbbls resulting from the Company's strategic transition to a more balanced commodity portfolio. Extensions and discoveries of approximately 49.7 MMbbls replaced 157 percent of production after royalties during the year.

Forecast Prices

The reference prices below were utilized in the determination of reserves.

	Natural Gas		Oil & NGLs	
	Henry Hub ($/MMBtu)	AECO (C$/MMBtu)	WTI ($/bbl)	Edmonton Light Sweet (C$/bbl)
2012 Price Assumptions				
2013	3.75	3.38	90.00	85.00
2014 - 2022	4.25 - 6.27	3.83 - 5.64	92.50 - 104.57	91.50 - 103.57
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr
2013 Price Assumptions				
2014	4.25	4.03	97.50	92.76
2015 - 2023	4.50 - 5.97	4.26 - 5.66	97.50 - 104.57	97.37 - 106.93
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr
2014 Price Assumptions				
2015	3.31	3.31	62.50	64.71
2016 - 2024	3.75 - 5.68	3.77 - 5.71	75.00 - 104.57	80.00 - 112.67
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr

U.S. Protocol Reserves Quantities

Proved Reserves by Country [1]
(12-month average trailing prices; After Royalties)

	Natural Gas (Bcf)			Oil & NGLs (MMbbls)		
(as at December 31)	**2014**	2013	2012	**2014**	2013	2012
Canada	**3,229**	3,975	4,550	**77.5**	110.2	101.6
United States	**2,265**	3,877	4,242	**284.3**	110.6	108.4
Total	**5,494**	7,852	8,792	**361.7**	220.8	210.0

(1) Numbers may not add due to rounding.

Proved Reserves Reconciliation [1]
(12-month average trailing prices; After Royalties)

	Natural Gas (Bcf)			Oil & NGLs (MMbbls)		
	Canada	United States	Total	Canada	United States	Total
December 31, 2013	3,975	3,877	7,852	110.2	110.6	220.8
Revisions and improved recovery	250	(511)	(261)	5.9	(5.3)	0.5
Extensions and discoveries	385	493	879	27.0	30.2	57.2
Purchase of reserves in place	6	234	240	0.1	201.0	201.1
Sale of reserves in place	(885)	(1,473)	(2,358)	(52.1)	(34.1)	(86.2)
Production	(503)	(355)	(858)	(13.6)	(18.1)	(31.7)
December 31, 2014	3,229	2,265	5,494	77.5	284.3	361.7

(1) Numbers may not add due to rounding.

Encana's 2014 proved natural gas reserves after royalties of approximately 5.5 Tcf decreased 2.4 Tcf from 2013 primarily due to the sale of reserves in place of approximately 2.4 Tcf resulting from the Company's strategic transition to a more balanced commodity portfolio. Extensions and discoveries of approximately 0.9 Tcf replaced 102 percent of production after royalties during the year.

Encana's 2014 proved oil and NGL reserves after royalties of approximately 361.7 MMbbls increased 140.9 MMbbls from 2013 primarily due to the purchase of reserves in place of approximately 201.1 MMbbls, partially offset by the sale of reserves in place of approximately 86.2 MMbbls resulting from the Company's strategic transition to a more balanced commodity portfolio. Extensions and discoveries of approximately 57.2 MMbbls replaced 180 percent of production after royalties during the year.

12-Month Average Trailing Prices

The reference prices below were utilized in the determination of reserves. The 12-month average trailing price is calculated as the average of the prices on the first day of each month within the trailing 12-month period.

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

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

Production Volumes

(average daily, after royalties)	**2014**	2013	2012
Natural Gas (MMcf/d)	**2,350**	2,777	2,981
Oil (Mbbls/d)	**49.4**	25.8	17.6
NGLs (Mbbls/d)	**37.4**	28.1	13.4
Total Oil & NGLs (Mbbls/d)	**86.8**	53.9	31.0
Total Production (MBOE/d)	**478.5**	516.7	527.9
Production Mix (%)			
Natural Gas	**82**	90	94
Oil & NGLs	**18**	10	6

Production Volumes by Play

(average daily, after royalties)	Natural Gas (MMcf/d)			Oil & NGLs (Mbbls/d)		
	2014	2013	2012	**2014**	2013	2012
Canadian Operations						
Montney	**514**	463	404	**18.7**	10.0	3.9
Duvernay	**11**	4	1	**2.1**	0.7	0.2
Other Upstream Operations						
Clearwater	**292**	335	374	**8.6**	9.9	8.6
Bighorn	**158**	255	242	**7.5**	8.9	5.8
Deep Panuke	**190**	41	-	**-**	-	-
Other and emerging	**213**	334	338	**0.3**	0.9	0.9
Total Canadian Operations	**1,378**	1,432	1,359	**37.2**	30.4	19.4
USA Operations						
Eagle Ford	**19**	-	-	**19.8**	-	-
Permian	**5**	-	-	**3.5**	-	-
DJ Basin	**43**	39	41	**11.6**	8.4	3.1
San Juan	**8**	3	-	**3.9**	1.4	0.2
Other Upstream Operations						
Piceance	**402**	455	475	**5.0**	5.1	2.2
Haynesville	**311**	348	475	**-**	-	-
Jonah	**100**	323	411	**1.8**	4.7	4.1
East Texas	**57**	136	167	**0.5**	1.0	0.5
Other and emerging	**27**	41	53	**3.5**	2.9	1.5
Total USA Operations	**972**	1,345	1,622	**49.6**	23.5	11.6
Total Production Volumes	**2,350**	2,777	2,981	**86.8**	53.9	31.0
Total Production Volumes – Growth Assets	**600**	509	446	**61.4**	21.5	8.1

The Production Volumes by Play presentation has been updated to align with the Company's business strategy. The table above reflects the Eagle Ford and Permian acquisitions as well as Montney, Duvernay, DJ Basin and San Juan, which have been segregated for presentation in 2014 as Encana focuses capital on these specific growth assets. Growth assets also includes the Tuscaloosa Marine Shale ("TMS") reported within Other and emerging results in the USA Operations. 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.

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

2014 versus 2013

In 2014, average natural gas production volumes of 2,350 MMcf/d decreased 427 MMcf/d from 2013 primarily due to divestitures resulting from the Company's strategic transition to a more balanced commodity portfolio and natural declines, partially offset by production from Deep Panuke. The Canadian Operations volumes were lower in 2014 primarily due to the sale of the Bighorn assets, the sale of the Jean Marie natural gas assets and natural declines, partially offset by higher production volumes from Deep Panuke and a successful drilling program in Montney. The USA Operations volumes were lower in 2014 primarily due to the sale of the Jonah and East Texas properties and natural declines mainly in Piceance and Haynesville.

In 2014, average oil and NGL production volumes of 86.8 Mbbls/d increased 32.9 Mbbls/d from 2013 primarily due to acquisitions and successful drilling programs in oil and liquids rich natural gas plays, partially offset by divestitures. The Canadian Operations volumes were higher in 2014 primarily due to successful drilling programs, mainly in Montney, partially offset by the sale of the Bighorn assets. The Canadian Operations volumes were also impacted by the sale of the Company's investment in PrairieSky, partially offset by higher royalty volumes in Clearwater associated with the lands transferred to PrairieSky. The USA Operations volumes were higher in 2014 primarily due to the acquisition of Eagle Ford and the Permian assets and successful drilling programs in the DJ Basin and San Juan, partially offset by the sale of the Jonah properties.

2013 versus 2012

In 2013, average natural gas production volumes of 2,777 MMcf/d decreased 204 MMcf/d from 2012 primarily due to the Company's capital investment focus in oil and liquids rich natural gas plays, a reduced capital investment program and natural declines, partially offset by shut-in production volumes in 2012. The Canadian Operations volumes were higher primarily due to successful drilling programs, production volumes from Deep Panuke and shut-in production volumes in 2012, partially offset by natural declines and the sale of the Jean Marie natural gas assets. The USA Operations volumes were lower primarily due to natural declines, partially offset by shut-in production volumes in 2012.

In 2013, average oil and NGL production volumes of 53.9 Mbbls/d increased 22.9 Mbbls/d from 2012. The Canadian Operations volumes were higher primarily due to the extraction of additional liquids volumes in Bighorn and Montney and successful drilling programs in Montney and Clearwater. The USA Operations volumes were higher primarily due to successful drilling programs in oil and liquids rich natural gas plays and new and renegotiated gathering and processing agreements which resulted in additional NGL volumes primarily in Piceance and Jonah.

Net Capital Investment

($ millions)	2014	2013	2012
Canadian Operations	$ 1,226	$ 1,365	$ 1,567
USA Operations	1,285	1,283	1,727
Market Optimization	-	3	7
Corporate & Other	15	61	175
Capital Investment	2,526	2,712	3,476
Acquisitions	3,016	184	379
Divestitures	(4,345)	(705)	(4,043)
Net Acquisitions & (Divestitures)	(1,329)	(521)	(3,664)
Net Capital Investment	$ 1,197	$ 2,191	$ (188)

Capital Investment by Play

($ millions)	2014	2013 [(1)]	2012 [(1)]
Canadian Operations			
Montney	$ 776	$ 565	$ 416
Duvernay	328	155	224
Other Upstream Operations			
Clearwater	48	193	220
Bighorn	22	304	363
Deep Panuke	8	46	55
Other and emerging	44	102	289
Total Canadian Operations	$ 1,226	$ 1,365	$ 1,567
USA Operations			
Eagle Ford	$ 274	$ -	$ -
Permian	117	-	-
DJ Basin	277	181	133
San Juan	287	166	84
Other Upstream Operations			
Piceance	48	266	360
Haynesville	51	220	349
Jonah	25	58	116
East Texas	9	106	172
Other and emerging	197	286	513
Total USA Operations	$ 1,285	$ 1,283	$ 1,727
Capital Investment – Growth Assets	$ 2,160	$ 1,165	$ 1,010

(1) 2013 and 2012 capital reflect the reclassification of capitalized operating costs from Other and emerging to the plays presented.

The Capital Investment by Play presentation has been updated to align with the Company's business strategy. The table above reflects the Eagle Ford and Permian acquisitions as well as Montney, Duvernay, DJ Basin and San Juan, which have been segregated for presentation in 2014 as Encana focuses capital on these specific growth assets. Growth assets also includes the TMS reported within Other and emerging results in the USA Operations. For the year ended December 31, 2014, capital investment in the TMS was $101 million (2013 – $98 million; 2012 – $153 million). 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.

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

2014

Capital investment during 2014 was $2,526 million compared to $2,712 million in 2013. The Company's disciplined capital spending focused on investment in high return scalable projects and opportunities where development has demonstrated success, as well as executing drilling programs with joint venture partners. During 2014, capital spending in the Company's growth assets totaled $2,160 million, representing approximately 86 percent of the Company's capital investment.

Acquisitions

Acquisitions in 2014 were $21 million in the Canadian Operations and $2,995 million in the USA Operations, which primarily included land and property purchases with oil and liquids rich production potential.

The USA Operations included approximately $2.9 billion, after closing adjustments, related to the acquisition of Eagle Ford. The Eagle Ford acquisition included 45,500 net acres located in the Eagle Ford shale formation in south Texas and provides significant oil reserves to the Company. Further information on the acquisition of Eagle Ford, including unaudited pro forma financial information, can be found in Note 3 to the Consolidated Financial Statements.

Divestitures

Divestitures in 2014 were $1,847 million in the Canadian Operations and $2,264 million in the USA Operations, which primarily included the sale of land and properties to balance the commodity mix in support of the Company's business strategy.

The Canadian Operations included approximately $1.7 billion, after closing adjustments, for the sale of the Company's Bighorn assets in west central Alberta which comprised approximately 360,000 net acres of land along with Encana's working interests in pipelines, facilities and service arrangements.

The USA Operations included approximately $1.6 billion, after closing adjustments, for the sale of the Jonah properties and approximately $495 million for the sale of certain properties in East Texas. The Jonah properties comprised approximately 19,000 net developed acres and 1,200 net wells as well as approximately 102,000 net undeveloped acres in Wyoming. The East Texas properties represented approximately 91,000 net acres located primarily in the Leon and Robertson counties of East Texas.

Amounts received from the Company's divestiture transactions have been deducted from the respective Canadian and U.S. full cost pools, except for divestitures that 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 year ended December 31, 2014, Encana recognized a gain of approximately $1,014 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 year ended December 31, 2014, Encana recognized a gain of approximately $209 million, before tax, on the sale of the Jonah properties in the U.S. cost centre and allocated goodwill of $68 million.

Other 2014 Capital Transactions

The following transactions involve the acquisition or disposition of common shares and, therefore, are excluded from the Net Capital Investment table.

Acquisition of Athlon

On November 13, 2014, Encana completed the acquisition of all of the issued and outstanding shares of common stock of Athlon for $5.93 billion, or $58.50 per share. As part of the acquisition, Encana assumed Athlon's $1.15 billion senior notes and repaid and terminated Athlon's credit facility with indebtedness outstanding of $335 million. The acquisition of Athlon added approximately 137,000 net acres in the Permian Basin in Texas to Encana's portfolio. The fair value of the assets acquired was $9,405 million including proved and unproved properties totaling $7,462 million and goodwill of $1,724 million. Goodwill arose 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. Further information on the acquisition of Athlon, including unaudited pro forma financial information, can be found in Note 3 to the Consolidated Financial Statements.

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. Following the completion of the secondary offering, Encana no longer holds 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.

During the second quarter of 2014, PrairieSky acquired Encana's royalty business with assets in Clearwater located predominantly in central and southern Alberta. Subsequently, Encana completed the initial public offering of 59.8 million common shares at a price of C$28.00 per common share for aggregate gross proceeds of approximately C$1.67 billion. Encana retained 70.2 million common shares of PrairieSky, representing a 54 percent ownership interest. For the period in which Encana held an ownership interest, the Company consolidated the financial position and results of operations of PrairieSky and recognized a noncontrolling interest for the third party ownership.

Further information on the PrairieSky transactions can be found in Note 18 to the Consolidated Financial Statements.

2013

Capital investment during 2013 was $2,712 million and reflected the Company's disciplined capital spending which focused on investment in Encana's highest return plays, investments in opportunities where development has demonstrated success and executing drilling programs with joint venture partners. Development continued in Bighorn, Piceance and Haynesville. Investment in the Company's growth assets was focused on Montney, Duvernay, the DJ Basin and San Juan.

Acquisitions

Acquisitions in 2013 were $28 million in the Canadian Operations and $156 million in the USA Operations, which primarily included land and property purchases with oil and liquids rich production potential.

Divestitures

Divestitures in 2013 were $685 million in the Canadian Operations and $18 million in the USA Operations. The Canadian Operations included the sale of the Company's Jean Marie natural gas assets in northeast British Columbia and other assets.

2012

Capital investment during 2012 was $3,476 million and focused on completing previously initiated drilling programs, executing drilling programs with joint venture partners and increasing investment in oil and liquids rich natural gas development and exploration opportunities. Development continued in Piceance, Haynesville, Bighorn and Clearwater, as well as in the Company's growth assets, including Montney, Duvernay, the TMS, the DJ Basin and San Juan. Capital investment in 2012 also continued in Other and emerging.

Acquisitions

Acquisitions in 2012 were $139 million in the Canadian Operations and $240 million in the USA Operations, which primarily included land and property purchases with oil and liquids rich production potential.

Divestitures

Divestitures in 2012 were $3,770 million in the Canadian Operations and $271 million in the USA Operations. The Canadian Operations included C$1.45 billion received from a Mitsubishi Corporation subsidiary, C$1.18 billion received from a PetroChina Company Limited subsidiary, C$100 million received from a Toyota Tsusho Corporation subsidiary and approximately C$920 million received from the sale of two natural gas processing plants. The USA Operations received the remaining proceeds of $114 million from the divestiture of the North Texas natural gas assets, of which the majority of the proceeds were received in December 2011.

Results of Operations

Canadian Operations

Operating Cash Flow

($ millions)	Natural Gas 2014	Natural Gas 2013	Natural Gas 2012	Oil & NGLs 2014	Oil & NGLs 2013	Oil & NGLs 2012	Total (1) 2014	Total (1) 2013	Total (1) 2012
Revenues, Net of Royalties, excluding Hedging	**$ 2,468**	$ 1,771	$ 1,263	**$ 872**	$ 722	$ 504	**$ 3,366**	$ 2,548	$ 1,802
Realized Financial Hedging Gain (Loss)	**(74)**	271	962	**18**	5	(4)	**(56)**	276	958
Revenues, Net of Royalties	**2,394**	2,042	2,225	**890**	727	500	**3,310**	2,824	2,760
Expenses									
Production and mineral taxes	**5**	4	1	**10**	11	8	**15**	15	9
Transportation and processing	**773**	724	549	**62**	32	6	**835**	756	555
Operating	**279**	322	327	**28**	39	14	**314**	372	352
Operating Cash Flow	**$ 1,337**	$ 992	$ 1,348	**$ 790**	$ 645	$ 472	**$ 2,146**	$ 1,681	$ 1,844

Production Volumes

	Natural Gas (MMcf/d) 2014	Natural Gas (MMcf/d) 2013	Natural Gas (MMcf/d) 2012	Oil & NGLs (Mbbls/d) 2014	Oil & NGLs (Mbbls/d) 2013	Oil & NGLs (Mbbls/d) 2012	Total (MBOE/d) 2014	Total (MBOE/d) 2013	Total (MBOE/d) 2012
Production Volumes – After Royalties	**1,378**	1,432	1,359	**37.2**	30.4	19.4	**266.9**	269.0	246.0

Operating Netback (2)

	Natural Gas ($/Mcf) 2014	Natural Gas ($/Mcf) 2013	Natural Gas ($/Mcf) 2012	Oil & NGLs ($/bbl) 2014	Oil & NGLs ($/bbl) 2013	Oil & NGLs ($/bbl) 2012	Total ($/BOE) 2014	Total ($/BOE) 2013	Total ($/BOE) 2012
Revenues, Net of Royalties, excluding Hedging	**$ 4.89**	$ 3.35	$ 2.58	**$ 64.16**	$ 65.06	$ 70.84	**$ 34.21**	$ 25.13	$ 19.95
Realized Financial Hedging Gain (Loss)	**(0.15)**	0.51	1.97	**1.36**	0.46	-	**(0.57)**	2.78	10.81
Revenues, Net of Royalties	**4.74**	3.86	4.55	**65.52**	65.52	70.84	**33.64**	27.91	30.76
Expenses									
Production and mineral taxes	**0.01**	0.01	-	**0.71**	0.96	1.13	**0.15**	0.15	0.10
Transportation and processing	**1.53**	1.37	1.12	**4.52**	2.89	0.75	**8.55**	7.62	6.26
Operating	**0.55**	0.61	0.67	**2.09**	3.56	2.09	**3.14**	3.65	3.85
Operating Netback	**$ 2.65**	$ 1.87	$ 2.76	**$ 58.20**	$ 58.11	$ 66.87	**$ 21.80**	$ 16.49	$ 20.55

(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.

2014 versus 2013

Operating Cash Flow of $2,146 million increased $465 million primarily due to the following significant items:

- Higher natural gas prices reflected higher benchmark prices. Realized natural gas prices for production from Deep Panuke were $8.34 per Mcf which increased the average realized natural gas price $0.54 per Mcf. Higher realized natural gas prices for production, including Deep Panuke, increased revenues $780 million. Lower liquids prices decreased revenues $13 million.
- Average natural gas production volumes of 1,378 MMcf/d were lower by 54 MMcf/d, which decreased revenues $83 million. Average oil and NGL production volumes of 37.2 Mbbls/d were higher by 6.8 Mbbls/d,

which increased revenues $163 million. Changes in production volumes are discussed in the Production Volumes section of this MD&A.

- Realized financial hedging losses were $56 million compared to gains of $276 million in 2013.
- Transportation and processing expense increased $79 million primarily due to costs related to Deep Panuke production and higher liquids volumes processed, partially offset by the lower U.S./Canadian dollar exchange rate and the sale of the Bighorn assets. The Deep Panuke offshore natural gas facility commenced commercial operations in December 2013.
- Operating expense decreased $58 million primarily due to lower salaries and benefits related to workforce reductions as a result of the 2013 restructuring, the lower U.S./Canadian dollar exchange rate, the sale of the Bighorn assets, the sale of the Jean Marie natural gas assets in the second quarter of 2013 and lower long-term compensation costs due to the decrease in the Encana share price.

2013 versus 2012

Operating Cash Flow of $1,681 million decreased $163 million primarily due to the following significant items:

- Higher natural gas prices reflected higher benchmark prices, which increased revenues by $405 million. Lower liquids prices decreased revenues by $63 million.
- Average natural gas production volumes of 1,432 MMcf/d were higher by 73 MMcf/d, which increased revenues by $103 million. Average oil and NGL production volumes of 30.4 Mbbls/d were higher by 11.0 Mbbls/d. This increased revenues by $281 million. Changes in production volumes are discussed in the Production Volumes section of this MD&A.
- Realized financial hedging gains were $276 million compared to $958 million in 2012.
- Transportation and processing expense increased $201 million primarily due to costs related to higher production volumes processed through third party facilities in Bighorn and Montney, costs related to the Deep Panuke offshore natural gas facility and higher firm processing costs.

Other Expenses

($ millions, except as indicated)	**2014**	2013	2012
Depreciation, depletion & amortization	**$ 625**	$ 601	$ 748
Depletion rate ($/BOE)	**6.40**	6.06	8.44
Impairments	**-**	-	1,822

In 2014, DD&A increased from 2013 primarily due to a higher depletion rate of $6.40 per BOE in 2014 compared to $6.06 per BOE in 2013, partially offset by the lower U.S./Canadian dollar exchange rate. The depletion rate was impacted by the sale of the Bighorn assets, the sale of the Company's investment in PrairieSky, a decline in proved reserves due to Encana's change in development plans as the Company strategically transitions to a more balanced commodity portfolio and the lower U.S./Canadian dollar exchange rate.

In 2013, DD&A decreased from 2012 due to a lower depletion rate of $6.06 per BOE in 2013 compared to $8.44 per BOE in 2012, partially offset by higher production volumes in 2013. The lower depletion rate primarily resulted from ceiling test impairments recognized in 2012 and deductions from the full cost pool for amounts received from divestitures during 2012 and 2013.

In 2012, the Canadian Operations recognized non-cash ceiling test impairments before tax of $1,822 million. The impairments primarily resulted from the decline in the 12-month average trailing natural gas prices, which reduced the Canadian Operations proved reserves volumes and values as calculated under SEC requirements.

USA Operations

Operating Cash Flow

($ millions)	Natural Gas 2014	2013	2012	Oil & NGLs 2014	2013	2012	Total (1) 2014	2013	2012
Revenues, Net of Royalties, excluding Hedging	**$ 1,640**	$ 1,872	$ 1,798	**$ 1,258**	$ 602	$ 348	**$ 2,927**	$ 2,499	$ 2,170
Realized Financial Hedging Gain (Loss)	**(85)**	260	1,195	**60**	4	-	**(25)**	264	1,195
Revenues, Net of Royalties	**1,555**	2,132	2,993	**1,318**	606	348	**2,902**	2,763	3,365
Expenses									
Production and mineral taxes	**44**	77	68	**74**	42	28	**118**	119	96
Transportation and processing	**651**	722	652	**7**	-	-	**658**	722	652
Operating	**235**	339	347	**115**	59	25	**354**	411	377
Operating Cash Flow	**$ 625**	$ 994	$ 1,926	**$ 1,122**	$ 505	$ 295	**$ 1,772**	$ 1,511	$ 2,240

Production Volumes

	Natural Gas (MMcf/d) 2014	2013	2012	Oil & NGLs (Mbbls/d) 2014	2013	2012	Total (MBOE/d) 2014	2013	2012
Production Volumes – After Royalties	**972**	1,345	1,622	**49.6**	23.5	11.6	**211.6**	247.7	281.9

Operating Netback (2)

	Natural Gas ($/Mcf) 2014	2013	2012	Oil & NGLs ($/bbl) 2014	2013	2012	Total ($/BOE) 2014	2013	2012
Revenues, Net of Royalties, excluding Hedging	**$ 4.62**	$ 3.81	$ 3.03	**$ 69.54**	$ 70.18	$ 82.33	**$ 37.53**	$ 27.37	$ 20.79
Realized Financial Hedging Gain (Loss)	**(0.24)**	0.53	2.01	**3.29**	0.44	-	**(0.33)**	2.93	11.58
Revenues, Net of Royalties	**4.38**	4.34	5.04	**72.83**	70.62	82.33	**37.20**	30.30	32.37
Expenses									
Production and mineral taxes	**0.12**	0.16	0.11	**4.10**	4.79	6.63	**1.53**	1.31	0.93
Transportation and processing	**1.83**	1.47	1.10	**0.39**	-	0.06	**8.52**	7.98	6.32
Operating	**0.66**	0.69	0.59	**6.36**	7.02	5.88	**4.53**	4.42	3.61
Operating Netback	**$ 1.77**	$ 2.02	$ 3.24	**$ 61.98**	$ 58.81	$ 69.76	**$ 22.62**	$ 16.59	$ 21.51

(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.

2014 versus 2013

Operating Cash Flow of $1,772 million increased $261 million primarily due to the following significant items:

- Higher natural gas prices reflected higher benchmark prices, which increased revenues $287 million. Lower liquids prices decreased revenues $10 million.
- Average natural gas production volumes of 972 MMcf/d were lower by 373 MMcf/d, which decreased revenues $519 million. Average oil and NGL production volumes of 49.6 Mbbls/d were higher by 26.1 Mbbls/d, which increased revenues $666 million. Changes in production volumes are discussed in the Production Volumes section of this MD&A.
- Realized financial hedging losses were $25 million compared to gains of $264 million in 2013.
- Transportation and processing expense decreased $64 million primarily due to the sale of the Jonah and East Texas properties.

- Operating expense decreased $57 million primarily due to lower salaries and benefits related to workforce reductions as a result of the 2013 restructuring, the sale of the Jonah properties and lower long-term compensation costs due to the decrease in the Encana share price, partially offset by the acquisition of Eagle Ford and the Permian assets.

2013 versus 2012

Operating Cash Flow of $1,511 million decreased $729 million primarily due to the following significant items:

- Higher natural gas prices reflected higher benchmark prices, which increased revenues by $385 million. Lower liquids prices decreased revenues by $105 million.
- Average natural gas production volumes of 1,345 MMcf/d were lower by 277 MMcf/d. This decreased revenues by $311 million. Average oil and NGL production volumes of 23.5 Mbbls/d were higher by 11.9 Mbbls/d. This increased revenues by $359 million. Changes in production volumes are discussed in the Production Volumes section of this MD&A.
- Realized financial hedging gains were $264 million compared to $1,195 million in 2012.
- Transportation and processing expense increased $70 million primarily due to costs related to new and renegotiated gathering and processing agreements.
- Operating expense increased $34 million primarily due to an increased focus on emerging oil and liquids rich natural gas plays.

Other Expenses

($ millions, except as indicated)	**2014**	2013	2012
Depreciation, depletion & amortization	**$ 992**	$ 818	$ 1,102
Depletion rate ($/BOE)	**12.85**	9.05	10.67
Impairments	**-**	-	2,842

In 2014, DD&A increased from 2013 due to a higher depletion rate of $12.85 per BOE in 2014 compared to $9.05 per BOE in 2013, partially offset by lower production volumes. The higher depletion rate in 2014 resulted primarily from the acquisition of Eagle Ford and the Permian assets, the sale of the Jonah properties and a decline in proved reserves due to Encana's change in development plans as the Company strategically transitions to a more balanced commodity portfolio.

In 2013, DD&A decreased from 2012 due to a lower depletion rate of $9.05 per BOE in 2013 compared to $10.67 per BOE in 2012 and lower production volumes in 2013. The lower depletion rate primarily resulted from ceiling test impairments recognized during 2012.

In 2012, the USA Operations recognized non-cash ceiling test impairments before tax of $2,842 million. The impairments primarily resulted from the decline in the 12-month average trailing natural gas prices, which reduced the USA Operations proved reserves volumes and values as calculated under SEC requirements.

Market Optimization

($ millions)	2014	2013	2012
Revenues	**$ 1,248**	$ 512	$ 419
Expenses			
Operating	**39**	38	48
Purchased product	**1,191**	441	349
Depreciation, depletion and amortization	**4**	12	12
	$ 14	$ 21	$ 10

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 increased in 2014 compared to 2013 primarily due to generally higher commodity prices, and higher third party purchases and sales of product resulting from transitional services related to the Company's divestiture activity. Revenues and purchased product expense increased in 2013 compared to 2012 primarily due to higher commodity prices, partially offset by lower volumes required for optimization.

Corporate and Other

($ millions)	2014	2013	2012
Revenues	**$ 559**	$ (241)	$ (1,384)
Expenses			
Transportation and processing	**12**	(2)	24
Operating	**28**	38	17
Depreciation, depletion and amortization	**124**	134	94
Impairments	**-**	21	31
	$ 395	$ (432)	$ (1,550)

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. Impairments relates to certain corporate assets.

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 the Contractual Obligations and Contingencies section of this MD&A as well as Note 14 to the Consolidated Financial Statements.

Other Operating Results

Expenses

($ millions)		2014		2013		2012
Accretion of asset retirement obligation	$	52	$	53	$	53
Administrative		327		439		392
Interest		654		563		522
Foreign exchange (gain) loss, net		403		325		(107)
(Gain) loss on divestitures		(3,426)		(7)		-
Other		71		1		1
	$	(1,919)	$	1,374	$	861

Administrative expense in 2014 decreased from 2013 primarily due to lower restructuring costs, lower long-term compensation costs and the lower U.S./Canadian dollar exchange rate. The decrease also reflects the cost savings attributable to workforce reductions associated with the 2013 restructuring. Restructuring costs incurred in 2014 were approximately $36 million compared to $88 million in 2013. Administrative expense in 2013 increased from 2012 primarily due to restructuring charges resulting from workforce reductions to align the organizational structure in support of the strategy announced in November 2013, partially offset by higher legal costs in 2012.

Interest expense in 2014 increased from 2013 primarily due to a one-time outlay of approximately $125 million associated with the early redemption of senior notes assumed in conjunction with the acquisition of Athlon and higher interest related to the Deep Panuke Production Field Centre (“PFC”), partially offset by lower interest on debt resulting from the long-term debt repayment and redemption in the first six months of 2014. Interest expense in 2013 increased from 2012 primarily due to interest related to The Bow office building. Further information on the PFC capital lease and The Bow office building can be found in the Contractual Obligations and Contingencies section of this MD&A as well as Note 14 to the Consolidated Financial Statements.

Foreign exchange gains and losses result from the impact of the fluctuations in the Canadian to U.S. dollar exchange rate. Foreign exchange gains and losses primarily arise from the revaluation and settlement of U.S. dollar long-term debt issued from Canada and the revaluation and settlement of other monetary assets and liabilities.

The gain on divestitures in 2014 primarily includes the before tax impact of the sale 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.

Other in 2014 includes transaction costs associated with the acquisitions of Athlon and Eagle Ford as well as reclamation charges relating to non-producing assets.

Income Tax

($ millions)		2014		2013		2012
Current Income Tax (Recovery)	$	243	$	(191)	$	(200)
Deferred Income Tax (Recovery)		960		(57)		(1,837)
Income Tax Expense (Recovery)	$	1,203	$	(248)	$	(2,037)

Current income tax expense in 2014 was $243 million compared to a recovery of $191 million in 2013. The current income tax expense in 2014 was primarily due to current taxes incurred on divestitures. The current income tax recovery in 2013 was primarily due to amounts in respect of prior periods. The current income tax recovery of $200 million in 2012 was primarily due to the carry back of tax losses to prior years.

Total income tax expense in 2014 was higher due to higher net earnings before tax primarily resulting from gains on divestitures and unrealized hedging gains, and amounts in respect of prior periods recognized in 2013. Total income tax was a recovery of $248 million in 2013 and decreased $1,789 million compared to 2012 primarily due to higher net earnings before tax mainly resulting from the non-cash ceiling test impairments included in the 2012 results. The Net Earnings variances are further discussed in the Financial Results section of this MD&A.

Encana's annual effective tax rate is impacted by earnings, statutory rate and other foreign differences, the effect of legislative changes, non-taxable capital gains and losses, tax differences on divestitures and transactions, and partnership tax allocations in excess of funding.

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

Liquidity and Capital Resources

($ millions)		2014		2013		2012
Net Cash From (Used In)						
Operating activities	$	**2,667**	$	2,289	$	3,107
Investing activities		**(4,729)**		(1,895)		361
Financing activities		**(39)**		(909)		(1,111)
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency		**(127)**		(98)		22
Increase (Decrease) in Cash and Cash Equivalents	$	**(2,228)**	$	(613)	$	2,379
Cash and Cash Equivalents, End of Year	$	**338**	$	2,566	$	3,179

Operating Activities

Net cash from operating activities in 2014 of $2,667 million increased $378 million from 2013. Net cash from operating activities in 2013 of $2,289 million decreased $818 million from 2012. These changes are primarily a result of the Cash Flow variances discussed in the Financial Results section of this MD&A. In 2014, the net change in non-cash working capital was a deficit of $9 million compared to $179 million in 2013 and $323 million in 2012.

The Company had a working capital surplus of $455 million at December 31, 2014 compared to $1,338 million at December 31, 2013. The decrease in working capital is primarily due to a decrease in cash and cash equivalents, an increase in accounts payable and accrued liabilities, an increase in deferred income tax liabilities and a decrease in deferred income tax assets, partially offset by a decrease in the current portion of long-term debt, an increase in risk management assets and an increase in accounts receivable and accrued revenues. At December 31, 2014, working capital included cash and cash equivalents of $338 million compared to $2,566 million at December 31, 2013. Encana expects that it will continue to meet the payment terms of its suppliers.

Investing Activities

Net cash used in investing activities in 2014 was $4,729 million compared to $1,895 million in 2013. The increase was primarily due to the acquisitions of Athlon and Eagle Ford, partially offset by proceeds from the Bighorn, Jonah and East Texas divestitures and proceeds from the sale of the Company's investment in PrairieSky. Net cash used in investing activities in 2013 was $1,895 million compared to net cash from investing activities of $361 million in 2012. The net cash used in investing activities primarily resulted from lower divestiture proceeds, partially offset by lower capital expenditures. Investing activities in 2013 included proceeds from the sale of the Company's 30 percent interest in the proposed Kitimat liquefied natural gas export terminal which closed in February 2013. Further information on capital expenditures, acquisitions and divestitures can be found in the Net Capital Investment section of this MD&A.

Net cash used in investing activities in 2014 also included cash in reserve added to escrow of $63 million compared to $44 million and $415 million released from escrow in 2013 and 2012, respectively. Cash in reserve includes monies which are not available for general operating use, are segregated or held in escrow and include amounts received from counterparties related to jointly developed assets.

Financing Activities

Net cash used in financing activities in 2014 was $39 million compared to $909 million in 2013. The decrease primarily resulted from the sale of a noncontrolling interest in PrairieSky for proceeds of $1,462 million and the issuance of revolving long-term debt of $1,277 million, partially offset by the repayment of long-term debt totaling $2,487 million as discussed below. Net cash used in financing activities in 2013 was $909 million compared to $1,111 million in 2012. The decrease in cash used primarily resulted from lower cash dividend payments in 2013.

Long-Term Debt

Encana's long-term debt, excluding the current portion, totaled $7,340 million at December 31, 2014 and $6,124 million at December 31, 2013. The current portion of long-term debt outstanding was nil at December 31, 2014 compared to $1,000 million at December 31, 2013.

At December 31, 2014, Encana had an outstanding balance of $1,277 million under the Company's existing revolving credit facility. The outstanding balance reflects principal obligations related to LIBOR loans maturing at various dates with a weighted average interest rate of 1.62 percent. 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. There were no outstanding balances at December 31, 2013. Additional detail on Encana's credit facilities can be found below and in Note 13 to the Consolidated Financial Statements.

On January 29, 2015, Encana implemented a U.S. Commercial Paper program ("U.S. CP Program") with $2.0 billion of capacity, which reduces the Company's borrowing costs. As of February 23, 2015, Encana had repaid the outstanding balance of $1,277 million which was drawn on the Company's revolving credit facility using $1.1 billion of 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.

Redemption of Athlon Debt Assumed

On November 13, 2014, Encana completed the acquisition of all issued and outstanding shares of common stock of Athlon and assumed Athlon's $500 million 7.375 percent senior notes due April 15, 2021 and $650 million 6.00 percent senior notes due May 1, 2022. In conjunction with the acquisition, Encana repaid and terminated Athlon's credit facility with indebtedness outstanding of $335 million. Encana funded the acquisition with cash on hand.

On December 16, 2014, Encana completed the redemption of all of Athlon's senior notes. The Company recognized a one-time outlay of approximately $125 million as a result of the redemption, but expects to save approximately $515 million in future interest expense associated with these notes. Upon acquisition, the Company recorded an increase in the fair value of the debt acquired from Athlon of approximately $12 million, which was expensed upon redemption of the senior notes and is included in Other expenses in the Company's Consolidated Statement of Earnings. Encana used proceeds from the Company's revolving credit facility of $1,277 million to redeem the senior notes.

Redemption of 5.80 Percent Notes

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.

Credit Facilities and Shelf Prospectus

Encana maintains two revolving bank credit facilities which remain committed through June 2018. At December 31, 2014, Encana had available unused committed revolving bank credit facilities of $2.7 billion as follows:

- A committed revolving bank credit facility for C$3.5 billion ($3.0 billion) for Encana, of which $1.7 billion remained unused.
- A committed revolving bank credit facility for a U.S. subsidiary for $1.0 billion, all of which remained unused.

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. At December 31, 2014, the shelf prospectus remained accessible, the availability of which is dependent upon market conditions. The shelf prospectus expires in July 2016. This shelf prospectus replaced a $4.0 billion debt shelf prospectus which expired in June 2014.

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 December 31, 2014 and 36 percent at December 31, 2013.

Outstanding Share Data

(millions)	February 24, 2015	December 31, 2014
Common Shares Outstanding	**741.2**	**741.2**
Stock Options with TSARs attached:		
Outstanding	**19.3**	**21.3**
Exercisable	**11.4**	**10.0**

Eligible employees have been granted stock options to purchase common shares in accordance with Encana's Employee Stock Option Plan. 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. The exercise of a TSAR for a cash payment does not result in the issuance of any Encana common shares and, therefore, has no dilutive effect. Historically, most holders of these options have elected to exercise their stock options as a TSAR in exchange for a cash payment.

Restricted Share Units ("RSUs") have been granted to eligible employees 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 value of one RSU is notionally equivalent to one Encana common share. As at December 31, 2014, there were approximately 9.0 million outstanding RSUs which vest three years from the date granted. The Company intends to settle vested RSUs in cash on the vesting date. A settlement in cash does not result in the issuance of any Encana common shares and, therefore, has no dilutive effect.

During 2014, Encana issued 240,839 common shares under the Company's dividend reinvestment plan ("DRIP") compared with 5.4 million common shares in 2013. The number of common shares issued under the DRIP decreased in 2014 as a result of Encana's February 2014 announcement that any future dividends in conjunction with the DRIP will be issued from its treasury without a discount to the average market price unless otherwise announced by the Company via news release. Prior to the February 2014 announcement, dividends issued under the DRIP were subject to a two percent discount.

Dividends

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

($ millions, except as indicated)	**2014**	2013
Dividend Payments	**$ 207**	$ 494
Dividend Payments ($/share)	**$ 0.28**	$ 0.67

The dividends paid in 2014 included $5 million in common shares issued in lieu of cash dividends under the Company's DRIP as disclosed above compared to $93 million for 2013.

On February 25, 2015, the Board declared a dividend of $0.07 per share payable on March 31, 2015 to common shareholders of record as of March 13, 2015.

On February 25, 2015, Encana announced that its Board has determined that effective with the dividend payable on March 31, 2015, all common shares distributed to participating shareholders pursuant to the Company's DRIP will be issued from Encana's treasury at a two percent discount to the average market price of the common shares. Any future dividends of common shares distributed to DRIP participants will be issued with the discount unless otherwise announced by Encana by way of news release.

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.

	2014	2013	2012
Debt to Debt Adjusted Cash Flow	**2.1x**	2.4x	2.0x
Debt to Adjusted Capitalization	**30%**	36%	37%

Contractual Obligations and Contingencies

Contractual Obligations

The following table outlines the Company's commitments at December 31, 2014:

	Expected Future Payments						
($ millions, undiscounted)	2015	2016	2017	2018	2019	Thereafter	Total
Long-Term Debt (1)	$ -	$ -	$ 700	$ 1,924	$ 500	$ 4,200	$ 7,324
Asset Retirement Obligation	44	44	180	23	23	3,313	3,627
Other Long-Term Obligations	80	81	82	82	83	1,652	2,060
Capital Leases	98	98	99	99	99	232	725
Obligations (2)	222	223	1,061	2,128	705	9,397	13,736
Transportation and Processing	878	825	815	800	673	3,204	7,195
Drilling and Field Services	312	138	93	47	16	17	623
Operating Leases	43	36	28	26	10	24	167
Commitments	1,233	999	936	873	699	3,245	7,985
Total Contractual Obligations	$ 1,455	$ 1,222	$ 1,997	$ 3,001	$ 1,404	$ 12,642	$ 21,721
Sublease Recoveries	$ (39)	$ (40)	$ (40)	$ (40)	$ (41)	$ (812)	$ (1,012)

(1) Principal component only. See Note 13 to the Consolidated Financial Statements.

(2) The Company has recorded $10,255 million in liabilities related to these obligations.

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 Consolidated Financial Statements.

Other Long-Term Obligations relates to the 25-year lease agreement with a third party developer for The Bow office building. Encana has recognized the accumulated construction costs for The Bow office building as an asset with a related liability. In 2012, Encana commenced payments to the third party developer. At the conclusion of the 25-year term, the remaining asset and corresponding liability are expected to be derecognized. Encana has subleased part of The Bow office space to a subsidiary of Cenovus Energy Inc. ("Cenovus"). Sublease Recoveries in the table above include the amounts expected to be recovered from Cenovus. Encana's undiscounted payments for The Bow are $2,060 million, of which $1,012 million is expected to be recovered from Cenovus.

Capital Leases primarily includes the obligation related to the Deep Panuke PFC, which commenced commercial operations in December 2013 following issuance of the Production Acceptance Notice. Encana's undiscounted future lease payments for the Deep Panuke PFC total $625 million ($462 million discounted).

In addition to the Commitments disclosed above, Encana 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. Encana also has obligations related to its risk management program and to fund its defined benefit pension and other post-employment benefit plans. Further information can be found in Note 23 to the Consolidated Financial Statements regarding the Company's risk management program. 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.

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Risk Management

Encana's business, prospects, financial condition, results of operation 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, which allows the Company to respond well 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 issues.

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 to achieve investment returns and growth objectives, while maintaining prescribed financial metrics.

To partially mitigate commodity price risk, the Company may enter into transactions that fix, set a floor or set a floor and cap on prices. 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 December 31, 2014, is disclosed in Note 23 to the 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. This credit exposure is mitigated 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 and 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.

As a means of mitigating the exposure to fluctuations in the U.S./Canadian dollar exchange rate, Encana may enter into foreign exchange contracts. Realized gains or losses on these contracts are recognized on settlement. By maintaining U.S. and Canadian operations, Encana has a natural hedge to some foreign exchange exposure.

Encana also maintains a mix of both U.S. dollar and Canadian dollar debt. This helps to offset the exposure to the fluctuations in the U.S./Canadian dollar exchange rate. In addition to direct issuance of U.S. dollar denominated debt, the Company may enter into cross currency swaps on a portion of its debt as a means of managing the U.S./Canadian dollar debt mix.

The Company may partially mitigate its exposure to interest rate changes by holding a mix of both fixed and floating rate debt. Encana may enter into interest rate swap transactions from time to time as an additional means of managing the fixed/floating rate debt portfolio mix.

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 prices mentioned above, continued market demand for its products and other risk 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; volatility in natural gas and liquids prices; 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; 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.

In addition, Encana undertakes a thorough review of previous capital programs to identify key learnings, which often include operational issues that positively and negatively impact project results. Mitigation plans are developed for the operational issues that had a negative impact on results. These mitigation plans are then incorporated into the current year plan for the project. On an annual basis, these results are analyzed for Encana's capital program with the results and identified learnings shared across the Company.

A peer review process is used to ensure that capital projects are appropriately risked and that knowledge is shared across the Company. Peer reviews are undertaken primarily for exploration projects and early stage plays, although they may occur for any type of project.

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.

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.

One of the processes Encana monitors relates to hydraulic fracturing. Hydraulic fracturing is used throughout the oil and gas industry where fracturing fluids are utilized to develop the reservoir. This process has been used in the oil and gas industry for approximately 60 years. Encana uses multiple techniques to fully understand the effect of each hydraulic fracturing operation it conducts. In all Encana operations, rigorous water management and protection is an essential part of this process.

Hydraulic fracturing processes are strictly regulated by various state and provincial government agencies. Encana meets or exceeds the requirements set out by the regulators. The U.S. and Canadian federal governments and certain U.S. state and Canadian provincial governments are currently reviewing certain aspects of the scientific, regulatory and policy framework under which hydraulic fracturing operations are conducted. At present, most of these governments are primarily engaged in the collection, review and assessment of technical information regarding the hydraulic fracturing process and have not provided specific details with respect to any significant actual, proposed or contemplated changes to hydraulic fracturing regulations.

In the state of Colorado, several cities have passed local ordinances limiting or banning certain oil and gas activities, including hydraulic fracturing. These local rule-making initiatives have not significantly impacted the Company's operations or development plans in the state to date. The ballot initiatives previously filed in the state seeking to transfer the authority to regulate all oil and gas activities, including hydraulic fracturing, to local governments were withdrawn in August 2014. 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.

Encana is committed to and supports the disclosure of hydraulic fracturing chemical information. Encana participates in the FracFocus Chemical Disclosure Registry (the "Registry") in the U.S. and the Alberta and British Columbia versions of the Registry. Encana works collaboratively with industry peers, trade associations, fluid suppliers and regulators to identify, develop and advance responsible hydraulic fracturing best practices. More information on hydraulic fracturing can be accessed on the Company's website at www.encana.com.

Air quality regulations in the state of Colorado were amended in February 2014 to address ozone non-attainment in the state. The amended regulations establish new leak detection and repair requirements and hydrocarbon emissions standards for the oil and gas industry in the state. Encana has reviewed the new requirements and does not anticipate they will have a material impact on its Colorado operations.

Climate Change Regulations

A number of federal, provincial and state governments have announced intentions to regulate greenhouse gases ("GHG") and certain other air emissions. While some jurisdictions have provided details on these regulations, it is anticipated that other jurisdictions will announce emission reduction plans in the future. As these federal and regional programs are under development, Encana is unable to predict the total impact of the potential regulations upon its business. Therefore, it is possible that the Company could face increases in operating and capital costs in order to comply with GHG emissions legislation. However, Encana will continue to work with governments to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

The Alberta Government has set targets for GHG emission reductions. In March 2007, regulations were amended to require facilities that emit more than 100,000 tonnes of GHG emissions per year to reduce their emissions intensity by 12 percent from a regulated baseline starting July 1, 2007. To comply, companies can make operating improvements, purchase carbon offsets or make a C$15 per tonne contribution to an Alberta Climate Change and Emissions Management Fund. At present, Encana does not own or operate any facilities subject to the emissions regulation. The Company's forecast cost of carbon associated with the Alberta regulations is not material to Encana and is being actively managed.

In British Columbia, effective July 1, 2008, a 'revenue neutral carbon tax' was applied to virtually all fossil fuels, including diesel, natural gas, coal, propane and home heating fuel. The tax applies to combustion emissions and to the purchase or use of fossil fuels within the province. The rate started at C$10 per tonne of carbon equivalent emissions and has risen to C$30 per tonne at present. The Company's forecast cost of carbon associated with the British Columbia regulations is not material to Encana and is being actively managed.

The Canadian federal government has announced that it will align GHG emission reduction targets with the U.S. The Canadian federal government has taken a sector-specific approach and, while progress has been made working with industry and the provinces on the development of oil and gas sector-specific regulations, the federal government has not committed to a definitive timeline for implementation and/or release of legislation. Encana will continue to monitor these developments during 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 which have not yet been announced. The EPA plans to propose this new rule and guidance in late summer 2015 with a final rule and guidance expected in 2016.

Encana intends to continue its activity to reduce its emissions intensity and improve its energy efficiency. The Company's efforts with respect to emissions management are founded with a focus on energy efficiency, the development of technology to reduce GHG emissions and active involvement in the creation of industry best practices.

Encana has a proactive strategy for addressing the implications of emerging carbon regulations which is composed of three principal elements:

- *Active Cost Management*. When regulations are implemented, a cost is placed on Encana's emissions (or a portion thereof) and, while these are not material at this stage, they are being actively managed to ensure compliance. Factors such as effective emissions tracking and attention to fuel consumption help to support and drive the Company's focus on cost reduction.

- *Anticipate and Respond to Price Signals.* As regulatory regimes for GHG develop in the jurisdictions where Encana operates, inevitably price signals begin to emerge. The price of potential carbon reductions plays a role in the economics of the projects that are implemented. In response to the anticipated price of carbon, Encana is also attempting, where appropriate, to realize the associated value of its reduction projects.
- *Work with Industry Groups.* Encana continues to work with governments, academics and industry leaders to develop and respond to emerging GHG regulations. By continuing to stay engaged in the debate on the most appropriate means to regulate these emissions, the Company gains useful knowledge that allows it to explore different strategies for managing its emissions and costs. These scenarios influence Encana's long-range planning and its analyses on the implications of regulatory trends.

Encana monitors developments in emerging climate change policy and legislation, and considers the associated costs of carbon in its planning. Management and the Board review the impact of a variety of carbon constrained scenarios on its business plans, with a current price range from approximately $20 to $125 per tonne of emissions applied to a range of emissions coverage levels. Although uncertainty remains regarding potential future emissions regulation, Encana's plan is to continue to assess and evaluate the cost of carbon relative to its investments across a range of scenarios.

Encana recognizes that there is a cost associated with carbon emissions. Encana is confident that GHG regulations and the cost of carbon at various price levels have been adequately considered as part of its business planning and scenarios analyses. Encana believes that the resource play strategy is an effective way to develop the resource, generate shareholder returns and coordinate overall environmental objectives with respect to carbon, air emissions, water and land. Encana is committed to transparency with its stakeholders and will keep them apprised of how these issues affect operations. Additional detail on Encana's GHG emissions is available in the Sustainability Report that is available on the Company's website at www.encana.com.

Controls and Procedures

Disclosure Controls and Procedures

The Company's President and Chief Executive Officer ("CEO") and Executive Vice-President, Finance and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that:

- Material information relating to the Company is made known to the CEO and CFO by others; and
- Information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's disclosure controls and procedures at the financial year end of the Company. Based on their evaluation, the officers have concluded that Encana's disclosure controls and procedures were effective as at December 31, 2014.

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 CEO and CFO, 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.

Under their supervision and with the participation of Management, including the CEO and CFO, an evaluation of the effectiveness of the Company's internal control over financial reporting was conducted at December 31, 2014, based on the Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, Management has concluded that the Company's internal control over financial reporting was effectively designed and operating effectively as at that date.

Except for changes relating to the continuing integration of Athlon, as discussed below, there have been no changes in the Company's internal control over financial reporting during the year ended December 31, 2014 that have materially affected, or are reasonably likely to materially affect, the effectiveness of the internal control over financial reporting.

In accordance with Section 3.3(1) of National Instrument 52-109 and Rules 13a-15(f) and 15d-15(f) under the United States Securities and Exchange Act of 1934, as amended, Management has limited the scope and design and subsequent evaluation of internal controls over financial reporting to exclude the controls, policies and procedures of Athlon, acquired through a business combination on November 13, 2014. Summary financial information related to Athlon's operations included in Encana's Consolidated Financial Statements for the year ended December 31, 2014 is as follows:

($ millions)	
Revenues	**$ 176**
Net Earnings (Loss)	**(3)**
Current Assets	**198**
Non-Current Assets	**3,096**
Current Liabilities	**190**
Non-Current Liabilities	**148**

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.

PricewaterhouseCoopers LLP, an independent firm of chartered accountants, was appointed by a vote of shareholders at the Company's last annual meeting to audit and provide independent opinions on both the Consolidated Financial Statements and the Company's internal control over financial reporting as at December 31, 2014, as stated in their Auditor's Report which is included in our audited Consolidated Financial Statements for the year ended December 31, 2014.

Accounting Policies and Estimates

Critical Accounting Estimates

Management is required to make judgments, assumptions and estimates in applying its accounting policies and practices, which have a significant impact on the financial results of the Company. A summary of Encana's significant accounting policies can be found in Note 1 to the Consolidated Financial Statements for the year ended December 31, 2014. The following discussion outlines the accounting policies and practices involving the use of estimates that are critical to determining Encana's financial results.

Upstream Assets and Reserves

Encana follows U.S. GAAP full cost accounting for natural gas, oil and NGL activities. Reserves estimates can have a significant impact on net earnings, as they are a key input to the Company's depletion, gain or loss and ceiling test impairment calculations. A downward revision in reserves estimates may increase depletion expense and may also result in a ceiling test impairment. A ceiling test impairment is recognized in net earnings when the carrying amount of a country cost centre exceeds the country cost centre ceiling. The carrying amount of a cost centre includes capitalized costs of proved oil and gas properties, net of accumulated depletion and the related deferred income taxes. The cost centre ceiling is the sum of the estimated after-tax future net cash flows from proved reserves as calculated under SEC requirements, using the 12-month average trailing prices and unescalated future development and production costs, discounted at 10 percent, plus unproved property costs. The 12-month average trailing price is calculated as the average of the price on the first day of each month within the trailing 12-month period. Any excess of the carrying amount over the calculated ceiling is recognized as an impairment in net earnings. During 2012, Encana recorded ceiling test impairments, which are discussed further in the Results of Operations section of this MD&A.

Annually, all of Encana's natural gas, oil and NGL reserves and resources are evaluated and reported on by IQREs. The estimation of reserves is a subjective process. Estimates are based on engineering data, projected future rates of production, and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. Reserves estimates can be revised upward or downward based on the results of future drilling, testing, production levels and economics of recovery.

The Company believes that the discounted after-tax future net cash flows from proved reserves required to be used in the ceiling test calculation are not indicative of the fair market value of Encana's oil and gas properties or of the future net cash flows expected to be generated from such properties. The discounted after-tax future net cash flows do not consider the value of unproved properties, the value of probable or possible reserves or future changes in commodity prices. Encana manages its business using estimates of reserves and resources based on forecast prices and costs.

Business Combinations

Encana follows the acquisition method of accounting for business combinations. Assets acquired and liabilities assumed are recognized at the date of acquisition at their respective estimated fair values. Any excess of the purchase price over the estimated fair values of the net assets acquired is recorded as goodwill. Any deficiency of the purchase price over the estimated fair values of the net assets acquired is recorded as a gain in net earnings. In determining fair value, Encana utilized valuation methodologies including the income approach.

The assumptions made in performing these valuations include discount rates, future commodity prices and costs, the timing of development activities, projections of oil and gas reserves, estimates to abandon and reclaim producing wells and tax amortization benefits available to a market participant. Any significant change in key assumptions may cause the acquisition accounting to be revised, including the recognition of additional goodwill or discount on acquisition.

The valuation of fair values are determined based on information that existed at the time of the acquisition, utilizing expectations and assumptions that would be available to and made by a market participant. However, there is no assurance the underlying assumptions or estimates associated with the valuation will occur as initially expected. Changes in key assumptions and estimates can impact net earnings through ceiling test impairments, impairments of goodwill, or lower future operating results.

Goodwill

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

The fair value used in the impairment test is based on estimates of discounted future cash flows which involves assumptions of natural gas and liquids reserves, including commodity prices, future costs and discount rates. Encana has assessed its goodwill for impairment at December 31, 2014 and has determined that no write-down is required.

Asset Retirement Obligation

Asset retirement obligations are those legal obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, offshore production platforms and natural gas processing plants. The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when incurred and a reasonable estimate of fair value can be made. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Changes in the estimated obligation resulting from revisions to estimated timing or amount of future cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost.

The asset retirement obligation is estimated by discounting the expected future cash flows of the settlement. The discounted cash flows are based on estimates of such factors as reserves lives, retirement costs, timing of settlements, credit-adjusted risk-free rates and inflation rates. These estimates will impact net earnings through accretion of the asset retirement obligation in addition to depletion of the asset retirement cost included in property, plant and equipment. Actual expenditures incurred are charged against the accumulated asset retirement obligation.

Income Taxes

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

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

Encana’s interim income tax expense is determined using an estimated annual effective income tax rate applied to year-to-date net earnings before income tax plus the effect of legislative changes and amounts in respect of prior periods. The estimated annual effective income tax rate is impacted by 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.

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

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty and the interpretations can impact net earnings through the income tax expense arising from the changes in deferred income tax assets or liabilities.

Derivative Financial Instruments

As described in the Risk Management section of this MD&A, derivative financial instruments are used by Encana to manage its exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. The Company’s policy is not to utilize derivative financial instruments for speculative purposes.

Derivative financial instruments are measured at fair value with changes in fair value recognized in net earnings. The fair values recorded in the Consolidated Balance Sheet reflect netting the asset and liability positions where counterparty master netting arrangements contain provisions for net settlement. Realized gains or losses from financial derivatives related to natural gas and oil commodity prices are recognized in revenues as the contracts are settled. Realized gains or losses from financial derivatives related to power commodity prices are recognized in transportation and processing expense as the related power contracts are settled. Unrealized gains and losses are recognized in revenues and transportation and processing expense accordingly, at the end of each respective reporting period based on the changes in fair value of the contracts.

The estimate of fair value of all derivative instruments is based on quoted market prices or, in their absence, third party market indications and forecasts. The estimated fair value of financial assets and liabilities is subject to measurement uncertainty.

Recent Accounting Pronouncements

Changes in Accounting Policies and Practices

As of January 1, 2014, Encana adopted the following Accounting Standards Updates ("ASU") issued by the Financial Accounting Standards Board ("FASB"), which have not had a material impact on the Company's Consolidated Financial Statements:

- ASU 2013-04, *Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date*, clarifies guidance for the recognition, measurement and disclosure of liabilities resulting from joint and several liability arrangements. The amendments have been applied retrospectively.

- ASU 2013-05, *Parent's Accounting for the Cumulative Translation Adjustment upon Derecognition of Certain Subsidiaries or Groups of Assets within a Foreign Entity or of an Investment in a Foreign Entity*, clarifies the applicable guidance for certain transactions that result in the release of the cumulative translation adjustment into net earnings. The amendments have been applied prospectively.

- ASU 2013-11, *Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists*, clarifies that a liability related to an unrecognized tax benefit or portions thereof should be presented as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss or a tax credit carryforward, except under specific situations. The amendments have been applied prospectively.

New Standards Issued Not Yet Adopted

As of January 1, 2015, Encana will be required to adopt ASU 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*, which 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 will be applied prospectively and are not expected to have a material impact on the Company's Consolidated Financial Statements.

As of January 1, 2016, Encana will be required to adopt 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 standard requires 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.

As of January 1, 2017, 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. The standard can be applied using either the full retrospective approach or a modified retrospective approach 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; 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.

	2014					2013					2012
($ millions)	**Annual**	**Q4**	**Q3**	**Q2**	**Q1**	Annual	Q4	Q3	Q2	Q1	Annual
Cash From (Used in) Operating Activities	**$ 2,667**	**$ 261**	**$ 696**	**$ 767**	**$ 943**	$ 2,289	$ 462	$ 935	$ 554	$ 338	$ 3,107
(Add back) deduct:											
Net change in other assets and liabilities	**(43)**	**(15)**	**(11)**	**(8)**	**(9)**	(80)	(21)	(15)	(22)	(22)	(78)
Net change in non-cash working capital	**(9)**	**(141)**	**155**	**119**	**(142)**	(179)	(183)	300	(81)	(215)	(323)
Cash tax on sale of assets	**(215)**	**40**	**(255)**	**-**	**-**	(33)	(11)	(10)	(8)	(4)	(29)
Cash Flow	**$ 2,934**	**$ 377**	**$ 807**	**$ 656**	**$ 1,094**	$ 2,581	$ 677	$ 660	$ 665	$ 579	$ 3,537
Deduct:											
Capital investment	**2,526**	**857**	**598**	**560**	**511**	2,712	717	641	639	715	3,476
Free Cash Flow	**$ 408**	**$ (480)**	**$ 209**	**$ 96**	**$ 583**	$ (131)	$ (40)	$ 19	$ 26	$ (136)	$ 61

Operating Earnings

Operating Earnings is a non-GAAP measure that adjusts Net Earnings 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 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 is defined as Net Earnings 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.

	2014					2013					2012
($ millions)	**Annual**	**Q4**	**Q3**	**Q2**	**Q1**	Annual	Q4	Q3	Q2	Q1	Annual
Net Earnings (Loss) Attributable to Common Shareholders	**$ 3,392**	**$ 198**	**$2,807**	**$ 271**	**$ 116**	$ 236	$ (251)	$ 188	$ 730	$ (431)	$(2,794)
After-tax (addition) / deduction:											
Unrealized hedging gain (loss)	**306**	**341**	**160**	**8**	**(203)**	(232)	(209)	(89)	332	(266)	(1,002)
Impairments	**-**	**-**	**-**	**-**	**-**	(16)	-	(16)	-	-	(3,188)
Restructuring charges	**(24)**	**(4)**	**(5)**	**(5)**	**(10)**	(64)	(64)	-	-	-	-
Non-operating foreign exchange gain (loss)	**(407)**	**(151)**	**(218)**	**156**	**(194)**	(282)	(124)	105	(162)	(101)	92
Gain (loss) on divestitures	**2,523**	**(11)**	**2,399**	**135**	**-**	-	-	-	-	-	-
Income tax adjustments	**(8)**	**(12)**	**190**	**(194)**	**8**	28	(80)	38	313	(243)	307
Operating Earnings	**$ 1,002**	**$ 35**	**$ 281**	**$ 171**	**$ 515**	$ 802	$ 226	$ 150	$ 247	$ 179	$ 997

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.

	2014					2013					2012
($ millions)	**Annual**	**Q4**	**Q3**	**Q2**	**Q1**	Annual	Q4	Q3	Q2	Q1	Annual
Upstream Operating Cash Flow											
Canadian Operations	**$ 2,146**	**$ 341**	**$ 477**	**$ 447**	**$ 881**	$ 1,681	$ 526	$ 406	$ 383	$ 366	$ 1,844
USA Operations	**1,772**	**480**	**505**	**353**	**434**	1,511	375	388	405	343	2,240
	$ 3,918	**$ 821**	**$ 982**	**$ 800**	**$ 1,315**	$ 3,192	$ 901	$ 794	$ 788	$ 709	$ 4,084
(Add back) deduct: Realized Hedging Gain (Loss)											
Canadian Operations	**$ (56)**	**$ 49**	**$ 19**	**$ (49)**	**$ (75)**	$ 276	$ 90	$ 95	$ 21	$ 70	$ 958
USA Operations	**(25)**	**78**	**11**	**(49)**	**(65)**	264	83	77	30	74	1,195
	$ (81)	**$ 127**	**$ 30**	**$ (98)**	**$ (140)**	$ 540	$ 173	$ 172	$ 51	$ 144	$ 2,153
Upstream Operating Cash Flow, excluding Hedging											
Canadian Operations	**$ 2,202**	**$ 292**	**$ 458**	**$ 496**	**$ 956**	$ 1,405	$ 436	$ 311	$ 362	$ 296	$ 886
USA Operations	**1,797**	**402**	**494**	**402**	**499**	1,247	292	311	375	269	1,045
	$ 3,999	**$ 694**	**$ 952**	**$ 898**	**$ 1,455**	$ 2,652	$ 728	$ 622	$ 737	$ 565	$ 1,931

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 expenses and operating expenses. 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.

Previously, Management monitored Net Debt to Debt Adjusted Cash Flow. Net Debt was defined as long-term debt, including current portion, less cash and cash equivalents.

($ millions)		**2014**		2013		2012
Debt	**$**	**7,340**	$	7,124	$	7,675
Cash Flow		**2,934**		2,581		3,537
Interest Expense, after tax		**486**		421		391
Debt Adjusted Cash Flow	**$**	**3,420**	$	3,002	$	3,928
Debt to Debt Adjusted Cash Flow		**2.1x**		2.4x		2.0x

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)		**2014**		2013		2012
Debt	**$**	**7,340**	$	7,124	$	7,675
Total Shareholders' Equity		**9,685**		5,147		5,295
Equity Adjustment for Impairments at December 31, 2011		**7,746**		7,746		7,746
Adjusted Capitalization	**$**	**24,771**	$	20,017	$	20,716
Debt to Adjusted Capitalization		**30%**		36%		37%

Advisory

Forward-Looking Statements

In the interest of providing Encana shareholders and potential investors with information regarding the Company and its subsidiaries, including Management's assessment of Encana's and its subsidiaries' future plans and operations, certain statements contained in this document constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of the "safe harbour" provisions of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "believe", "expect", "plan", "intend", "forecast", "target", "project", "objective", "strategy", "strives", "agreed to" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this document include, but are not limited to, statements with respect to:

- achieving the Company's focus on developing its strong portfolio of resource plays producing natural gas, oil and NGLs
- commitment to growing long-term shareholder value through a disciplined focus on generating profitable growth
- pursuing its key business objectives of balancing its commodity mix, focusing capital investments in high return, scalable projects, maintaining portfolio flexibility, maximizing profitability through operating efficiencies, reducing costs and preserving balance sheet strength
- the expected timing and closing date of the transaction with Veresen Midstream Limited Partnership and the expectation that regulatory approvals will be obtained and closing conditions satisfied
- anticipated revenues and operating expenses
- improving operating efficiencies, fostering technological innovation, lowering cost structures and the success of the resource play hub model
- the anticipated proceeds from various joint venture, partnership and other agreements entered into by the Company, including their successful implementation, expected future benefits and the Company's ability to fund future development costs associated with those agreements
- statements with respect to future ceiling test impairments
- anticipated dividends
- anticipated oil, natural gas and NGLs prices
- anticipated production from Eagle Ford
- projections contained in the 2015 Corporate Guidance (including estimates of cash flow including per share amounts, natural gas, oil and NGLs production, capital investment and its allocation, operating costs, sensitivities on price and their impact on cash flow and operating earnings, assumptions regarding oil, natural gas and NGLs prices and foreign exchange rates)
- estimates of reserves and resources
- projections relating to the adequacy of the Company's provision for taxes and legal claims
- the flexibility of capital spending plans and the source of funding therefor
- anticipated access to capital markets and ability to meet financial obligations and finance growth
- the benefits of the Company's risk management program, including the impact of derivative financial instruments
- projections that the Company has access to cash and cash equivalents and a range of funding at competitive rates
- the Company's ability to meet payment terms of its suppliers and be in compliance with all financial covenants under its credit facility agreements
- the Company's intention to settle vested RSUs in cash on the vesting date
- anticipated debt repayments and the ability to make such repayments
- expected future interest expense savings associated with Athlon's senior notes
- expectations surrounding environmental legislation including regulations relating to carbon, air quality, water, land and hydraulic fracturing and the impact such regulations could have on the Company
- anticipated flexibility to refinance maturing long-term debt or repay debt maturities from existing sources of liquidity
- anticipated cash and cash equivalents
- expectation to fund 2015 commitments from cash flow, cash and cash equivalents
- the anticipated effect of the Company's risk mitigation policies, systems, processes and insurance program
- the Company's ability to manage its Debt to Debt Adjusted Cash Flow and Debt to Adjusted Capitalization ratios
- the expected impact and timing of various accounting pronouncements, rule changes and standards on the Company and its financial statements

Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the Company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These assumptions, risks and uncertainties include, among other things:

- volatility of, and assumptions regarding natural gas and liquids prices, including substantial or extended decline of the same and their adverse effect on the Company's operations and financial condition and the value and amount of its reserves
- assumptions based upon the Company's current guidance
- risks and uncertainties associated with announced but not completed transactions including the risk that the transactions may not be completed on a timely basis or at all
- fluctuations in currency and interest rates
- risk that the Company may not conclude divestitures of certain assets or other transactions or receive amounts contemplated under the transaction agreements (such transactions may include third party capital investments, farm-outs or partnerships, which Encana may refer to from time to time as "partnerships" or "joint ventures" and the funds received in respect thereof which Encana may refer to from time to time as "proceeds", "deferred purchase price" and/or "carry capital", regardless of the legal form) as a result of various conditions not being met
- product supply and demand
- market competition
- risks inherent in the Company's and its subsidiaries' marketing operations, including credit risks
- imprecision of reserves estimates and estimates of recoverable quantities of natural gas and liquids from plays and other sources not currently classified as proved, probable or possible reserves or economic contingent resources, including future net revenue estimates
- marketing margins
- potential disruption or unexpected technical difficulties in developing new facilities
- unexpected cost increases or technical difficulties in constructing or modifying processing facilities
- risks associated with technology
- the Company's ability to acquire or find additional reserves
- hedging activities resulting in realized and unrealized losses
- business interruption and casualty losses
- risk of the Company not operating all of its properties and assets
- counterparty risk
- downgrade in credit rating and its adverse effects
- liability for indemnification obligations to third parties
- variability of dividends to be paid
- the Company's ability to generate sufficient cash flow from operations to meet its current and future obligations
- the Company's ability to access external sources of debt and equity capital
- the timing and the costs of well and pipeline construction
- the Company's ability to secure adequate product transportation
- changes in royalty, tax, environmental, greenhouse gas, carbon, accounting and other laws or regulations or the interpretations of such laws or regulations
- political and economic conditions in the countries in which the Company operates; terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the Company
- risk arising from price basis differential
- risk arising from inability to enter into attractive hedges to protect the Company's capital program
- other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by Encana

Although Encana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this document are made as of the date hereof and, except as required by law, Encana undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this document are expressly qualified by this cautionary statement.

Forward-looking information respecting anticipated 2015 cash flow for Encana is based upon, among other things, achieving average production for 2015 of between 1,600 MMcf/d and 1,700 MMcf/d of natural gas and 130 Mbbls/d to 150 Mbbls/d of liquids, commodity prices for natural gas and liquids based on NYMEX $3.00 per MMBtu and WTI of $50 per bbl, an estimated U.S./Canadian dollar exchange rate of 0.80 and a weighted average number of outstanding shares for Encana of approximately 741 million.

Assumptions relating to forward-looking statements generally include Encana's current expectations and projections made in light of, and generally consistent with, its historical experience and its perception of historical trends, including the conversion of resources into reserves and production as well as expectations regarding rates of advancement and innovation, generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in this document.

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 February 25, 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

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 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 are anticipated to come 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

In this document, certain natural gas volumes have been converted to BOE on the basis of six Mcf to one bbl. Barrels of oil equivalent may be misleading, particularly if used in isolation. A conversion ratio of 6:1 is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead.

Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

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.

Condensed Consolidated Statement of Earnings *(unaudited)*

($ millions, except per share amounts)		Three Months Ended December 31, 2014	2013	Twelve Months Ended December 31, 2014	2013
Revenues, Net of Royalties	*(Note 3)*	**$ 2,254**	$ 1,423	**$ 8,019**	$ 5,858
Expenses	*(Note 3)*				
Production and mineral taxes		**36**	37	**133**	134
Transportation and processing		**356**	405	**1,505**	1,476
Operating		**178**	221	**735**	859
Purchased product		**347**	138	**1,191**	441
Depreciation, depletion and amortization		**451**	388	**1,745**	1,565
Impairments		**-**	-	**-**	21
Accretion of asset retirement obligation	*(Note 12)*	**13**	13	**52**	53
Administrative	*(Note 16)*	**58**	167	**327**	439
Interest	*(Note 6)*	**252**	139	**654**	563
Foreign exchange (gain) loss, net	*(Note 7)*	**149**	160	**403**	325
(Gain) loss on divestitures	*(Notes 5, 15)*	**16**	(3)	**(3,426)**	(7)
Other	*(Note 4)*	**63**	7	**71**	1
		1,919	1,672	**3,390**	5,870
Net Earnings (Loss) Before Income Tax		**335**	(249)	**4,629**	(12)
Income tax expense (recovery)	*(Note 8)*	**137**	2	**1,203**	(248)
Net Earnings (Loss)		**198**	(251)	**3,426**	236
Net earnings attributable to noncontrolling interest	*(Note 15)*	**-**	-	**(34)**	-
Net Earnings (Loss) Attributable to Common Shareholders		**$ 198**	$ (251)	**$ 3,392**	$ 236
Net Earnings (Loss) per Common Share					
Basic & Diluted	*(Note 13)*	**$ 0.27**	$ (0.34)	**$ 4.58**	$ 0.32

Condensed Consolidated Statement of Comprehensive Income *(unaudited)*

($ millions)		Three Months Ended December 31, 2014	2013	Twelve Months Ended December 31, 2014	2013
Net Earnings (Loss)		**$ 198**	$ (251)	**$ 3,426**	$ 236
Other Comprehensive Income (Loss), Net of Tax					
Foreign currency translation adjustment	*(Note 14)*	**58**	(27)	**22**	(46)
Pension and other post-employment benefit plans	*(Notes 14, 18)*	**(17)**	52	**(17)**	60
Other Comprehensive Income		**41**	25	**5**	14
Comprehensive Income (Loss)		**239**	(226)	**3,431**	250
Comprehensive Income Attributable to Noncontrolling Interest	*(Note 15)*	**-**	-	**(34)**	-
Comprehensive Income (Loss) Attributable to Common Shareholders		**$ 239**	$ (226)	**$ 3,397**	$ 250

See accompanying Notes to Condensed Consolidated Financial Statements

Condensed Consolidated Balance Sheet *(unaudited)*

($ millions)		As at December 31, 2014	As at December 31, 2013
Assets			
Current Assets			
Cash and cash equivalents		$ 338	$ 2,566
Accounts receivable and accrued revenues		1,307	988
Risk management	*(Note 20)*	707	56
Income tax receivable		509	562
Deferred income taxes		-	118
		2,861	4,290
Property, Plant and Equipment, at cost:	*(Note 9)*		
Natural gas and oil properties, based on full cost accounting			
Proved properties		42,615	51,603
Unproved properties		6,133	1,068
Other		2,711	3,148
Property, plant and equipment		51,459	55,819
Less: Accumulated depreciation, depletion and amortization		(33,444)	(45,784)
Property, plant and equipment, net	*(Note 3)*	18,015	10,035
Cash in Reserve		73	10
Other Assets		394	526
Risk Management	*(Note 20)*	65	204
Deferred Income Taxes		296	939
Goodwill	*(Notes 3, 4, 5, 15)*	2,917	1,644
	(Note 3)	$ 24,621	$ 17,648
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable and accrued liabilities		$ 2,243	$ 1,895
Income tax payable		15	29
Risk management	*(Note 20)*	20	25
Current portion of long-term debt	*(Note 10)*	-	1,000
Deferred income taxes		128	3
		2,406	2,952
Long-Term Debt	*(Note 10)*	7,340	6,124
Other Liabilities and Provisions	*(Note 11)*	2,484	2,520
Risk Management	*(Note 20)*	7	5
Asset Retirement Obligation	*(Note 12)*	870	900
Deferred Income Taxes		1,829	-
		14,936	12,501
Commitments and Contingencies	*(Note 21)*		
Shareholders' Equity			
Share capital - authorized unlimited common shares, without par value			
2014 issued and outstanding: 741.2 million shares (2013: 740.9 million shares)	*(Note 13)*	2,450	2,445
Paid in surplus	*(Notes 13, 15, 17)*	1,358	15
Retained earnings		5,188	2,003
Accumulated other comprehensive income	*(Note 14)*	689	684
Total Shareholders' Equity		9,685	5,147
		$ 24,621	$ 17,648

See accompanying Notes to Condensed Consolidated Financial Statements

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

Twelve Months Ended December 31, 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 17)*	**-**	**(2)**	**-**	**-**	**-**	**(2)**
Net Earnings		**-**	**-**	**3,392**	**-**	**34**	**3,426**
Dividends on Common Shares	*(Note 13)*	**-**	**-**	**(207)**	**-**	**-**	**(207)**
Common Shares Issued Under Dividend Reinvestment Plan	*(Note 13)*	**5**	**-**	**-**	**-**	**-**	**5**
Other Comprehensive Income	*(Note 14)*	**-**	**-**	**-**	**5**	**-**	**5**
Sale of Noncontrolling Interest	*(Note 15)*	**-**	**1,345**	**-**	**-**	**117**	**1,462**
Distributions to Noncontrolling Interest Owners	*(Note 15)*	**-**	**-**	**-**	**-**	**(18)**	**(18)**
Sale of Investment in PrairieSky	*(Note 15)*	**-**	**-**	**-**	**-**	**(133)**	**(133)**
Balance, December 31, 2014		**$ 2,450**	**$ 1,358**	**$ 5,188**	**$ 689**	**$ -**	**$ 9,685**

Twelve Months Ended December 31, 2013 ($ millions)		Share Capital	Paid in Surplus	Retained Earnings	Accumulated Other Comprehensive Income	Non-Controlling Interest	Total Shareholders' Equity
Balance, December 31, 2012		$ 2,354	$ 10	$ 2,261	$ 670	$ -	$ 5,295
Share-Based Compensation	*(Note 17)*	-	3	-	-	-	3
Net Earnings		-	-	236	-	-	236
Common Shares Cancelled	*(Note 13)*	(2)	2	-	-	-	-
Dividends on Common Shares	*(Note 13)*	-	-	(494)	-	-	(494)
Common Shares Issued Under Dividend Reinvestment Plan	*(Note 13)*	93	-	-	-	-	93
Other Comprehensive Income	*(Note 14)*	-	-	-	14	-	14
Balance, December 31, 2013		$ 2,445	$ 15	$ 2,003	$ 684	$ -	$ 5,147

See accompanying Notes to Condensed Consolidated Financial Statements

Condensed Consolidated Statement of Cash Flows *(unaudited)*

($ millions)		Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	Twelve Months Ended December 31, 2014	Twelve Months Ended December 31, 2013
Operating Activities					
Net earnings (loss)		**$ 198**	$ (251)	**$ 3,426**	$ 236
Depreciation, depletion and amortization		**451**	388	**1,745**	1,565
Impairments		**-**	-	**-**	21
Accretion of asset retirement obligation	*(Note 12)*	**13**	13	**52**	53
Deferred income taxes	*(Note 8)*	**135**	27	**960**	(57)
Unrealized (gain) loss on risk management	*(Note 20)*	**(489)**	301	**(444)**	345
Unrealized foreign exchange (gain) loss	*(Note 7)*	**174**	147	**440**	330
(Gain) loss on divestitures	*(Notes 5, 15)*	**16**	(3)	**(3,426)**	(7)
Other		**(81)**	44	**(34)**	62
Net change in other assets and liabilities		**(15)**	(21)	**(43)**	(80)
Net change in non-cash working capital		**(141)**	(183)	**(9)**	(179)
Cash From (Used in) Operating Activities		**261**	462	**2,667**	2,289
Investing Activities					
Capital expenditures	*(Note 3)*	**(857)**	(717)	**(2,526)**	(2,712)
Acquisitions	*(Note 5)*	**(41)**	(23)	**(3,016)**	(184)
Corporate acquisition	*(Note 4)*	**(5,962)**	-	**(5,962)**	-
Proceeds from divestitures	*(Note 5)*	**(9)**	95	**4,345**	705
Proceeds from sale of investment in PrairieSky	*(Notes 5, 15)*	**-**	-	**2,172**	-
Cash in reserve		**38**	24	**(63)**	44
Net change in investments and other		**232**	65	**321**	252
Cash From (Used in) Investing Activities		**(6,599)**	(556)	**(4,729)**	(1,895)
Financing Activities					
Issuance of revolving long-term debt	*(Notes 10, 20)*	**1,277**	-	**1,277**	-
Repayment of revolving long-term debt	*(Note 4)*	**(335)**	-	**(335)**	-
Repayment of long-term debt	*(Note 10)*	**(1,150)**	(500)	**(2,152)**	(500)
Dividends on common shares	*(Note 13)*	**(50)**	(39)	**(202)**	(401)
Proceeds from sale of noncontrolling interest	*(Note 15)*	**(1)**	-	**1,462**	-
Distributions to noncontrolling interest owners	*(Note 15)*	**-**	-	**(18)**	-
Capital lease payments and other financing arrangements	*(Note 9)*	**(11)**	(5)	**(71)**	(8)
Cash From (Used in) Financing Activities		**(270)**	(544)	**(39)**	(909)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**(28)**	(54)	**(127)**	(98)
Increase (Decrease) in Cash and Cash Equivalents		**(6,636)**	(692)	**(2,228)**	(613)
Cash and Cash Equivalents, Beginning of Period		**6,974**	3,258	**2,566**	3,179
Cash and Cash Equivalents, End of Period		**$ 338**	$ 2,566	**$ 338**	$ 2,566
Cash, End of Period		**$ 142**	$ 161	**$ 142**	$ 161
Cash Equivalents, End of Period		**196**	2,405	**196**	2,405
Cash and Cash Equivalents, End of Period		**$ 338**	$ 2,566	**$ 338**	$ 2,566

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"). See Note 15 for further details regarding the noncontrolling interest. As of September 26, 2014, Encana no longer holds an interest in PrairieSky. 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, 2013, 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, 2013.

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.

2. Recent Accounting Pronouncements

Changes in Accounting Policies and Practices

On January 1, 2014, Encana adopted the following Accounting Standards Updates ("ASU") issued by the Financial Accounting Standards Board ("FASB"), which have not had a material impact on the Company's interim Condensed Consolidated Financial Statements:

- ASU 2013-04, "Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date", clarifies guidance for the recognition, measurement and disclosure of liabilities resulting from joint and several liability arrangements. The amendments have been applied retrospectively.

- ASU 2013-05, "Parent’s Accounting for the Cumulative Translation Adjustment upon Derecognition of Certain Subsidiaries or Groups of Assets within a Foreign Entity or of an Investment in a Foreign Entity", clarifies the applicable guidance for certain transactions that result in the release of the cumulative translation adjustment into net earnings. The amendments have been applied prospectively.

- ASU 2013-11, "Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists", clarifies that a liability related to an unrecognized tax benefit or portions thereof should be presented as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss or a tax credit carryforward, except under specific situations. The amendments have been applied prospectively.

2. Recent Accounting Pronouncements (continued)

New Standards Issued Not Yet Adopted

- As of January 1, 2015, Encana will be required to adopt ASU 2014-08, "Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity", which 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 will be applied prospectively and are not expected to have a material impact on the Company's Consolidated Financial Statements.

- As of January 1, 2016, Encana will be required to adopt 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 standard 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.

- As of January 1, 2017, 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. The standard can be applied using either the full retrospective approach or a modified retrospective approach 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 December 31)

Segment and Geographic Information

	Canadian Operations		USA Operations		Market Optimization	
	2014	2013	**2014**	2013	**2014**	2013
Revenues, Net of Royalties	**$ 604**	$ 845	**$ 771**	$ 691	**$ 358**	$ 155
Expenses						
Production and mineral taxes	**2**	4	**34**	33	**-**	-
Transportation and processing	**193**	225	**152**	175	**-**	-
Operating	**68**	90	**105**	108	**2**	12
Purchased product	**-**	-	**-**	-	**347**	138
	341	526	**480**	375	**9**	5
Depreciation, depletion and amortization	**122**	156	**298**	195	**-**	3
	$ 219	$ 370	**$ 182**	$ 180	**$ 9**	$ 2

	Corporate & Other		Consolidated	
	2014	2013	**2014**	2013
Revenues, Net of Royalties	**$ 521**	$ (268)	**$ 2,254**	$ 1,423
Expenses				
Production and mineral taxes	**-**	-	**36**	37
Transportation and processing	**11**	5	**356**	405
Operating	**3**	11	**178**	221
Purchased product	**-**	-	**347**	138
	507	(284)	**1,337**	622
Depreciation, depletion and amortization	**31**	34	**451**	388
Impairments	**-**	-	**-**	-
	$ 476	$ (318)	**886**	234
Accretion of asset retirement obligation			**13**	13
Administrative			**58**	167
Interest			**252**	139
Foreign exchange (gain) loss, net			**149**	160
(Gain) loss on divestitures			**16**	(3)
Other			**63**	7
			551	483
Net Earnings (Loss) Before Income Tax			**335**	(249)
Income tax expense			**137**	2
Net Earnings (Loss)			**198**	(251)
Net earnings attributable to noncontrolling interest			**-**	-
Net Earnings (Loss) Attributable to Common Shareholders			**$ 198**	$ (251)

Intersegment Information

	Market Optimization					
	Marketing Sales		Upstream Eliminations		Total	
	2014	2013	**2014**	2013	**2014**	2013
Revenues, Net of Royalties	**$ 1,631**	$ 1,466	**$ (1,273)**	$ (1,311)	**$ 358**	$ 155
Expenses						
Transportation and processing	**100**	131	**(100)**	(131)	**-**	-
Operating	**3**	20	**(1)**	(8)	**2**	12
Purchased product	**1,519**	1,306	**(1,172)**	(1,168)	**347**	138
Operating Cash Flow	**$ 9**	$ 9	**$ -**	$ (4)	**$ 9**	$ 5

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. Segmented Information (continued)

Results of Operations (For the twelve months ended December 31)

Segment and Geographic Information

	Canadian Operations		USA Operations		Market Optimization	
	2014	2013	**2014**	2013	**2014**	2013
Revenues, Net of Royalties	**$ 3,310**	$ 2,824	**$ 2,902**	$ 2,763	**$ 1,248**	$ 512
Expenses						
Production and mineral taxes	**15**	15	**118**	119	**-**	-
Transportation and processing	**835**	756	**658**	722	**-**	-
Operating	**314**	372	**354**	411	**39**	38
Purchased product	**-**	-	**-**	-	**1,191**	441
	2,146	1,681	**1,772**	1,511	**18**	33
Depreciation, depletion and amortization	**625**	601	**992**	818	**4**	12
	$ 1,521	$ 1,080	**$ 780**	$ 693	**$ 14**	$ 21

	Corporate & Other		Consolidated	
	2014	2013	**2014**	2013
Revenues, Net of Royalties	**$ 559**	$ (241)	**$ 8,019**	$ 5,858
Expenses				
Production and mineral taxes	**-**	-	**133**	134
Transportation and processing	**12**	(2)	**1,505**	1,476
Operating	**28**	38	**735**	859
Purchased product	**-**	-	**1,191**	441
	519	(277)	**4,455**	2,948
Depreciation, depletion and amortization	**124**	134	**1,745**	1,565
Impairments	**-**	21	**-**	21
	$ 395	$ (432)	**2,710**	1,362
Accretion of asset retirement obligation			**52**	53
Administrative			**327**	439
Interest			**654**	563
Foreign exchange (gain) loss, net			**403**	325
(Gain) loss on divestitures			**(3,426)**	(7)
Other			**71**	1
			(1,919)	1,374
Net Earnings (Loss) Before Income Tax			**4,629**	(12)
Income tax expense (recovery)			**1,203**	(248)
Net Earnings			**3,426**	236
Net earnings attributable to noncontrolling interest			**(34)**	-
Net Earnings Attributable to Common Shareholders			**$ 3,392**	$ 236

Intersegment Information

	Market Optimization					
	Marketing Sales		Upstream Eliminations		Total	
	2014	2013	**2014**	2013	**2014**	2013
Revenues, Net of Royalties	**$ 7,371**	$ 5,662	**$ (6,123)**	$ (5,150)	**$ 1,248**	$ 512
Expenses						
Transportation and processing	**458**	516	**(458)**	(516)	**-**	-
Operating	**62**	75	**(23)**	(37)	**39**	38
Purchased product	**6,822**	4,993	**(5,631)**	(4,552)	**1,191**	441
Operating Cash Flow	**$ 29**	$ 78	**$ (11)**	$ (45)	**$ 18**	$ 33

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. Segmented Information (continued)

Capital Expenditures

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2014	2013	**2014**	2013
Canadian Operations	**$ 302**	$ 354	**$ 1,226**	$ 1,365
USA Operations	**548**	343	**1,285**	1,283
Market Optimization	**-**	1	**-**	3
Corporate & Other	**7**	19	**15**	61
	$ 857	$ 717	**$ 2,526**	$ 2,712

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

	Goodwill As at		Property, Plant and Equipment As at		Total Assets As at	
	December 31, 2014	December 31, 2013	**December 31, 2014**	December 31, 2013	**December 31, 2014**	December 31, 2013
Canadian Operations	**$ 788**	$ 1,171	**$ 2,338**	$ 2,728	**$ 3,632**	$ 4,452
USA Operations	**2,129**	473	**13,817**	5,127	**16,800**	6,350
Market Optimization	**-**	-	**1**	91	**181**	161
Corporate & Other	**-**	-	**1,859**	2,089	**4,008**	6,685
	$ 2,917	$ 1,644	**$ 18,015**	$ 10,035	**$ 24,621**	$ 17,648

4. Business Combinations

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 are 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 (See Note 10). Athlon's operations focused on the acquisition and development of oil and gas properties located in the Permian Basin in Texas.

The transaction was 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 preliminary purchase price allocation, representing consideration paid and the fair values of the assets acquired and liabilities assumed as of the acquisition date, is shown in the table below.

Preliminary Purchase Price Allocation	
Assets Acquired:	
Cash	**$ 2**
Accounts receivable and other current assets	**133**
Risk management	**80**
Proved properties	**2,124**
Unproved properties	**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	**(25)**
Deferred income taxes	**(1,724)**
Total Purchase Price (1)	**$ 5,964**

(1) 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.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

4. Business Combinations (continued)

Athlon Energy Inc. Acquisition (continued)

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 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.

The results of operations attributable to the Athlon acquisition are included in the Company's Condensed Consolidated Statement of Earnings beginning November 13, 2014. The assets acquired generated revenues of $176 million and a net loss of $3 million for the period from November 13, 2014 to December 31, 2014.

Eagle Ford Acquisition

On June 20, 2014, Encana completed the acquisition of approximately 45,500 net acres located in the Eagle Ford shale formation from Freeport-McMoRan Oil & Gas LLC and PXP Producing Company LLC 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 are included in other expenses.

The transaction was accounted for under the acquisition method. The final purchase price allocation, representing consideration paid and the fair values of the assets acquired and liabilities assumed as of the acquisition date, is shown in the table below. Based on the allocation of the consideration paid, no goodwill was recognized.

Final Purchase Price Allocation		
Assets Acquired:		
Inventory	**$**	**4**
Proved properties		**2,873**
Unproved properties		**78**
Liabilities Assumed:		
Asset retirement obligation		**(32)**
Total Purchase Price	**$**	**2,923**

The Company used the income approach valuation technique. The fair values of the assets acquired and liabilities assumed are categorized within Level 3 of the fair value hierarchy. The fair values of the assets acquired and liabilities assumed were determined using relevant market assumptions, including future commodity prices and costs, timing of development activities, projections of oil and gas reserves, and estimates to abandon and reclaim producing wells.

The results of operations attributable to the Eagle Ford assets are included in the Company's Condensed Consolidated Statement of Earnings beginning June 20, 2014. The assets acquired generated revenues of $585 million and net earnings of $222 million for the period from June 20, 2014 to December 31, 2014.

Unaudited Pro Forma Financial Information

The following unaudited pro forma financial information has been prepared assuming the Athlon and Eagle Ford acquisitions occurred on January 1, 2013. 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 dates indicated. In addition, the pro forma information does not project Encana's results of operations for any future period.

	Athlon		**Eagle Ford**	
	Twelve Months Ended December 31,		Twelve Months Ended December 31,	
($ millions, except per share amounts)	**2014**	2013	**2014**	2013
Revenues, Net of Royalties	**$ 8,572**	$ 6,139	**$ 8,760**	$ 7,189
Net Earnings Attributable to Common Shareholders	**$ 3,486**	$ 158	**$ 3,641**	$ 741
Net Earnings per Common Share				
Basic & Diluted	**$ 4.71**	$ 0.21	**$ 4.91**	$ 1.01

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. Acquisitions and Divestitures

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2014	2013	**2014**	2013
Acquisitions				
Canadian Operations	**$ 7**	$ 11	**$ 21**	$ 28
USA Operations	**34**	12	**2,995**	156
Total Acquisitions	**41**	23	**3,016**	184
Divestitures				
Canadian Operations	**3**	(93)	**(1,847)**	(685)
USA Operations	**6**	(2)	**(2,264)**	(18)
Market Optimization	**-**	-	**(205)**	-
Corporate & Other	**-**	-	**(29)**	(2)
Total Divestitures	**9**	(95)	**(4,345)**	(705)
Net Acquisitions & (Divestitures)	**$ 50**	$ (72)	**$ (1,329)**	$ (521)

Acquisitions

For the twelve months ended December 31, 2014, acquisitions in the Canadian Operations totaled $21 million (2013 - $28 million), which primarily included land and property purchases with oil and liquids rich production potential.

For the twelve months ended December 31, 2014, acquisitions in the USA Operations totaled $2,995 million (2013 - $156 million), which primarily included the purchase of certain properties in the Eagle Ford shale formation in south Texas as described in Note 4.

Divestitures

For the twelve months ended December 31, 2014, divestitures in the Canadian Operations were $1,847 million (2013 - $685 million), which primarily included the sale of the Company's Bighorn assets in west central Alberta for approximately $1,725 million. During the twelve months ended December 31, 2013, divestitures included the sale of the Company's Jean Marie natural gas assets in northeast British Columbia and other assets.

For the twelve months ended December 31, 2014, divestitures in the USA Operations were $2,264 million (2013 - $18 million), which primarily included the sale of the Jonah properties for proceeds of approximately $1,636 million and the sale of certain properties in East Texas for proceeds of approximately $495 million.

Amounts received from the divestiture transactions have been deducted from the respective Canadian and U.S. full cost pools, except for divestitures that result in a significant alteration between capitalized costs and proved reserves in 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 twelve months ended December 31, 2014, Encana recognized a gain of approximately $1,014 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 twelve months ended December 31, 2014, Encana recognized a gain of approximately $209 million, before tax, on the sale of the Jonah properties in the U.S. cost centre and allocated goodwill of $68 million.

OTHER CAPITAL TRANSACTIONS

The following transactions involve the acquisition or disposition of common shares and, therefore, are excluded from the acquisitions and divestitures table above.

Acquisition of Athlon

On November 13, 2014, Encana acquired all of the issued and outstanding shares of common stock of Athlon for $5.93 billion, or $58.50 per share. See Note 4 for further details regarding the Athlon transaction.

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 December 31, 2014	Three Months Ended December 31, 2013	Twelve Months Ended December 31, 2014	Twelve Months Ended December 31, 2013
Interest Expense on:				
Debt	**$ 206**	$ 112	**$ 509**	$ 460
The Bow office building	**18**	20	**75**	76
Capital leases	**9**	6	**37**	9
Other	**19**	1	**33**	18
	$ 252	$ 139	**$ 654**	$ 563

Interest on Debt for the three and twelve months ended December 31, 2014 includes a one-time outlay of approximately $125 million associated with the early redemption of senior notes assumed in conjunction with the Athlon acquisition (See Note 10).

Interest on Capital leases and Other were previously reported together in 2013.

7. Foreign Exchange (Gain) Loss, Net

	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	Twelve Months Ended December 31, 2014	Twelve Months Ended December 31, 2013
Unrealized Foreign Exchange (Gain) Loss on:				
Translation of U.S. dollar debt issued from Canada	**$ 180**	$ 156	**$ 456**	$ 349
Translation of U.S. dollar risk management contracts issued from Canada	**(6)**	(9)	**(16)**	(19)
	174	147	**440**	330
Foreign Exchange on Intercompany Transactions	**-**	-	**28**	-
Other Monetary Revaluations and Settlements	**(25)**	13	**(65)**	(5)
	$ 149	$ 160	**$ 403**	$ 325

8. Income Taxes

	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	Twelve Months Ended December 31, 2014	Twelve Months Ended December 31, 2013
Current Tax				
Canada	**$ 2**	$ 19	**$ 249**	$ (152)
United States	**(2)**	(50)	**(21)**	(64)
Other countries	**2**	6	**15**	25
Total Current Tax Expense (Recovery)	**2**	(25)	**243**	(191)
Deferred Tax				
Canada	**15**	(151)	**713**	(106)
United States	**139**	97	**246**	52
Other countries	**(19)**	81	**1**	(3)
Total Deferred Tax Expense (Recovery)	**135**	27	**960**	(57)
	$ 137	$ 2	**$ 1,203**	$ (248)

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

9. Property, Plant and Equipment, Net

	As at December 31, 2014			As at December 31, 2013		
	Cost	Accumulated DD&A [1]	Net	Cost	Accumulated DD&A [1]	Net
Canadian Operations						
Proved properties	$ 18,271	$ (16,566)	$ 1,705	$ 25,003	$ (23,012)	$ 1,991
Unproved properties	478	-	478	598	-	598
Other	155	-	155	139	-	139
	18,904	(16,566)	2,338	25,740	(23,012)	2,728
USA Operations						
Proved properties	24,279	(16,260)	8,019	26,529	(22,074)	4,455
Unproved properties	5,655	-	5,655	470	-	470
Other	143	-	143	202	-	202
	30,077	(16,260)	13,817	27,201	(22,074)	5,127
Market Optimization	8	(7)	1	223	(132)	91
Corporate & Other	2,470	(611)	1,859	2,655	(566)	2,089
	$ 51,459	$ (33,444)	$ 18,015	$ 55,819	$ (45,784)	$ 10,035

(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 $306 million which have been capitalized during the twelve months ended December 31, 2014 (2013 - $372 million). Included in Corporate and Other are $65 million (2013 - $71 million) of international property costs, which have been fully impaired.

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 following successful completion of the Production Field Centre ("PFC") and issuance of the Production Acceptance Notice. As at December 31, 2014, Canadian Operations property, plant and equipment and total assets include the PFC, which is under a capital lease totaling $520 million (2013 - $536 million).

As at December 31, 2014, the total carrying value of assets under capital lease was $547 million (2013 - $683 million). 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.

Other Arrangement

As at December 31, 2014, Corporate and Other property, plant and equipment and total assets include a carrying value of $1,431 million (2013 - $1,587 million) related to The Bow office building, which is under a 25-year lease agreement. The Bow asset is being depreciated over the 60-year estimated life of the building. At the conclusion of the 25-year term, the remaining asset and corresponding liability are expected to be derecognized as disclosed in Note 11.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

10. Long-Term Debt

	C$ Principal Amount	As at December 31, 2014	As at December 31, 2013
Canadian Dollar Denominated Debt			
5.80% due January 18, 2018	$ 750	$ 647	$ 705
U.S. Dollar Denominated Debt			
Revolving credit and term loan borrowings		1,277	-
U.S. Unsecured Notes			
5.80% due May 1, 2014		-	1,000
5.90% due December 1, 2017		700	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
		6,677	6,400
Total Principal		7,324	7,105
Increase in Value of Debt Acquired		34	40
Debt Discounts		(18)	(21)
Current Portion of Long-Term Debt		-	(1,000)
		$ 7,340	$ 6,124

Long-term debt is accounted for at amortized cost using the effective interest method of amortization. As at December 31, 2014, total long-term debt had a carrying value of $7,340 million and a fair value of $7,788 million (2013 - carrying value of $7,124 million and a fair value of $7,805 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 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.

On December 16, 2014, Encana completed the redemption of the $500 million 7.375 percent senior notes due April 15, 2021 and the $650 million 6.00 percent senior notes due May 1, 2022, which were assumed by Encana in conjunction with the Athlon acquisition as discussed in Note 4. The Company recognized a one-time outlay of approximately $125 million as a result of the early redemption. Upon acquisition, the Company recorded an increase in the fair value of the debt acquired from Athlon of approximately $12 million, which was expensed upon redemption of the senior notes and is included in other expenses in the Company's Condensed Consolidated Statement of Earnings. Encana used proceeds from the Company's revolving credit facility of $1,277 million to redeem the senior notes.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

11. Other Liabilities and Provisions

	As at December 31, 2014	As at December 31, 2013
The Bow Office Building (See Note 9)	**$ 1,486**	$ 1,631
Capital Lease Obligations (See Note 9)	**473**	544
Unrecognized Tax Benefits	**279**	133
Pensions and Other Post-Employment Benefits	**144**	110
Long-Term Incentives (See Note 17)	**70**	58
Other	**32**	44
	$ 2,484	$ 2,520

Long-Term Incentives was previously reported in Other in 2013.

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	$ 80	$ 81	$ 82	$ 82	$ 83	$ 1,652	**$ 2,060**
Sublease Recoveries	$ (39)	$ (40)	$ (40)	$ (40)	$ (41)	$ (812)	**$ (1,012)**

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.

The PFC commenced commercial operations in December 2013. Accordingly, Encana derecognized the asset under construction and related liability and recorded the PFC as a capital lease asset with a corresponding capital lease obligation. 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, the lease contract qualifies as a variable interest and 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 lease entity and its affiliates, other than the contractual payments under the lease and operating contracts.

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	$ 98	$ 98	$ 99	$ 99	$ 99	$ 232	**$ 725**
Less Amounts Representing Interest	39	36	32	27	23	36	**193**
Present Value of Expected Future Lease Payments	$ 59	$ 62	$ 67	$ 72	$ 76	$ 196	**$ 532**

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

12. Asset Retirement Obligation

	As at December 31, 2014	As at December 31, 2013
Asset Retirement Obligation, Beginning of Year	**$ 966**	$ 969
Liabilities Incurred and Acquired (See Note 4)	**85**	38
Liabilities Settled and Divested	**(188)**	(126)
Change in Estimated Future Cash Outflows	**35**	68
Accretion Expense	**52**	53
Foreign Currency Translation	**(37)**	(36)
Asset Retirement Obligation, End of Year	**$ 913**	$ 966
Current Portion	**$ 43**	$ 66
Long-Term Portion	**870**	900
	$ 913	$ 966

13. Share Capital

Authorized

The Company is authorized to issue an unlimited number of no par value common shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares.

Issued and Outstanding

	As at December 31, 2014		As at December 31, 2013	
	Number (millions)	Amount	Number (millions)	Amount
Common Shares Outstanding, Beginning of Year	**740.9**	**$ 2,445**	736.3	$ 2,354
Common Shares Cancelled	**-**	**-**	(0.8)	(2)
Common Shares Issued Under Dividend Reinvestment Plan	**0.3**	**5**	5.4	93
Common Shares Outstanding, End of Year	**741.2**	**$ 2,450**	740.9	$ 2,445

During the twelve months ended December 31, 2014, Encana issued 240,839 common shares totaling $5 million under the Company's dividend reinvestment plan (2013 - issued 5,385,845 common shares totaling $93 million).

During the twelve months ended December 31, 2013, Encana cancelled 767,327 common shares reserved for issuance to shareholders upon exchange of predecessor companies' shares. In accordance with the terms of the merger agreement which formed Encana, shares which remained unexchanged were extinguished. Accordingly, the weighted average book value of the common shares extinguished of $2 million was transferred to paid in surplus.

Dividends

During the three months ended December 31, 2014, Encana paid dividends of $0.07 per common share totaling $51 million (2013 - $0.07 per common share totaling $52 million). During the twelve months ended December 31, 2014, Encana paid dividends of $0.28 per common share totaling $207 million (2013 - $0.67 per common share totaling $494 million).

For the three and twelve months ended December 31, 2014, the dividends paid included $1 million and $5 million, respectively, in common shares which were issued in lieu of cash dividends under the Company's dividend reinvestment plan (2013 - $13 million and $93 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:

(millions, except per share amounts)	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	Twelve Months Ended December 31, 2014	Twelve Months Ended December 31, 2013
Net Earnings (Loss) Attributable to Common Shareholders	**$ 198**	$ (251)	**$ 3,392**	$ 236
Number of Common Shares:				
Weighted average common shares outstanding - Basic	**741.1**	740.4	**741.0**	737.7
Effect of dilutive securities	**-**	-	**-**	-
Weighted average common shares outstanding - Diluted	**741.1**	740.4	**741.0**	737.7
Net Earnings (Loss) per Common Share				
Basic	**$ 0.27**	$ (0.34)	**$ 4.58**	$ 0.32
Diluted	**$ 0.27**	$ (0.34)	**$ 4.58**	$ 0.32

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 December 31, 2014 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.

Encana Share Units Previously Held by Cenovus Employees

On November 30, 2009, Encana completed a corporate reorganization to split into two independent publicly traded energy companies - Encana Corporation and Cenovus Energy Inc. (the "Split Transaction"). In conjunction with the Split Transaction, each holder of Encana share units disposed of their right in exchange for the grant of new Encana share units and Cenovus share units. Share units included TSARs, Performance TSARs, SARs, and Performance SARs. The terms and conditions of the share units were similar to the terms and conditions of the original share units. There was no impact on Encana's net earnings for the share units held by Cenovus employees. As at December 31, 2014, all remaining share units held by Cenovus employees have expired.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

14. Accumulated Other Comprehensive Income

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2014	2013	**2014**	2013
Foreign Currency Translation Adjustment				
Balance, Beginning of Period	**$ 657**	$ 720	**$ 693**	$ 739
Current Period Change in Foreign Currency Translation Adjustment	**58**	(27)	**22**	(46)
Balance, End of Period	**$ 715**	$ 693	**$ 715**	$ 693
Pension and Other Post-Employment Benefit Plans				
Balance, Beginning of Period	**$ (9)**	$ (61)	**$ (9)**	$ (69)
Net Actuarial Gains and (Losses) and Plan Amendment (See Note 18)	**(22)**	65	**(22)**	65
Income Taxes	**7**	(17)	**7**	(17)
Reclassification of Net Actuarial (Gains) and Losses to Net Earnings (See Note 18)	**(1)**	-	**(1)**	11
Income Taxes	**-**	-	**-**	(3)
Reclassification of Net Prior Service Costs and (Credits) to Net Earnings (See Note 18)	**(1)**	-	**(1)**	-
Income Taxes	**-**	-	**-**	-
Settlement and Curtailment in Defined Benefit Plan Expense (See Note 18)	**-**	6	**-**	6
Income Taxes	**-**	(2)	**-**	(2)
Balance, End of Period	**$ (26)**	$ (9)	**$ (26)**	$ (9)
Total Accumulated Other Comprehensive Income	**$ 689**	$ 684	**$ 689**	$ 684

15. Noncontrolling Interest

Initial Public Offering of Common Shares of PrairieSky

On May 22, 2014, PrairieSky filed a final prospectus to qualify the distribution of 52.0 million common shares (the "IPO"), to be sold by Encana pursuant to the terms of an underwriting agreement dated May 22, 2014, at a price of C$28.00 per common share (the "Offering Price").

On May 27, 2014, prior to closing the IPO, PrairieSky acquired from Encana a royalty business in exchange for common shares of PrairieSky pursuant to the Purchase and Sale Agreement dated May 22, 2014 between PrairieSky and Encana (the "Agreement"). The royalty business assets acquired by PrairieSky comprise: (i) fee simple mineral title in lands prospective for petroleum, natural gas and certain other mines and minerals located predominantly in central and southern Alberta (the "Fee Lands"); (ii) lessor interests in and to leases that are currently issued in respect of certain Fee Lands; (iii) royalty interests, including overriding royalty interests, gross overriding royalty interests and production payments on lands located predominantly in Alberta; (iv) an irrevocable, perpetual licence to certain proprietary seismic data of Encana (the "Seismic Licence"); and (v) certain other related assets as set forth in the Agreement.

As part of the Agreement, PrairieSky and Encana entered into: (i) a Seismic Licence Agreement whereby Encana granted the Seismic Licence to PrairieSky; and (ii) Lease Issuance and Administration Agreements whereby PrairieSky issued leases to document Encana's retention of its working interest in respect of certain Fee Lands and pursuant to which PrairieSky receives royalties from Encana.

On May 29, 2014, Encana completed the IPO of 52.0 million common shares of PrairieSky at the Offering Price 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.

The noncontrolling interest in the former consolidated subsidiary, PrairieSky, was reflected as a separate component of Total Equity in the Condensed Consolidated Balance Sheet. 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 $82 million, was recognized as paid in surplus.

15. Noncontrolling Interest (continued)

Secondary Public Offering of Common Shares of PrairieSky

On September 8, 2014, Encana and PrairieSky announced 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 on September 26, 2014, Encana no longer holds 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 $2,094 million, which is included in (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 is 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 controlling interest in PrairieSky. 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. For the twelve months ended December 31, 2014, net earnings and comprehensive income of $34 million were attributable to the noncontrolling interest as presented in the Condensed Consolidated Statement of Earnings and Condensed Consolidated Statement of Comprehensive Income.

16. Restructuring Charges

In November 2013, Encana announced its plans to align the organizational structure in support of the Company's strategy. For the twelve months ended December 31, 2014, Encana has incurred restructuring charges totaling $36 million relating primarily to severance costs, which are included in administrative expense in the Company's Condensed Consolidated Statement of Earnings (2013 - $88 million). Of the $124 million in restructuring charges incurred to date, $4 million remains accrued as at December 31, 2014 (2013 - $65 million). Total restructuring charges are expected to be approximately $133 million before tax. The remaining restructuring charges of approximately $9 million are anticipated to be incurred in 2015.

17. 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 December 31, 2014, 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	1.01%	1.01%
Dividend Yield	2.02%	1.91%
Expected Volatility Rate	30.66%	29.11%
Expected Term	1.5 yrs	1.7 yrs
Market Share Price	US$13.87	C$16.17

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

17. Compensation Plans (continued)

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

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2014	2013	**2014**	2013
Compensation Costs of Transactions Classified as Cash-Settled	**$ (90)**	$ 36	**$ 25**	$ 63
Compensation Costs of Transactions Classified as Equity-Settled [(1)]	**(1)**	(1)	**(2)**	3
Total Share-Based Compensation Costs	**(91)**	35	**23**	66
Less: Total Share-Based Compensation Costs Capitalized	**35**	(13)	**(6)**	(22)
Total Share-Based Compensation Expense	**$ (56)**	$ 22	**$ 17**	$ 44
Recognized on the Condensed Consolidated Statement of Earnings in:				
Operating expense	**$ (19)**	$ 10	**$ 12**	$ 18
Administrative expense	**(37)**	12	**5**	26
	$ (56)	$ 22	**$ 17**	$ 44

(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 December 31, 2014, the liability for share-based payment transactions totaled $99 million (2013 - $169 million), of which $29 million (2013 - $111 million) is recognized in accounts payable and accrued liabilities.

	As at December 31, 2014	As at December 31, 2013
Liability for Cash-Settled Share-Based Payment Transactions:		
Unvested	**$ 78**	$ 121
Vested	**21**	48
	$ 99	$ 169

The following units were granted primarily in conjunction with the Company's February annual long-term incentive award. The TSARs and SARs were granted at the market price of Encana's common shares on the grant date.

Twelve Months Ended December 31, 2014 (thousands of units)	
TSARs	5,271
SARs	3,139
PSUs	646
DSUs	166
RSUs	4,697

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

18. 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 twelve months ended December 31 as follows:

	Pension Benefits		OPEB		Total	
	2014	2013	**2014**	2013	**2014**	2013
Defined Benefit Plan Expense	**$ -**	$ 21	**$ 12**	$ 11	**$ 12**	$ 32
Defined Contribution Plan Expense	**34**	43	**-**	-	**34**	43
Total Benefit Plans Expense	**$ 34**	$ 64	**$ 12**	$ 11	**$ 46**	$ 75

Of the total benefit plans expense, $36 million (2013 - $60 million) was included in operating expense and $10 million (2013 - $15 million) was included in administrative expense.

The defined periodic pension and OPEB expense for the twelve months ended December 31 are as follows:

	Pension Benefits		OPEB		Total	
	2014	2013	**2014**	2013	**2014**	2013
Current Service Costs	**$ 3**	$ 4	**$ 10**	$ 12	**$ 13**	$ 16
Interest Cost	**12**	12	**4**	4	**16**	16
Expected Return On Plan Assets	**(15)**	(16)	**-**	-	**(15)**	(16)
Amounts Reclassified From Accumulated Other Comprehensive Income:						
Amortization of net actuarial (gains) and losses	**-**	11	**(1)**	-	**(1)**	11
Amortization of net prior service costs	**-**	-	**(1)**	-	**(1)**	-
Settlement	**-**	5	**-**	-	**-**	5
Curtailment	**-**	1	**-**	(5)	**-**	(4)
Special Termination Benefits	**-**	4	**-**	-	**-**	4
Total Defined Benefit Plan Expense	**$ -**	$ 21	**$ 12**	$ 11	**$ 12**	$ 32

The amounts recognized in other comprehensive income for the twelve months ended December 31 are as follows:

	Pension Benefits		OPEB		Total	
	2014	2013	**2014**	2013	**2014**	2013
Net Actuarial (Gains) Losses	**$ 8**	$ (46)	**$ 14**	$ (6)	**$ 22**	$ (52)
Plan Amendment	**-**	-	**-**	(13)	**-**	(13)
Amortization of Net Actuarial Gains and Losses	**-**	(11)	**1**	-	**1**	(11)
Amortization of Net Prior Service Costs	**-**	-	**1**	-	**1**	-
Settlement and Curtailment	**-**	(6)	**-**	-	**-**	(6)
Total Amounts Recognized in Other Comprehensive (Income) Loss, Before Tax	**$ 8**	$ (63)	**$ 16**	$ (19)	**$ 24**	$ (82)
Total Amounts Recognized in Other Comprehensive (Income) Loss, After Tax	**$ 6**	$ (46)	**$ 11**	$ (14)	**$ 17**	$ (60)

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

19. 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 except for the amounts associated with share units issued as part of the Split Transaction, as disclosed below. 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 for share units resulting from the Split Transaction, which are discussed further in Notes 20 and 13, respectively. 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 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**

As at December 31, 2013	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	$ -	$ 71	$ -	$ 71	$ (15)	$ 56
Long-term	-	204	-	204	-	204
Risk Management Liabilities						
Current	-	38	2	40	(15)	25
Long-term	-	-	5	5	-	5
Share Units Resulting from the Split Transaction						
Encana Share Units Held by Cenovus Employees [2]	$ -	$ -	$ -	$ -	$ -	$ -
Cenovus Share Units Held by Encana Employees						
Accounts payable and accrued liabilities [3]	-	-	8	8	-	8

(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.

(2) There were no remaining Encana share units held by Cenovus employees as at December 31, 2014 (2013 - 3.9 million share units with a weighted average exercise price of C$29.06).

(3) There were no remaining Cenovus share units held by Encana employees as at December 31, 2014.

19. Fair Value Measurements (continued)

The Company's Level 1 and Level 2 risk management assets and liabilities consist of commodity fixed price contracts and basis swaps with terms to 2018. The fair values of these contracts are based on a market approach and are estimated using inputs which are either directly or indirectly observable at the reporting date, such as exchange and other published prices, broker quotes and observable trading activity.

Level 3 Fair Value Measurements

As at December 31, 2014, the Company's Level 3 risk management assets and liabilities consist of power purchase contracts with terms to 2017. The fair values of the power purchase contracts are based on the income approach and are modelled internally using observable and unobservable inputs such as forward power prices in less active markets. The 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. Changes in amounts related to share units resulting from the Split Transaction are recognized in operating expense, administrative expense and capitalized within property, plant and equipment as described in Note 17.

A summary of changes in Level 3 fair value measurements for the twelve months ended December 31 is presented below:

	Risk Management		Share Units Resulting from Split Transaction	
	2014	2013	**2014**	2013
Balance, Beginning of Year	**$ (7)**	$ (12)	**$ (8)**	$ (36)
Total Gains (Losses)	**(19)**	3	**3**	16
Purchases, Issuances and Settlements:				
Purchases	**-**	-	**-**	-
Settlements	**8**	2	**5**	12
Transfers in and out of Level 3	**-**	-	**-**	-
Balance, End of Year	**$ (18)**	$ (7)	**$ -**	$ (8)
Change in unrealized gains (losses) related to assets and liabilities held at end of year	**$ (13)**	$ (2)	**$ -**	$ 20

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

	Valuation Technique	Unobservable Input	**As at December 31, 2014**	As at December 31, 2013
Risk Management - Power	Discounted Cash Flow	Forward prices ($/Megawatt Hour)	**$40.70 - $48.50**	$49.25 - $54.47
Share Units Resulting from the Split Transaction	Option Model	Cenovus share unit volatility	**-**	27.75%

A 10 percent increase or decrease in estimated forward power prices would cause a corresponding $5 million (2013 - $7 million) increase or decrease to net risk management assets and liabilities. As at December 31, 2014, all share units resulting from the Split Transaction have expired. As at December 31, 2013, a five percentage point increase or decrease in Cenovus share unit estimated volatility would cause no increase or decrease to accounts payable and accrued liabilities.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

20. 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 19 for a discussion of fair value measurements.

Unrealized Risk Management Position	**As at December 31, 2014**	As at December 31, 2013
Risk Management Assets		
Current	**$ 707**	$ 56
Long-term	**65**	204
	772	260
Risk Management Liabilities		
Current	**20**	25
Long-term	**7**	5
	27	30
Net Risk Management Assets	**$ 745**	$ 230

Commodity Price Positions as at December 31, 2014

	Notional Volumes		Term	Average Price		Fair Value
Natural Gas Contracts						
Fixed Price Contracts						
NYMEX Fixed Price	1,062	MMcf/d	2015	4.29	US$/Mcf	**$ 487**
Basis Contracts [(1)]			2015-2018			**120**
Other Financial Positions						**(3)**
Natural Gas Fair Value Position						**604**
Crude Oil Contracts						
Fixed Price Contracts						
WTI Fixed Price	12.3	Mbbls/d	2015	92.88	US$/bbl	**161**
WTI Fixed Price	1.2	Mbbls/d	2016	92.35	US$/bbl	**14**
Basis Contracts [(2)]			2015-2016			**(16)**
Crude Oil Fair Value Position						**159**
Power Purchase Contracts						
Fair Value Position						**(18)**
Total Fair Value Position						**$ 745**

(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) 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)

20. 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 December 31,		Twelve Months Ended December 31,	
	2014	2013	**2014**	2013
Revenues, Net of Royalties	**$ 126**	$ 175	**$ (84)**	$ 544
Transportation and Processing	**(2)**	(1)	**(7)**	-
Gain (Loss) on Risk Management	**$ 124**	$ 174	**$ (91)**	$ 544

	Unrealized Gain (Loss)			
	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2014	2013	**2014**	2013
Revenues, Net of Royalties	**$ 500**	$ (296)	**$ 456**	$ (347)
Transportation and Processing	**(11)**	(5)	**(12)**	2
Gain (Loss) on Risk Management	**$ 489**	$ (301)	**$ 444**	$ (345)

Reconciliation of Unrealized Risk Management Positions from January 1 to December 31

	2014		2013
	Fair Value	**Total Unrealized Gain (Loss)**	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	**$ 230**		
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Year	**353**	**$ 353**	$ 199
Foreign Exchange Translation Adjustment on Canadian Dollar Contracts	**1**		
Fair Value of Athlon Crude Oil Contracts Acquired	**70**		
Fair Value of Contracts Realized During the Year	**91**	**91**	(544)
Fair Value of Contracts, End of Year	**$ 745**	**$ 444**	$ (345)

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 swaps and options. 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 against crude oil commodity price risk including widening price differentials between North American and world prices, the Company has entered into fixed price contracts and basis swaps.

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)

20. 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 as at December 31 as follows:

	2014		2013	
	10% Price Increase	10% Price Decrease	10% Price Increase	10% Price Decrease
Natural Gas Price	$ (105)	$ 105	$ (441)	$ 441
Crude Oil Price	(22)	22	(19)	19
Power Price	5	(5)	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 December 31, 2014, the Company had no significant collateral balances posted or received and there were no credit derivatives in place.

As at December 31, 2014, 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 December 31, 2014, approximately 94 percent (2013 - 87 percent) of Encana's accounts receivable and financial derivative credit exposures were with investment grade counterparties.

As at December 31, 2014, Encana had three counterparties (2013 - four counterparties) whose net settlement position individually accounted for more than 10 percent of the fair value of the outstanding in-the-money net risk management contracts by counterparty. As at December 31, 2014, these counterparties accounted for 16 percent, 16 percent and 15 percent (2013 - 24 percent, 14 percent, 14 percent and 13 percent) 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 December 31, 2014, the Company had committed revolving bank credit facilities totaling $4.0 billion which include C$3.5 billion ($3.0 billion) on a revolving bank credit facility for Encana and $1.0 billion on a revolving bank credit facility for a U.S. subsidiary, the latter of which remains unused. The facilities remain committed through June 2018. Of the C$3.5 billion ($3.0 billion) revolving bank credit facility, $1.7 billion remained unused and $1.3 billion was drawn to redeem the senior notes assumed by Encana in conjunction with the Athlon acquisition as discussed in Note 10.

Encana also has accessible capacity under a shelf prospectus for up to $6.0 billion, or the equivalent in foreign currencies, the availability of which is dependent on market conditions, to issue up to $6.0 billion of 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.

20. 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	$ 2,243	$ -	$ -	$ -	$ -	**$ 2,243**
Risk Management Liabilities	20	7	-	-	-	**27**
Long-Term Debt (1)	396	1,493	3,030	1,610	6,392	**12,921**

(1) Principal and interest.

Included in Encana's long-term debt obligations of $12,921 million at December 31, 2014 are $1,277 million in principal obligations related to LIBOR loans drawn on the credit facility. These amounts are fully supported and Management expects that 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.

To mitigate the exposure to the fluctuating U.S./Canadian dollar exchange rate, Encana maintains a mix of both U.S. dollar and Canadian dollar debt and may also enter into foreign exchange derivatives. As at December 31, 2014, Encana had $6.7 billion in U.S. dollar debt issued from Canada that was subject to foreign exchange exposure (2013 - $5.4 billion) and $0.6 billion in debt that was not subject to foreign exchange exposure (2013 - $1.7 billion). There were no foreign exchange derivatives outstanding as at December 31, 2014.

Encana's foreign exchange (gain) loss primarily includes unrealized foreign exchange gains and losses on the translation 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 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 $61 million change in foreign exchange (gain) loss as at December 31, 2014 (2013 - $48 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 December 31, 2014.

As at December 31, 2014, the Company had floating rate debt of $1,277 million. Accordingly, the sensitivity in net earnings for each one percent change in interest rates on floating rate debt was $10 million (2013 - nil).

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

21. Commitments and Contingencies

Commitments

The following table outlines the Company's commitments as at December 31, 2014:

	Expected Future Payments						
(undiscounted)	2015	2016	2017	2018	2019	Thereafter	Total
Transportation and Processing	$ 878	$ 825	$ 815	$ 800	$ 673	$ 3,204	**$ 7,195**
Drilling and Field Services	312	138	93	47	16	17	**623**
Operating Leases	43	36	28	26	10	24	**167**
Total	$ 1,233	$ 999	$ 936	$ 873	$ 699	$ 3,245	**$ 7,985**

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.

Supplemental Financial Information *(unaudited)*

Financial Results

($ millions, except per share amounts)	2014 Year	2014 Q4	2014 Q3	2014 Q2	2014 Q1	2013 Year	2013 Q4	2013 Q3	2013 Q2	2013 Q1
Cash Flow (1)	**2,934**	**377**	807	656	1,094	2,581	677	660	665	579
Per share - Diluted (3)	**3.96**	**0.51**	1.09	0.89	1.48	3.50	0.91	0.89	0.90	0.79
Operating Earnings (2)	**1,002**	**35**	281	171	515	802	226	150	247	179
Per share - Diluted (3)	**1.35**	**0.05**	0.38	0.23	0.70	1.09	0.31	0.20	0.34	0.24
Net Earnings (Loss) Attributable to Common Shareholders	**3,392**	**198**	2,807	271	116	236	(251)	188	730	(431)
Per share - Diluted (3)	**4.58**	**0.27**	3.79	0.37	0.16	0.32	(0.34)	0.25	0.99	(0.59)
Effective Tax Rate using										
Canadian Statutory Rate	**25.7%**					25.1%				
Foreign Exchange Rates (US$ per C$1)										
Average	**0.905**	**0.881**	0.918	0.917	0.906	0.971	0.953	0.963	0.977	0.992
Period end	**0.862**	**0.862**	0.892	0.937	0.905	0.940	0.940	0.972	0.951	0.985
Cash Flow Summary										
Cash From (Used in) Operating Activities	**2,667**	**261**	696	767	943	2,289	462	935	554	338
Deduct (Add back):										
Net change in other assets and liabilities	**(43)**	**(15)**	(11)	(8)	(9)	(80)	(21)	(15)	(22)	(22)
Net change in non-cash working capital	**(9)**	**(141)**	155	119	(142)	(179)	(183)	300	(81)	(215)
Cash tax on sale of assets	**(215)**	**40**	(255)	-	-	(33)	(11)	(10)	(8)	(4)
Cash Flow (1)	**2,934**	**377**	807	656	1,094	2,581	677	660	665	579
Operating Earnings Summary										
Net Earnings (Loss) Attributable to Common Shareholders	**3,392**	**198**	2,807	271	116	236	(251)	188	730	(431)
After-tax (addition) deduction:										
Unrealized hedging gain (loss)	**306**	**341**	160	8	(203)	(232)	(209)	(89)	332	(266)
Impairments	**-**	**-**	-	-	-	(16)	-	(16)	-	-
Restructuring charges	**(24)**	**(4)**	(5)	(5)	(10)	(64)	(64)	-	-	-
Non-operating foreign exchange gain (loss)	**(407)**	**(151)**	(218)	156	(194)	(282)	(124)	105	(162)	(101)
Gain (loss) on divestitures	**2,523**	**(11)**	2,399	135	-	-	-	-	-	-
Income tax adjustments	**(8)**	**(12)**	190	(194)	8	28	(80)	38	313	(243)
Operating Earnings (2)	**1,002**	**35**	281	171	515	802	226	150	247	179

(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 is a non-GAAP measure defined as net earnings 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) Net earnings attributable to common shareholders, operating earnings and cash flow per common share are calculated using the weighted average number of Encana common shares outstanding as follows:

(millions)	2014 Year	2014 Q4	2014 Q3	2014 Q2	2014 Q1	2013 Year	2013 Q4	2013 Q3	2013 Q2	2013 Q1
Weighted Average Common Shares Outstanding										
Basic	**741.0**	**741.1**	741.1	741.0	741.0	737.7	740.4	738.3	736.1	736.2
Diluted	**741.0**	**741.1**	741.1	741.0	741.0	737.7	740.4	738.3	736.1	736.2

Supplemental Financial & Operating Information *(unaudited)*

Financial Metrics

	2014 Year	2013 Year
Debt to Debt Adjusted Cash Flow	**2.1x**	2.4x
Debt to Adjusted Capitalization	**30%**	36%

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

	2014					2013				
($ millions)	**Year**	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Capital Investment										
Canadian Operations	**1,226**	**302**	293	350	281	1,365	354	301	301	409
USA Operations	**1,285**	**548**	305	206	226	1,283	343	330	327	283
Market Optimization	**-**	**-**	(2)	1	1	3	1	-	2	-
Corporate & Other	**15**	**7**	2	3	3	61	19	10	9	23
Capital Investment	**2,526**	**857**	598	560	511	2,712	717	641	639	715
Net Acquisitions & (Divestitures) (1)	**(1,329)**	**50**	(2,007)	652	(24)	(776)	(72)	(51)	(312)	(341)
Net Capital Investment	**1,197**	**907**	(1,409)	1,212	487	1,936	645	590	327	374

(1) Q1 2013 Net Acquisitions & (Divestitures) includes proceeds received from the sale of the Company's 30 percent interest in the proposed Kitimat liquefied natural gas export terminal in British Columbia and associated undeveloped lands in the Horn River Basin.

Capital Investment

	2014					2013				
($ millions)	**Year**	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Capital Investment										
Montney	**776**	**157**	205	208	206	565	186	136	107	136
Duvernay	**328**	**118**	58	81	71	155	68	11	28	48
Eagle Ford	**274**	**149**	113	12	-	-	-	-	-	-
Permian	**117**	**117**	-	-	-	-	-	-	-	-
DJ Basin	**277**	**81**	68	69	59	181	46	55	50	30
San Juan	**287**	**96**	89	50	52	166	33	61	46	26
	2,059	**718**	533	420	388	1,067	333	263	231	240
Other Upstream Operations (1)	**452**	**132**	65	136	119	1,581	364	368	397	452
Market Optimization	**-**	**-**	(2)	1	1	3	1	-	2	-
Corporate & Other	**15**	**7**	2	3	3	61	19	10	9	23
Capital Investment	**2,526**	**857**	598	560	511	2,712	717	641	639	715

(1) 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"). 2014 capital investment for the TMS was $101 million (2013 - $98 million).

Supplemental Financial & Operating Information *(unaudited)*

Production Volumes - After Royalties

	2014					2013				
(average)	**Year**	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Natural Gas (MMcf/d)	**2,350**	**1,861**	2,199	2,541	2,809	2,777	2,744	2,723	2,766	2,877
Oil (Mbbls/d)	**49.4**	**68.8**	62.1	34.2	32.1	25.8	33.0	27.2	22.9	20.0
NGLs (Mbbls/d)	**37.4**	**37.6**	41.9	34.0	35.8	28.1	33.0	31.0	24.7	23.5
Oil & NGLs (Mbbls/d)	**86.8**	**106.4**	104.0	68.2	67.9	53.9	66.0	58.2	47.6	43.5
Total (MBOE/d)	**478.5**	**416.7**	470.6	491.8	536.1	516.7	523.4	512.1	508.6	523.0

Production Volumes - After Royalties

	2014					2013				
(average)	**Year**	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Natural Gas (MMcf/d)										
Canadian Operations	**1,378**	**1,111**	1,374	1,463	1,568	1,432	1,528	1,414	1,364	1,422
USA Operations	**972**	**750**	825	1,078	1,241	1,345	1,216	1,309	1,402	1,455
	2,350	**1,861**	2,199	2,541	2,809	2,777	2,744	2,723	2,766	2,877
Oil (Mbbls/d)										
Canadian Operations	**13.6**	**9.4**	14.7	13.9	16.4	11.9	16.8	12.3	10.3	8.0
USA Operations	**35.8**	**59.4**	47.4	20.3	15.7	13.9	16.2	14.9	12.6	12.0
	49.4	**68.8**	62.1	34.2	32.1	25.8	33.0	27.2	22.9	20.0
NGLs (Mbbls/d)										
Canadian Operations	**23.6**	**18.8**	27.6	23.5	24.6	18.5	21.7	20.5	15.7	16.0
USA Operations	**13.8**	**18.8**	14.3	10.5	11.2	9.6	11.3	10.5	9.0	7.5
	37.4	**37.6**	41.9	34.0	35.8	28.1	33.0	31.0	24.7	23.5
Oil & NGLs (Mbbls/d)										
Canadian Operations	**37.2**	**28.2**	42.3	37.4	41.0	30.4	38.5	32.8	26.0	24.0
USA Operations	**49.6**	**78.2**	61.7	30.8	26.9	23.5	27.5	25.4	21.6	19.5
	86.8	**106.4**	104.0	68.2	67.9	53.9	66.0	58.2	47.6	43.5
Total (MBOE/d)										
Canadian Operations	**266.9**	**213.4**	271.4	281.4	302.4	269.0	293.2	268.5	253.3	261.1
USA Operations	**211.6**	**203.3**	199.2	210.4	233.7	247.7	230.2	243.6	255.3	261.9
	478.5	**416.7**	470.6	491.8	536.1	516.7	523.4	512.1	508.6	523.0

Oil & NGLs Production Volumes - After Royalties

	2014		2013	
(average Mbbls/d)	**Year**	**% of Total**	Year	% of Total
Oil	**49.4**	**57**	25.8	49
Plant Condensate	**12.0**	**14**	8.7	16
Butane	**6.8**	**8**	4.5	8
Propane	**10.2**	**11**	7.2	13
Ethane	**8.4**	**10**	7.7	14
	86.8	**100**	53.9	100

Supplemental Financial & Operating Information *(unaudited)*

Results of Operations

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

	2014					2013				
($ millions)	**Year**	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Natural Gas - Canadian Operations										
Revenues, Net of Royalties, excluding Hedging	**2,468**	**402**	480	569	1,017	1,771	509	381	459	422
Realized Financial Hedging Gain (Loss)	**(74)**	**25**	20	(44)	(75)	271	84	102	19	66
Expenses										
Production and mineral taxes	**5**	**2**	1	-	2	4	2	1	-	1
Transportation and processing	**773**	**177**	186	209	201	724	207	183	165	169
Operating	**279**	**57**	66	72	84	322	82	72	80	88
Operating Cash Flow	**1,337**	**191**	247	244	655	992	302	227	233	230
Natural Gas - USA Operations										
Revenues, Net of Royalties, excluding Hedging	**1,640**	**274**	307	463	596	1,872	426	440	547	459
Realized Financial Hedging Gain (Loss)	**(85)**	**13**	10	(43)	(65)	260	80	84	27	69
Expenses										
Production and mineral taxes	**44**	**11**	(10)	14	29	77	19	16	27	15
Transportation and processing	**651**	**149**	162	177	163	722	175	184	179	184
Operating	**235**	**52**	50	65	68	339	97	78	78	86
Operating Cash Flow	**625**	**75**	115	164	271	994	215	246	290	243
Natural Gas - Total Operations										
Revenues, Net of Royalties, excluding Hedging	**4,108**	**676**	787	1,032	1,613	3,643	935	821	1,006	881
Realized Financial Hedging Gain (Loss)	**(159)**	**38**	30	(87)	(140)	531	164	186	46	135
Expenses										
Production and mineral taxes	**49**	**13**	(9)	14	31	81	21	17	27	16
Transportation and processing	**1,424**	**326**	348	386	364	1,446	382	367	344	353
Operating	**514**	**109**	116	137	152	661	179	150	158	174
Operating Cash Flow	**1,962**	**266**	362	408	926	1,986	517	473	523	473
Oil & NGLs - Canadian Operations										
Revenues, Net of Royalties, excluding Hedging	**872**	**149**	251	227	245	722	222	204	156	140
Realized Financial Hedging Gain (Loss)	**18**	**24**	(1)	(5)	-	5	6	(7)	2	4
Expenses										
Production and mineral taxes	**10**	**-**	3	4	3	11	2	7	1	1
Transportation and processing	**62**	**16**	16	16	14	32	18	7	4	3
Operating	**28**	**10**	8	4	6	39	7	11	9	12
Operating Cash Flow	**790**	**147**	223	198	222	645	201	172	144	128
Oil & NGLs - USA Operations										
Revenues, Net of Royalties, excluding Hedging	**1,258**	**412**	452	215	179	602	177	169	134	122
Realized Financial Hedging Gain (Loss)	**60**	**65**	1	(6)	-	4	3	(7)	3	5
Expenses										
Production and mineral taxes	**74**	**23**	23	15	13	42	14	11	9	8
Transportation and processing	**7**	**3**	4	-	-	-	-	-	-	-
Operating	**115**	**51**	44	12	8	59	10	12	14	23
Operating Cash Flow	**1,122**	**400**	382	182	158	505	156	139	114	96
Oil & NGLs - Total Operations										
Revenues, Net of Royalties, excluding Hedging	**2,130**	**561**	703	442	424	1,324	399	373	290	262
Realized Financial Hedging Gain (Loss)	**78**	**89**	-	(11)	-	9	9	(14)	5	9
Expenses										
Production and mineral taxes	**84**	**23**	26	19	16	53	16	18	10	9
Transportation and processing	**69**	**19**	20	16	14	32	18	7	4	3
Operating	**143**	**61**	52	16	14	98	17	23	23	35
Operating Cash Flow	**1,912**	**547**	605	380	380	1,150	357	311	258	224

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Operating Statistics - After Royalties

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

	2014					2013				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Natural Gas - Canadian Operations ($/Mcf)										
Price (1)	**4.89**	**3.93**	3.78	4.27	7.17	3.35	3.60	2.90	3.69	3.21
Production and mineral taxes	**0.01**	**0.01**	0.01	-	0.01	0.01	0.02	0.01	-	0.01
Transportation and processing	**1.53**	**1.73**	1.47	1.57	1.42	1.37	1.46	1.38	1.33	1.29
Operating	**0.55**	**0.55**	0.52	0.55	0.59	0.61	0.59	0.55	0.65	0.66
Netback	**2.80**	**1.64**	1.78	2.15	5.15	1.36	1.53	0.96	1.71	1.25
Natural Gas - USA Operations ($/Mcf)										
Price	**4.62**	**3.95**	4.05	4.72	5.34	3.81	3.81	3.66	4.29	3.50
Production and mineral taxes	**0.12**	**0.17**	(0.14)	0.15	0.26	0.16	0.18	0.13	0.21	0.11
Transportation and processing	**1.83**	**2.16**	2.13	1.80	1.46	1.47	1.56	1.53	1.40	1.40
Operating	**0.66**	**0.75**	0.65	0.67	0.61	0.69	0.86	0.65	0.61	0.66
Netback	**2.01**	**0.87**	1.41	2.10	3.01	1.49	1.21	1.35	2.07	1.33
Natural Gas - Total Operations ($/Mcf)										
Price (2)	**4.78**	**3.94**	3.88	4.46	6.37	3.57	3.69	3.26	3.99	3.35
Production and mineral taxes	**0.06**	**0.08**	(0.05)	0.06	0.12	0.08	0.09	0.07	0.11	0.06
Transportation and processing	**1.66**	**1.90**	1.72	1.67	1.44	1.42	1.51	1.46	1.36	1.35
Operating	**0.60**	**0.63**	0.57	0.60	0.60	0.65	0.70	0.60	0.63	0.66
Netback	**2.46**	**1.33**	1.64	2.13	4.21	1.42	1.39	1.13	1.89	1.28
Oil & NGLs - Canadian Operations ($/bbl)										
Price	**64.16**	**57.50**	64.79	66.13	66.36	65.06	62.80	67.33	65.88	64.72
Production and mineral taxes	**0.71**	**0.10**	0.67	1.12	0.80	0.96	0.61	1.91	0.62	0.58
Transportation and processing	**4.52**	**5.92**	4.21	4.60	3.80	2.89	5.15	2.41	1.53	1.33
Operating	**2.09**	**4.00**	2.05	1.06	1.75	3.56	2.03	3.74	3.77	5.61
Netback	**56.84**	**47.48**	57.86	59.35	60.01	57.65	55.01	59.27	59.96	57.20
Oil & NGLs - USA Operations ($/bbl)										
Price	**69.54**	**57.30**	79.43	77.46	73.61	70.18	69.46	72.53	68.56	69.91
Production and mineral taxes	**4.10**	**3.16**	4.18	5.19	5.46	4.79	5.06	4.90	4.57	4.50
Transportation and processing	**0.39**	**0.49**	0.63	-	-	-	-	-	-	-
Operating	**6.36**	**7.11**	7.80	4.29	3.16	7.02	4.11	5.13	7.54	13.16
Netback	**58.69**	**46.54**	66.82	67.98	64.99	58.37	60.29	62.50	56.45	52.25
Oil & NGLs - Total Operations ($/bbl)										
Price	**67.24**	**57.35**	73.48	71.23	69.23	67.30	65.58	69.60	67.10	67.04
Production and mineral taxes	**2.65**	**2.35**	2.75	2.95	2.65	2.63	2.46	3.22	2.41	2.33
Transportation and processing	**2.16**	**1.93**	2.09	2.53	2.30	1.63	3.01	1.36	0.84	0.73
Operating	**4.54**	**6.29**	5.46	2.51	2.31	5.07	2.90	4.35	5.48	8.98
Netback	**57.89**	**46.78**	63.18	63.24	61.97	57.97	57.21	60.67	58.37	55.00
Total Operations Netback - Canadian Operations ($/BOE)										
Price	**34.21**	**28.06**	29.21	31.02	46.20	25.13	27.02	23.42	26.62	23.34
Production and mineral taxes	**0.15**	**0.09**	0.15	0.16	0.18	0.15	0.17	0.29	0.05	0.09
Transportation and processing	**8.55**	**9.79**	8.10	8.76	7.87	7.62	8.31	7.60	7.30	7.16
Operating	**3.14**	**3.39**	2.96	2.98	3.29	3.65	3.32	3.34	3.88	4.13
Netback	**22.37**	**14.79**	18.00	19.12	34.86	13.71	15.22	12.19	15.39	11.96
Total Operations Netback - USA Operations ($/BOE)										
Price	**37.53**	**36.64**	41.38	35.48	36.82	27.37	28.42	27.23	29.35	24.61
Production and mineral taxes	**1.53**	**1.84**	0.72	1.51	1.99	1.31	1.54	1.22	1.55	0.97
Transportation and processing	**8.52**	**8.17**	9.03	9.23	7.75	7.98	8.24	8.24	7.69	7.80
Operating	**4.53**	**5.51**	5.12	4.05	3.60	4.42	5.06	4.04	3.97	4.65
Netback	**22.95**	**21.12**	26.51	20.69	23.48	13.66	13.58	13.73	16.14	11.19
Total Operations Netback ($/BOE)										
Price	**35.67**	**32.25**	34.36	32.93	42.12	26.20	27.63	25.23	27.99	23.97
Production and mineral taxes	**0.76**	**0.94**	0.39	0.74	0.97	0.71	0.77	0.73	0.80	0.53
Transportation and processing	**8.54**	**9.00**	8.50	8.96	7.82	7.79	8.28	7.90	7.50	7.48
Operating (3)	**3.76**	**4.43**	3.87	3.44	3.43	4.01	4.08	3.67	3.92	4.38
Netback	**22.61**	**17.88**	21.60	19.79	29.90	13.69	14.50	12.93	15.77	11.58

(1) Canadian Operations price reflects Deep Panuke price for 2014 of $8.34/Mcf on natural gas production volumes of 190 MMcf/d. Excluding the impact of the Deep Panuke operations, the natural gas price for 2014 is $4.35/Mcf.

(2) Excluding the impact of the Deep Panuke operations, the natural gas price for 2014 is $4.47/Mcf.

(3) 2014 operating expense includes costs related to long-term incentives of $0.06/BOE (2013 - $0.08/BOE).

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Operating Statistics - After Royalties (continued)

Impact of Realized Financial Hedging

	2014					2013				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Natural Gas ($/Mcf)										
Canadian Operations	**(0.15)**	**0.24**	0.16	(0.33)	(0.53)	0.51	0.60	0.78	0.15	0.50
USA Operations	**(0.24)**	**0.19**	0.12	(0.44)	(0.58)	0.53	0.72	0.69	0.21	0.53
Total Operations	**(0.19)**	**0.22**	0.15	(0.38)	(0.55)	0.52	0.65	0.74	0.18	0.51
Oil & NGLs ($/bbl)										
Canadian Operations	**1.36**	**9.35**	(0.31)	(1.22)	(0.09)	0.46	1.62	(2.59)	1.00	2.20
USA Operations	**3.29**	**8.94**	0.25	(2.28)	0.04	0.44	1.15	(2.73)	1.32	2.67
Total Operations	**2.46**	**9.05**	0.02	(1.70)	(0.04)	0.45	1.43	(2.65)	1.15	2.41
Total ($/BOE)										
Canadian Operations	**(0.57)**	**2.49**	0.78	(1.89)	(2.77)	2.78	3.32	3.78	0.91	2.93
USA Operations	**(0.33)**	**4.15**	0.58	(2.57)	(3.07)	2.93	3.96	3.44	1.28	3.14
Total Operations	**(0.46)**	**3.30**	0.70	(2.18)	(2.90)	2.85	3.60	3.62	1.09	3.03

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

	2014					2013				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Natural Gas Price ($/Mcf)										
Canadian Operations	**4.74**	**4.17**	3.94	3.94	6.64	3.86	4.20	3.68	3.84	3.71
USA Operations	**4.38**	**4.14**	4.17	4.28	4.76	4.34	4.53	4.35	4.50	4.03
Total Operations	**4.59**	**4.16**	4.03	4.08	5.82	4.09	4.34	4.00	4.17	3.86
Natural Gas Netback ($/Mcf)										
Canadian Operations	**2.65**	**1.88**	1.94	1.82	4.62	1.87	2.13	1.74	1.86	1.75
USA Operations	**1.77**	**1.06**	1.53	1.66	2.43	2.02	1.93	2.04	2.28	1.86
Total Operations	**2.27**	**1.55**	1.79	1.75	3.66	1.94	2.04	1.87	2.07	1.79
Oil & NGLs Price ($/bbl)										
Canadian Operations	**65.52**	**66.85**	64.48	64.91	66.27	65.52	64.42	64.74	66.88	66.92
USA Operations	**72.83**	**66.24**	79.68	75.18	73.65	70.62	70.61	69.80	69.88	72.58
Total Operations	**69.70**	**66.40**	73.50	69.53	69.19	67.75	67.01	66.95	68.25	69.45
Oil & NGLs Netback ($/bbl)										
Canadian Operations	**58.20**	**56.83**	57.55	58.13	59.92	58.11	56.63	56.68	60.96	59.40
USA Operations	**61.98**	**55.48**	67.07	65.70	65.03	58.81	61.44	59.77	57.77	54.92
Total Operations	**60.35**	**55.83**	63.20	61.54	61.93	58.42	58.64	58.02	59.52	57.41
Total Price ($/BOE)										
Canadian Operations	**33.64**	**30.55**	29.99	29.13	43.43	27.91	30.34	27.20	27.53	26.27
USA Operations	**37.20**	**40.79**	41.96	32.91	33.75	30.30	32.38	30.67	30.63	27.75
Total Operations	**35.21**	**35.55**	35.06	30.75	39.22	29.05	31.23	28.85	29.08	27.00
Total Netback ($/BOE)										
Canadian Operations	**21.80**	**17.28**	18.78	17.23	32.09	16.49	18.54	15.97	16.30	14.89
USA Operations	**22.62**	**25.27**	27.09	18.12	20.41	16.59	17.54	17.17	17.42	14.33
Total Operations	**22.15**	**21.18**	22.30	17.61	27.00	16.54	18.10	16.55	16.86	14.61

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Results by Play

	2014					2013				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Natural Gas Production (MMcf/d) - After Royalties										
Canadian Operations										
Montney	**514**	**570**	517	484	484	463	500	513	424	413
Duvernay	**11**	**12**	15	9	8	4	7	5	2	1
Other Upstream Operations (1)										
Clearwater	**292**	**249**	291	305	324	335	329	332	331	347
Bighorn	**158**	**(3)**	162	230	246	255	283	253	242	243
Deep Panuke	**190**	**79**	186	243	253	41	133	30	-	-
Other and emerging	**213**	**204**	203	192	253	334	276	281	365	418
Total Canadian Operations	**1,378**	**1,111**	1,374	1,463	1,568	1,432	1,528	1,414	1,364	1,422
USA Operations										
Eagle Ford	**19**	**35**	35	5	-	-	-	-	-	-
Permian	**5**	**20**	-	-	-	-	-	-	-	-
DJ Basin	**43**	**49**	38	43	40	39	43	37	39	37
San Juan	**8**	**8**	9	7	7	3	6	3	1	1
Other Upstream Operations (1)										
Piceance	**402**	**367**	398	407	436	455	452	444	465	459
Haynesville	**311**	**252**	298	365	331	348	261	336	375	420
Jonah	**100**	**-**	-	124	282	323	296	320	332	346
East Texas	**57**	**-**	21	97	113	136	123	132	145	145
Other and emerging	**27**	**19**	26	30	32	41	35	37	45	47
Total USA Operations	**972**	**750**	825	1,078	1,241	1,345	1,216	1,309	1,402	1,455
Oil & NGLs Production (Mbbls/d) - After Royalties										
Canadian Operations										
Montney	**18.7**	**24.6**	20.7	13.3	16.1	10.0	13.5	11.8	7.8	6.7
Duvernay	**2.1**	**2.5**	2.6	1.8	1.4	0.7	1.2	0.7	0.5	0.3
Other Upstream Operations (1)										
Clearwater	**8.6**	**2.0**	9.9	11.3	11.3	9.9	12.2	9.8	9.2	8.5
Bighorn	**7.5**	**(1.5)**	8.7	11.0	12.1	8.9	10.9	9.9	7.4	7.4
Other and emerging	**0.3**	**0.6**	0.4	-	0.1	0.9	0.7	0.6	1.1	1.1
Total Canadian Operations	**37.2**	**28.2**	42.3	37.4	41.0	30.4	38.5	32.8	26.0	24.0
USA Operations										
Eagle Ford	**19.8**	**36.1**	37.6	5.0	-	-	-	-	-	-
Permian	**3.5**	**13.8**	-	-	-	-	-	-	-	-
DJ Basin	**11.6**	**14.0**	11.8	10.1	10.5	8.4	10.7	8.2	7.8	6.8
San Juan	**3.9**	**5.6**	3.5	3.9	2.7	1.4	2.9	1.9	0.4	0.3
Other Upstream Operations (1)										
Piceance	**5.0**	**4.3**	4.8	5.3	5.4	5.1	5.3	5.5	5.2	4.3
Jonah	**1.8**	**-**	0.2	2.5	4.7	4.7	4.6	4.8	4.9	4.6
East Texas	**0.5**	**-**	-	1.0	1.2	1.0	1.0	1.1	0.9	0.8
Other and emerging	**3.5**	**4.4**	3.8	3.0	2.4	2.9	3.0	3.9	2.4	2.7
Total USA Operations	**49.6**	**78.2**	61.7	30.8	26.9	23.5	27.5	25.4	21.6	19.5

(1) 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.

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Results by Play (continued)

	2014					2013				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Drilling Activity (net wells drilled)										
Canadian Operations										
Montney	**79**	**14**	15	23	27	61	18	14	13	16
Duvernay	**24**	**5**	7	6	6	12	4	4	2	2
Other Upstream Operations (1)										
Clearwater	**174**	**84**	24	-	66	283	115	81	-	87
Bighorn	**1**	**-**	1	-	-	21	1	3	9	8
Other and emerging	**1**	**-**	1	-	-	13	2	2	5	4
Total Canadian Operations	**279**	**103**	48	29	99	390	140	104	29	117
USA Operations										
Eagle Ford	**35**	**21**	14	-	-	-	-	-	-	-
Permian	**28**	**28**	-	-	-	-	-	-	-	-
DJ Basin	**64**	**15**	17	14	18	51	11	13	15	12
San Juan	**43**	**19**	15	5	4	19	4	7	6	2
Other Upstream Operations (1)										
Piceance	**1**	**-**	-	-	1	85	20	20	23	22
Haynesville	**-**	**-**	-	-	-	19	7	5	5	2
Jonah	**18**	**-**	-	6	12	49	9	13	13	14
East Texas	**-**	**-**	-	-	-	7	3	2	-	2
Other and emerging	**15**	**5**	4	4	2	7	2	2	-	3
Total USA Operations	**204**	**88**	50	29	37	237	56	62	62	57

(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.