LONG RUN EXPLORATION LTD.

Management's Discussion and Analysis

September 30, 2014

Management's Discussion and Analysis

For the three and nine months ended September 30, 2014

This Management's Discussion & Analysis ("MD&A") of the financial condition and results of operations of Long Run Exploration Ltd. ("Long Run", the "Company", "its" or "our") should be read in conjunction with the unaudited interim financial statements for the period ended September 30, 2014 and the audited financial statements and MD&A for the year ended December 31, 2013. The disclosure which is unchanged from the MD&A for the year ended December 31, 2013 may not be repeated herein.

The Company follows International Financial Reporting Standards ("IFRS"). Amounts shown in the MD&A are in Canadian dollars unless otherwise stated. All production volumes disclosed herein are sales volumes. Certain prior year amounts have been reclassified to conform to current year presentation.

The MD&A contains certain measures that do not have any standardized meaning as prescribed by IFRS and therefore are considered non-Generally Accepted Accounting Principles ("Non-GAAP") measures. Readers are cautioned that the MD&A should be read in conjunction with the disclosure in the Non-GAAP Measures and the Advisory sections located at the end of this document. The Advisory provides information on forward-looking statements and oil and natural gas information.

See the Abbreviations section at the end of this document for abbreviations used throughout.

This document is dated November 5, 2014.

Long Run's Strategy

Long Run is engaged in the development, acquisition, exploration and production of oil and natural gas in western Canada. Specifically, the Company is focused on controlled exploitation and strategic acquisitions within the Western Canadian Sedimentary Basin. The Company's core areas are located in central and northern Alberta, including the Montney at Peace River, the Cardium and Bluesky in the Deep Basin, Viking at Redwater and the Bluesky at Boyer.

Long Run has assembled large land blocks and has invested in crude oil and natural gas infrastructure in its key areas to obtain operatorship, control infrastructure and build our multi-year inventory of locations. The Company's near term strategy is to develop the potential of Long Run's oil and liquids-rich natural gas resources, selectively explore on our current land base and maintain a strong focus on cost control and efficiencies. Additionally, Long Run will continue to pursue strategic asset and corporate acquisitions of crude oil and natural gas properties, while reviewing our portfolio for potential dispositions. Long Run is committed to portfolio management and maintaining a strong capital structure.

In 2014, the Company transitioned its business model to a balanced intermediate producer paying a monthly dividend, while continuing to provide annual per share growth to shareholders. Long Run is focused on providing long-term value to shareholders through a sustainable dividend model. Controlled exploitation of our core assets and strategic acquisitions form the basis of our goal of funding both net capital expenditures and dividends from funds flow from operations. Throughout the commodity price cycle, we remain committed to protecting our dividend through active portfolio management, proactive hedging and a focus on cost efficiencies.

Highlights

Highlights for the three months ended September 30, 2014 include:

- Generated funds flow from operations of $80.2 million, a 29% increase over $62.3 million in the third quarter 2013.

- Averaged 34,795 Boe/d of production, a 38% increase from 25,293 Boe/d in the third quarter of 2013. Third party restrictions and plant outages reduced production by approximately 1,600 Boe/d in the quarter.

- Declared monthly dividends of $0.035 per share, totaling $0.11 per share for the quarter, or $18.8 million. Maintained a sustainable basic payout ratio of 23%, without the assistance of a dividend reinvestment plan.

- Executed our focused development program, drilling 21.0 net wells, with a 100% success rate. Capital expenditures totaled $75.8 million, including facility costs spent to provide flexibility for future development and reduce reliance on third party processing. Expenditures were concentrated in our Peace River Montney, Deep Basin Cardium and Redwater Viking areas.

- Successfully closed the acquisition of Crocotta Energy Inc. (“Crocotta”) described further below.

Highlights for the nine months ended September 30, 2014 include:

- Generated funds flow from operations of $223.7 million, a 28% increase over $174.2 million in 2013.

- Averaged 29,730 Boe/d of production, a 22% increase from 24,451 Boe/d in 2013. Third party restrictions and plant outages reduced production by approximately 600 Boe/d in the period.

- Successfully transitioned to a dividend plus growth model. Dividends declared in the first nine months of 2014 totaled $0.31 per share, or $45.9 million, with a basic payout ratio of 21%. Long Run increased our monthly dividend by 5% from $0.0335 per share to $0.035 per share starting with the June dividend paid in July.

- Executed a focused development program, drilling 90.5 net wells, with a 100% success rate. Capital expenditures totaled $233.9 million, concentrated in our Peace River Montney and Redwater Viking areas.

- Successfully closed a strategic property acquisition (the “Deep Basin Acquisition”) on May 30, 2014 for $228.8 million, which provides a key entry point into the Pine Creek, Kakwa and Wapiti areas of Alberta. A $120.0 million bought deal equity financing was closed in conjunction with the acquisition. Long Run’s credit facility borrowing base was increased by $100 million to $575 million upon closing of the transaction.

- Successfully closed and integrated the Crocotta acquisition on August 6, 2014 for $346.9 million. The acquisition enhances our new Deep Basin core area by providing exploration and development opportunities and adding strategic ownership of gathering and processing infrastructure in Pine Creek.

  Crocotta was acquired pursuant to a plan of arrangement (the “Arrangement”) under the *Business Corporations Act* (Alberta). Under the Arrangement, Crocotta shareholders received a combination of Long Run Common Shares, as well as common shares and warrants of a newly established Montney-focused exploration company (“ExploreCo”). ExploreCo assets, including assets in northeast British Columbia and northwest Alberta, were excluded from Long Run’s acquisition of

Crocotta. For each Crocotta share held, shareholders of Crocotta received 0.415 of a Long Run Common Share, one common share of ExploreCo, and 0.2 arrangement warrants of ExploreCo.

As consideration for Crocotta, Long Run issued 43.8 million Common Shares and assumed $115.5 million of the net debt of Crocotta, defined as bank debt, net of cash, less working capital. Long Run's credit facility borrowing base was increased by $120 million to $695 million upon closing of the transaction.

- Issued $75 million of convertible debentures to strengthen the balance sheet by providing Long Run with additional financial flexibility through the diversification of indebtedness and interest rate certainty on a portion of its debt. The convertible debentures bear an annual interest rate of 6.40% and are convertible into Long Run Common Shares at conversion price of $7.40 per share.

Quarterly Results Overview

($000s, except per share or unless otherwise noted)	Nine months ended September 30		2014			2013			
	2014	2013	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1
Funds flow from operations [1]	**223,678**	174,175	**80,199**	73,429	70,050	55,934	62,304	63,227	48,644
Per share, basic [1]	**1.54**	1.39	**0.45**	0.55	0.56	0.45	0.50	0.50	0.39
Per share, diluted [1]	**1.53**	1.39	**0.45**	0.54	0.56	0.44	0.50	0.50	0.39
Net earnings (loss)	**68,257**	29,796	**40,644**	20,842	6,771	(5,531)	9,524	21,099	(827)
Per share, basic	**0.47**	0.24	**0.23**	0.16	0.05	(0.04)	0.08	0.17	(0.01)
Per share, diluted	**0.47**	0.24	**0.23**	0.15	0.05	(0.04)	0.08	0.17	(0.01)
Dividends declared	**45,888**	-	**18,781**	14,468	12,639	-	-	-	-
Per share	**0.31**	-	**0.11**	0.10	0.10	-	-	-	-
Payout ratio [1]	**21%**	-	**23%**	20%	18%	-	-	-	-
Revenues, before royalties	**477,542**	350,746	**166,978**	158,678	151,886	124,816	129,923	117,210	103,613
Capital expenditures	**233,938**	234,934	**75,759**	57,330	100,848	41,637	93,137	38,878	102,919
Net acquisitions (divestitures) [2]	**(26,878)**	22,434	**(8,147)**	(15,051)	(3,679)	86,328	3,331	1,158	17,945
Production									
Oil *(Bbl/d)*	**12,745**	11,432	**13,071**	12,476	12,684	13,251	11,709	11,471	11,109
Natural gas liquids *(Bbl/d)*	**2,223**	1,282	**3,031**	2,038	1,584	1,520	1,478	1,116	1,249
Natural gas *(Mcf/d)*	**86,414**	70,422	**112,161**	78,524	68,071	73,392	72,634	71,058	67,516
Total *(Boe/d)*	**29,370**	24,451	**34,795**	27,602	25,613	27,003	25,293	24,431	23,611
Prices, including derivatives									
Oil *($/Bbl)*	**86.67**	80.85	**84.66**	89.59	85.89	71.14	87.44	81.80	72.77
Natural gas liquids *($/Bbl)*	**69.28**	73.74	**57.98**	72.76	86.87	69.21	76.05	68.91	75.33
Natural gas *($/Mcf)*	**4.68**	3.58	**4.23**	4.61	5.53	4.04	3.23	3.89	3.63
Total *($/Boe)*	**56.80**	52.31	**50.75**	59.13	62.67	49.78	54.29	53.29	49.12
Operating netback *($/Boe)*	**34.03**	30.46	**31.41**	35.04	36.55	27.09	30.74	32.57	27.93

[1] *See Non-GAAP measures section*
[2] *Excludes $228.8 million paid for the Deep Basin Acquisition on May 30, 2014*

Third quarter 2014 compared to third quarter 2013

Funds flow from operations for 2014 totaled $80.2 million, an increase of $17.9 million from $62.3 million in the third quarter of 2013. The increased funds flow was attributable to higher production volumes and a higher natural gas price, partially offset by lower liquids prices, higher royalties and operating costs associated with the increase in production and higher general and administration expense due to Crocotta transaction costs. Funds flow from operations in the third quarter of 2014 included 1.8 months of operating results from the Crocotta assets acquired on August 6, 2014. General and administration expense included $4.8 million of transaction costs associated with the Crocotta acquisition.

Net earnings for 2014 were $40.6 million, an increase of $31.1 million from $9.5 million in the third quarter of 2013. The increase in net earnings resulted from the increased funds flow from operations and a higher unrealized gain on oil derivatives, which were partially offset by higher depletion expense related to the increase in production volumes.

Nine months ended September 30, 2014 compared to nine months ended September 30, 2013

Funds flow from operations for 2014 was $223.7 million, an increase of $49.5 million from 2013, primarily due to higher production volumes and commodity prices, partially offset by higher royalties and operating costs associated with the increase in production volumes, a higher realized loss on derivatives, higher general and administration expense and higher interest expense. 2014 funds flow from operations included four months of operating results from the Deep Basin properties and two months of operating results from the Crocotta assets acquired. General and administration expense included $6.8 million of transaction costs associated with the acquisitions.

Net earnings for 2014 were $68.3 million, an increase of $38.5 million from $29.8 million in 2013. The increase in net earnings resulted from the higher funds flow from operations, an increased unrealized gain on oil derivatives and higher gains on disposals of assets, partially offset by higher depletion expense related to the increase in production volumes.

Significant Properties

Within the Western Canadian Sedimentary Basin, Long Run operates two significant light oil areas, Peace River and Redwater. During 2014, the Company added the Deep Basin as a new core development area focused on oil and liquids-rich natural gas. The Company also owns a significant low decline shallow gas property at Boyer in northern Alberta.

Development of the Peace River area, located in northern Alberta, is focused on the Montney oil resource play at Normandville and Girouxville. During the third quarter of 2014, Long Run invested $40.3 million into the Peace River area and drilled 12.0 net horizontal Montney oil wells, with a 100% success rate. Third quarter 2014 production averaged 13,972 Boe/d, consisting of 7,782 Bbl/d of oil and NGLs and 37.1 MMcf/d of natural gas. In the first nine months of 2014, Long Run invested $126.8 million, drilling 42.5 net wells (40.5 Montney horizontal oil wells) with a 100% success rate, resulting in average production of 11,821 Boe/d (59% oil and NGLs). Capital expenditures for 2014 are expected to total $135 million, including the drilling of approximately 44 net wells. The Company operates, transports, and processes all of its production within Peace River.

In the Redwater area, located near Edmonton, Alberta, development is focused on the Viking oil resource play. During the third quarter of 2014, Long Run invested $20.8 million in the Redwater area, drilling 6.0 net wells, with a 100% success rate. Third quarter 2014 production averaged 8,311 Boe/d, consisting of 5,325 Bbl/d of oil and NGLs and 17.9 MMcf/d of natural gas. In the first nine months of 2014, Long Run invested $77.0 million, drilling 44.0 net wells with a 100% success rate, resulting in average production of 7,008 Boe/d (73% oil and NGLs). Capital expenditures for 2014 are expected to total $80 million, including the drilling of approximately 45 net wells. The Company operates, transports, and processes substantially all of its production within the Redwater area.

Following the closing of the Deep Basin Acquisition on May 30, 2014 and the Crocotta acquisition on August 6, 2014, the Company has development and exploration assets located in the Deep Basin at Pine Creek, Kakwa and Wapiti in western Alberta. The development focus is on Cardium liquids-rich natural gas and light oil. The Crocotta acquisition added significant ownership of operated gathering and processing infrastructure in the Deep Basin area, comprised of 50 MMcf/d of natural gas handling, oil batteries, pipeline gathering systems and an Alliance pipeline connection (meter station). The assets also included a working interest in the Edson (Pine Creek) natural gas plant and provide access to increased NGL value through existing marketing arrangements.

During the third quarter of 2014, Long Run invested $14.2 million in the Deep Basin area, drilling 3.0 net wells, with a 100% success rate. Third quarter 2014 production in the Deep Basin averaged 7,859 Boe/d, consisting of 2,218 Bbl/d of oil and NGLs and 33.8 MMcf/d of natural gas. Of total production in the Deep Basin area for the quarter, 3,859 Boe/d was attributed to the Deep Basin Acquisition and 4,000 Boe/d to the Crocotta acquisition, with the Crocotta production reflecting 1.8 months of operating results. During the quarter, third party restrictions and plant outages reduced production by approximately 1,600 Boe/d, of which 1,200 Boe/d was in the Deep Basin. Capital expenditures for 2014 are expected to total $55 million, including the drilling of approximately 11 net wells.

Capital Investment

Capital Expenditures, Acquisitions & Dispositions

($000s)	**Q3 2014**	Q3 2013	**Nine months ended September 30 2014**	Nine months ended September 30 2013
Drilling and completion	**52,530**	72,746	**162,495**	173,054
Plant and facilities	**19,740**	18,699	**59,551**	56,048
Geological and geophysical	**1,951**	601	**7,185**	2,694
Other assets	**1,538**	1,091	**4,707**	3,138
Capital expenditures	**75,759**	93,137	**233,938**	234,934
Acquisitions – land	**1,071**	5,302	**5,765**	16,389
– properties	**7,423**	5,500	**12,334**	19,369
Dispositions	**(16,641)**	(7,471)	**(44,977)**	(13,324)
Net capital expenditures excluding the Deep Basin Acquisition	**67,612**	96,468	**207,060**	257,368
Deep Basin Acquisition	**-**	-	**228,767**	-
Net capital expenditures	**67,612**	96,468	**435,827**	257,368

Drilling Activity

	Q3 2014 Wells		Q3 2013 Wells		Success Rate *(net wells)*	
	Gross	**Net**	Gross	Net	**Q3 2014**	Q3 2013
Peace River	**12.0**	**12.0**	20.0	19.5	**100%**	100%
Redwater	**6.0**	**6.0**	27.0	26.6	**100%**	100%
Deep Basin	**3.0**	**3.0**	-	-	**100%**	-
Other	**-**	**-**	4.0	4.0	**-**	100%
	21.0	**21.0**	51.0	50.1	**100%**	100%

	Nine months ended September 30					
	2014 Wells		2013 Wells		Success Rate *(net wells)*	
	Gross	**Net**	Gross	Net	**2014**	2013
Peace River	**43.0**	**42.5**	43.0	42.5	**100%**	98%
Redwater	**44.0**	**44.0**	65.0	63.2	**100%**	100%
Deep Basin	**3.0**	**3.0**	-	-	**100%**	-
Other	**1.0**	**1.0**	8.0	8.0	**100%**	75%
	91.0	**90.5**	116.0	113.7	**100%**	97%

Capital Expenditures

Capital expenditures in the third quarter of 2014 were $75.8 million, with $40.3 million (53%) in Peace River, $20.8 million (27%) in Redwater and $14.2 million (19%) in the Deep Basin. Capital expenditures included facility costs spent to provide flexibility for future development and reduce reliance on third party processing. The Company drilled 21 (21.0 net) wells with a 100% success rate in the period.

Capital expenditures in the third quarter of 2013 were $93.1 million, with $48.6 million (52%) in Peace River and $40.0 million (43%) in Redwater. The Company drilled 51 (50.1 net) oil wells with a 100% success rate in the period.

Capital expenditures in the first nine months of 2014 were $233.9 million, with 126.8 million (54%) in Peace River, $77.0 million (33%) in Redwater and $14.2 million (6%) in the Deep Basin. The Company drilled 91 (90.5 net) wells with a 100% success rate in the period.

Capital expenditures in the first nine months of 2013 were $234.9 million, with $113.3 million (48%) in Peace River and $91.6 million (39%) in Redwater. The Company drilled 116 (113.7 net) wells with a 97% success rate.

Acquisitions and Dispositions

The active management of our portfolio of assets resulted in net divestitures of $8.1 million during the third quarter of 2014. Acquisitions were $8.5 million, consisting primarily of a minor property tuck-in in Redwater. The Company received $16.6 million in disposition proceeds primarily related to a property disposition in Pine Creek.

Excluding the Deep Basin Acquisition, net dispositions of minor properties in the first nine months of 2014 were $26.9 million. These dispositions included the sale of the heavy oil Lloydminster property for proceeds of $12 million, the sale of a Pine Creek property for proceeds of $14.8 million and the sale of a Peace River property for proceeds of $15.3 million.

Net acquisitions of minor properties in the first nine months of 2013 were $22.4 million.

Enhanced Oil Recovery

The timeline of our ongoing Enhanced Oil Recovery (“EOR”) projects remains intact. Currently we are injecting water for pressure maintenance and enhanced recovery at our two major fields: the Peace River Montney and the Redwater Viking. EOR projects initiated in 2013 in Peace River at Normandville and Girouxville continue to operate successfully to date. We expect to expand both of these projects during the fourth quarter of 2014 with patterned waterflood pilots, utilizing multiple horizontal injectors and producers. These expanded pilots form the basis from which EOR may be implemented across the rest of these fields, beginning late in 2015 or in 2016.

In the Redwater Viking, a second EOR pilot project is planned to be implemented in the fourth quarter of 2014. This will complement the first EOR project, which was initiated during 2013, and will provide additional technical data which will be used to evaluate field-wide EOR implementation, expected to start in late 2015.

Production

Average Production by Product

	Q3 2014	Q3 2013	Nine months ended September 30 2014	Nine months ended September 30 2013
Liquids *(Bbl/d)*				
Light oil	**12,708**	10,322	**12,007**	9,887
Heavy oil	**363**	1,387	**738**	1,545
NGLs	**3,031**	1,478	**2,223**	1,282
Total	**16,102**	13,187	**14,968**	12,714
Natural Gas *(Mcf/d)*	**112,161**	72,634	**86,414**	70,422
Total *(Boe/d)*	**34,795**	25,293	**29,370**	24,451

Average Production by Area

	Q3 2014				Q3 2013			
	Oil *(Bbl/d)*	NGLs *(Bbl/d)*	Natural Gas *(Mcf/d)*	Total *(Boe/d)*	Oil *(Bbl/d)*	NGLs *(Bbl/d)*	Natural Gas *(Mcf/d)*	Total *(Boe/d)*
Peace River	**7,356**	**426**	**37,143**	**13,972**	5,434	281	26,316	10,101
Redwater	**5,152**	**173**	**17,916**	**8,311**	4,599	57	7,316	5,875
Deep Basin	**563**	**1,655**	**33,845**	**7,859**	-	-	-	-
Boyer	**-**	**1**	**17,569**	**2,929**	-	1	19,434	3,241
Kaybob	**-**	**767**	**5,688**	**1,715**	11	931	5,887	1,923
Other	**-**	**9**	**-**	**9**	1,665	208	13,681	4,153
	13,071	**3,031**	**112,161**	**34,795**	11,709	1,478	72,634	25,293

	Nine months ended September 30, 2014				Nine months ended September 30, 2013			
	Oil *(Bbl/d)*	NGLs *(Bbl/d)*	Natural Gas *(Mcf/d)*	Total *(Boe/d)*	Oil *(Bbl/d)*	NGLs *(Bbl/d)*	Natural Gas *(Mcf/d)*	Total *(Boe/d)*
Peace River	**6,644**	**317**	**29,163**	**11,821**	5,377	238	25,336	9,837
Redwater	**5,018**	**111**	**11,279**	**7,008**	4,221	52	7,403	5,507
Deep Basin	**224**	**694**	**13,923**	**3,239**	-	-	-	-
Boyer	**-**	**1**	**17,415**	**2,903**	-	1	18,905	3,152
Kaybob	**-**	**924**	**5,309**	**1,810**	14	779	5,588	1,725
Other	**859**	**176**	**9,325**	**2,589**	1,820	212	13,190	4,230
	12,745	**2,223**	**86,414**	**29,370**	11,432	1,282	70,422	24,451

Production for the third quarter of 2014 averaged 34,795 Boe/d, an increase of 9,502 Boe/d (38%) from 25,293 Boe/d in the third quarter of 2013. Production for the first nine months of 2014 averaged 29,370 Boe/d, an increase of 4,919 Boe/d (20%) from 24,451 Boe/d in the third quarter of 2013. The production increases resulted from our development drilling over the past year, the Deep Basin Acquisition on May 30, 2014 and the Crocotta acquisition on August 6, 2014. Production in the third quarter of 2014 was reduced by approximately 1,600 Boe/d due to third party restrictions and plant outages.

Production for the third quarter 2014 increased at Peace River by 3,871 Boe/d (38%) to 13,972 Boe/d from 10,101 Boe/d in 2013, and at Redwater by 2,436 Boe/d (41%) to 8,311 Boe/d from 5,875 Boe/d. The Deep Basin property added 7,859 Boe/d of production in the quarter. Long Run's Deep Basin Acquisition added approximately 4,900 Boe/d of production to the Redwater and Deep Basin properties, and the Crocotta assets added approximately 4,000 Boe/d to the Deep Basin property.

In the third quarter of 2014, longer than scheduled third party plant turnarounds, third party pipeline repairs and third party unscheduled maintenance reduced Long Run's average daily production by approximately 1,600 Boe/d. These outages included an extended turnaround at a third party operated gas processing plant at Edson (Pine Creek), third party plant capacity restrictions and an extended turnaround at a third party operated gas plant at Kakwa, and unscheduled third party pipeline repairs and pipeline restrictions resulting in reduced nominations at Wapiti. The completion of the facility expansion at Kakwa in early 2015, where Long Run will have firm capacity, will significantly reduce unplanned restrictions in the Deep Basin area.

Commodity Pricing

	Q3 2014	Q3 2013	Nine months ended September 30 2014	Nine months ended September 30 2013
Benchmark pricing				
WTI *($US/Bbl)*	**97.21**	105.83	**99.60**	97.79
Edmonton Light Sweet *($CAD/Bbl)*	**97.18**	104.98	**100.80**	95.54
AECO *($/Mcf)*	**4.02**	2.43	**4.78**	3.18
Cdn$/US$ exchange rate	**1.09**	1.04	**1.09**	1.02
Prices, excluding derivatives				
Liquids *($/Bbl)*				
Light oil	**88.08**	95.47	**92.16**	85.61
Heavy oil	**81.47**	87.40	**80.20**	70.78
Total Oil	**87.90**	94.51	**91.47**	83.61
NGLs	**57.98**	76.05	**69.28**	73.74
Total	**82.26**	92.44	**88.18**	82.61
Natural Gas *($/Mcf)*	**4.29**	2.65	**4.91**	3.24
Total *($/Boe)*	**52.16**	55.84	**59.56**	52.54
Prices, including derivatives				
Liquids *($/Bbl)*				
Oil	**84.66**	87.44	**86.67**	80.85
NGLs	**57.98**	76.05	**69.28**	73.74
Total	**79.64**	86.16	**84.09**	80.14
Natural Gas *($/Mcf)*	**4.23**	3.23	**4.68**	3.58
Total *($/Boe)*	**50.75**	54.29	**56.80**	52.31

The Company's financial results are influenced by fluctuations in commodity prices, exchange rates and Canadian price differentials. Our average oil price for the third quarter of 2014 was $87.90/Bbl, a decrease of $6.61/Bbl over 2013 due to a decrease in West Texas Intermediate benchmark pricing which was partially offset by a stronger U.S. dollar. Long Run's average oil price during the first nine months of 2014 was $91.47/Bbl, an increase of $7.86/Bbl over 2013 due to an increase in West Texas Intermediate benchmark pricing and a stronger U.S. dollar.

In the third quarter of 2014, Long Run's natural gas price was $4.29/Mcf, an increase of $1.64/Mcf over 2013. Our average natural gas price during the first nine months of 2014 was $4.91/Mcf, an increase of $1.67/Mcf over 2013. The increased price in both periods reflects the strengthening of AECO benchmark pricing. AECO pricing in 2014 was favorably influenced by the reduction in natural gas storage levels brought about by the cold winter experienced in North America. The Company's natural gas price reflects premiums received for the liquids content included in the natural gas production.

The Company enters into financial derivative contracts for the purpose of protecting funds flow from operations from the volatility of commodity prices. During the third quarter of 2014, our oil price including derivative contracts was $84.66/Bbl, including a realized loss of $3.24/Bbl. The Company's natural gas price including derivatives of $4.23/Mcf included a realized loss of $0.06/Mcf. During the nine months ended September 30, 2014, Long Run's oil price including derivative contracts of $86.67/Bbl included a loss on derivative contracts of $4.80/Bbl. The Company's natural gas price including derivatives of $4.68/Mcf included a realized loss of $0.23/Mcf.

Operating Results

Operating Netback & Funds Flow from Operations

	Q3 2014		Q3 2013	
	$000s	**$/Boe**	$000s	$/Boe
Revenues	**166,978**	**52.16**	129,923	55.84
Royalties	**(19,377)**	**(6.05)**	(15,377)	(6.61)
	147,601	**46.11**	114,546	49.23
Realized loss on derivatives	**(4,529)**	**(1.42)**	(3,585)	(1.54)
Transportation costs	**(5,272)**	**(1.65)**	(5,816)	(2.50)
Operating costs	**(37,238)**	**(11.63)**	(33,614)	(14.45)
Operating netback	**100,562**	**31.41**	71,531	30.74
General and administration	**(12,537)**	**(3.92)**	(5,378)	(2.31)
Interest	**(7,566)**	**(2.36)**	(3,633)	(1.56)
Exploration expenses	**(254)**	**(0.08)**	(179)	(0.08)
Capital and other taxes	**(6)**	**0.00**	(37)	(0.02)
Funds flow from operations[1]	**80,199**	**25.05**	62,304	26.77

[1] *See Non-GAAP Measures section.*

	Nine months ended September 30, 2014			
	2014		2013	
	$000s	**$/Boe**	$000s	$/Boe
Revenues	**477,542**	**59.56**	350,746	52.54
Royalties	**(55,441)**	**(6.91)**	(36,920)	(5.53)
	422,101	**52.65**	313,826	47.01
Realized loss on derivatives	**(22,108)**	**(2.76)**	(1,544)	(0.23)
Transportation costs	**(16,102)**	**(2.01)**	(15,549)	(2.33)
Operating costs	**(111,046)**	**(13.85)**	(93,439)	(14.00)
Operating netback	**272,845**	**34.03**	203,294	30.45
General and administration	**(30,400)**	**(3.79)**	(18,332)	(2.75)
Interest	**(17,989)**	**(2.24)**	(10,490)	(1.57)
Exploration expenses	**(772)**	**(0.10)**	(215)	(0.03)
Capital and other taxes	**(6)**	**0.00**	(82)	(0.01)
Funds flow from operations[1]	**223,678**	**27.90**	174,175	26.09

[1] *See Non-GAAP Measures section.*

Third quarter 2014 compared to third quarter 2013

In the third quarter of 2014, funds flow from operations was $80.2 million, an increase of $17.9 million from the third quarter of 2013 due to the following:

- Higher liquids and natural gas production, attributable to successful drilling programs, the Deep Basin Acquisition and the Crocotta acquisition increased revenue by $35.0 million; and

- Higher natural gas prices, excluding derivative contracts, increased revenue by $11.0 million.

Partially offset by:

- Lower liquids prices, excluding derivative contracts, decreased revenue by $8.9 million.

- Royalties associated with increased revenue were $4.0 million higher, averaging 11.6% of revenue in 2014 compared to 11.8% in 2013;

- The realized loss on financial derivative contracts of $4.5 million increased $1.0 million from 2013. During 2014, we realized a loss on oil derivative contracts of $3.9 million and a loss on natural gas derivative contracts of $0.6 million due to higher benchmark pricing;

- Operating costs increased $3.6 million resulting from higher production volumes. The decrease per Boe reflects the impact of the lower cost properties obtained through the Deep Basin and Crocotta acquisitions. Operating costs are expected to average approximately $12.75/Boe in the fourth quarter of 2014;

- General and administration expense increased $7.2 million due to $4.8 million of transaction costs associated with the Crocotta acquisition and higher employee costs. Excluding transaction costs, general and administration expense averaged $2.42/Boe. General and administration expense is expected to average approximately $2.50/Boe in the fourth quarter of 2014; and

- Interest expense increased $3.9 million, attributable to a higher average debt balance outstanding primarily resulting from the Company’s recent acquisitions.

Nine months ended September 30, 2014 compared to nine months ended September 30, 2013

In the first nine months of 2014, funds flow from operations was $223.7 million, an increase of $49.5 million from the first nine months of 2013 due to the following:

- Higher liquids and natural gas production increased revenue by $77.0 million, attributable to successful drilling programs, the Deep Basin Acquisition and the Crocotta acquisition; and

- Higher liquids and natural gas prices, excluding derivative contracts, increased revenue by $49.8 million.

Partially offset by:

- Royalties associated with increased revenue were $18.5 million higher, averaging 11.6% of revenue in 2014 compared to 10.5% in 2013. The increase reflects the impact of higher commodity pricing and favorable gas cost allowance adjustments in 2013;

- The realized loss on financial derivative contracts of $22.1 million increased $20.6 million compared to 2013. During 2014, there was a realized loss on oil derivative contracts of $16.7 million and a loss on natural gas derivative contracts of $5.3 million due to higher benchmark pricing;

- Operating costs increased $17.6 million primarily resulting from the higher production volumes. Operating costs are expected to average approximately $13.50/Boe for 2014;

- General and administration expense increased $12.1 million due to $6.8 million of transaction costs associated with the Deep Basin and Crocotta acquisitions and higher employee costs. Excluding the transaction costs, general and administration expense averaged $2.95/Boe. General and administration expense is expected to average approximately $2.80/Boe for 2014, excluding transaction costs; and

- Interest expense increased $7.5 million, attributable to a higher average debt outstanding primarily resulting from the Company's recent acquisitions.

Other Income & Expenses

($000s)	**Q3 2014**	Q3 2013	**Nine months ended September 30 2014**	Nine months ended September 30 2013
Unrealized gain (loss) on derivatives	**33,737**	(11,050)	**23,926**	(12,892)
Share-based compensation	**(525)**	(1,167)	**(1,700)**	(3,258)
Accretion	**(3,025)**	(1,558)	**(7,806)**	(4,591)
Depletion and depreciation	**(65,567)**	(43,290)	**(165,690)**	(121,014)
Gain on disposal of assets	**9,750**	8,563	**19,434**	9,698
Deferred income tax expense	**(13,925)**	(4,278)	**(23,585)**	(12,322)
	(39,555)	(52,780)	**(155,421)**	(144,379)
Funds flow from operations[1]	**80,199**	62,304	**223,678**	174,175
Net earnings	**40,644**	9,524	**68,257**	29,796

[1] *See Non-GAAP Measures section.*

Third quarter 2014 compared to third quarter 2013

In comparing the third quarter of 2014 to the third quarter of 2013:

- There was an unrealized gain on financial derivatives of $33.7 million in 2014, compared to a loss of $11.1 million in 2013. The unrealized gain of $33.7 million included gains of $30.4 million on crude oil derivative contracts reflecting decreased forward oil prices and $3.3 million on natural gas derivative contracts attributable to decreases in forward natural gas prices;

- Depletion and depreciation expense of $65.6 million increased $22.3 million due to the increase in production volumes and the depletion rate. The depletion rate for 2014 was $20.50/Boe compared to $18.60/Boe in 2013. The 2014 rate reflects costs associated with the development of oil properties and the properties acquired in late 2013; and

- The gain on disposal of assets of $9.8 million increased $1.2 million from 2013. The gain in 2014 related primarily to the disposition of a property in the Deep Basin.

Nine months ended September 30, 2014 compared to nine months ended September 30, 2013

In comparing the nine months ended September 30, 2014 to the nine months ended September 30, 2013:

- There was an unrealized gain on financial derivative contracts of $23.9 million, compared to a loss of $12.9 million in 2013. The unrealized gain of $23.9 million primarily results from our oil derivative contracts, which reflects the decrease in forward oil prices;

- Depletion and depreciation expense of $165.7 million increased $44.7 million due to the increase in production volumes and the depletion rate. The depletion rate for 2014 of $20.70/Boe compared to $18.10 /Boe in 2013. The 2014 rate reflects costs associated with the development of oil properties and the properties acquired in late 2013; and

- The gain on disposal of assets of $19.4 million increased by $9.7 million from 2013. The gain in 2014 related primarily to the disposition of our heavy oil properties at Lloydminster, an overriding royalty disposition in our Peace River area, and a minor property within the Deep Basin area.

In determining deferred income tax expense, the Company's effective tax rate differs from the Canadian statutory tax rate due to permanent differences that primarily arise due to share-based compensation costs. The Company's statutory tax rate is 25%.

Liquidity and Capital Resources

Net Debt

($000s)	**September 30, 2014**	December 31, 2013
Bank debt	**632,377**	423,553
Working capital deficiency	**11,604**	28,602
Convertible Debentures – face value	**75,000**	-
Net debt[1]	**718,981**	452,155

[1] *See Non-GAAP Measures section.*

The Company's net debt at September 30, 2014 increased $266.8 million from December 31, 2013, primarily attributable to $115.2 million of the Deep Basin Acquisition being funded with debt, as well as the assumption of $115.5 million of Crocotta net debt.

The capital intensive nature of the Company's activities generally results in the Company carrying a working capital deficit, as reflected in the net debt calculation. The Company maintains sufficient unused credit facilities to satisfy working capital deficiencies. At September 30, 2014, the Company had $62.6 million of unused capacity on its credit facilities.

Credit Facilities

At December 31, 2013, the Company had credit facilities of $475 million. During the second quarter, the Company's credit facilities increased from $475 million to $575 million in connection with the Deep Basin Acquisition, and the termination date was extended to May 31, 2017.

On August 6, 2014, the credit facilities borrowing base increased by $120 million to $695 million upon closing of the Crocotta acquisition. The credit facilities consist of a $655 million revolving syndicated facility and a $40 million operating facility. Total borrowings permitted under these facilities cannot exceed the borrowing base, which is determined by the lenders on a semi-annual basis or upon the occurrence of a material event.

Security for the credit facilities at September 30, 2014 included a demand debenture for $1.5 billion which provides for a first ranking security interest and floating charge over all of the assets and property of the Company.

The credit facilities are subject to semi-annual review with the next review scheduled for November 2014. The bank debt has been classified as long term on the statement of financial position as the Company does not intend to repay the facility within the next 12 months. While the Company does not anticipate a reduction to the borrowing base below the level of bank debt currently outstanding, there is no assurance that the borrowing base will be maintained at current levels until May 31, 2017.

At September 30, 2014, the Company was in compliance with all covenants, obligations, and conditions of its credit agreement. The covenant requirements under the credit facilities have not changed since December 31, 2013. These covenants relate to bank debt and total debt to trailing 12 month EBITDA, interest coverage, permitted dispositions and permitted hedging. EBITDA is defined in the credit facilities as earnings before interest, exploration expenses, taxes, depletion and depreciation, and other non-cash items. The bank covenants require a senior debt to EBITDA ratio of less than 3:1 (September 30, 2014 – 2.09:1) and a total debt to EBITDA ratio of less than 3.5:1 (September 30, 2014 – 2.09:1). The interest coverage ratio, defined as EBITDA to interest expense, must be at least 3.5:1 (September 30, 2014 – 13.6:1). The convertible debentures issued in January 2014 are not considered debt for the debt to EBITDA ratio calculations under the credit agreement. Dispositions are permitted up to 10% of the borrowing base without formal approval of the lending syndicate. Commodity hedges are permitted on up to

75% of 2014 forecasted oil and NGLs and natural gas production net of royalties (2015 - 75%; 2016 - 50%). Interest rate hedges are permitted up to 75% of the 2014 total debt balance (2015 - 75%; 2016 - 50%). Further details on the calculations of the covenants can be found in the Company's credit facility agreement filed on SEDAR at www.sedar.com on May 5, 2014, June 6, 2014 and August 25, 2014 under the Company's profile.

Convertible Debentures

On January 28, 2014, the Company issued convertible unsecured subordinated debentures (the "convertible debentures") in the principal amount of $75 million at par. The convertible debentures bear interest at an annual rate of 6.40%, payable semi-annually in arrears. Prior to maturity on January 31, 2019, the convertible debentures are convertible into Common Shares at a conversion price of $7.40 per Common Share, subject to adjustments in certain events. The increase in the Company's dividend rate associated with the closing of the Deep Basin Acquisition is not expected to adjust the convertible debentures conversion price in 2014.

Share Capital

# of units (000s)	**November 5, 2014**	**September 30, 2014**	December 31, 2013
Common Shares	**193,498**	**193,498**	110,143
Options	**8,912**	**8,942**	10,266
Non-Voting Convertible Shares[1]	**-**	**-**	15,513
Warrants	**-**	**-**	2,300

[1] Each Non-Voting Convertible Share was convertible into one Common Share in certain events, including on transfer to a holder that would not be a Control Person (as defined in the share provisions thereof).

In connection with the Deep Basin Acquisition on April 30, 2014, Long Run closed the offering of 23.5 million subscription receipts ("Subscription Receipts") at a price of $5.10 per Subscription Receipt, for gross proceeds of $120.0 million. The Subscription Receipts were converted to Common Shares on May 30, 2014 upon closing of the Deep Basin Acquisition. The proceeds were used to fund a portion of the acquisition.

On May 21, 2014, Sprott Resource Corp. ("Sprott") closed a secondary offering by Sprott of 12.7 million Long Run Common Shares on a bought deal basis at a price of $5.35 per share. Long Run received no proceeds from this transaction and the total number of Long Run shares outstanding did not change. Upon completion of the secondary offering, Sprott converted their 15.5 million Long Run Non-Voting Convertible Shares into 15.5 million Long Run Common Shares. This also had no impact on the total number of Long Run shares outstanding or Long Run's total shareholders' equity.

In the first nine months of 2014, there were 483,000 Long Run Common Shares issued on the exercise of stock options. The Company did not grant stock options in the first nine months of 2014.

On August 6, 2014, upon closing of the Crocotta acquisition, Long Run issued 43.8 million Long Run Common Shares, based on an exchange ratio of 0.415 Long Run Common Shares for each of the 105.6 million Crocotta common shares outstanding.

At December 31, 2013, each warrant entitled the holder to acquire 0.4167 Common Shares of the Company at an exercise price of $3.10 per 0.4167 of a share until September 15, 2014. The exchange ratio and exercise price were subject to adjustment upon the payment of dividends by the Company. At June 30, 2014, the warrants entitled the holder to acquire 0.4329 Common Shares of the Company at an exercise price of $2.98 per 0.4329 of a share. All outstanding warrants expired unexercised on September 15, 2014.

Dividends

In 2014 the Company transitioned its business model to a dividend plus growth model. Dividends are payable on Long Run Common Shares and Non-Voting Convertible Shares. Long Run initially established a monthly dividend to shareholders of $0.0335 per share ($0.402 per share annualized). Following the completion of the Deep Basin Acquisition, Long Run's monthly dividend was increased to $0.035 per share ($0.42 per share annualized) effective for the June 2014 dividend, payable in July 2014. During the first nine months of 2014, dividends of $45.9 million ($0.31 per share) have been declared. From October 1, 2014 to November 5, 2014, an additional $6.8 million ($0.035 per share) of dividends have been declared and will be paid on November 14, 2014.

Long Run's dividend rate is subject to Board approval and will be reviewed regularly. Factors and conditions potentially impacting the monthly dividend rate include production volumes, current and future commodity prices, commodity hedging, foreign exchange rates, and acquisition opportunities.

Capital Structure

Long Run's capital structure consists of debt plus equity. The Company's primary capital management objective is to maintain a strong statement of financial position, which is expected to provide Long Run with financial flexibility and access to capital. This supports our objective of paying a monthly dividend while providing annual per share growth to shareholders.

The Company currently targets net debt to funds flow from operations at or below 1.5 times and debt to debt plus equity at or below 0.4 times. While the Company may exceed these ratios from time to time, efforts are made after a period of variation to bring the measures back in line. To manage the capital structure, the Company may adjust capital spending, adjust the dividend rate, issue equity, issue new debt or repay existing debt in response to changes in the business environment. For the calculation of these metrics, see note 11 to the interim financial statements for three and nine months ended September 30, 2014.

Net debt to funds flow from operations at September 30, 2014 was 2.2 times, reflecting an annualized funds flow from operations which only included 7.8 months of the Crocotta acquisition's financial results. On a pro-forma basis, assuming 12 months of Crocotta financial results and removing related transaction costs, Long Run's net debt to funds flow was 2.0 times, consistent with the ratio at December 31, 2013.

The Company believes that it has access to sufficient capital through operating activities, external debt and equity sources, and undrawn committed credit facilities to meet 2014 guidance on capital spending and dividend payments.

2014 Outlook

Long Run is focused on providing long-term value to shareholders through a sustainable dividend model. Controlled exploitation of our core assets and strategic acquisitions form the basis of our goal of funding both net capital expenditures and dividends from funds flow from operations. Throughout the commodity price cycle, we remain committed to protecting our dividend through active portfolio management, proactive hedging and a focus on cost efficiencies.

We are updating our 2014 guidance to account for forecasted third party outages and lower oil prices as discussed further below. In looking ahead to 2015, we are reviewing our capital spending plans under a variety of commodity price environments. The Company plans to release its 2015 guidance in mid-December. For 2015, Long Run has placed hedges on approximately 30% of production. Approximately 40% of our liquids production is hedged for the first quarter of 2015, which will assist to support a strong capital program. Long Run will endeavor to add additional hedges during 2015 to increase overall hedged volumes into the range of 35 to 50%.

2014 Guidance Update

In the third quarter of 2014, longer than scheduled third party plant turnarounds, third party pipeline repairs and third party unscheduled maintenance reduced Long Run's average daily production by approximately 1,600 Boe/d. These outages included an extended turnaround at a third party operated gas processing plant at Edson (Pine Creek), third party plant capacity restrictions and an extended turnaround at a third party operated gas plant at Kakwa, and unscheduled third party pipeline repairs and pipeline restrictions resulting in reduced nominations at Wapiti. We anticipate that ongoing third party restrictions at both Kakwa and Wapiti, as well as unscheduled third party sales gas pipeline repairs at Cherhill, will impact production volumes by approximately 1,300 Boe/d on average in the fourth quarter. The completion of the facility expansion at Kakwa in early 2015, where Long Run will have firm capacity, will significantly reduce unplanned restrictions in the Deep Basin area.

As a result of the outages and projected fourth quarter downtime, we have revised our 2014 production guidance from 32,100 Boe/d to 31,400 Boe/d. Using our revised production guidance and including the impact of current oil pricing, we anticipate that our funds flow from operations in 2014 will now be $300 million, down from our initial estimate of $320 million. The funds flow revision of $20 million includes $13 million due to the third party production outages and $7 million for lower achieved and forecasted oil prices. As a result of Long Run's proactive hedge program, which took into account our recent acquisitions, approximately 65% of our fourth quarter 2014 liquids production is hedged, which has limited the impact of the lower oil price.

We have moved forward facility expansion projects at Peace River and the Deep Basin from 2015 into late 2014. These projects provide increased flexibility in planning future development and reduce reliance on third parties. The impact of the accelerated funding, as well as additional well servicing and recompletion costs, will increase 2014 development capital by $35 million to $285 million. The additional 2014 development capital will be funded by the net divestitures of minor properties, of which $26.9 million has been received as at September 30, 2014. Long Run will continue to focus on selective dispositions as part of our ongoing capital management and portfolio rationalization process.

Development capital by area for 2014 is expected to be $135 million in the Peace River Montney (44 net wells), $80 million in the Redwater Viking (45 net wells) and $55 million in the Deep Basin Cardium (11 net wells).

Further details on the 2014 guidance update can be found in the Company's press release filed on SEDAR at www.sedar.com on November 5, 2014 under the Company's profile.

Contractual Obligations and Contingencies

Contractual Obligations

Commitments

($000s)	2014	2015	2016	2017	2018	Thereafter	Total
Bank loan	-	-	-	632,377	-	-	632,377
Convertible debentures [1]	-	-	-	-	-	75,000	75,000
Operating leases	994	4,712	4,238	5,979	7,720	58,072	81,715
Processing	-	4,380	4,380	4,380	4,380	26,281	43,801
Transportation	1,458	9,245	12,667	11,247	8,953	8,556	52,126
Fractionation	641	2,224	1,228	233	-	-	4,326
Capital	1,597	4,293	2,147	-	-	-	8,037
Total	4,690	24,854	24,660	654,216	21,053	167,909	897,382

[1] *Face value. Assumes the convertible debentures are not converted into Common Shares.*

At September 30, 2014, the Company is committed under operating leases for office space, contracts related to the processing of natural gas, transportation of natural gas and NGLs, fractionation of natural gas liquids, and capital commitments for drilling rig services. Commitments increased by $384.2 million from December 31, 2013, mainly attributed to the increase in the bank loan, the issuance of the convertible debentures, and additional product transportation commitments ($6.6 million – December 31, 2013).

Other than the operating leases, the Company has no off-balance sheet financing arrangements.

Contingencies

The Company is involved in various claims and legal actions arising in the normal course of business. The Company does not expect that the outcome of these proceedings will have a material adverse effect on the Company as a whole.

Risk Management

Long Run is engaged in the development, acquisition, exploration and production of oil and natural gas in western Canada. The Company is exposed to a number of risks, both financial and operational, through the pursuit of its strategic objectives. Actively managing these risks improves the ability to effectively execute our business strategy. Financial risks associated with the petroleum industry include fluctuations in commodity prices, interest rates, currency exchange rates and the cost of goods and services. Financial risks also include third party credit risk and liquidity risk. Operational risks include reservoir performance uncertainties, competition, and regulatory, environment and safety concerns. The nature of these risks has not changed substantially since December 31, 2013.

For a further and more in-depth discussion of risk management, see the Company's annual financial statements and MD&A for the year ended December 31, 2013 and the Company's Annual Information Form for the year ended December 31, 2013.

Commodity Price

To partially mitigate exposure to commodity price risk, the Company enters into various financial derivative instruments. The Company has entered into crude oil and natural gas derivative contracts, including costless collars, fixed price, calls and call swaptions. As at September 30, 2014, the Company had contracts for crude oil volumes of 8,744 Bbl/d for the remainder of 2014 and 3,658 Bbl/d for 2015. As well, at September 30, 2014, the Company had average natural gas volumes of 49.8 MMcf/d contracted for the remainder of 2014 and 41.9 MMcf/d for 2015. Further details on the derivative contracts can be found in note 14 of the interim financial statements for the three and nine months ended September 30, 2014.

In the first nine months of 2014, the Company realized a $22.1 million loss as a result of its commodity price risk management. The realized loss included a $16.7 million loss on crude oil contracts and a $5.3 million loss on natural gas financial derivative contracts. In the first nine months of 2014, the Company recognized an unrealized gain on crude oil financial derivative contracts of $23.8 million and an unrealized loss on natural gas financial derivative contracts of $0.1 million. At September 30, 2014, the fair value of crude oil derivatives was an asset of $6.2 million and the fair value of natural gas derivatives was a liability of $0.9 million.

Critical Accounting Judgments, Estimates and Accounting Policies

For a full understanding of the Company's critical accounting judgments, estimates and accounting policies, the following should be read in conjunction with the annual audited financial statements and MD&A for the year ended December 31, 2013.

Critical Accounting Estimates

The Company is required to make judgments, estimates and assumptions in the application of accounting policies that could have a significant impact on its financial results. Actual results may differ from those estimates and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. Further details on the basis of presentation and significant accounting policies can be found in the annual financial statements and MD&A for the year ended December 31, 2013. There have been no significant changes to the accounting policies since December 31, 2013.

Adoption of New Accounting Policies

As required by IFRS, the Company adopted IFRIC 21 – *Levies* and the amendment to IAS 36 - *Impairment of Assets* as of January 1, 2014. The adoption of these policies did not have a material impact on the Company's financial results. Further details of these standards can be found in note 3 of the financial statements for the period ended September 30, 2014.

Future Accounting Pronouncements

As required by IFRS, the Company will be required to adopt the IFRS 11 – *Joint Arrangements* amendments on January 1, 2016, IFRS 15 – *Contracts with Customers* on January 1, 2017, and IFRS 9 – *Financial Instruments* on January 1, 2018. The Company has not yet determined the impact of adoption of these policies on the financial results. Further details of these standards can be found in note 3 of the financial statements for the period ended September 30, 2014.

Control Environment

Disclosure Controls and Procedures

The Company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

Internal Controls over Financial Reporting

The CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles applicable to the Company.

The Company is required to disclose any change in the Company's internal controls over financial reporting that occurred during the Company's most recent interim period that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Detailed Quarterly Results

The Corporation's quarterly funds flow from operations is significantly impacted by changes in production volumes, fluctuations in commodity prices, exchange rates and realized gains and losses on financial derivative contracts. In addition to these items, net earnings are impacted by impairments and unrealized gains and losses on financial derivative contracts. Acquisitions and divestitures can also have a significant impact on Long Run's results. The following significant transactions have impacted the Company's quarterly results:

- In the third quarter of 2014, Long Run completed the Crocotta acquisition on August 6, 2014 for total consideration of $231.4 million. Production from the Crocotta assets averaged 4,000 Boe/d (29% oil and NGLs) during the third quarter of 2014.

- In the second quarter of 2014, Long Run completed the Deep Basin Acquisition on May 30, 2014 for total consideration of $228.8 million. Production from the assets averaged 2,008 Boe/d (28% oil and NGLs) during the second quarter of 2014 and 4,900 Boe/d (29% oil and NGLs) during the third quarter of 2014.

- In the fourth quarter of 2013, Long Run completed two significant light oil acquisitions in the Peace River and Redwater areas for total consideration of approximately $95 million, with combined production of approximately 1,800 Boe/d (70% oil and NGLs) at the closing dates.

- In the fourth quarter of 2012, the Company completed a plan of arrangement to acquire Guide Exploration Ltd. ("Guide"). Funds flow from operations and net earnings prior to October 23, 2012 do not include the results of operations from the Guide properties.

	2014			2013				2012
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Funds flow from operations *($000s)*	80,199	73,429	70,050	55,934	62,304	63,227	48,644	38,407
Per share, basic[1]	0.45	0.55	0.56	0.45	0.50	0.50	0.39	0.33
Per share, diluted[1]	0.45	0.54	0.56	0.44	0.50	0.50	0.39	0.33
Net earnings (loss) *($000s)*	40,644	20,842	6,771	(5,531)	9,524	21,099	(827)	(56,590)
Per share, basic	0.23	0.16	0.05	(0.04)	0.08	0.17	(0.01)	(0.49)
Per share, diluted	0.23	0.15	0.05	(0.04)	0.08	0.17	(0.01)	(0.49)
Dividend *($000s)*	18,781	14,468	12,639	-	-	-	-	-
Per share	0.11	0.10	0.10	-	-	-	-	-
Payout ratio[1]	23%	20%	18%	-	-	-	-	-
Capital *($000s)*								
Drilling and completion	52,530	34,851	75,114	30,750	72,746	19,541	80,767	46,623
Plant and facilities	19,740	16,441	23,370	8,760	18,699	17,697	19,652	10,590
Geological and geophysical	1,951	4,295	939	566	601	779	1,314	772
Other assets	1,538	1,743	1,425	1,561	1,091	861	1,186	355
Capital expenditures	75,759	57,330	100,848	41,637	93,137	38,878	102,919	58,340
Net acquisitions (dispositions)	(8,147)	213,716	(3,679)	86,328	3,331	1,158	17,945	(169,731)
Capital investment	67,612	271,046	97,169	127,965	96,468	40,036	120,864	(111,391)
Wells drilled *(net)*								
Peace	12.0	11.0	19.5	9.5	19.5	4.0	19.0	5.0
Redwater	6.0	11.0	27.0	1.0	26.6	8.0	28.6	12.0
Deep Basin	3.0	-	-	-	-	-	-	-
Other	-	-	1.0	1.0	4.0	-	4.0	-
	21.0	22.0	47.5	11.5	50.1	12.0	51.6	17.0
Plato – disposed 2012	-	-	-	-	-	-	-	9.5
Total	21.0	22.0	47.5	11.5	50.1	12.0	51.6	26.5
Production								
Liquids *(Bbl/d)*								
Light oil	12,708	11,808	11,491	11,811	10,322	9,802	9,528	9,125
Heavy oil	363	668	1,193	1,440	1,387	1,669	1,581	1,538
NGLs	3,031	2,038	1,584	1,520	1,478	1,116	1,249	1,332
	16,102	14,514	14,268	14,771	13,187	12,587	12,358	11,995
Natural Gas *(Mcf/d)*	112,161	78,524	68,071	73,392	72,634	71,058	67,516	56,453
Total *(Boe/d)*	34,795	27,602	25,613	27,003	25,293	24,431	23,611	21,405
Production by area (Boe/d)								
Peace River	13,972	10,820	10,637	11,500	10,101	9,952	9,453	6,691
Redwater	8,311	6,588	6,101	6,285	5,875	5,444	5,195	5,050
Deep Basin	7,859	1,771	-	-	-	-	-	-
Boyer	2,929	3,045	2,732	2,861	3,241	3,274	2,938	2,220
Kaybob	1,715	1,909	1,804	1,851	1,923	1,426	1,847	2,118
Other	9	3,469	4,339	4,506	4,153	4,335	4,178	3,615
	34,795	27,602	25,613	27,003	25,293	24,431	23,611	19,694
Plato – disposed 2012	-	-	-	-	-	-	-	1,711
Total	34,795	27,602	25,613	27,003	25,293	24,431	23,611	21,405

	2014			2013				2012
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Benchmark pricing								
WTI *($US/Bbl)*	97.21	102.98	98.68	97.46	105.83	94.20	94.37	88.18
Edmonton Light Sweet *($CAD/Bbl)*	97.18	105.62	99.83	86.58	104.98	92.33	88.19	83.99
AECO *($/Mcf)*	4.02	4.69	5.72	3.53	2.43	3.53	3.20	3.21
Cdn$/US$ exchange rate	1.09	1.09	1.10	1.05	1.04	1.02	1.01	0.99
Prices, excluding derivatives								
Liquids *($/Bbl)*								
Light oil	88.08	97.50	91.24	75.06	95.47	83.70	76.69	76.24
Heavy oil	81.47	81.79	78.90	62.69	87.40	71.52	55.10	57.89
NGLs	57.98	72.76	86.87	69.21	76.05	68.91	75.33	67.08
Total	82.26	93.30	89.72	73.25	92.44	80.78	73.79	72.87
Natural Gas *($/Mcf)*	4.29	4.89	5.96	3.73	2.65	3.73	3.37	3.35
Total *($/Boe)*	52.16	63.17	65.89	50.24	55.84	52.72	48.76	50.27
Prices, including derivatives								
Oil *($/Bbl)*	84.66	89.59	85.89	71.14	87.44	81.80	72.77	76.54
NGLs *($/Bbl)*	57.98	72.76	86.87	69.21	76.05	68.91	75.33	67.08
Natural Gas *($/Mcf)*	4.23	4.61	5.53	4.04	3.23	3.89	3.63	4.19
Total *($/Boe)*	50.75	59.13	62.67	49.78	54.29	53.29	49.12	53.99
Netback *($/Boe)*								
Revenues	52.16	63.17	65.89	50.24	55.84	52.72	48.76	50.27
Royalties	(6.05)	(7.01)	(8.01)	(7.33)	(6.61)	(4.38)	(5.55)	(6.36)
Realized gain (loss) on derivatives	(1.42)	(4.04)	(3.22)	(0.46)	(1.54)	0.57	0.36	3.72
Transportation costs	(1.65)	(2.10)	(2.41)	(2.00)	(2.50)	(2.36)	(2.11)	(2.27)
Operating costs	(11.63)	(14.98)	(15.70)	(13.36)	(14.45)	(13.98)	(13.53)	(11.78)
Operating Netback	31.41	35.04	36.55	27.09	30.74	32.57	27.93	33.58
G&A	(3.92)	(3.64)	(3.79)	(2.82)	(2.31)	(2.47)	(3.51)	(11.86)
Interest	(2.36)	(2.19)	(2.13)	(1.73)	(1.56)	(1.63)	(1.52)	(1.96)
Corporate Netback	25.13	29.21	30.63	22.54	26.87	28.47	22.90	19.76
Funds flow from operations[1] *($000s)*								
Revenues	166,978	158,678	151,886	124,816	129,923	117,210	103,613	99,000
Royalties	(19,377)	(17,598)	(18,466)	(18,213)	(15,377)	(9,753)	(11,790)	(12,521)
Realized gain (loss) on derivatives	(4,529)	(10,157)	(7,422)	(1,145)	(3,585)	1,285	756	7,320
Transportation costs	(5,272)	(5,287)	(5,543)	(4,971)	(5,816)	(5,250)	(4,483)	(4,474)
Operating costs	(37,238)	(37,614)	(36,194)	(33,198)	(33,614)	(31,083)	(28,742)	(23,195)
	100,562	88,022	84,261	67,289	71,531	72,409	59,354	66,130
G&A	(12,537)	(9,134)	(8,729)	(7,017)	(5,378)	(5,493)	(7,461)	(23,351)
Interest	(7,566)	(5,507)	(4,916)	(4,300)	(3,633)	(3,634)	(3,223)	(3,864)
Other	(260)	48	(566)	(38)	(216)	(55)	(26)	(508)
	80,199	73,429	70,050	55,934	62,304	63,227	48,644	38,407

[1] *See Non-GAAP Measures section.*

Non-GAAP Measures

The MD&A contains terms commonly used in the oil and natural gas industry, such as funds flow from operations, funds flow from operations per share, net debt and payout ratio. These terms are not defined by IFRS and therefore may not be comparable to similar measures presented by other companies. There are measures commonly used in the oil and gas industry and by Long Run to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. These terms should not be considered an alternative to, or more meaningful than, cash provided by operating activities or net earnings as determined in accordance with IFRS as indicators of Long Run's performance.

Funds Flow from Operations

	2014			2013				2012
($000s)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Cash flow from operating activities	**78,006**	67,280	59,781	65,932	61,756	60,835	45,733	43,325
Change in non-cash working capital	**(996)**	5,452	8,923	(11,758)	(266)	1,958	1,949	(5,722)
Abandonment costs	**3,189**	697	1,346	1,760	814	434	962	804
Funds flow from operations	**80,199**	73,429	70,050	55,934	62,304	63,227	48,644	38,407
Weighted average outstanding shares *(000s)*								
- Basic	**176,318**	134,291	125,730	125,629	125,620	125,620	125,620	115,421
- Diluted	**177,003**	135,437	126,129	126,245	125,620	125,620	125,620	115,421
Funds flow from operations per share *($/share)*								
- Basic	**0.45**	0.55	0.56	0.45	0.50	0.50	0.39	0.33
- Diluted	**0.45**	0.54	0.56	0.44	0.50	0.50	0.39	0.33

	Nine months ended September 30	
($000s)	**2014**	2013
Cash flow from operating activities	**205,067**	168,324
Change in non-cash working capital	**13,379**	3,641
Abandonment costs	**5,232**	2,210
Funds flow from operations	**223,678**	174,175
Weighted average outstanding shares *(000s)*		
- Basic	**145,632**	125,620
- Diluted	**146,511**	125,620
Funds flow from operations per share *($/share)*		
- Basic	**1.54**	1.39
- Diluted	**1.53**	1.39

Net Debt

($000s)	**September 30, 2014**	December 31, 2013
Bank debt	**632,377**	423,553
Working capital deficiency		
Accounts payable and accrued liabilities	**105,486**	89,606
Restricted cash	**(2,390)**	-
Accounts receivable	**(78,079)**	(53,433)
Prepaid expenses and deposits	**(13,413)**	(7,571)
Convertible debentures – face value	**75,000**	-
Net Debt	**718,981**	452,155

Payout Ratio

Payout ratio is defined as dividends declared divided by funds flow from operations.

Advisory

Forward-Looking Statements

This document contains forward-looking statements and forward-looking information (collectively "forward-looking information") within the meaning of applicable securities laws relating to the Company's plans and other aspects of Long Run's anticipated future operations, management focus, objectives, strategies, financial, operating and production results and opportunities, including expected effects of the Crocotta acquisition anticipated 2014 fourth quarter operating and general and administration expense, 2014 average production, commodity mix, 2014 capital expenditures, nature of expenditures and method of funding capital expenditures and dividends, drilling and development plans and the timing thereof, timing of new wells being brought on production, and timing of expansion of EOR and timing of second pilot EOR project, expectation that unused credit facilities will be sufficient to satisfy working capital deficiencies and that the Company has sufficient capital to meet guidance of capital expenditures and dividends, timing of review of credit facilities and anticipation that it will not be reduced, expectation that the increase in dividends will not adjust the conversion rate of convertible debentures in 2014, expectation that planned facilities expansions at Kakwa will reduce restrictions, timing of release of 2015 guidance, expected effects of oil pricing on sustainability and expected third-party outages in the fourth quarter of 2014 and expected impacts on production. Forward-looking information typically uses words such as "anticipate", "believe", "project", "expect", "goal", "plan", "intend" or similar words suggesting future outcomes, statements that actions, events or conditions "may", "would", "could" or "will" be taken or occur in the future. Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although the Company believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which the Company operates; the timely receipt of any required regulatory approvals; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Company has an interest in to operate the field in a safe, efficient and effective manner; the ability of the Company to obtain financing and access capital on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Company to secure adequate product transportation; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company operates; the ability of the Company to successfully market its oil and natural gas products; expectations and assumptions concerning prevailing and future commodity prices, exchange rates, interest rates, applicable royalty rates and tax laws; future production rates and estimates of operating costs; performance of existing and future wells; reserve and resource volumes; anticipated timing and results of capital expenditures; the success obtained in drilling new wells; the sufficiency of budgeted capital expenditures in carrying out planned activities; the timing, location and extent of future drilling operations; the state of the economy and the exploration and production business; results of operations; business prospects and opportunities; the availability and cost of financing, labor and services; the impact of increasing competition; and Long Run's ability to integrate the assets acquired pursuant to the Deep Basin Acquisition and the Crocotta acquisition and the effects thereof. Included herein are estimates of Long Run's 2014 funds flow from operations, based on assumptions provided herein other assumptions utilized in arriving at Long Run's capital budget. To the extent such estimates constitute a financial outlook, they were approved by management on November 5, 2014 and are included herein to provide readers with an understanding of the anticipated funds available to Long Run to fund its capital expenditures, dividends and the effects thereof and readers are cautioned that the information may not be appropriate for other purposes.

These forward-looking statements sometimes include words to the effect that management believes or expects a stated condition or result. All estimates and statements that describe the Company's objectives, goals or future plans are forward-looking statements. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties including, without limitation, risks associated with oil and natural gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources. The payment of a dividend by the Company is subject to declaration thereof by the board of directors and continuation of the dividend policy will be subject to and dependent on the Company's cash flow and other expenditures, including capital expenditures. As a consequence, Long Run's actual results may differ materially from those expressed in, or implied by, the forward-looking statements.

Readers are cautioned that the foregoing list of factors and assumptions is not exhaustive. Additional information on these and other factors that could affect Long Run's operations and financial results are included elsewhere herein and in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), or at Long Run's website (www.longrunexploration.com). Furthermore, the forward-looking statements contained herein are made as at the date hereof and Long Run does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Oil & Natural Gas Information

Petroleum and natural gas reserves and volumes are converted to a common unit of measure on a basis of six thousand cubic feet of natural gas to one barrel of oil. Boes may be misleading, particularly if used in isolation. The forgoing conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of six to one, utilizing a conversion on a six to one basis may be misleading as an indication of value.

Operating netback per BOE is calculated by subtracting royalties, transportation and operating costs from revenues and dividing by total production. Corporate netback per Boe is calculated as operating netback less interest and general and administration expense and divided by total production.

Abbreviations

Oil and Natural Gas Liquids		Natural Gas	
MBbl	thousand barrels	MMcf	million cubic feet
MMBbl	million barrels	Mcf/d	thousand cubic feet per day
Bbl/d	barrels per day	MMcf/d	million cubic feet per day
NGL	natural gas liquids	Mmbtu	million British Thermal Units
Boe	barrels of oil equivalent		
Boe/d	barrels of oil equivalent per day		
Liquids	light oil, heavy oil, and NGLs		

Additional Information

Additional information relating to Long Run, including Long Run's Annual Information Form, can be accessed on-line on SEDAR at www.sedar.com, or from the Company's website at www.longrunexploration.com.