LONG RUN EXPLORATION LTD.

Management's Discussion and Analysis

March 31, 2015

Management's Discussion and Analysis
For the three months ended March 31, 2015

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 March 31, 2015 and the audited financial statements and MD&A for the year ended December 31, 2014. The disclosure which is unchanged from the MD&A for the year ended December 31, 2014 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 reflect the current year classification of capital expenditures and production volumes by area.

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 May 6, 2015.

Long Run's Strategy

Long Run Exploration Ltd. is an intermediate oil and natural gas company focused on development, exploration and production in the Western Canadian Sedimentary Basin. We complement our development programs with strategic acquisitions and dispositions. Targeting a production mix balanced between oil and natural gas, activities are concentrated in our core areas, which include the Peace River Montney, the Deep Basin Cardium, the Redwater Viking and the Boyer Bluesky.

Long Run has assembled a large land position and is continuing to add oil and natural gas infrastructure in our key areas, providing flexibility for future growth and development. Through controlled exploitation, enhanced recovery and selective low risk exploration, Long Run strives to maximize operating and cost efficiencies.

With a strong asset base and drilling opportunities, Long Run believes that strengthening the balance sheet is the first step in being able to further advance properties and drive longer term growth for the Company. We continue to evaluate our business model in light of prevailing market conditions and opportunities, with the goal of balancing financial flexibility and operational momentum. We are focused on disciplined capital management, portfolio rationalization and cost saving measures to help improve our financial flexibility in the near term. In response to the depressed commodity price environment, we have adopted a fiscally prudent and conservative current year plan to preserve the long term value for our shareholders. Our capital program remains focused on high-grade development projects in our core operating areas.

Long Run's focus for 2015 remains on strengthening our balance sheet through a reduced capital program and selective asset dispositions. We continue to anticipate $100 million in capital spending for 2015, of which approximately $50 - $55 million is planned for the first half of the year. We will revisit our plans for the second half of the year if commodity prices further deteriorate. Our 2015 capital program is anticipated to be fully funded by our estimated annual funds flow from operations of between $120 and $135 million. We expect that additional cash flows generated from commodity price improvements, our cost savings initiatives and disposition proceeds will be used to reduce outstanding debt. We are currently targeting debt reduction of $100.0 million in 2015.

Highlights

Highlights for the three months ended March 31, 2015 include:

- Executed a focused development program, drilling 9.0 successful net wells. Net capital expenditures were $43.9 million, concentrated on our Peace River Montney and Deep Basin Cardium core areas.
- Averaged 35,602 Boe/d of production, an increase of 9,989 Boe/d from 25,613 Boe/d in the first quarter of 2014. The production increase resulted from the Deep Basin acquisitions in 2014 and our successful drilling programs. Third party outages experienced in the second half of 2014 were substantially resolved by February 2015 following the startup of the third party facility at Kakwa where Long Run has firm capacity. First quarter production was reduced by approximately 800 Boe/d as a result of third party restrictions.
- Generated funds flow from operations of $40.0 million ($0.21/share) compared to $70.1 million ($0.56/share) in the first quarter of 2014, reflecting lower commodity prices partially offset by higher production volumes.
- Recorded a net loss of $22.8 million compared to net earnings of $6.8 million in 2014, primarily as a result of lower funds flow from operations.
- Remain on track to meet 2015 annual production guidance of 32,000 - 33,000 Boe/d based on planned capital expenditures of $100 million.
- Successfully negotiated a number of non-core dispositions. As at May 6, 2015, Long Run has closed approximately $10 million in current year dispositions. Proceeds from these dispositions will be directed towards debt repayment.

Quarterly Results Overview

	2015	2014			
($000s, except per share or unless otherwise noted)	**Q1**	Q4	Q3	Q2	Q1
Funds flow from operations [1]	**39,958**	68,178	80,199	73,429	70,050
Per share, basic [1]	**0.21**	0.35	0.45	0.55	0.56
Per share, diluted [1]	**0.21**	0.35	0.45	0.54	0.56
Net earnings (loss)	**(22,818)**	(258,652)	40,644	20,842	6,771
Per share, basic	**(0.12)**	(1.34)	0.23	0.16	0.05
Per share, diluted	**(0.12)**	(1.34)	0.23	0.15	0.05
Revenues, before royalties	**81,324**	133,354	166,978	158,678	151,886
Capital expenditures	**45,315**	70,094	75,759	57,330	100,848
Net divestitures [2]	**(1,392)**	(1,797)	(8,147)	(15,051)	(3,679)
Net capital expenditures [2]	**43,923**	68,297	67,612	42,279	97,169
Production					
Oil *(Bbl/d)*	**10,557**	12,130	13,071	12,476	12,684
Natural gas liquids *(Bbl/d)*	**5,210**	5,609	3,031	2,038	1,584
Total Liquids *(Bbl/d)*	**15,767**	17,739	16,102	14,514	14,268
Natural gas *(Mcf/d)*	**119,007**	112,576	112,161	78,524	68,071
Total *(Boe/d)*	**35,602**	36,502	34,795	27,602	25,613
Prices, including derivatives					
Oil *($/Bbl)*	**65.34**	79.35	84.66	89.59	85.89
Natural gas liquids *($/Bbl)*	**22.50**	30.02	57.98	72.76	86.87
Total Liquids *($/Bbl)*	**51.18**	63.75	79.64	87.23	85.99
Natural gas *($/Mcf)*	**3.17**	4.15	4.23	4.61	5.53
Total *($/Boe)*	**33.45**	43.92	50.75	59.13	62.67
Operating netback *($/Boe)*	**16.94**	25.04	31.41	35.04	36.55

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

First quarter 2015 compared to first quarter 2014

Funds flow from operations for 2015 was $40.0 million, a decrease of $30.1 million from 2014. Funds flow in 2015 reflects lower revenue associated with decreased realized commodity prices, partially offset by the increase in revenue associated with higher production volumes.

Average production volumes during 2015 increased by 9,989 Boe/d to 35,602 Boe/d from 25,613 Boe/d in 2014. The production growth resulted from the Deep Basin acquisitions in 2014 and our successful drilling program over the past year. Third party outages experienced in the second half of 2014 were substantially resolved by February 2015. First quarter of 2015 third party restrictions totaled approximately 800 Boe/d.

Our average 2015 oil price including derivatives of $65.34/Bbl decreased from $85.89/Bbl in 2014. A decrease in the West Texas Intermediate benchmark pricing was partially offset by an increase in the U.S. dollar exchange rate and a gain on oil financial derivatives. Average NGL pricing for the quarter decreased to $22.50/Bbl from $86.87/Bbl in 2014, reflecting lower market prices as well as the change in our NGL product mix due to the Deep Basin acquisitions. Long Run's average natural gas price including derivatives decreased to $3.17/Mcf from $5.53/Mcf in 2014, primarily attributable to weaker AECO benchmark prices.

The net loss for 2015 was $22.8 million, compared to net earnings of $6.8 million in 2014. The loss resulted primarily from lower funds flow from operations and increased depletion expense associated with increased production volumes.

Significant Properties

Long Run's key development areas within our property portfolio include the Peace River Montney, the Deep Basin and the Redwater Viking. The Peace River Montney is focused on Montney light oil development at Normandville and Girouxville. The Deep Basin property was acquired by Long Run through two strategic acquisitions completed in May and August 2014. The Deep Basin area, including the Edson and Kakwa/Elmworth properties, is focused on light oil and liquids rich natural gas development from the Cardium and Bluesky formations. The Redwater Viking property is focused on light oil development from the Viking formation. The Company also owns a significant low decline shallow gas property at Boyer in northern Alberta.

In the first quarter of 2015, Long Run invested $14.4 million in the Peace River Montney, drilling 5.0 net Montney horizontal oil wells with a 100% success rate. Production in the area averaged 9,527 Boe/d (57% oil and NGLs). Capital expenditures for 2015 are expected to total approximately $20 million. No further wells are planned for the remainder of the year in the area. The Company operates, transports, and processes all of its production within the Peace River area.

Development of the Deep Basin property is a key focus for Long Run in 2015. In the first quarter of 2015, Long Run invested $13.8 million in the Edson area, drilling 3.0 net wells, with a 100% success rate. Production in the Edson area averaged 7,498 Boe/d (44% oil and NGLs). Capital expenditures for this area for 2015 are expected to total approximately $29 million, including the drilling of approximately 6.0 net wells. In the first quarter of 2015, Long Run invested $12.1 million in the Kakwa/Elmworth area, drilling 1.0 net wells, with a 100% success rate as well as investing in plant and battery equipment. Production in the Kakwa/Elmworth area averaged 4,942 Boe/d (24% oil and NGLs). Capital expenditures for this area for 2015 are expected to total approximately $27 million, including the drilling of approximately 5.0 net wells.

In the Redwater Viking area, located near Edmonton, Alberta, Long Run invested $1.7 million, drilling no wells in the first quarter. Production averaged 3,749 Boe/d (87% oil and NGLs). Capital expenditures for 2015 are expected to total approximately $4 million. Based on the current price environment, no wells are planned to be drilled in 2015 in the area. The Company operates, transports, and processes substantially all of its production within the Redwater area.

Capital Investment

Capital Expenditures, Acquisitions & Dispositions

($000s)		**Q1 2015**	Q1 2014
Drilling and completion		**31,577**	75,114
Plant and facilities		**12,202**	23,370
Geological and geophysical		**778**	939
Other assets		**758**	1,425
Capital expenditures		**45,315**	100,848
Acquisitions	– land	**61**	1,201
	– properties	**534**	3,562
Dispositions		**(1,987)**	(8,442)
Net capital expenditures		**43,923**	97,169

Drilling Activity

		Q1 2015 Wells		Q1 2014 Wells		Success Rate *(net wells)*	
		Gross	**Net**	Gross	Net	**Q1 2015**	Q1 2014
Peace River	– Montney	**5.0**	**5.0**	18.0	17.5	**100%**	100%
	– Other	**-**	**-**	2.0	2.0	**-**	100%
Deep Basin	– Edson	**3.0**	**3.0**	-	-	**100%**	-
	– Kakwa/Elmworth	**1.0**	**1.0**	-	-	**100%**	-
Redwater	– Viking	**-**	**-**	27.0	27.0	**-**	100%
	– Other	**-**	**-**	1.0	-	**-**	100%
Other		**-**	**-**	1.0	1.0	**-**	100%
		9.0	**9.0**	49.0	47.5	**100%**	100%

Capital Expenditures

Capital expenditures in the first quarter of 2015 were $45.3 million, with $14.4 million (32%) in the Peace River Montney, $13.8 million (30%) in the Deep Basin at Edson, $12.1 million (27%) in the Deep Basin at Kakwa/Elmworth and $1.7 million (4%) in the Redwater Viking. The Company drilled 9.0 (9.0 net) wells with a 100% success rate in the period. Capital expenditures included facility costs in the Deep Basin spent to provide flexibility for future development and to reduce reliance on third party processing.

Capital expenditures in the first quarter of 2014 were $100.8 million, with $51.1 million (51%) in the Peace River Montney and $36.0 million (36%) in the Redwater Viking. The Company drilled 49.0 (47.5 net) wells with a 100% success rate in 2014.

Acquisitions and Dispositions

Dispositions of $2.0 million in the first quarter of 2015 and $8.4 million in the first quarter of 2014 related primarily to minor property dispositions in the Peace River area.

At May 6, 2015, Long Run has closed approximately $10 million in current year dispositions.

Enhanced Oil Recovery

Enhanced oil recovery ("EOR") remains a key part of the Company's strategic development plans. Long Run's first EOR project is in our Peace River Montney area where the Company has two active EOR expansion projects. The EOR expansion at Normandville covers 5 sections (16 horizontal producers, 8 horizontal injection wells, 1 vertical injection well) and became operational in early December 2014. A similar EOR expansion began in January 2015 at Girouxville covering 1.5 sections (6 horizontal producers, 4 horizontal injection wells). Operations at both waterflood projects are advancing according to our reservoir models, and we anticipate clearer indications of response within the next three to six months. Successful implementation in our Montney has the potential to substantially improve recoveries, reduce production declines and improve capital efficiencies. Full field implementation of EOR at Normandville and Girouxville could ultimately cover approximately 30 net sections.

Redwater remains an active area for Long Run as the site of our second major EOR project. Long Run initiated the first Viking EOR project in the north part of the field in December of 2013. A second complementary EOR project, located in the south part of the trend, began injection in early December 2014. Together these projects cover an area of 1.125 sections and include 11 horizontal Viking producers, 6 vertical Viking producers, and 5 horizontal injection wells. Long Run is currently injecting water for pressure maintenance at both projects and anticipates initial results in the next 12-18 months.

Production

Average Production by Product

	Q1 2015	Q1 2014
Liquids *(Bbl/d)*		
Light oil	**10,242**	11,491
Heavy oil	**315**	1,193
NGLs	**5,210**	1,584
Total	**15,767**	14,268
Natural Gas *(Mcf/d)*	**119,007**	68,071
Total *(Boe/d)*	**35,602**	25,613

Average Production by Area

		Q1 2015				Q1 2014			
		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	– Montney	**5,107**	**312**	**24,649**	**9,527**	5,476	187	21,786	9,294
	– Other	**854**	**152**	**9,871**	**2,651**	1,214	191	13,042	3,579
Deep Basin	– Edson	**724**	**2,561**	**25,277**	**7,498**	-	3	95	19
	– Kakwa/Elmworth	**19**	**1,152**	**22,623**	**4,942**	-	-	-	-
Redwater	– Viking	**3,219**	**42**	**2,929**	**3,749**	4,643	41	4,085	5,365
	– Other	**630**	**117**	**15,191**	**3,279**	1,350	134	8,012	2,819
Boyer		**-**	**-**	**15,138**	**2,523**	1	-	16,392	2,733
Other		**4**	**874**	**3,329**	**1,433**	-	1,028	4,659	1,804
		10,557	**5,210**	**119,007**	**35,602**	12,684	1,584	68,071	25,613

During the first quarter of 2015, production averaged 35,602 Boe/d, an increase of 9,989 Boe/d from 25,613 Boe/d in the first quarter of 2014. The production increase resulted from the Deep Basin property acquired in 2014 and our successful development drilling over the past year.

Peace River Montney production for the first quarter of 2015 was maintained with the drilling of only 29 net wells since the first quarter of 2014.

Deep Basin production totaled 12,440 Boe/d and averaged 7,498 Boe/d at Edson and 4,942 Boe/d at Kakwa/Elmworth in the first quarter of 2015. Since acquiring the Deep Basin assets in 2014, Long Run has drilled 15 successful net wells. Third party outages experienced in the second half of 2014 were substantially resolved by February 2015 following the startup of the third party facility at Kakwa where Long Run has firm capacity. First quarter production was reduced by approximately 800 Boe/d as a result of third party restrictions.

Redwater Viking production for the first quarter of 2015 decreased by 1,616 Boe/d to 3,749 Boe/d from 5,365 Boe/d in the first quarter of 2014, due primarily to capital invested in Peace River and the Deep Basin.

Commodity Pricing

	Q1 2015	Q1 2014
Benchmark pricing		
WTI *($US/Bbl)*	**48.57**	98.68
Edmonton Light Sweet *($CAD/Bbl)*	**51.85**	99.83
AECO *($/Mcf)*	**2.76**	5.72
Cdn$/US$ exchange rate	**1.24**	1.10
Prices, excluding derivatives		
Liquids *($/Bbl)*		
Light oil	**42.32**	91.24
Heavy oil	**37.36**	78.90
Total oil	**42.17**	90.08
NGLs	**22.50**	86.87
Total	**35.67**	89.72
Natural Gas *($/Mcf)*	**2.80**	5.96
Total *($/Boe)*	**25.38**	65.89
Prices, including derivatives		
Liquids *($/Bbl)*		
Oil	**65.34**	85.89
NGLs	**22.50**	86.87
Total	**51.18**	85.99
Natural Gas *($/Mcf)*	**3.17**	5.53
Total *($/Boe)*	**33.45**	62.67

The Company's financial results are influenced by fluctuations in commodity prices, exchange rates and Canadian price differentials. Our average oil price excluding derivatives for the first quarter of 2015 was $42.17/Bbl, a decrease of $47.91/Bbl from the first quarter of 2014. This resulted from a decrease in West Texas Intermediate benchmark pricing, partially offset by an increase in the U.S dollar exchange rate.

Long Run's NGL price in the first quarter of 2015 of $22.50/Bbl decreased $64.37/Bbl from the first quarter of 2014. This reflected lower market prices as well as the change in our NGL product mix due to the Deep Basin acquisitions in 2014.

In the first quarter of 2015, our natural gas price excluding derivatives was $2.80/Mcf, a decrease of $3.16/Mcf over the first quarter of 2014 due to the weakening of AECO benchmark pricing. 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 first quarter of 2015, our oil price of $65.34/Bbl included a realized gain on derivatives of $23.17/Bbl. The Company's natural gas price of $3.17/Mcf included a realized gain on derivatives of $0.37/Mcf for the first quarter of 2015.

Operating Results

Operating Netback & Funds Flow from Operations

	Q1 2015		Q1 2014	
	$000s	$/Boe	$000s	$/Boe
Revenues	**81,324**	**25.38**	151,886	65.89
Royalties	**(6,321)**	**(1.97)**	(18,466)	(8.01)
	75,003	**23.41**	133,420	57.88
Realized gain (loss) on derivatives	**25,845**	**8.07**	(7,422)	(3.22)
Transportation costs	**(5,421)**	**(1.69)**	(5,543)	(2.41)
Operating costs	**(41,184)**	**(12.85)**	(36,194)	(15.70)
Operating netback	**54,243**	**16.94**	84,261	36.55
General and administration	**(6,406)**	**(2.00)**	(8,729)	(3.79)
Interest	**(7,875)**	**(2.46)**	(4,916)	(2.13)
Exploration expenses	**(4)**	**-**	(566)	(0.24)
Capital and other taxes	**-**	**-**	-	-
Funds flow from operations[1]	**39,958**	**12.48**	70,050	30.39

[1] See Non-GAAP Measures section.

During the first quarter of 2015, funds flow from operations was $40.0 million, a decrease of $30.1 million from the first quarter of 2014 primarily resulting from the following:

- Lower commodity prices, excluding derivatives, decreased revenue by $74.5 million. Of this total, lower oil prices decreased revenue by $46.0 million, NGL prices decreased revenue by $9.1 million and lower natural gas prices decreased revenue by $19.4 million; and

- Lower oil production decreased revenue by $16.8 million as a result of production declines mainly at Redwater.

Partially offset by:

- Higher NGL and natural gas production increased revenue by $20.1 million. Higher production is attributable to the Deep Basin acquisitions made in 2014 and our successful drilling programs. Of the total revenue increase, NGL production contributed $7.3 million and natural gas production contributed $12.8 million;

- The realized gain on financial derivative contracts was $25.8 million compared to a loss of $7.4 million in 2014. During 2015, Long Run realized gains on oil derivative contracts of $22.0 million and on natural gas derivative contracts of $4.0 million due to lower benchmark pricing; and

- Royalties were $12.2 million lower due to the decreased revenue, averaging 8% of revenue in 2015 compared to 12% in 2014. The royalty rate decreased in 2015 due to lower commodity prices. Royalty rates are expected to average approximately 11% in 2015.

For the first quarter of 2015, operating costs averaged $12.85/Boe, reflecting the addition of the lower cost Deep Basin assets and lower fuel costs. Operating costs are expected to average $13.50/Boe in 2015. For the first quarter of 2015, general and administration expenses averaged $2.00/Boe, reflecting lower employee costs which include lower than planned bonuses. General and administration expense is expected to average $2.50/Boe for the year.

Other Income & Expenses

($000s)	**Q1 2015**	Q1 2014
Unrealized loss on derivatives	**(7,475)**	(10,783)
Share-based compensation	**(950)**	(582)
Accretion	**(2,675)**	(2,122)
Depletion and depreciation	**(60,584)**	(49,663)
Gain on disposal of assets	**2,143**	2,328
Deferred income tax recovery (expense)	**6,765**	(2,457)
	(62,776)	(63,279)
Funds flow from operations[1]	**39,958**	70,050
Net earnings (loss)	**(22,818)**	6,771

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

In comparing the first quarter of 2015 to the first quarter of 2014:

- There was an unrealized loss on financial derivative contracts of $7.5 million, compared to a loss of $10.8 million in 2014. In 2015, unrealized losses of $5.7 million were recognized on our oil derivative contracts and an unrealized loss of $1.4 million was recognized on our natural gas derivative contracts;

- Depletion and depreciation expense of $60.6 million increased $10.9 million due to increased production volumes. The depletion rate for 2015 was $18.90/Boe compared to $21.55/Boe in 2014. The decreased depletion rate in 2015 reflects the impact of the impairment taken at the end of 2014; and

- Deferred income tax recovery of $6.8 million was recorded in 2015 on a loss before tax of $29.6 million. A deferred income tax expense of $2.5 million was recognized in 2014 on earnings before tax of $9.2 million.

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)	March 31, 2015	December 31, 2014
Bank debt	**625,702**	611,717
Working capital deficiency	**47,864**	52,881
Convertible debentures – face value	**75,000**	75,000
Net debt[1]	**748,566**	739,598

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

The Company's net debt at March 31, 2015 increased $9.0 million from December 31, 2014, primarily attributable to funds flow being exceeded by capital expenditures.

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 March 31, 2015, the Company had letters of credit outstanding totaling $5.0 million and had drawn $625.7 million against the Company's credit facilities, leaving $64.3 million of borrowing capacity available.

Credit Facilities

At March 31, 2015, the Company had borrowing base credit facilities of $695.0 million, consisting of a $655.0 million revolving syndicated facility and a $40.0 million operating facility. At March 31, 2015, $625.7 million was drawn against the credit facilities (December 31, 2014 - $611.7 million). During 2015, Long Run plans to repay $100.0 million of its bank debt primarily through asset dispositions. As a result, $100.0 million of bank debt has been classified as a current liability.

Under the credit facilities, total borrowings cannot exceed the borrowing base, which is determined by the lenders on a semi-annual basis, or upon the occurrence of a material event. The level of the borrowing base is determined by the lenders based upon their review of, among other things, the Company's reserves and the value thereof, utilizing commodity prices determined by the lenders which may be different than those utilized by the Company's independent reserve evaluator. The borrowing base was last confirmed by the lenders on November 25, 2014, upon completion of their semi-annual review.

Security for the credit facilities at March 31, 2015 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 bear interest at the prime rate or Libor rate, plus a margin, and in respect of banker's acceptances requires the payment of a stamping fee equal to a margin. The margins ranged from 1.00% per annum to 3.50% per annum, based upon the Company's debt to earnings before interest, taxes, exploration expenses, and all non-cash items including depletion and depreciation, unrealized gain/loss on derivatives, gain/loss on sale of assets, accretion and share based compensation ("Bank EBITDA") ratio. For the three months ended March 31, 2015, the effective interest rate, including standby and other fees, was 4.5% (March 31, 2014 – 4.5%).

At March 31, 2015, the Company was in compliance with all covenants, obligations and conditions of its credit agreement. The covenants in the facilities relate to debt to Bank EBITDA, interest coverage, permitted distributions and dispositions and permitted hedging. The bank covenants require a senior debt to Bank EBITDA ratio of less than 3:1 (March 31, 2015 – 2.17:1) and a total debt to Bank EBITDA ratio of less than 3.5:1 (March 31, 2015 – 2.17:1). The interest coverage ratio, defined as Bank EBITDA to interest expense, must be at least 3.5:1 (March 31, 2015 – 10.04:1). The convertible debentures issued in January

2014 are not considered debt for the debt to Bank 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 2015 forecasted oil and NGLs and natural gas production net of royalties (2016 - 75%; 2017 - 50%). Interest rate hedges are permitted up to 75% of the total debt balance. 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.

We are currently in the annual credit facility review process with our lending syndicate, which we expect to be completed by May 31, 2015. It is currently anticipated that our total credit facilities of $695.0 million will be maintained, segregated into a borrowing base component and a non-revolving term loan component. While details of the non-revolving term loan component have not yet been determined, repayment is expected to be required no later than May 31, 2016. The Company currently anticipates that amendments will be made to our credit facility financial covenants until May 31, 2016, providing increased financial flexibility.

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.

Share Capital

# of units (000s)	**May 6, 2015**	March 31, 2015	December 31, 2014
Common Shares	**193,498**	193,498	193,498
Options	**8,466**	8,733	8,879
Restricted Awards	**5,079**	5,094	-

During January 2015, a total of 5.2 million restricted awards were granted. Each restricted award entitles the holder to a Long Run Common Share or the value of a Long Run Common Share (subject to certain adjustments, including for dividends paid on the Common Shares) on the vesting date. The Company currently intends to settle the awards with equity. The awards vest equally over three years, on the first, second and third anniversaries of the grant date.

Dividends

In the first quarter of 2015 the Company declared and paid dividends totaling $3.4 million (March 31, 2014 - $12.6 million had been declared, of which $8.3 million had been paid). On December 15, 2014, Long Run lowered the amount of the monthly dividend to $0.0175 per share, starting with the January 2015 dividend payable in February 2015. The monthly dividend was suspended in February 2015 as management focuses on strengthening the balance sheet.

Capital Structure

The Company's primary capital management objective is to strengthen our financial position and financial flexibility. To manage the capital structure, the Company may adjust capital spending, dispose of properties, adjust dividends declared, issue new shares, issue new debt or repay existing debt.

In managing its capital structure, the Company monitors financial metrics as indicators of overall financial strength. The financial metrics the Company currently monitors include net debt to funds flow from operations and debt to debt plus equity. The Company's objective is to target net debt to funds flow from operations at or below a ratio of 1.5 and debt to debt plus equity at a ratio at or below 0.4. While the

Company may exceed these rates from time to time, efforts are made after a period of variation to bring the measures back in line. For the calculation of these metrics, see Note 10 to the interim financial statements for the three months ended March 31, 2015.

The net debt to funds flow from operations at March 31, 2015 was calculated based on first quarter funds flow annualized. The resulting net debt to funds flow from operations of 4.7 times reflects the lower commodity prices experienced in the first quarter. At March 31, 2015, the Company had a debt to debt plus equity ratio of 0.50 times. During 2015, the Company expects to repay $100.0 million of its bank debt to improve its financial position, funded primarily through asset dispositions. Repayment of debt is expected to assist in strengthening our financial position.

Contractual Obligations and Contingencies

Contractual Obligations

Commitments

($000s)	**2015**	**2016**	**2017**	**2018**	**2019**	**Thereafter**	**Total**
Operating leases	3,340	4,329	6,041	7,753	7,482	50,604	79,549
Processing	3,492	6,024	6,024	6,024	6,024	31,941	59,529
Transportation	8,158	14,499	13,201	9,577	4,573	9,295	59,303
Fractionation	2,639	3,868	3,602	880	-	-	10,989
Capital	10,282	7,866	5,884	245	-	-	24,277
Total	27,911	36,586	34,752	24,479	18,079	91,840	233,647

At March 31, 2015 the Company is committed under operating leases for office space, contracts related to the processing of natural gas, transportation of oil and natural gas and NGLs, fractionation of natural gas liquids, and capital commitments for drilling rig services. Commitments increased by $42.0 million from December 31, 2014, as a result of an increase in processing, transportation and drilling commitments.

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, 2014.

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, 2014 and the Company's Annual Information Form for the year ended December 31, 2014.

Commodity Price

To partially mitigate exposure to commodity price risk, the Company enters into various financial derivative instruments. The Company has entered into oil and natural gas derivative contracts, including costless collars, fixed price contracts, and calls. As at March 31, 2015, the Company had contracts for oil volumes of 5,411 Bbl/d for 2015 and 1,000 Bbl/d contracted for 2016. At March 31, 2015, the Company had average natural gas volumes of approximately 61.0 MMcf/d contracted for 2015 and 33.2 MMcf/d contracted for 2016. Further details on the derivative contracts can be found in Note 13 of the interim financial statements for the three months ended March 31, 2015.

In the first three months of 2015, the Company realized a $25.8 million gain as a result of its commodity price risk management. The realized gain included a $22.0 million gain on oil financial derivative contracts and a $4.0 million gain on natural gas contracts. In the first three months of 2015, the Company recognized an unrealized loss on oil financial derivative contracts of $5.7 million and an unrealized loss on natural gas contracts of $1.4 million. At March 31, 2015, the fair value of oil derivatives was an asset of $44.2 million and the fair value of natural gas derivatives was an asset of $14.0 million.

Liquidity Risk

Liquidity risk arises through excess financial obligations due over available financial assets at any point in time. The Company's objective in managing liquidity risk is to maintain sufficient capital in order to meet its current and future liquidity requirements. The Company is exposed to liquidity risk, as well as risks related to the continued availability of debt and equity financing at acceptable terms.

The Company's objective in managing liquidity risk is to maintain sufficient capital in order to meet its liquidity requirements at any point in time. With the goal of improving liquidity in the current price environment, the Company is currently planning to reduce bank debt by $100.0 million in 2015, through asset rationalization, a reduced capital budget and the suspension of the Company's dividend.

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, 2014.

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, 2014. There have been no significant changes to the accounting policies since December 31, 2014.

Future Accounting Pronouncements

There were no new or amended standards issued during the three months ended March 31, 2015 that are applicable to the Company in the current or future periods. A description of standards and interpretations that will be adopted by the Company in future periods can be found in Note 4 of the annual financial statements for the year ended December 31, 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:

- During the first quarter of 2015, Long Run suspended its monthly dividend. The dividend was suspended in order to focus on strengthening the balance sheet and directing funds to maintaining operational momentum in our key areas.

- During the fourth quarter of 2014, Long Run recorded property impairment charges of $400.0 million ($300.0 million after tax) at Peace River, the Deep Basin, Redwater and Kaybob. The impairment charges were a result of the drop in forecast commodity prices at December 31, 2014.

- During the third quarter of 2014, Long Run completed the Crocotta acquisition on August 6, 2014, for total consideration of $346.9 million. Production from the properties averaged approximately 6,200 Boe/d from August 6 through December 31, 2014, in the Deep Basin area.

- During the second quarter of 2014, Long Run completed the Deep Basin property acquisition on May 30, 2014, for total consideration of $228.8 million. Production from the property averaged approximately 5,200 Boe/d from May 30 through December 31, 2014, in the Deep Basin and Redwater areas.

- During 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 at the closing dates.

	2015	2014				2013		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Funds flow from operations[1]								
($000s)	**39,958**	68,178	80,199	73,429	70,050	55,934	62,304	63,227
Per share, basic[1]	**0.21**	0.35	0.45	0.55	0.56	0.45	0.50	0.50
Per share, diluted[1]	**0.21**	0.35	0.45	0.54	0.56	0.44	0.50	0.50
Net earnings (loss) *($000s)*	**(22,818)**	(258,652)	40,644	20,842	6,771	(5,531)	9,524	21,099
Per share, basic	**(0.12)**	(1.34)	0.23	0.16	0.05	(0.04)	0.08	0.17
Per share, diluted	**(0.12)**	(1.34)	0.23	0.15	0.05	(0.04)	0.08	0.17
Capital *($000s)*								
Drilling and completion	**31,577**	40,928	52,530	34,851	75,114	30,750	72,746	19,541
Plant and facilities	**12,202**	26,935	19,740	16,441	23,370	8,760	18,699	17,697
Geological and geophysical	**778**	247	1,951	4,295	939	566	601	779
Other assets	**758**	1,984	1,538	1,743	1,425	1,561	1,091	861
Capital expenditures	**45,315**	70,094	75,759	57,330	100,848	41,637	93,137	38,878
Net acquisitions (dispositions)	**(1,392)**	(1,797)	(8,147)	213,716	(3,679)	86,328	3,331	1,158
Capital investment	**43,923**	68,297	67,612	271,046	97,169	127,965	96,468	40,036
Wells drilled *(net)*								
Peace - Montney	**5.0**	1.0	12.0	11.0	17.5	9.5	19.5	4.0
- Other	**-**	-	-	-	2.0	-	-	-
Deep Basin - Edson	**3.0**	2.0	3.0	-	-	-	-	-
- Kakwa/Elmworth	**1.0**	6.0	-	-	-	-	-	-
Redwater - Viking	**-**	1.0	6.0	10.0	27.0	1.0	26.6	6.0
- Other	**-**	-	-	1.0	-	-	4.0	2.0
Other	**-**	-	-	-	1.0	1.0	-	-
Total	**9.0**	10.0	21.0	22.0	47.5	11.5	50.1	12.0
Production								
Liquids *(Bbl/d)*								
Light oil	**10,242**	11,895	12,708	11,808	11,491	11,811	10,322	9,802
Heavy oil	**315**	235	363	668	1,193	1,440	1,387	1,669
NGLs	**5,210**	5,609	3,031	2,038	1,584	1,520	1,478	1,116
	15,767	17,739	16,102	14,514	14,268	14,771	13,187	12,587
Natural Gas *(Mcf/d)*	**119,007**	112,576	112,161	78,524	68,071	73,392	72,634	71,058
Total *(Boe/d)*	**35,602**	36,502	34,795	27,602	25,613	27,003	25,293	24,431
Production by area *(Boe/d)*								
Peace - Montney	**9,527**	10,661	10,918	9,340	9,294	11,500	10,101	9,951
- Other	**2,651**	2,650	3,054	3,160	3,579	2,169	1,960	1,879
Deep Basin - Edson	**7,498**	7,665	4,654	338	19	-	-	-
- Kakwa/Elmworth	**4,942**	3,579	3,207	1,433	-	-	-	-
Redwater - Viking	**3,749**	4,451	5,122	5,617	5,365	6,285	5,875	5,444
- Other	**3,279**	3,242	3,196	2,758	2,819	2,327	2,022	2,167
Boyer	**2,523**	2,727	2,929	3,046	2,733	2,861	3,241	3,274
Other	**1,433**	1,527	1,715	1,910	1,804	1,861	2,094	1,716
Total	**35,602**	36,502	34,795	27,602	25,613	27,003	25,293	24,431

	2015	2014				2013		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Benchmark pricing								
WTI *($US/Bbl)*	**48.57**	73.12	97.21	102.98	98.68	97.46	105.83	94.20
Edmonton Light Sweet *($CAD/Bbl)*	**51.85**	75.65	97.18	105.62	99.83	86.58	104.98	92.33
AECO *($/Mcf)*	**2.76**	3.75	4.02	4.69	5.72	3.53	2.43	3.53
Cdn$/US$ exchange rate	**1.24**	1.13	1.09	1.09	1.10	1.05	1.04	1.02
Prices, excluding derivatives								
Liquids *($/Bbl)*								
Light oil	**42.32**	66.73	88.08	97.50	91.24	75.06	95.47	83.70
Heavy oil	**37.36**	60.71	81.47	81.79	78.90	62.69	87.40	71.52
NGLs	**22.50**	30.02	57.98	72.76	86.87	69.21	76.05	68.91
Total	**35.67**	55.04	82.26	93.30	89.72	73.25	92.44	80.78
Natural Gas *($/Mcf)*	**2.80**	4.13	4.29	4.89	5.96	3.73	2.65	3.73
Total *($/Boe)*	**25.38**	39.71	52.16	63.17	65.89	50.24	55.84	52.72
Prices, including derivatives								
Oil *($/Bbl)*	**65.34**	79.35	84.66	89.59	85.89	71.14	87.44	81.80
NGLs *($/Bbl)*	**22.50**	30.02	57.98	72.76	86.87	69.21	76.05	68.91
Natural Gas *($/Mcf)*	**3.17**	4.15	4.23	4.61	5.53	4.04	3.23	3.89
Total *($/Boe)*	**33.45**	43.92	50.75	59.13	62.67	49.78	54.29	53.29
Netback *($/Boe)*								
Revenues	**25.38**	39.71	52.16	63.17	65.89	50.24	55.84	52.72
Royalties	**(1.97)**	(4.42)	(6.05)	(7.01)	(8.01)	(7.33)	(6.61)	(4.38)
Realized gain (loss) on derivatives	**8.07**	4.21	(1.42)	(4.04)	(3.22)	(0.46)	(1.54)	0.57
Transportation costs	**(1.69)**	(1.75)	(1.65)	(2.10)	(2.41)	(2.00)	(2.50)	(2.36)
Operating costs	**(12.85)**	(12.71)	(11.63)	(14.98)	(15.70)	(13.36)	(14.45)	(13.98)
Operating Netback	**16.94**	25.04	31.41	35.04	36.55	27.09	30.74	32.57
G&A	**(2.00)**	(2.32)	(3.92)	(3.64)	(3.79)	(2.82)	(2.31)	(2.47)
Interest	**(2.46)**	(2.39)	(2.36)	(2.19)	(2.13)	(1.73)	(1.56)	(1.63)
Corporate Netback	**12.48**	20.33	25.13	29.21	30.63	22.54	26.87	28.47
Funds flow from operations[1] *($000s)*								
Revenues	**81,324**	133,354	166,978	158,678	151,886	124,816	129,923	117,210
Royalties	**(6,321)**	(14,835)	(19,377)	(17,598)	(18,466)	(18,213)	(15,377)	(9,753)
Realized gain (loss) on derivatives	**25,845**	14,145	(4,529)	(10,157)	(7,422)	(1,145)	(3,585)	1,285
Transportation costs	**(5,421)**	(5,891)	(5,272)	(5,287)	(5,543)	(4,971)	(5,816)	(5,250)
Operating costs	**(41,184)**	(42,684)	(37,238)	(37,614)	(36,194)	(33,198)	(33,614)	(31,083)
	54,243	84,089	100,562	88,022	84,261	67,289	71,531	72,409
G&A	**(6,406)**	(7,793)	(12,537)	(9,134)	(8,729)	(7,017)	(5,378)	(5,493)
Interest	**(7,875)**	(8,038)	(7,566)	(5,507)	(4,916)	(4,300)	(3,633)	(3,634)
Other	**(4)**	(80)	(260)	48	(566)	(38)	(216)	(55)
	39,958	68,178	80,199	73,429	70,050	55,934	62,304	63,227

[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 and net debt. 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

	2015	2014				2013		
($000s)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Cash flow from operating activities	**48,832**	80,866	78,006	67,280	59,781	65,932	61,756	60,835
Change in non-cash working capital	**(11,491)**	(18,865)	(996)	5,452	8,923	(11,758)	(266)	1,958
Abandonment costs	**2,617**	6,177	3,189	697	1,346	1,760	814	434
Funds flow from operations	**39,958**	68,178	80,199	73,429	70,050	55,934	62,304	63,227
Weighted average outstanding shares *(000s)*								
- Basic	**193,498**	193,497	176,318	134,291	125,730	125,629	125,620	125,620
- Diluted	**193,498**	193,497	177,003	135,437	126,129	126,245	125,620	125,620
Funds flow from operations per share *($/share)*								
- Basic	**0.21**	0.35	0.45	0.55	0.56	0.45	0.50	0.50
- Diluted	**0.21**	0.35	0.45	0.54	0.56	0.44	0.50	0.50

Net Debt

($000s)	**March 31, 2015**	December 31, 2014
Bank debt	**625,702**	611,717
Working capital deficiency		
Accounts payable and accrued liabilities	**114,608**	132,439
Accounts receivable	**(51,615)**	(65,135)
Prepaid expenses and deposits	**(15,129)**	(14,423)
Convertible debentures – face value	**75,000**	75,000
Net Debt	**748,566**	739,598

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 2015 capital expenditure budget, nature and timing of expenditures and method of funding, drilling and development plans and the timing thereof, 2015 average production guidance, continuation of programs focused on cost reductions and selective property dispositions, use of additional cash generated from operations, cost saving initiatives and disposition proceeds, expected timing of response from EOR projects, timing of expansion of projects and possible effects thereof, expectation that unused credit facilities will be sufficient to satisfy working capital deficiencies, timing of annual credit facility review and expected terms of credit facility following review including anticipated amendments to financial covenants and effects thereof, targeted debt reduction in the year, plans to settle restricted awards with equity and expected operating costs, royalty rates and general administrative expenses. 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 acquisitions and the Crocotta acquisition and the effects thereof. Included herein is an estimate of Long Run's 2015 funds flow from operations based on assumptions provided herein and WTI US$52.50/Bbl, AECO $2.60/GJ and FX CDN/USD $0.80 and other assumptions utilized in arriving at Long Run's capital budget. To the extent such estimate constitutes a financial outlook, it was approved by management March 4, 2015 and is included herein to provide readers with an understanding of the anticipated funds available to fund its capital expenditures and for other purposes 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. 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

Oil 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 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

Bbl	Barrels
MBbl	thousand barrels
MMBbl	million barrels
Bbl/d	barrels per day
NGL	natural gas liquids
Boe	barrels of oil equivalent
MBoe	thousand barrels of oil equivalent
Boe/d	barrels of oil equivalent per day
Liquids	light oil, heavy oil, and NGLs

Natural Gas

MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMbtu	million British Thermal Units

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.