LONG RUN EXPLORATION LTD.

Management's Discussion and Analysis

June 30, 2015

LONG RUN EXPLORATION

Management's Discussion and Analysis

For the three and six months ended June 30, 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 June 30, 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 July 29, 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.

Long Run continues to examine strategic and financial means to improve the capital structure of the Company. 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 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 long term value for our shareholders. Our capital program targets high-grade development projects in our core operating areas.

Our 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. Our 2015 capital program is expected to be fully funded by our estimated annual funds flow from operations of between $120 - $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 million in 2015. The Company plans to repay an additional $145 million of bank debt due by May 29, 2016 through asset dispositions and/or alternative debt refinancing.

Highlights

Second quarter 2015 compared to second quarter 2014

- Generated funds flow from operations of $45.9 million ($0.24/share), a decrease of $27.5 million compared to $73.4 million ($0.54/share) in 2014, reflecting lower commodity prices and lower oil production partially offset by higher natural gas and NGLs production, a gain on financial derivatives and lower royalties.

- Averaged 34,457 Boe/d of production, an increase of 6,855 Boe/d from 27,602 Boe/d in 2014. The production increase resulted primarily from the liquids-rich natural gas weighted Deep Basin acquisitions in 2014.

- Reduced capital expenditures to $8.8 million compared to $57.3 million in 2014.

- Executed non-core dispositions totaling $10.1 million, with proceeds being directed towards debt repayment.

- Oil prices including derivatives averaged $72.03/Bbl compared to $89.59/Bbl in 2014 as a result of a decrease in the West Texas Intermediate benchmark pricing, partially offset by an increase in the U.S. dollar exchange rate and a realized gain on oil financial derivatives.

  Average NGLs pricing for the quarter decreased to $24.48/Bbl from $72.76/Bbl in 2014, reflecting lower market prices as well as the change in our NGLs product mix due to the Deep Basin acquisitions in 2014.

  Natural gas prices including derivatives averaged $3.30/Mcf compared to $4.61/Mcf in 2014, primarily attributable to weaker AECO benchmark prices partially offset by a realized gain on natural gas financial derivatives.

- Recorded a net loss of $50.1 million compared to net earnings of $20.8 million in 2014, primarily as a result of lower funds flow from operations and higher unrealized losses on financial derivatives.

- Completed the semi-annual review of the Company's credit facilities with our bank syndicate on May 29, 2015. Total credit facilities were maintained at $695 million. The amended credit facilities consist of a $410 million revolving syndicated facility, a $40 million revolving operating facility and a $245 million non-revolving syndicated facility.

Six months ended June 30, 2105 compared to six months ended June 30, 2014

- Reduced net debt by $30.4 million, on track with our debt reduction goal of $100 million for 2015. The reduction in net debt was a result of disposition proceeds and funds flow from operations exceeding capital expenditures.

- Generated funds flow from operations of $85.9 million ($0.44/share) compared to $143.5 million ($1.10/share) in 2014, reflecting lower commodity prices and lower oil production partially offset by higher natural gas and NGLs production, a gain on financial derivatives and lower royalties.

- Averaged 35,026 Boe/d of production, an increase of 8,413 Boe/d from 26,613 Boe/d in 2014. The production increase resulted from the liquids-rich natural gas weighted Deep Basin acquisitions in 2014. Production for 2015 remains on track to meet annual guidance of 32,000 - 33,000 Boe/d based on planned capital expenditures of $100 million.

- Executed a focused development program, drilling 9.0 successful net wells. Capital expenditures of $54.1 million compared to $158.2 million in 2014 and were in line with our planned capital expenditures of $50 - $55 million. Capital spending in 2015 was concentrated on our Peace River Montney and Deep Basin Cardium core areas. In 2014, capital spending was focused on Peace River Montney and Redwater Viking.

- Successfully executed non-core dispositions for total proceeds of $12.1 million.

- Oil prices including derivatives decreased to $68.52/Bbl from $87.73/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 realized gain on oil financial derivatives.

  Average NGLs pricing decreased to $23.44/Bbl from $78.89/Bbl in 2014, reflecting lower market prices as well as the change in our NGLs product mix due to the Deep Basin acquisitions in 2014.

  Natural gas prices including derivatives decreased to $3.23/Mcf from $5.03/Mcf in 2014, primarily attributable to weaker AECO benchmark prices, partially offset by a realized gain on natural gas financial derivatives.

- Recorded a net loss of $73.0 million compared to net earnings of $27.6 million in 2014, primarily as a result of lower funds flow from operations, higher unrealized losses on financial derivatives and increased depletion expense associated with higher production volumes.

Quarterly Results Overview

($000s, except per share or unless otherwise noted)	Six months ended June 30		2015		2014			
	2015	2014	**Q2**	Q1	Q4	Q3	Q2	Q1
Funds flow from operations [1]	**85,882**	143,479	**45,924**	39,958	68,178	80,199	73,429	70,050
Per share, basic [1]	**0.44**	1.10	**0.24**	0.21	0.35	0.45	0.55	0.56
Per share, diluted [1]	**0.44**	1.10	**0.24**	0.21	0.35	0.45	0.54	0.56
Net earnings (loss)	**(72,954)**	27,613	**(50,136)**	(22,818)	(258,652)	40,644	20,842	6,771
Per share, basic	**(0.38)**	0.21	**(0.26)**	(0.12)	(1.34)	0.23	0.16	0.05
Per share, diluted	**(0.38)**	0.21	**(0.26)**	(0.12)	(1.34)	0.23	0.15	0.05
Revenues, before royalties	**174,760**	310,564	**93,436**	81,324	133,354	166,978	158,678	151,886
Capital expenditures	**54,085**	158,179	**8,770**	45,315	70,094	75,759	57,330	100,848
Net divestitures [2]	**(10,922)**	(18,730)	**(9,530)**	(1,392)	(1,797)	(8,147)	(15,051)	(3,679)
Net capital expenditures [2]	**43,163**	139,448	**(760)**	43,923	68,297	67,612	42,279	97,169
Production								
Oil *(Bbl/d)*	**9,990**	12,580	**9,429**	10,557	12,130	13,071	12,476	12,684
Natural gas liquids *(Bbl/d)*	**4,933**	1,812	**4,659**	5,210	5,609	3,031	2,038	1,584
Total Liquids *(Bbl/d)*	**14,923**	14,392	**14,088**	15,767	17,739	16,102	14,514	14,268
Natural gas *(Mcf/d)*	**120,620**	73,327	**122,214**	119,007	112,576	112,161	78,524	68,071
Total *(Boe/d)*	**35,026**	26,613	**34,457**	35,602	36,502	34,795	27,602	25,613
Prices, including derivatives								
Oil *($/Bbl)*	**68.52**	87.73	**72.03**	65.34	79.35	84.66	89.59	85.89
Natural gas liquids *($/Bbl)*	**23.44**	78.89	**24.48**	22.50	30.02	57.98	72.76	86.87
Total Liquids *($/Bbl)*	**53.61**	86.62	**56.31**	51.18	63.75	79.64	87.23	85.99
Natural gas *($/Mcf)*	**3.23**	5.03	**3.30**	3.17	4.15	4.23	4.61	5.53
Total *($/Boe)*	**34.24**	60.82	**35.04**	33.45	43.92	50.75	59.13	62.67
Operating netback *($/Boe)*	**18.41**	35.76	**19.92**	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*

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, located near Edmonton, Alberta, 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.

During the second quarter of 2015, Long Run invested $3.3 million into the Peace River Montney area, drilling no wells during the quarter. Second quarter 2015 production averaged 8,767 Boe/d, consisting of 4,809 Bbl/d of oil and NGLs and 23,749 MMcf/d of natural gas. In the first six months of 2015, Long Run invested $17.7 million, drilling 5.0 net Montney wells with a 100% success rate, resulting in average production of 9,145 Boe/d (56% oil and NGLs). Capital expenditures for 2015 are expected to total approximately $24 million for this area. 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.

Long Run invested $2.9 million in the Deep Basin - Edson area in the second quarter of 2015, drilling no new wells. Second quarter 2015 production averaged 7,366 Boe/d, consisting of 3,023 Bbl/d of oil and NGLs and 26,058 Mcf/d of natural gas. In the first six months of 2015, Long Run invested $16.7 million, drilling 3.0 net wells with a 100% success rate, resulting in average production of 7,432 Boe/d (42% oil and NGLs). Capital expenditures for 2015 are expected to total approximately $29 million for this area, including the drilling of approximately 6.0 net wells.

In the Deep Basin - Kakwa/Elmworth area, Long Run invested $0.4 million in the second quarter of 2015, with no new wells drilled. Second quarter 2015 production averaged 5,706 Boe/d, consisting of 1,078 Bbl/d of oil and NGLs and 27,765 Mcf/d of natural gas. In the first six months of 2015, Long Run invested $12.5 million, drilling 1.0 net wells with a 100% success rate, resulting in average production of 5,325 Boe/d (21% oil and NGLs). Capital expenditures for 2015 are expected to total approximately $13 million for this area. No further wells are planned for the remainder of 2015.

In the Redwater Viking, Long Run invested $1.7 million in the second quarter of 2015, drilling no wells. Second quarter production averaged 3,295 Boe/d, consisting of 2,860 Bbl/d of oil and NGLs and 2,608 Mcf/d of natural gas. In the first six months of 2015, Long Run invested $3.4 million, with production averaging 3,520 Boe/d (87% oil and NGLs). Capital expenditures for 2015 are expected to total approximately $19 million for this area, with 12.0 net wells planned for the area in the second half of 2015. The Company operates, transports, and processes substantially all of its production within the Redwater area.

For the second half of 2015, Long Run had previously planned to drill 3.0 Edson Cardium wells and 4.0 Kakwa/Elmworth Cardium wells. After reviewing expected cost structures and factoring in forecast commodity prices, we have reallocated capital spending from Kakwa/Elmworth to the Redwater Viking area. As a result, we plan to drill 12.0 Redwater Viking wells and 3.0 Edson Cardium wells in the second half of 2015. This reallocation is reflected in the 2015 planned capital spending described above.

Capital Investment

Capital Expenditures, Acquisitions & Dispositions

($000s)	Q2 2015	Q2 2014	Six months ended June 30 2015	Six months ended June 30 2014
Drilling and completion	**4,484**	34,851	**36,061**	109,965
Plant and facilities	**1,967**	16,441	**14,169**	39,811
Geological and geophysical	**42**	4,295	**820**	5,234
Other assets	**2,277**	1,743	**3,035**	3,169
Capital expenditures	**8,770**	57,330	**54,085**	158,179
Acquisitions – land	**528**	3,493	**589**	4,694
– properties	**24**	230,117	**558**	233,678
Dispositions	**(10,082)**	(19,894)	**(12,069)**	(28,336)
Net capital expenditures	**(760)**	271,046	**43,163**	368,215

Drilling Activity

		Q2 2015 Wells Gross	Q2 2015 Wells Net	Q2 2014 Wells Gross	Q2 2014 Wells Net	Success Rate *(net wells)* Q2 2015	Success Rate *(net wells)* Q2 2014
Peace River	– Montney	**-**	**-**	11.0	11.0	**-**	100%
	– Other	**-**	**-**	-	-	**-**	-
Deep Basin	– Edson	**-**	**-**	-	-	**-**	-
	– Kakwa/Elmworth	**-**	**-**	-	-	**-**	-
Redwater	– Viking	**-**	**-**	10.0	10.0	**-**	100%
	– Other	**-**	**-**	1.0	1.0	**-**	100%
Other		**-**	**-**	-	-	**-**	-
		-	**-**	22.0	22.0	**-**	100%

Six months ended June 30		2015 Wells Gross	2015 Wells Net	2014 Wells Gross	2014 Wells Net	Success Rate *(net wells)* 2015	Success Rate *(net wells)* 2014
Peace River	– Montney	**5.0**	**5.0**	29.0	28.5	**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	**-**	**-**	37.0	37.0	**-**	100%
	– Other	**-**	**-**	2.0	1.0	**-**	100%
Other		**-**	**-**	1.0	1.0	**-**	100%
		9.0	**9.0**	71.0	69.5	**100%**	100%

Capital Expenditures

Capital expenditures in the second quarter of 2015 were $8.8 million, including $3.3 million (38%) in the Peace River Montney, $2.9 million (33%) in the Deep Basin at Edson, $0.4 million (5%) in the Deep Basin at Kakwa/Elmworth and $1.7 million (19%) in the Redwater Viking. No new wells were drilled during the quarter.

Capital expenditures in the second quarter of 2014 were $57.3 million, including $32.0 million (56%) in the Peace River Montney and $12.0 million (21%) in the Redwater Viking. The Company drilled 22.0 (22.0 net) wells with a 100% success rate in 2014.

Capital expenditures in the first six months of 2015 were $54.1 million, including $17.7 million (33%) in the Peace River Montney, $16.7 million (31%) in the Deep Basin at Edson, $12.5 million (23%) in the Deep Basin at Kakwa/Elmworth and $3.4 million (6%) in the Redwater Viking. The Company drilled 9.0 (9.0 net) wells with a 100% success rate in the first half of 2015.

Capital expenditures in the first six months of 2014 were $158.2 million, including $83.1 million (53%) in the Peace River Montney and $48.0 million (30%) in the Redwater Viking. The Company drilled 71.0 (69.5 net) wells with a 100% success rate in 2014.

Acquisitions and Dispositions

Net disposition proceeds of $9.5 million were received in the second quarter of 2015 and $10.9 million were received in the first six months of 2015. Dispositions proceeds of $10.1 million were received in the second quarter of 2015 relating to a pipeline sale and the disposition of minor properties producing approximately 50 Boe/d. Proceeds from these dispositions have been directed towards debt repayment.

Net acquisitions in the second quarter of 2014 were $213.7 million and for the first six months of 2014 were $210.0 million. Net acquisitions primarily related to the Deep Basin asset acquisition, which closed on May 30, 2014. The acquisition included development and exploration assets located primarily in the Kakwa/Elmworth and Edson areas. Production from the acquisition properties averaged 6,000 Boe/d (28% oil and NGLs) in the month of June 2014, of which 5,200 Boe/d was located in the Deep Basin area.

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 EOR implementation in the Montney area 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

	Q2 2015	Q2 2014	Six months ended June 30 2015	Six months ended June 30 2014
Liquids *(Bbl/d)*				
Light oil	**9,059**	11,808	**9,647**	11,651
Heavy oil	**370**	668	**343**	929
NGLs	**4,659**	2,038	**4,933**	1,812
Total	**14,088**	14,514	**14,923**	14,392
Natural Gas *(Mcf/d)*	**122,214**	78,524	**120,620**	73,327
Total *(Boe/d)*	**34,457**	27,602	**35,026**	26,613

Average Production by Area

		Q2 2015 Oil *(Bbl/d)*	Q2 2015 NGLs *(Bbl/d)*	Q2 2015 Natural Gas *(Mcf/d)*	Q2 2015 Total *(Boe/d)*	Q2 2014 Oil *(Bbl/d)*	Q2 2014 NGLs *(Bbl/d)*	Q2 2014 Natural Gas *(Mcf/d)*	Q2 2014 Total *(Boe/d)*
Peace River	– Montney	**4,557**	**252**	**23,749**	**8,767**	5,492	224	21,741	9,340
	– Other	**724**	**82**	**8,182**	**2,170**	998	108	12,324	3,160
Deep Basin	– Edson	**594**	**2,429**	**26,058**	**7,366**	38	50	1,502	338
	– Kakwa/Elmworth	**87**	**991**	**27,765**	**5,706**	64	360	6,049	1,433
Redwater	– Viking	**2,812**	**48**	**2,608**	**3,295**	4,855	70	4,152	5,617
	– Other	**649**	**87**	**14,330**	**3,124**	1,028	244	8,915	2,758
Boyer		**6**	**3**	**15,898**	**2,659**	-	1	18,272	3,046
Other		**-**	**767**	**3,624**	**1,370**	1	981	5,569	1,910
		9,429	**4,659**	**122,214**	**34,457**	12,476	2,038	78,524	27,602

		Six months ended June 30, 2015 Oil *(Bbl/d)*	Six months ended June 30, 2015 NGLs *(Bbl/d)*	Six months ended June 30, 2015 Natural Gas *(Mcf/d)*	Six months ended June 30, 2015 Total *(Boe/d)*	Six months ended June 30, 2014 Oil *(Bbl/d)*	Six months ended June 30, 2014 NGLs *(Bbl/d)*	Six months ended June 30, 2014 Natural Gas *(Mcf/d)*	Six months ended June 30, 2014 Total *(Boe/d)*
Peace River	– Montney	**4,830**	**282**	**24,197**	**9,145**	5,485	205	21,763	9,317
	– Other	**789**	**117**	**9,022**	**2,410**	1,105	149	12,681	3,368
Deep Basin	– Edson	**659**	**2,495**	**25,670**	**7,432**	19	27	802	180
	– Kakwa/Elmworth	**53**	**1,071**	**25,208**	**5,325**	32	181	3,042	720
Redwater	– Viking	**3,014**	**45**	**2,768**	**3,520**	4,750	56	4,119	5,493
	– Other	**640**	**102**	**14,758**	**3,202**	1,188	189	8,466	2,788
Boyer		**3**	**2**	**15,520**	**2,592**	-	1	17,337	2,890
Other		**2**	**819**	**3,477**	**1,400**	1	1,004	5,117	1,857
		9,990	**4,933**	**120,620**	**35,026**	12,580	1,812	73,327	26,613

During the second quarter of 2015, production averaged 34,457 Boe/d, an increase of 6,855 Boe/d from 27,602 Boe/d in 2014. Production in the first half of 2015 averaged 35,026 Boe/d, an increase of 8,413 Boe/d from 26,613 Boe/d in 2014. The production increases resulted primarily from the Deep Basin acquisitions in 2014.

Peace River Montney production averaged 8,767 Boe/d in the second quarter of 2015, compared to 9,340 Boe/d in 2014. Over the first six months of 2015, production averaged 9,145 Boe/d compared to 9,317 Boe/d in 2014. The lower production volumes are primarily a result of reduced capital spending in the area over the past 12 months, partially offset by lower declines.

Deep Basin production averaged 13,072 Boe/d in the second quarter of 2015 compared to 1,771 Boe/d in 2014. Over the first six months of 2015, production averaged 12,757 Boe/d compared to 900 Boe/d in 2014. Since acquiring the Deep Basin assets in May and August of 2014, Long Run has drilled 15.0 successful net wells on the acquired properties. As a result, production in the second quarter of 2015 is up 1,828 Boe/d to 13,072 Boe/d from 11,244 Boe/d in the fourth quarter of 2014.

Redwater Viking production for the second quarter of 2015 averaged 3,295 Boe/d compared to 5,617 Boe/d in 2014. Production averaged 3,520 Boe/d over the first six months of 2015 compared to 5,493 Boe/d in 2014. The lower production volumes are primarily a result of reduced capital spending in the area over the past 12 months, partially offset by lower declines. Long Run invested $3.4 million in the Redwater Viking over the first six months of 2015 compared to $48.0 million in 2014.

Commodity Pricing

			Six months ended June 30	
	Q2 2015	Q2 2014	**2015**	2014
Benchmark pricing				
WTI *(US$/Bbl)*	**57.96**	102.98	**53.29**	100.81
Edmonton Light Sweet *(CDN$/Bbl)*	**67.73**	105.62	**59.84**	102.64
AECO *($/Mcf)*	**2.66**	4.69	**2.71**	5.17
CDN$/US$ exchange rate	**1.23**	1.09	**1.24**	1.10
Prices, excluding derivatives				
Liquids *($/Bbl)*				
Light oil	**58.53**	97.50	**49.97**	94.43
Heavy oil	**53.33**	81.79	**46.03**	79.95
Total Oil	**58.33**	96.65	**49.84**	93.36
NGLs	**24.48**	72.76	**23.44**	78.89
Total	**47.13**	93.30	**41.11**	91.54
Natural Gas *($/Mcf)*	**2.89**	4.89	**2.84**	5.38
Total *($/Boe)*	**29.80**	63.17	**27.57**	64.47
Prices, including derivatives				
Liquids *($/Bbl)*				
Oil	**72.03**	89.59	**68.52**	87.73
NGLs	**24.48**	72.76	**23.44**	78.89
Total	**56.31**	87.23	**53.61**	86.62
Natural Gas *($/Mcf)*	**3.30**	4.61	**3.23**	5.03
Total *($/Boe)*	**35.04**	59.13	**34.24**	60.82

The Company's financial results are influenced by fluctuations in commodity prices, exchange rates and Canadian price differentials. Long Run's average oil price excluding derivatives for the second quarter of 2015 was $58.33/Bbl, a decrease of $38.32/Bbl from 2014. Our average oil price excluding derivatives during the first six months of 2015 was $49.84/Bbl, a decrease of $43.52/Bbl over 2014. The decreases resulted from lower West Texas Intermediate benchmark pricing, partially offset by an increase in the U.S dollar exchange rate.

Long Run's NGLs price in the second quarter of 2015 was $24.48/Bbl, a decrease of $48.28/Bbl over 2014. Our average NGLs price during the first six months of 2015 was $23.44/Bbl, a decrease of $55.45/Bbl over 2014. The decreases were a result of lower market prices as well as the change in our NGLs product mix due to the Deep Basin acquisitions in 2014.

In the second quarter of 2015, the Company's natural gas price excluding derivatives was $2.89/Mcf, a decrease of $2.00/Mcf over 2014. Our average natural gas price during the first six months of 2015 was $2.84/Mcf, a decrease of $2.54/Mcf from 2014. The decreases were primarily 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 second quarter of 2015, our oil price of $72.03/Bbl included a realized gain on derivatives of $13.70/Bbl. The Company's natural gas price of $3.30/Mcf included a realized gain on derivatives of $0.41/Mcf. During the six months ended June 30, 2015, Long Run's oil price including financial derivative contracts of $68.52/Bbl included a gain on the derivative contract of $18.68/Bbl. The Company's natural gas price including derivatives of $3.23/Mcf included a realized gain on the derivative contracts of $0.39/Mcf.

Operating Results

Operating Netback & Funds Flow from Operations

	Q2 2015		Q2 2014	
	$000s	$/Boe	$000s	$/Boe
Revenues	93,436	29.80	158,678	63.17
Royalties	(6,400)	(2.04)	(17,598)	(7.01)
	87,036	27.76	141,080	56.16
Realized gain (loss) on derivatives	16,432	5.24	(10,157)	(4.04)
Transportation costs	(4,784)	(1.53)	(5,287)	(2.10)
Operating costs	(36,207)	(11.55)	(37,614)	(14.98)
Operating netback	62,477	19.92	88,022	35.04
General and administration	(7,929)	(2.53)	(9,134)	(3.64)
Interest	(8,624)	(2.75)	(5,507)	(2.19)
Exploration expenses	-	-	48	0.02
Capital and other taxes	-	-	-	-
Funds flow from operations[1]	45,924	14.64	73,429	29.23

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

	Six months ended June 30			
	2015		2014	
	$000s	$/Boe	$000s	$/Boe
Revenues	174,760	27.57	310,564	64.47
Royalties	(12,721)	(2.01)	(36,064)	(7.49)
	162,039	25.56	274,500	56.98
Realized gain (loss) on derivatives	42,277	6.67	(17,579)	(3.65)
Transportation costs	(10,205)	(1.61)	(10,830)	(2.25)
Operating costs	(77,391)	(12.21)	(73,808)	(15.32)
Operating netback	116,720	18.41	172,283	35.76
General and administration	(14,335)	(2.26)	(17,863)	(3.71)
Interest	(16,499)	(2.60)	(10,423)	(2.16)
Exploration expenses	(4)	-	(518)	(0.11)
Capital and other taxes	-	-	-	-
Funds flow from operations[1]	85,882	13.55	143,479	29.78

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

Second quarter 2015 compared to second quarter 2014

During the second quarter of 2015, funds flow from operations was $45.9 million, a decrease of $27.5 million from the second quarter of 2014 primarily resulting from the following:

- Lower commodity prices, excluding derivatives, decreased revenue by $55.5 million. Of this total, $32.7 million was attributable to lower oil prices, $14.3 million to lower natural gas prices and $9.0 million to lower NGLs prices; and
- Lower oil production decreased revenue by $27.0 million as a result of reduced capital spending over the past 12 months at Redwater and Peace River.

Partially offset by:

- Higher natural gas and NGLs production increased revenue by $17.3 million. Higher production volumes were attributable to the Deep Basin properties acquired in 2014 and our successful Cardium drilling program. Of the total revenue increase, natural gas production contributed $11.5 million and NGLs production contributed $5.8 million;
- The realized gain on financial derivative contracts of $16.4 million compared to a loss of $10.2 million in 2014. During 2015, Long Run realized gains on oil derivative contracts of $11.8 million and on natural gas derivative contracts of $4.6 million; and
- Royalties were $11.2 million lower in 2015, averaging 7% of revenue compared to 11% in 2014. Lower royalties resulted from lower commodity prices as well as lower oil production volumes.

Operating costs for 2015 averaged $11.55/Boe compared to $14.98/Boe in 2014, reflecting the addition of the lower cost Deep Basin assets and lower utilities, fuel and chemical costs.

General and administration expense for 2015 averaged $2.53/Boe compared to $3.64/Boe in 2014. The higher expense in 2014 was primarily due to transaction costs associated with the Deep Basin asset acquisition.

Six months ended June 30, 2015 compared to six months ended June 30, 2014

During the first six months of 2015, funds flow from operations was $85.9 million, a decrease of $57.6 million from the first six months of 2014 primarily resulting from the following:

- Lower commodity prices, excluding derivatives, decreased revenue by $129.9 million. Of this total, $79.0 million was attributable to lower oil prices, $33.7 million to lower natural gas prices and $18.2 million to lower NGLs prices;

- Lower oil production decreased revenue by $43.4 million as a result of reduced capital spending over the past 12 months at Redwater and Peace River; and

- Higher interest expense decreased revenues by $6.0 million due mainly to a higher average debt balance. Interest rates are anticipated to average approximately 6.5% in 2015.

Partially offset by:

- Higher natural gas and NGLs production increased revenue by $37.6 million. Higher production volumes were attributable to the Deep Basin acquisitions made in 2014 and our successful Cardium drilling programs over the past year. Of the total revenue increase, natural gas production contributed $24.3 million and NGLs production contributed $13.2 million;

- The realized gain on financial derivative contracts of $42.3 million compared to a loss of $17.6 million in 2014. During 2015, Long Run realized gains on oil derivative contracts of $33.8 million and on natural gas derivative contracts of $8.6 million; and

- Royalties were $23.4 million lower in 2015, averaging 7% of revenue compared to 12% in 2014. Lower royalties resulted from lower commodity prices as well as lower oil production volumes. Royalty rates are expected to average approximately 10 - 11% in 2015.

Operating costs for 2015 averaged $12.21/Boe compared to $15.32/Boe in 2014, reflecting the addition of the lower cost Deep Basin assets and lower utilities, fuel and chemical costs. Annual operating costs are expected to average $13.25/Boe for 2015.

General and administration expense for 2015 averaged $2.26/Boe compared to $3.71/Boe in 2014. The higher expense in 2014 was primarily a result of transaction costs associated with the Deep Basin asset acquisition and higher employee costs. Annual general and administration expense is expected to average $2.50/Boe for 2015.

Other Income & Expenses

($000s)	Q2 2015	Q2 2014	Six months ended June 30 2015	Six months ended June 30 2014
Unrealized gain (loss) on derivatives	**(27,587)**	972	**(35,062)**	(9,811)
Share-based compensation	**(823)**	(593)	**(1,773)**	(1,175)
Accretion	**(2,665)**	(2,659)	**(5,340)**	(4,781)
Depletion and depreciation	**(58,103)**	(50,460)	**(118,687)**	(100,123)
Gain (loss) on disposal of assets	**(6,882)**	7,356	**(4,739)**	9,684
Deferred income tax recovery (expense)	**-**	(7,203)	**6,765**	(9,660)
	(96,060)	(52,587)	**(158,836)**	(115,866)
Funds flow from operations[1]	**45,924**	73,429	**85,882**	143,479
Net earnings (loss)	**(50,136)**	20,842	**(72,954)**	27,613

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

Second quarter 2015 compared to second quarter 2014

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

- There was an unrealized loss on financial derivative contracts of $27.6 million compared to a gain of $1 million in 2014. In 2015, an unrealized loss of $24.5 million was recognized on our oil derivative contracts and $3.6 million was recognized on our natural gas derivative contracts.
- Depletion and depreciation expense of $58.1 million increased $7.6 million due to increased production volumes partially offset by a lower depletion rate. The depletion rate for 2015 was $18.55/Boe compared to $20.10/Boe in 2014. The lower depletion rate in 2015 reflects the impact of the impairment taken at the end of 2014.
- The loss on disposal of assets of $6.9 million compares to a gain of $7.4 million in 2014. The loss in 2015 is related primarily to the disposal of a minor property in our Peace River area. The gain in 2014 related primarily to the disposition of our heavy oil properties and an overriding royalty in our Peace River area.
- A deferred income tax recovery was not recorded in 2015 due to the impact of lower commodity pricing on the estimated realization of the Company’s tax pools.

Six months ended June 30, 2015 compared to six months ended June 30, 2014

In comparing the six months ended June 30, 2015 to the six months ended June 30, 2014:

- There was an unrealized loss on financial derivative contracts of $35.1 million compared to a loss of $9.8 million in 2014. In 2015, an unrealized loss of $30.2 million was recognized on our oil derivative contracts and $5.1 million was recognized on our natural gas derivative contracts.

- Depletion and depreciation expense of $118.7 million increased $18.6 million from 2014 due to increased production volumes partially offset by a lower depletion rate. The depletion rate for 2015 was $18.70/Boe compared to $20.80/Boe in 2014. The lower depletion rate in 2015 reflects the impact of the impairment taken at the end of 2014.

- The loss on disposal of assets of $4.7 million compares to a gain of $9.7 million in 2014. The loss in 2015 is related primarily to the disposal of a minor property in our Peace River area. The gain in 2014 related primarily to the disposition of our heavy oil properties and an overriding royalty in our Peace River area.

- A deferred income tax recovery of $6.8 million was recorded in 2015 on a loss before tax of $79.7 million. The deferred income tax recovery was limited to $6.8 million due to the impact of lower commodity pricing on the estimated realization of the Company’s tax pools. A deferred income tax expense of $9.7 million was recognized in 2014 on earnings before tax of $37.3 million.

Liquidity and Capital Resources

Net Debt

($000s)	June 30, 2015	December 31, 2014
Bank debt – current	**245,000**	100,000
– long-term	**380,943**	511,717
	625,943	611,717
Working capital deficiency	**8,303**	52,881
Convertible debentures – face value	**75,000**	75,000
Net debt[1]	**709,246**	739,598

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

The Company's net debt at June 30, 2015 decreased $30.4 million from December 31, 2014, primarily attributable to proceeds from dispositions and funds flow from operations exceeding capital expenditures. The $30.4 million net debt reduction in the first half of 2015 is on track to meet our debt reduction target of $100 million for the year.

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 June 30, 2015, Long Run had drawn $625.9 million against the Company's credit facilities and had letters of credit outstanding totaling $6.1 million, leaving $63.0 million of borrowing capacity available.

Credit Facilities

On May 29, 2015, the Company completed the semi-annual review of its credit facilities with its banking syndicate. Credit facilities were maintained at $695 million. The amended credit facilities consist of a $410 million revolving syndicated facility, a $40 million revolving operating facility and a $245 million non-revolving syndicated facility. At June 30, 2015, $625.9 million was drawn against the credit facilities (December 31, 2014 - $611.7 million).

The revolving syndicated facility and the revolving operating facility, which comprise the Company's borrowing base facilities, are reviewed semi-annually and terminate on May 31, 2017 unless extended. The non-revolving syndicated facility is due on May 29, 2016. Prior to May 29, 2016, proceeds received on the aggregate sale of assets in excess of $30 million are required to be applied against the non-revolving syndicated facility.

During 2015, Long Run plans to repay $100 million of outstanding debt primarily through disposition proceeds and funds flow from operations exceeding capital expenditures. The Company plans to repay the remaining $145 million of debt on the non-revolving syndicated facility due May 29, 2016 through further strategic and financial means, which may include additional asset dispositions and alternative debt refinancing.

Under the borrowing base 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 next borrowing base review will occur prior to November 30, 2015.

Security for the credit facilities at June 30, 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 applicable to the borrowing base facilities range from 1.00% per annum to 4.50% per annum, based upon the ratio of 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"). Interest and fees payable on the non-revolving syndicated facility are based upon the borrowing base facility margins plus 3.50%. For the six months ended June 30, 2015, the effective interest rate, including standby and other fees, was 4.7% (June 30, 2014 – 4.4%).

At June 30, 2015, the Company was in compliance with all covenants, obligations and conditions of its credit agreement. The covenants under the credit facilities include covenants which relate to senior debt and total debt to Bank EBITDA, interest coverage, permitted dispositions, permitted hedging and permitted distributions (regular cash dividends to shareholders are not permitted until the $245 million non-revolving syndicated facility has been repaid).

As part of the credit facilities review, the financial covenants were amended to provide increased financial flexibility. The revised financial covenants require the Company's ratios of senior debt to Bank EBITDA and total debt to Bank EBITDA to be less than 4.50x from May 31, 2015 to March 31, 2016 and less than 5.0x from April 1, 2016 to June 30, 2016 (June 30, 2015 – 2.37:1). After June 30, 2016, the bank covenants require a senior debt to Bank EBITDA ratio of less than 3.0x and a total debt to Bank EBITDA ratio of less than 3.5x. The interest coverage ratio, defined as Bank EBITDA to interest expense, is required to be greater than 2.75x until June 30, 2016 and greater than 3.5x for each fiscal quarter after June 30, 2016 (June 30, 2015 – 8.31:1). The convertible debentures issued in January 2014 are not considered debt for the debt to Bank EBITDA ratio calculations under the credit agreement. 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 June 3, 2015 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.

Share Capital

# of units (000s)	**July 29, 2015**	June 30, 2015	December 31, 2014
Common Shares	193,498	193,498	193,498
Options	8,211	8,268	8,879
Restricted Awards	4,839	4,884	-

In 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 second quarter of 2015, no dividends were declared or paid to shareholders. The monthly dividend was suspended in February 2015 as the Company focuses on strengthening the balance sheet. During the six months ended June 30, 2015, $3.4 million in dividends had been declared and paid (June 30, 2014 - $27.1 million in dividends were declared, of which $21.9 million had been paid).

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 six months ended June 30, 2015.

The net debt to funds flow from operations at June 30, 2015 was calculated based on second quarter funds flow annualized. The resulting net debt to funds flow from operations of 3.86 times reflects the lower commodity prices experienced in the second quarter. At June 30, 2015, the Company had a debt to debt plus equity ratio of 0.52 times. During 2015, the Company plans to reduce outstanding debt by $100 million, primarily through asset dispositions. The Company plans to repay the remaining $145 million due May 29, 2016 on the non-revolving syndicated facility through further strategic and financial means, which may include additional asset dispositions and alternative debt financing.

Contractual Obligations and Contingencies

Contractual Obligations

($000s)	2015	2016	2017	2018	2019	Thereafter	Total
Operating leases	2,253	4,329	6,041	7,753	7,482	50,604	78,462
Processing	2,113	6,024	6,024	6,024	6,024	31,941	58,150
Transportation	5,827	14,723	13,242	9,562	4,610	9,495	57,459
Fractionation	1,462	2,843	2,653	650	-	-	7,608
Capital	6,504	9,969	7,501	308	-	-	24,282
Commitments	18,159	37,888	35,461	24,297	18,116	92,040	225,961
Bank loan		245,000	380,943	-	-	-	625,943
Convertible debentures[1]	-	-	-	-	75,000	-	75,000
	18,159	282,888	416,404	24,297	93,116	92,040	926,904

[1]*Face value*

At June 30, 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 $34.3 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. At June 30, 2015, the Company had contracts for oil volumes of 4,500 Bbl/d for the remainder of 2015 and 1,000 Bbl/d contracted for 2016. At June 30, 2015, the Company had contracts for natural gas volumes of approximately 62.6 MMcf/d for the remainder of 2015 and 37.9 MMcf/d contracted for 2016. Further details on the derivative contracts can be found in Note 13 of the interim financial statements for the six months ended June 30, 2015.

In the first six months of 2015, the Company realized a $42.3 million gain as a result of its commodity price risk management. The realized gain included a $33.8 million gain on oil financial derivative contracts and a $8.6 million gain on natural gas contracts. In the first six months of 2015, the Company recognized an unrealized loss on oil financial derivative contracts of $30.2 million and an unrealized loss on natural gas contracts of $5.1 million. At June 30, 2015, the fair value of oil derivatives was an asset of $19.7 million and the fair value of natural gas derivatives was an asset of $10.4 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 net debt by $100 million in 2015, primarily through disposition proceeds and funds flow from operations exceeding capital expenditures. The Company plans to repay the remaining $145 million of debt on the non-revolving syndicated facility due May 29, 2016 through further strategic or financial means, which may include additional asset dispositions and alternative debt refinancing.

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 six months ended June 30, 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.

	2015		2014				2013	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Funds flow from operations[1] *($000s)*	**45,924**	39,958	68,178	80,199	73,429	70,050	55,934	62,304
Per share, basic[1]	**0.24**	0.21	0.35	0.45	0.55	0.56	0.45	0.50
Per share, diluted[1]	**0.24**	0.21	0.35	0.45	0.54	0.56	0.44	0.50
Net earnings (loss) *($000s)*	**(50,136)**	(22,818)	(258,652)	40,644	20,842	6,771	(5,531)	9,524
Per share, basic	**(0.26)**	(0.12)	(1.34)	0.23	0.16	0.05	(0.04)	0.08
Per share, diluted	**(0.26)**	(0.12)	(1.34)	0.23	0.15	0.05	(0.04)	0.08
Capital *($000s)*								
Drilling and completion	**4,484**	31,577	40,928	52,530	34,851	75,114	30,750	72,746
Plant and facilities	**1,967**	12,202	26,935	19,740	16,441	23,370	8,760	18,699
Geological and geophysical	**42**	778	247	1,951	4,295	939	566	601
Other assets	**2,277**	758	1,984	1,538	1,743	1,425	1,561	1,091
Capital expenditures	**8,770**	45,315	70,094	75,759	57,330	100,848	41,637	93,137
Net acquisitions (dispositions)	**(9,530)**	(1,392)	(1,797)	(8,147)	213,716	(3,679)	86,328	3,331
Capital investment	**(760)**	43,923	68,297	67,612	271,046	97,169	127,965	96,468
Wells drilled *(net)*								
Peace - Montney	**-**	5.0	1.0	12.0	11.0	17.5	9.5	19.5
- 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
- Other	**-**	-	-	-	1.0	-	-	4.0
Other	**-**	-	-	-	-	1.0	1.0	-
Total	**-**	9.0	10.0	21.0	22.0	47.5	11.5	50.1
Production								
Liquids *(Bbl/d)*								
Light oil	**9,059**	10,242	11,895	12,708	11,808	11,491	11,811	10,322
Heavy oil	**370**	315	235	363	668	1,193	1,440	1,387
NGLs	**4,659**	5,210	5,609	3,031	2,038	1,584	1,520	1,478
	14,088	15,767	17,739	16,102	14,514	14,268	14,771	13,187
Natural Gas *(Mcf/d)*	**122,214**	119,007	112,576	112,161	78,524	68,071	73,392	72,634
Total *(Boe/d)*	**34,457**	35,602	36,502	34,795	27,602	25,613	27,003	25,293
Production by area *(Boe/d)*								
Peace - Montney	**8,767**	9,527	10,661	10,918	9,340	9,294	11,500	10,101
- Other	**2,170**	2,651	2,650	3,054	3,160	3,579	2,169	1,960
Deep Basin - Edson	**7,366**	7,498	7,665	4,654	338	19	-	-
- Kakwa/Elmworth	**5,706**	4,942	3,579	3,207	1,433	-	-	-
Redwater - Viking	**3,295**	3,749	4,451	5,122	5,617	5,365	6,285	5,875
- Other	**3,124**	3,279	3,242	3,196	2,758	2,819	2,327	2,022
Boyer	**2,659**	2,523	2,727	2,929	3,046	2,733	2,861	3,241
Other	**1,370**	1,433	1,527	1,715	1,910	1,804	1,861	2,094
Total	**34,457**	35,602	36,502	34,795	27,602	25,613	27,003	25,293

	2015		2014				2013	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Benchmark pricing								
WTI *(US$/Bbl)*	**57.96**	48.57	73.12	97.21	102.98	98.68	97.46	105.83
Edmonton Light Sweet (CDN$*/Bbl)*	**67.73**	51.85	75.65	97.18	105.62	99.83	86.58	104.98
AECO *($/Mcf)*	**2.66**	2.76	3.75	4.02	4.69	5.72	3.53	2.43
CDN$/US$ exchange rate	**1.23**	1.24	1.13	1.09	1.09	1.10	1.05	1.04
Prices, excluding derivatives								
Liquids *($/Bbl)*								
Light oil	**58.53**	42.32	66.73	88.08	97.50	91.24	75.06	95.47
Heavy oil	**53.33**	37.36	60.71	81.47	81.79	78.90	62.69	87.40
NGLs	**24.48**	22.50	30.02	57.98	72.76	86.87	69.21	76.05
Total	**47.13**	35.67	55.04	82.26	93.30	89.72	73.25	92.44
Natural Gas *($/Mcf)*	**2.89**	2.80	4.13	4.29	4.89	5.96	3.73	2.65
Total *($/Boe)*	**29.80**	25.38	39.71	52.16	63.17	65.89	50.24	55.84
Prices, including derivatives								
Oil *($/Bbl)*	**72.03**	65.34	79.35	84.66	89.59	85.89	71.14	87.44
NGLs *($/Bbl)*	**24.48**	22.50	30.02	57.98	72.76	86.87	69.21	76.05
Natural Gas *($/Mcf)*	**3.30**	3.17	4.15	4.23	4.61	5.53	4.04	3.23
Total *($/Boe)*	**35.04**	33.45	43.92	50.75	59.13	62.67	49.78	54.29
Netback *($/Boe)*								
Revenues	**29.80**	25.38	39.71	52.16	63.17	65.89	50.24	55.84
Royalties	**(2.04)**	(1.97)	(4.42)	(6.05)	(7.01)	(8.01)	(7.33)	(6.61)
Realized gain (loss) on derivatives	**5.24**	8.07	4.21	(1.42)	(4.04)	(3.22)	(0.46)	(1.54)
Transportation costs	**(1.53)**	(1.69)	(1.75)	(1.65)	(2.10)	(2.41)	(2.00)	(2.50)
Operating costs	**(11.55)**	(12.85)	(12.71)	(11.63)	(14.98)	(15.70)	(13.36)	(14.45)
Operating Netback	**19.92**	16.94	25.04	31.41	35.04	36.55	27.09	30.74
G&A	**(2.53)**	(2.00)	(2.32)	(3.92)	(3.64)	(3.79)	(2.82)	(2.31)
Interest	**(2.75)**	(2.46)	(2.39)	(2.36)	(2.19)	(2.13)	(1.73)	(1.56)
Corporate Netback	**14.64**	12.48	20.33	25.13	29.21	30.63	22.54	26.87
Funds flow from operations[1] *($000s)*								
Revenues	**93,436**	81,324	133,354	166,978	158,678	151,886	124,816	129,923
Royalties	**(6,400)**	(6,321)	(14,835)	(19,377)	(17,598)	(18,466)	(18,213)	(15,377)
Realized gain (loss) on derivatives	**16,432**	25,845	14,145	(4,529)	(10,157)	(7,422)	(1,145)	(3,585)
Transportation costs	**(4,785)**	(5,421)	(5,891)	(5,272)	(5,287)	(5,543)	(4,971)	(5,816)
Operating costs	**(36,206)**	(41,184)	(42,684)	(37,238)	(37,614)	(36,194)	(33,198)	(33,614)
	62,477	54,243	84,089	100,562	88,022	84,261	67,289	71,531
G&A	**(7,929)**	(6,406)	(7,793)	(12,537)	(9,134)	(8,729)	(7,017)	(5,378)
Interest	**(8,624)**	(7,875)	(8,038)	(7,566)	(5,507)	(4,916)	(4,300)	(3,633)
Other	**-**	(4)	(80)	(260)	48	(566)	(38)	(216)
	45,924	39,958	68,178	80,199	73,429	70,050	55,934	62,304

[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	
($000s)	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Cash flow from operating activities	**37,585**	48,832	80,866	78,006	67,280	59,781	65,932	61,756
Change in non-cash working capital	**7,975**	(11,491)	(18,865)	(996)	5,452	8,923	(11,758)	(266)
Abandonment costs	**364**	2,617	6,177	3,189	697	1,346	1,760	814
Funds flow from operations	**45,924**	39,958	68,178	80,199	73,429	70,050	55,934	62,304
Weighted average outstanding shares *(000s)*								
- Basic	**193,498**	193,498	193,497	176,318	134,291	125,730	125,629	125,620
- Diluted	**193,498**	193,498	193,497	177,003	135,437	126,129	126,245	125,620
Funds flow from operations per share *($/share)*								
- Basic	**0.24**	0.21	0.35	0.45	0.55	0.56	0.45	0.50
- Diluted	**0.24**	0.21	0.35	0.45	0.54	0.56	0.44	0.50

	Six months ended June 30	
($000s)	**2015**	2014
Cash flow from operating activities	**86,417**	127,061
Change in non-cash working capital	**(3,516)**	14,375
Abandonment costs	**2,981**	2,043
Funds flow from operations	**85,882**	143,479
Weighted average outstanding shares *(000s)*		
- Basic	**193,498**	130,035
- Diluted	**193,498**	130,916
Funds flow from operations per share *($/share)*		
- Basic	**0.44**	1.10
- Diluted	**0.44**	1.10

Net Debt

($000s)	June 30, 2015	December 31, 2014
Bank debt	**625,943**	611,717
Working capital deficiency		
Accounts payable and accrued liabilities	**75,558**	132,439
Accounts receivable	**(47,818)**	(65,135)
Prepaid expenses and deposits	**(19,437)**	(14,423)
Convertible debentures – face value	**75,000**	75,000
Net Debt	**709,246**	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, plans to repay bank debt and 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 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, debt reduction 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, including the realized gain (loss) on financial derivatives 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	
Bbl	Barrels	MMcf	million cubic feet
MBbl	thousand barrels	Mcf/d	thousand cubic feet per day
MMBbl	million barrels	MMcf/d	million cubic feet per day
Bbl/d	barrels per day	MMbtu	million British Thermal Units
NGLs	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		

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.