LONG RUN EXPLORATION LTD.

Management's Discussion and Analysis

June 30, 2013

Management's Discussion and Analysis
For the six months ended June 30, 2013

This Management's Discussion & Analysis ("MD&A") of financial condition and results of operations of Long Run Exploration Ltd. ("Long Run", the "Corporation" or "its"), formerly WestFire Energy Ltd. ("WestFire"), should be read in conjunction with the unaudited interim financial statements for the six months ended June 30, 2013 and the audited financial statements and MD&A for the year ended December 31, 2012. The disclosure which is unchanged from the MD&A for the year ended December 31, 2012 may not be repeated herein. On October 23, 2012, the Corporation completed a plan of arrangement, the "Guide Arrangement", with Guide Exploration Ltd. ("Guide"). Comparative results prior to October 23, 2012, do not include the results of operations from the Guide properties.

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

The MD&A contains certain measures that do not have any standardized meaning as prescribed by IFRS and therefore are considered non-Generally Accepted Accounting Principles ("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 section 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 31, 2013.

Long Run's Strategy

Long Run is engaged in the development, exploration and acquisition of oil and natural gas in western Canada. Specifically, the Corporation is focused on controlled exploitation, exploration and strategic acquisitions within the Peace River and Edmonton regions of the Western Canadian Sedimentary Basin.

Long Run has assembled large land blocks and has invested in natural gas and crude oil infrastructure in its key areas so as to obtain operatorship and control of the facilities. Additionally, Long Run has pursued and will continue to pursue strategic asset and corporate acquisitions of crude oil and natural gas properties.

Near term strategy will be to develop the potential of Long Run's oil resources, selectively explore on our current land base and maintain a continued strong focus on cost control and efficiencies. For 2013, Long Run plans to spend approximately $275 million on capital expenditures, targeted on oil development in the Montney oil projects at Peace River and Viking oil projects at Redwater near Edmonton. The capital program is expected to increase average production volumes to 25,000 BOE/d for 2013. Long Run has increased its capital guidance for 2013 from $265 million to $275 million to reflect costs incurred in the second quarter of 2013 for plant turnarounds, as well as increased spending on land in proximity to our core areas.

Second Quarter Highlights

Highlights of results during the period ended June 30, 2013 include:

- Production averaged 24,431 BOE/d in the second quarter of 2013, up 3% from 23,611 BOE/d in the first quarter of 2013, and up 112% from 11,549 BOE/d in the second quarter of 2012. The increased production reflects results from the active drilling programs, as well as production from properties acquired in the Guide Arrangement. Long Run is in line to achieve 2013 annual average daily production guidance of 25,000 BOE/d, based upon average production of 24,023 BOE/d during the first half of 2013, the success of development work to-date and the repeatability of well performance at key oil properties.
- Funds flow from operations was $63.2 million ($0.50 per share) in the second quarter of 2013, up 30% (28% per share) from $48.6 million ($0.39 per share) in the first quarter of 2013, and up 84% (22% per share) from $34.4 million ($0.41 per share) in the three months ended June 30, 2012. The increases are attributable to higher production volumes and stronger commodity pricing, including narrower price differentials.
- Successful drilling during the quarter resulted in 12 (12.0 net) oil wells in the Peace River and Redwater areas. Second quarter capital spending of $38.9 million also included a scheduled major facility turnaround at Long Run's Kaybob asset.
- During May 2013, the available borrowing base of $430.0 million under the Corporation's credit facilities was confirmed and the termination date of the credit facilities was extended to May 31, 2016.

Results Overview

($000s, except per share)	Six months ended June 30 2013	2012	2013 Q2	Q1	2012 Q4	Q3	Q2	Q1	2011 Q4	Q3
Funds flow from operations [1]	**111,871**	**63,766**	**63,227**	48,644	38,407	26,546	34,385	29,381	29,896	27,448
Per share, basic & diluted [1]	**0.89**	**0.77**	**0.50**	0.39	0.33	0.32	0.41	0.35	0.36	0.33
Net earnings (loss)	**20,272**	**18,685**	**21,099**	(827)	(56,590)	(4,747)	17,506	1,179	(66,612)	11,427
Per share, basic & diluted	**0.16**	**0.22**	**0.17**	(0.01)	(0.49)	(0.06)	0.21	0.01	(0.80)	0.14
Production										
Liquids *(Bbl/d)*	**12,473**	**7,212**	**12,587**	12,358	11,995	7,854	8,291	6,133	5,872	5,499
Natural Gas *(Mcf/d)*	**69,297**	**17,918**	**71,058**	67,516	56,453	18,214	19,548	16,288	16,376	17,766
Total *(BOE/d)*	**24,023**	**10,198**	**24,431**	23,611	21,405	10,890	11,549	8,848	8,601	8,460
Prices, including derivatives										
Liquids *($/Bbl)*	**76.90**	**82.57**	**80.67**	73.03	75.49	77.67	80.68	85.15	88.74	85.97
Natural Gas *($/Mcf)*	**3.76**	**2.10**	**3.89**	3.63	4.19	2.44	1.94	2.29	3.41	4.20
Total *($/BOE)*	**51.26**	**63.02**	**53.29**	49.12	53.99	61.34	61.57	64.92	69.26	66.79
Revenues, before royalties	**220,823**	**117,511**	**117,210**	103,613	99,000	60,094	64,025	53,486	56,192	51,568
Capital expenditures	**141,797**	**108,789**	**38,878**	102,919	58,342	29,192	44,615	64,173	72,443	58,451
Net acquisitions (divestitures)	**19,103**	**5,718**	**1,158**	17,945	(169,734)	(138)	466	5,252	109	858

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

Second quarter 2013 compared to first quarter 2013

In the second quarter of 2013, funds flow from operations was $63.2 million ($0.50/share), an increase of $14.6 million ($0.11/share) from the first quarter of 2013, attributable to higher production volumes and commodity prices for both liquids and natural gas, as well as lower general and administration expenses, partially offset by higher operating expenses associated with the increase in production.

During the second quarter, production at Kaybob was down approximately 421 BOE/d, resulting from downtime during the planned plant turnaround in May. Despite this reduction, overall production increased 820 BOE/d, reflecting results from the active first quarter drilling program, the Q1 2013 property acquisition, and warmer weather during the quarter.

The net earnings for the second quarter of 2013 were $21.1 million, compared to a net loss of $0.8 million in the first quarter. In addition to the increase in funds flow from operations, the Corporation recognized an $8.9 million unrealized gain on financial derivatives, compared to an unrealized loss of $10.8 million on financial derivative contracts recorded in the first quarter.

Second quarter 2013 compared to second quarter 2012

Funds flow from operations for the second quarter of 2013 increased $28.8 million from the second quarter of 2012, primarily due to higher liquids and natural gas production, partially offset by higher operating expenses associated with the increase in production.

Net earnings for the second quarter of 2013 were $21.1 million, compared to net earnings of $17.5 million during the three months ended June 30, 2012. The higher funds flow from operations in 2013 was offset by increased depletion expense associated with the higher production volumes and lower unrealized gains on financial derivative contracts. During the second quarter of 2012 the Corporation recognized a gain on farm-out of $11.4 million and impairments of $16.1 million.

Six months ended June 30, 2013 compared to six months ended June 30, 2012

Funds flow from operations for the six months ended June 30, 2013 was $48.1 million higher than during the six months ended June 30, 2012, primarily due to higher production volumes for both liquids and natural gas, partially offset by higher operating expenses associated with the increased production.

Net earnings for the first six months of 2013 were $20.3 million, compared to net earnings of $18.7 million during the first six months of 2012. In addition to a loss on unrealized financial derivative contracts in 2013 compared to a gain in 2012, the higher funds flow from operations in 2013 was offset by increased depletion expense associated with the increase in production volumes during the period. The impairment of $16.1 million recorded at June 30, 2012 was partially offset by the $11.4 million gain on farm-out also recognized in the first six months of 2012.

The Corporation's quarterly funds flow from operations is significantly impacted by changes in production volumes, fluctuations in commodity prices 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. Funds flow from operations and net earnings prior to October 23, 2012 do not include the results of operations from the Guide properties, which were acquired as part of the Guide Arrangement.

Capital Investment

($000s)	Six months ended June 30 2013	Six months ended June 30 2012	Q2 2013	Q1 2013	Q2 2012
Drilling and completion	**100,308**	83,715	**19,541**	80,767	30,374
Plant and facilities	**37,349**	21,662	**17,697**	19,652	12,003
Geological and geophysical	**2,093**	1,833	**779**	1,314	999
Other assets	**2,047**	1,579	**861**	1,186	1,239
Capital expenditures	**141,797**	108,789	**38,878**	102,919	44,615
Acquisitions – land & facilities	**11,087**	5,718	**970**	10,117	466
– properties	**13,869**	-	**20**	13,849	-
Dispositions	**(5,853)**	-	**168**	(6,021)	-
Capital investment	**160,900**	114,507	**40,036**	120,864	45,081

Capital expenditures during the six months ended June 30, 2013 were $141.8 million, compared to $108.8 million in the same period of the prior year. Capital activity in 2013 has focused on oil development in the Peace River and Redwater areas, with $64.7 million invested in Peace River and $51.6 million in invested in Redwater. During the six months ended June 30, 2013, the Corporation drilled 65 (63.6 net) wells, resulting in 62 (60.6 net) oil wells. A total of 22 (22.0 net) oil wells were drilled in Peace River and 38 (36.6 net) oil wells were drilled in Redwater.

Capital spending during the six months ended June 30, 2012 was also focused on drilling and completion activities, with $65.5 million invested at Redwater. The Corporation drilled 82 (72.9 net) oil wells, including 47 (43.4 net) oil wells at Redwater, during the first two quarters of 2012.

Capital spending in the second quarter of 2013 was $38.9 million, compared to $102.9 million during the first quarter. As well as a planned major facility turnaround at Kaybob, capital activities during the three months ended June 30 included drilling 12 (12.0 net) oil wells. The reduced activity level in the second quarter reflects access restrictions during spring break-up and a heavier weighting of the annual capital budget to the first quarter of the year.

Long Run completed a property acquisition in the Cherhill area on March 28, 2013 for $13.9 million, including purchase price adjustments. The transaction focused on the strategic consolidation of crude oil and solution natural gas processing capacity and infrastructure, developed and undeveloped acreage, as well as production which averaged approximately 2.4 MMcf/d of natural gas and 200 Bbl/d of crude oil and natural gas liquids at the time of closing.

Production

Production by Product

	Six months ended June 30		2013		2012				2011	
	2013	2012	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Liquids *(Bbl/d)*										
Light oil	**9,666**	5,506	**9,802**	9,528	9,125	6,057	6,310	4,702	3,974	3,493
Heavy oil	**1,625**	693	**1,669**	1,581	1,538	1,128	868	518	530	542
NGLs	**1,182**	1,013	**1,116**	1,249	1,332	669	1,113	913	1,368	1,464
Total	**12,473**	7,212	**12,587**	12,358	11,995	7,854	8,291	6,133	5,872	5,499
Natural Gas *(Mcf/d)*	**69,297**	17,918	**71,058**	67,516	56,453	18,214	19,548	16,288	16,376	17,766
Total *(BOE/d)*	**24,023**	10,198	**24,431**	23,611	21,405	10,890	11,549	8,848	8,601	8,460

Production during the six months ended June 30, 2013 averaged 24,023 BOE/d, up 136% from 10,198 BOE/d during the six months ended June 30, 2012. Average production during the second quarter of 2013 of 24,431 BOE/d was 112% higher than production of 11,549 BOE/d during the second quarter of 2012. The production increases in 2013 compared to 2012 reflect results from the active drilling programs in the fourth quarter of 2012 and first quarter of 2013, as well as production from the properties acquired in the Guide Arrangement on October 23, 2012.

Production in the Peace River area, acquired during the Guide Arrangement, has increased 23% to 9,952 BOE/d in the second quarter of 2013 from 8,070 BOE/d in October 2012.

In the second quarter of 2013, liquids production was 12,587 Bbl/d, an increase of 229 Bbl/d from the first quarter of 2013. Production increases in the Redwater and Peace River areas, reflecting results from the active first quarter drilling program, more than offset decreased production at Kaybob of 132 Bbl/d attributable to downtime during the planned plant turnaround in May.

In the second quarter of 2013, natural gas production increased 3.5 Mmcf/d from the first quarter. Natural gas production at Peace River increased 2.6 Mmcf/d, representing gas production associated with the new oil wells drilled during the year. As well, natural gas production at Boyer increased 2.0 Mmcf/d, benefiting from warmer weather during the quarter, while natural gas production at Kaybob decreased 1.7 Mmcf/d due to the planned plant turnaround in May.

All planned turnarounds for 2013 have been completed and Long Run anticipates no major maintenance or turnaround impacts to production for the remainder of 2013.

Production by Area

	Q2 2013			Q1 2013			Q2 2012		
	Liquids (Bbl/d)	Natural Gas (Mcf/d)	Total (BOE/d)	Liquids (Bbl/d)	Natural Gas (Mcf/d)	Total (BOE/d)	Liquids (Bbl/d)	Natural Gas (Mcf/d)	Total (BOE/d)
Redwater	**4,195**	**7,494**	**5,444**	3,961	7,402	5,195	5,279	8,813	6,748
Kaybob	**655**	**4,626**	**1,426**	787	6,362	1,847	1,051	9,638	2,657
Other	**749**	**332**	**804**	783	354	842	848	668	959
	5,599	**12,452**	**7,674**	5,531	14,118	7,884	7,178	19,119	10,364
Peace River	**5,596**	**26,133**	**9,952**	5,531	23,529	9,453	-	-	-
Boyer	**2**	**19,633**	**3,274**	-	17,627	2,938	-	-	-
Other	**1,390**	**12,840**	**3,531**	1,296	12,242	3,336	-	-	-
	12,587	**71,058**	**24,431**	12,358	67,516	23,611	7,178	19,119	10,364
Production sold									
Plato - Dec 2012	**-**	**-**	**-**	-	-	-	1,113	429	1,185
	12,587	**71,058**	**24,431**	12,358	67,516	23,611	8,291	19,548	11,549

	Six months ended June 30					
	2013			2012		
	Liquids (Bbl/d)	Natural Gas (Mcf/d)	Total (BOE/d)	Liquids (Bbl/d)	Natural Gas (Mcf/d)	Total (BOE/d)
Redwater	**4,079**	**7,448**	**5,320**	4,627	8,714	6,079
Kaybob	**720**	**5,489**	**1,635**	957	8,133	2,313
Other	**766**	**343**	**823**	660	591	758
	5,565	**13,280**	**7,778**	6,244	17,438	9,150
Peace River	**5,564**	**24,838**	**9,704**	-	-	-
Boyer	**1**	**18,635**	**3,107**	-	-	-
Other	**1,343**	**12,544**	**3,434**	-	-	-
	12,473	**69,297**	**24,023**	6,244	17,438	9,150
Production sold						
Plato - Dec 2012	**-**	**-**	**-**	968	480	1,048
	12,473	**69,297**	**24,023**	7,212	17,918	10,198

Peace River Second Quarter Update

Long Run acquired the Peace River area as part of the Guide Arrangement in October 2012. In the second quarter of 2013, production in this area averaged 9,952 BOE/d. Still benefitting from the successful first quarter drilling program, production increased 499 BOE/d from the first quarter of 2013. As well, second quarter production has increased 1,882 BOE/d from the time of the Arrangement.

Long Run invested $15.0 million in the Peace River area during the second quarter of 2013, including the drilling of 4 (4.0 net) successful horizontal Montney oil wells at Girouxville/Normandville. These late second-quarter drills came on production in early July. Long Run anticipates drilling an additional 27 (27.0 net) wells in this play during the second half of 2013.

The transition from analysis and planning to the pilot project stage of Long Run's enhanced oil recovery ("EOR") work is moving forward in the Montney at Normandville using pressure maintenance via down-dip water injection. Long Run's pilot project commenced in the second quarter, with water injection beginning on May 1, 2013. Computer simulations and data collected early in the project suggest response could come in 2014. Long Run expects near-term results from this EOR work to provide better visibility on ultimate recoveries from this project. Assuming positive results, Long Run anticipates expanding the scope of this project in 2014. Secondary recovery is a key part of the long-term development plan for this play.

Redwater Second Quarter Update

In the second quarter of 2013, Redwater area production averaged 5,444 BOE/d, an increase of 249 BOE/d from the first quarter of 2013. A total of $13.6 million was invested in the Redwater area in the second quarter of 2013. A total of 8 (8.0 net) successful oil wells were drilled, all of which were completed and tied-in in July. As well, all of the wells drilled during the first quarter have been completed, tied-in and are currently on-production. Development plans remain on-track for this play with up to 30 (30.0 net) wells anticipated for the remainder of 2013.

Production at Redwater during the six months ended June 30, 2013 was 759 BOE/d lower than during the six months ended June 30, 2012. Prior to the Guide Arrangement in October 2012, the Company redeployed capital spending to the Plato area, which resulted in production declines at Redwater during the latter half of 2012. Subsequent to the Guide Arrangement, the Company has refocused its capital spending on the Redwater area.

Plans for water injection as part of early-stage work on a broader EOR strategy continue at Redwater. As part of these plans, Long Run anticipates implementing a pilot EOR scheme injecting water into the formation to test the viability of such a project. While Long Run is confident that such a water injection scheme holds promise, a better understanding of the project economics which will underpin this plan are needed before increased capital in future years can be allocated to EOR at Redwater.

Commodity Pricing

	Six months ended June 30		2013		2012				2011	
	2013	2012	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Benchmark pricing										
WTI *($US/Bbl)*	**94.28**	98.21	**94.20**	94.37	88.18	92.22	93.49	102.93	94.06	89.76
Edmonton Light Sweet *($C/Bbl)*	**90.26**	88.09	**92.33**	88.19	83.99	84.33	83.95	92.23	97.35	91.74
AECO *($/Mcf)*	**3.36**	2.03	**3.53**	3.20	3.21	2.29	1.90	2.15	3.17	3.66
Prices, excluding derivatives										
Liquids *($/Bbl)*										
Light oil	**80.27**	85.71	**83.70**	76.69	76.24	80.28	82.79	89.64	96.37	89.97
Heavy oil	**63.57**	66.69	**71.52**	55.10	57.89	59.77	64.03	71.13	77.17	64.01
NGLs	**72.28**	79.31	**68.91**	75.33	67.08	62.24	74.95	84.60	83.90	85.11
Total	**77.34**	82.98	**80.78**	73.79	72.87	75.78	79.77	87.34	91.65	86.10
Natural Gas *($/Mcf)*	**3.56**	2.10	**3.73**	3.37	3.35	2.44	1.94	2.29	3.32	3.95
Total *($/BOE)*	**50.79**	63.31	**52.72**	48.76	50.27	59.98	60.92	66.43	71.01	66.26
Prices, including derivatives										
Liquids *($/Bbl)*	**76.91**	82.57	**80.67**	73.03	75.49	77.67	80.68	85.15	88.74	85.97
Natural Gas *($/Mcf)*	**3.76**	2.10	**3.89**	3.63	4.19	2.44	1.94	2.29	3.41	4.20
Total *($/BOE)*	**51.26**	63.02	**53.29**	49.12	53.99	61.34	61.57	64.92	69.26	66.79

The Corporation’s financial results are influenced by fluctuations in commodity prices and Canadian price differentials. Long Run’s liquids price of $80.78/Bbl for the second quarter of 2013 was $6.99/Bbl higher than the price received in the first quarter as a result of the tightening of Canadian differentials. During the second quarter, the light oil differentials decreased reflecting a reduction in the Canadian supply of light barrels due to planned and unplanned maintenance. The increase in the heavy oil price was a result of delays in some of the larger bitumen projects, unplanned maintenance and increased refinery runs. Rail also continues to be instrumental in clearing some of the bottlenecks on the export pipelines, while allowing Canadian oil to reach new markets.

The average price received by Long Run for liquids in the second quarter of 2013 was $1.01/Bbl higher than that received in the second quarter of 2012. The Corporation’s prices prior to the Guide Arrangement on October 23, 2012 do not reflect the current production mix.

Long Run’s natural gas price of $3.73/Mcf for the second quarter of 2013 was up $0.36/Mcf from the price received during the first quarter of 2013. This was consistent with the increase in the AECO benchmark price during the quarter arising largely from a reduction in storage levels. The Corporation’s natural gas price reflects premiums received for the liquids content included in the natural gas production.

The Corporation enters into derivative financial contracts for the purpose of protecting funds flow from operations from the volatility of commodity prices. For the second quarter of 2013, Long Run’s liquids price including derivative contracts was $80.67/Bbl, which included a realized loss of $0.11/Bbl. The Corporation’s natural gas price including derivatives was $3.89/Mcf, which included a realized gain of $0.16/Mcf.

Operating Results

Operating Netback & Funds Flow from Operations

	Q2 2013		Q1 2013		Q2 2012	
	$000s	$/BOE	$000s	$/BOE	$000s	$/BOE
Revenues	**117,210**	**52.72**	103,613	48.76	64,025	60.92
Royalties	**(9,753)**	**(4.38)**	(11,790)	(5.55)	(5,814)	(5.52)
	107,457	**48.34**	91,823	43.21	58,211	55.39
Realized gain on derivatives	**1,285**	**0.57**	756	0.36	682	0.65
Transportation costs	**(5,250)**	**(2.36)**	(4,483)	(2.11)	(2,037)	(1.94)
Operating costs	**(31,083)**	**(13.98)**	(28,742)	(13.53)	(16,128)	(15.35)
Operating netback	**72,409**	**32.57**	59,354	27.93	40,728	38.76
General and administrative	**(5,493)**	**(2.47)**	(7,461)	(3.51)	(4,100)	(3.90)
Interest	**(3,634)**	**(1.63)**	(3,223)	(1.52)	(2,161)	(2.06)
Exploration expenses	**(36)**	**(0.02)**	-	-	-	-
Capital and other taxes	**(19)**	**(0.01)**	(26)	(0.01)	(82)	(0.08)
Funds flow from operations[1]	**63,227**	**28.44**	48,644	22.89	34,385	32.72

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

	Six months ended June 30			
	2013		2012	
	$000s	$/BOE	$000s	$/BOE
Revenues	**220,823**	**50.79**	117,511	63.31
Royalties	**(21,543)**	**(4.96)**	(10,693)	(5.76)
	199,280	**45.83**	106,818	57.55
Realized gain (loss) on derivatives	**2,041**	**0.47**	(533)	(0.29)
Transportation costs	**(9,733)**	**(2.24)**	(3,453)	(1.86)
Operating costs	**(59,825)**	**(13.76)**	(28,895)	(15.57)
Operating netback	**131,763**	**30.30**	73,937	39.84
General and administrative	**(12,954)**	**(2.98)**	(6,687)	(3.60)
Interest	**(6,857)**	**(1.57)**	(3,297)	(1.77)
Exploration expenses	**(36)**	**(0.01)**	-	-
Capital and other taxes	**(45)**	**(0.01)**	(187)	(0.10)
Funds flow from operations[1]	**111,871**	**25.73**	63,766	34.36

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

Second quarter 2013 compared to first quarter 2013

In the second quarter of 2013, funds flow from operations was $63.2 million, an increase of $14.6 million from the first quarter of 2013 primarily due to:

- Higher liquids and natural gas production, which increased revenue by $4.2 million;
- Higher prices for liquids and natural gas which, excluding derivative contracts, increased revenue by $7.7 million and $2.2 million, respectively;
- The average royalty rate for the second quarter, impacted by a favorable prior year gas cost allowance adjustment, was 8.3% compared to 11.4% for the first quarter; and

- Lower general and administrative expenses of $2.0 million as the first quarter included higher employee costs.

Partially offset by:

- Higher operating and transportation costs expenses of $2.3 million and $0.8 million, respectively, reflecting the increase in production.

Second quarter 2013 compared to second quarter 2012

In the second quarter of 2013, funds flow from operations increased $28.8 million from the second quarter of 2012 primarily due to:

- Higher liquids and natural gas production, attributable to the properties acquired in the Guide Arrangement and successful drilling in the Peace River and Redwater areas, increasing revenue by $49.3 million.

Partially offset by:

- Royalties associated with the increased revenue were $3.9 million higher in 2013 compared to 2012, averaging 8.3% of revenue in 2013 compared to 9.1% of revenue 2012. A favorable prior year gas cost allowance adjustment received during 2013 lowered the average royalty rate by 1.7%; and
- Higher operating expenses of $15.0 million and transportation expenses of $3.2 million resulting from the higher production volumes. On a per unit basis, operating expenses decreased due to higher production from lower cost properties.

Six months ended June 30, 2013 compared to six months ended June 30, 2012

During the six months ended June 30, 2013, funds flow from operations increased $48.1 million from the six months ended June 30, 2012:

- Higher liquids and natural gas production, attributable to the properties acquired in the Guide Arrangement and successful drilling in the Peace River and Redwater areas, increased revenue by $105.8 million.

Partially offset by:

- Lower liquids prices, excluding derivative contracts, which decreased revenue by $7.2 million;
- Royalties which were $10.9 million higher in 2013 compared to 2012, averaging 9.8% of revenue in 2013 compared to 9.1% of revenue in 2012;
- Higher operating expenses of $30.9 million and transportation expenses of $6.3 million associated with the increase in production volumes. On a per unit basis, operating expenses decreased due to higher production from lower cost properties; and
- Higher general and administrative expenses of $6.3 million attributable to the significant change in business after the Guide Arrangement. On a per unit basis, general and administrative expenses have decreased from $3.60/BOE in 2012 to $2.98/BOE in 2013, reflecting the synergies of the Guide transaction.

Other Income & Expenses

($000s)	Six months ended June 30 2013	2012	Q2 2013	Q1 2013	Q2 2012
Unrealized gain (loss) on derivatives	**(1,842)**	20,247	**8,918**	(10,760)	25,489
Depletion and depreciation	**(77,724)**	(51,083)	**(40,265)**	(37,459)	(29,467)
Accretion	**(3,033)**	(711)	**(1,575)**	(1,458)	(381)
Share-based compensation	**(2,091)**	(1,930)	**(1,103)**	(988)	(1,020)
Impairments	**-**	(16,116)	**-**	-	(16,116)
Gain (loss) on disposition	**1,135**	11,373	**(418)**	1,553	11,373
Deferred income tax (expense) recovery	**(8,044)**	(5,867)	**(7,685)**	(359)	(6,375)
Other	**-**	(994)	**-**	-	(382)
	(91,599)	(45,081)	**(42,128)**	(49,471)	(16,879)
Funds flow from operations[1]	**111,871**	63,766	**63,227**	48,644	34,385
Net earnings (loss)	**20,272**	18,685	**21,099**	(827)	17,506

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

Second quarter 2013 compared to first quarter 2013

In comparing the second quarter of 2013 to the first quarter of 2013:

- The unrealized loss on financial derivative contracts of $10.7 million recorded in the first quarter was replaced by an unrealized gain on financial derivative contracts of $8.9 million in the second quarter, reflecting new contracts entered into during the quarter, a decrease in the natural gas forward commodity price and an increase in the crude oil forward commodity price. The unrealized gain for the second quarter included $3.5 million related to the crude oil contracts and $5.0 million related to natural gas contracts.

Second quarter 2013 compared to second quarter 2012

During the second quarter of 2013, compared to the second quarter of 2012:

- The unrealized gain on derivative contracts recorded at June 30, 2013 was $8.9 million, down $16.6 million from the $25.5 million recorded at June 30, 2012, due to a smaller change in crude oil forward commodity prices.

- Depletion and depreciation expense increased $10.8 million, reflecting the increase in production volumes during 2013, partially offset by an average depletion rate of $18.19/BOE during 2013 compared to a rate of $28.04/BOE during 2012. The 2013 depletion rate reflects the impact of the Guide Arrangement and the impairment of oil and natural gas properties recorded at December 31, 2012.

- An impairment of oil and natural gas properties of $16.1 million was recognized in 2012, attributable to a weakening of the future price forecasts for natural gas.

- A gain on disposition of $11.4 million was recorded in 2012 related to a farm-out agreement with an industry partner on lands in west central Saskatchewan.

Six months ended June 30, 2013 compared to six months ended June 30, 2012

In comparing the six months ended June 30, 2013 with the six months ended June 30, 2012:

- The unrealized gain on financial derivative contracts of $20.3 million during 2012, which resulted from an increase in crude oil forward commodity prices, was replaced by an unrealized loss on financial derivative contracts of $1.8 million during 2013.
- Depletion and depreciation expense increased $26.6 million due to the increase in production volumes, partially offset by a decrease in the depletion rate. The depletion rate was $17.88/BOE during 2013, compared to $27.52/BOE in 2012. The 2013 depletion rate reflects the impact of the Guide Arrangement and the impairment of oil and natural gas properties recorded in 2012.
- An impairment of oil and natural gas properties of $16.1 million was recognized in 2012, attributable to a weakening of the future price forecasts for natural gas.
- A gain on disposition of $11.4 million was recorded in 2012, related to a farm-out agreement with an industry partner on lands in west central Saskatchewan.

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

Liquidity and Capital Resources

Bank Debt

($000s)	**June 30, 2013**	December 31, 2012
Bank debt	**327,603**	261,173
Working capital deficiency	**15,945**	31,950
Net debt[1]	**343,548**	293,123

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

The Corporation's bank debt and net debt at June 30, 2013 have increased from December 31, 2012 as a result of the planned first and second quarter capital programs. Of the $275 million of 2013 planned capital investment, $160.9 million had been incurred by the end of the second quarter. Capital investing activities during the six months ended June 30, 2013, which also included net acquisitions of $19.1 million, were primarily funded by funds flow from operations of $111.9 million and bank debt of $66.4 million. The capital intensive nature of the Corporation's activities generally results in the Corporation carrying a working capital deficit, as reflected in the net debt calculation. The Corporation maintains sufficient unused credit facilities to satisfy working capital deficiencies.

At June 30, 2013, the Corporation had $102.4 million of unused capacity on its credit facilities. The Company has credit facilities of $450.0 million, consisting of a $420.0 million revolving syndicated facility and a $30.0 million operating facility. Total borrowings permitted under these facilities cannot exceed the borrowing base, which is determined by the lenders on a semi-annual basis or upon the occurrence of a material adverse effect. On May 3, 2013, the available borrowing base was re-confirmed at $430.0 million and the termination date was extended to May 31, 2016.

In conjunction with the extension of the credit facility to May 2016, the Corporation determined it does not intend to repay the facility in the next twelve months. As a result, the bank debt has been classified as long-term on the June 30, 2013 statement of financial position. At June 30, 2013, the Corporation does not anticipate a reduction to the borrowing base below the level of bank debt currently outstanding. The next borrowing base review will occur prior to November 30, 2013 and the next annual review will occur prior to May 31, 2014. There is no assurance that the borrowing base will be maintained at current levels until May 31, 2016.

Security for the credit facilities includes a demand debenture for $1.0 billion which provides for a first ranking security interest and floating charge over all of the assets and property of the Corporation. The Corporation is currently in compliance with all covenants, obligations and conditions of its credit agreement.

Share Capital

# of units (000s)	**July 31, 2013**	**June 30, 2013**	December 31, 2012
Common Shares	**110,107**	**110,107**	110,107
Non-Voting Convertible Shares	**15,513**	**15,513**	15,513
Options	**9,538**	**9,538**	8,042
Warrants[1]	**2,300**	**2,300**	2,300

[1] Each common share purchase warrant ("Warrant") entitles the holder to purchase 0.4167 of a common share at an exercise price of $3.10 per 0.4167 of a share until September 15, 2014. The Warrants are not exercisable until the twenty-day volume weighted average trading price of the common shares exceeds $12.00 per share.

In the six months ended June 30, 2013, there were no changes to common shares or non-voting convertible shares. At June 30, 2013, the weighted average shares (common shares and non-voting convertible shares) outstanding were 125.6 million. The Corporation granted 2.0 million stock options in the first six months of 2013, with an average exercise price of $4.39 per share.

Capital Structure

Long Run's capital structure consists of total debt plus equity, with equity defined as retained earnings (deficit) plus share capital. The Corporation's primary capital management objective is to maintain a strong statement of financial position, affording it the financial flexibility to achieve goals of continued growth and access to capital. The Corporation may adjust capital spending, issue equity, issue new debt or repay existing debt in response to changes in the business environment.

The Corporation currently targets net debt to funds flow from operations at or below 1.5 times and bank debt to debt plus equity at or below 0.4 times. While the Corporation may exceed these ratios from time to time, efforts are made after a period of variation to bring the measures back in line. At June 30, 2013, net debt to funds flow from operations was 1.4 times and bank debt to debt plus equity was 0.4 times. For calculations of these metrics, see note 13 to the interim financial statements for the six months ended June 30, 2013.

The Corporation believes that it has access to sufficient capital through operating activities, external equity sources and to undrawn committed credit facilities to meet current spending forecasts.

Contractual Obligations and Contingencies

Contractual Obligations

($000s)	**2013**	**2014**	**2015**	**2016**	**2017**	**Thereafter**	**Total**
Bank loan	-	-	-	327,603	-	-	327,603
Operating leases	1,226	2,552	2,524	2,467	1,233	-	10,002
Firm transportation agreements	1,725	2,495	836	434	91	22	5,603
Vehicle leases	46	11	11	5	-	-	73
Capital commitments	4,794	-	-	-	-	-	4,794
	7,791	5,058	3,371	330,509	1,324	22	348,075

Operating lease payments are primarily for office space, firm transportation agreements relate to the transportation of natural gas, and capital commitments include contracts for drilling rig services.

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

Contingencies

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

Risk Management

The Corporation is exposed to a number of risks, both financial and operational, through the pursuit of its strategic objectives. Some of these risks impact the oil and natural gas industry as a whole, and others are unique to the Corporation’s operations. Actively managing these risks improves the ability to effectively execute Long Run’s business strategy. Exposure to reserves replacement risk, capital requirements risk, capital project execution risk, operational risk, transportation restrictions, safety risk, environmental risk, regulatory risk, credit risk, financial risk and liquidity risk has not changed substantially since December 31, 2012. For a further and more in-depth discussion of risk management, see the Corporation’s annual financial statements and MD&A for the year ended December 31, 2012 and the Corporation's Annual Information Form for the year ended December 31, 2012.

Commodity Price Risk

The Corporation enters into derivative financial contracts for the purpose of protecting funds flow from operations from the volatility of commodity prices. The Corporation has entered into crude oil and natural gas derivative contracts including costless collars, fixed price, calls and swaptions. The fair values of these financial derivatives were determined using an income valuation which was provided by the counterparties with whom the transactions were completed. The valuations were reviewed by the Corporation for reasonableness, giving consideration to factors such as the commodity forward price strips and historical volatilities. The Corporation currently has crude oil volumes of 6,473 Bbl/d contracted for the remainder of 2013, 6,321 Bbl/d for 2014 and 1,158 Bbl/d for 2015. As well, the Corporation currently has average natural gas volumes of 41.1 MMcf/d contracted for July to December 2013 and 27.5 MMcf/d for 2014. Further details on the derivative contracts can be found in note 12 of the interim financial statements for the six months ended June 30, 2013.

In the first six months of 2013, the Corporation realized a $2.0 million gain as a result of its commodity price risk management. The Corporation recognized an unrealized loss for crude derivative contracts of $0.3 million and natural gas derivative contracts of $2.1 million. At June 30, 2013, the fair values of crude oil and natural gas derivatives were $14.2 million liability and $6.1 million asset, respectively.

Critical Accounting Judgments, Estimates and Accounting Policies

For a full understanding of the Corporation'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, 2012.

Critical Accounting Estimates

The Corporation 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 notes to the annual financial statements and MD&A for the year ended December 31, 2012.

Adoption of New Accounting Policies

As required by IFRS, the Corporation adopted the following new accounting standards as of January 2, 2013:

- IFRS 10 Consolidated Financial Statements
- IFRS 11 Joint Arrangements
- IFRS 12 Disclosure of Interests in Other Entities
- IFRS 13 Fair Value Measurement
- IAS 28 Investments in Associates and Joint Ventures

The adoption of these standards did not have an impact on the Company's financial results. Further details can be found in the MD&A for the year ended December 31, 2012 and in note 3 of the interim financial statements for the six months ended June 30, 2013.

Control Environment

Disclosure Controls and Procedures

The Corporation'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 Corporation is made known to the Corporation'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 Corporation 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 Corporation's financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles applicable to the Corporation.

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

It should be noted that a control system, including the Corporation'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.

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. Management believes that funds flow from operations and net debt are useful financial measures which assist in demonstrating the Corporation's ability to fund capital expenditures necessary for future growth or to repay debt. These terms are not defined by IFRS and therefore may not be comparable to similar measures presented by other companies. 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 an indicator of Long Run's performance.

Net Debt

($000s)	**June 30, 2013**	**December 31, 2012**
Bank debt	327,603	261,173
Working capital deficiency		
Accounts payable and accrued liabilities	80,802	91,821
Cash	-	(3,803)
Accounts receivable	(54,705)	(48,912)
Prepaid expenses and deposits	(10,152)	(7,156)
Net Debt	343,548	293,123

Funds Flow from Operations

	2013		2012				2011	
($000s)	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Cash flow from operating activities	**60,835**	45,733	43,325	31,417	27,941	33,353	15,759	47,251
Change in non-cash working capital	**1,958**	1,949	(5,722)	(4,871)	6,444	(3,972)	13,691	(19,803)
Abandonment costs	**434**	962	804	-	-	-	446	-
Funds flow from operations	**63,227**	48,644	38,407	26,546	34,385	29,381	29,896	27,448
Weighted average outstanding shares (000s)								
- Basic	**125,620**	125,620	115,421	82,969	82,969	82,969	82,969	82,969
- Diluted	**125,620**	125,620	115,421	83,016	83,061	83,121	83,066	83,315
Funds flow from operations per share ($)								
- Basic	**0.50**	0.39	0.33	0.32	0.41	0.35	0.36	0.33
- Diluted	**0.50**	0.39	0.33	0.32	0.41	0.35	0.36	0.33

	Six months ended June 30	
($000s)	**2013**	2012
Cash flow from operating activities	**106,568**	61,294
Change in non-cash working capital	**3,907**	2,472
Abandonment costs	**1,396**	-
Funds flow from operations	**111,871**	63,766
Weighted average outstanding shares (000s)		
- Basic	**125,620**	82,969
- Diluted	**125,620**	83,080
Funds flow from operations per share ($)		
- Basic	**0.89**	0.77
- Diluted	**0.89**	0.77

Advisory

Forward-Looking Statements

Statements that are not historical facts may be considered forward looking statements, including management's assessment of future plans and operations, development plans and strategy, drilling plans and the timing thereof, timing of completion and/or placing of new wells on production, anticipation that no major maintenance or turnaround impacts to production for remainder of 2013, timing of response from waterflood pilot project at Normandville and timing of implementation of pilot project at Redwater, timing of borrowing base review for credit facilities, expectation that the Corporation maintains sufficient credit facilities to satisfy its working capital deficiency and has access to sufficient capital to meet spending forecasts, 2013 capital expenditure budget, nature of expenditures and method of financing thereof, expected 2013 average production, the effect of commodity risk management strategies and the expected continued volatility in commodity prices and stock markets and the effects thereof.

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 Corporation'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.

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 Corporation 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 Corporation 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 Corporation operates; the timely receipt of any required regulatory approvals; the ability of the Corporation 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 Corporation has an interest in to operate the field in a safe, efficient and effective manor; the ability of the Corporation to obtain financing 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 Corporation to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Corporation operates; and the ability of the Corporation to successfully market its oil and natural gas products.

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

Oil & Natural Gas Information

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

Abbreviations

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

Additional Information

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