LONG RUN EXPLORATION LTD.

Management's Discussion and Analysis

December 31, 2015

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For the year ended December 31, 2015

This Management's Discussion & Analysis ("MD&A") of the financial condition and results of operations of Long Run Exploration Ltd. ("Long Run", the "Company", "its" or "our") should be read in conjunction with the audited financial statements for the years ended December 31, 2015 and 2014.

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 March 9, 2016.

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 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.

During 2015, we continued to examine strategic and financial options to improve the capital structure of the Company and create value for all stakeholders given the low commodity price environment. As part of this process, Long Run entered into an arrangement agreement (the "Arrangement Agreement") with Calgary Sinoenergy Investment Corp. (the "Purchaser") and Qingdao Sinoenergy Capital Corporation (the "Guarantor") on December 20, 2015. Pursuant to the proposed plan of arrangement (the "Arrangement"), the Purchaser agreed to acquire: i) all of the outstanding common shares of Long Run ("Common Shares") for cash consideration of $0.52 per share; and ii) all of the Long Run outstanding 6.40% convertible debentures for cash consideration of $750 per $1,000 principal amount of debentures plus accrued and unpaid interest.

Completion of the Arrangement is subject to various closing conditions including receipt of Long Run securityholder approval, court and regulatory approvals in Canada and regulatory approvals required by the Purchaser in China. Long Run securityholder approval was received at a special meeting held on February 29, 2016. The Court of Queen's Bench of Alberta ("Court") approved the Arrangement on March 2, 2016. Long Run and the Purchaser are working together toward the completion of the required Canadian regulatory approvals, including under the *Investment Canada Act* and the *Competition Act* (Canada). The Purchaser has confirmed it has completed its applicable filings with and is in receipt of required approvals from the National Development and Reform Commission, Ministry of Commerce Qingdao Branch and the State Administration of Foreign Exchange in China. The Arrangement is currently expected to close in late April 2016 following the receipt of Canadian regulatory approvals.

Annual Highlights

Highlights for the year ended December 31, 2015 include:

- Entered into the Arrangement Agreement on December 20, 2015, pursuant to which Long Run will be acquired by Calgary Sinoenergy Investment Corp. Cash consideration paid to Long Run securityholders will include $0.52 per Common Share and $750 per $1,000 principal amount of debentures plus accrued and unpaid interest for the Long Run convertible debentures.

- Generated funds flow from operations of $151.6 million ($0.78/share) compared to $291.9 million ($1.85/share) in 2014, primarily reflecting lower commodity prices and lower oil production, partially offset by a gain on financial derivatives, higher natural gas and NGLs production, lower royalties and lower operating costs.

- Reduced capital expenditures to $91.0 million from $304.0 million in 2014 in response to the depressed commodity price environment. Long Run completed a 23.0 net well drilling program focused on the Redwater Viking, Deep Basin Cardium and Peace River Montney properties.

- Reduced net debt over the year by $64.6 million to $675.0 million, primarily as a result of disposition proceeds and funds flow from operations exceeding capital expenditures. The Company completed $31.0 million in non-core dispositions in 2015.

- Averaged 32,386 Boe/d of production compared to 31,168 Boe/d in 2014. The increase in production resulted from a full year of production from the Deep Basin properties acquired in 2014 and our successful drilling in the area, partially offset by the impact of reduced capital spending in 2015.

- Realized an oil price including derivatives of $68.88/Bbl compared to $84.89/Bbl in 2014 as a result of a decrease in 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 in 2015 decreased to $22.52/Bbl from $51.24/Bbl in 2014, reflecting lower market prices as well as the change in the Company's NGLs product mix due to the Deep Basin properties acquired in 2014.

  Natural gas prices including derivatives averaged $3.25/Mcf compared to $4.52/Mcf in 2014, primarily attributable to weaker AECO benchmark prices, partially offset by a realized gain on natural gas financial derivatives.

- Generated an operating netback of $18.45/Boe and corporate netback of $12.82/Boe compared to $31.38/Boe and $25.65/Boe, respectively, in 2014. The 2015 netbacks reflect weak commodity prices, partially offset by a realized gain on financial derivatives and lower royalties. Operating costs improved to $11.79/Boe from $13.51/Boe in 2014 primarily due to the addition of the lower cost Deep Basin assets and lower fuel, maintenance and chemical costs. General and administration expense excluding transaction costs decreased to $2.38/Boe from $2.79/Boe in 2014, reflecting lower employee costs.

- Reported a net loss of $645.0 million compared to a net loss of $190.4 million in 2014. The 2015 net loss was primarily a result of non-cash impairment charges of $350.0 million and a provision recorded against the Company's deferred tax asset of $162.0 million, both attributable to the decline in future commodity price forecasts during 2015.

Annual Results Overview

($000s, except per share or unless otherwise noted)	Year Ended December 31		
	2015	2014	2013
Funds flow from operations [1]	**151,636**	291,856	230,109
Per share, basic [1]	**0.78**	1.85	1.83
Per share, diluted [1]	**0.78**	1.85	1.83
Net earnings (loss)	**(645,032)**	(190,395)	24,265
Per share, basic	**(3.33)**	(1.21)	0.19
Per share, diluted	**(3.33)**	(1.21)	0.19
Dividends declared	**3,386**	66,206	-
Per share	**0.02**	0.41	-
Revenues, before royalties	**311,770**	610,896	475,562
Capital expenditures	**91,039**	304,031	276,571
Net acquisitions (divestitures) [2]	**(28,374)**	(28,674)	108,762
Production			
Oil *(Bbl/d)*	**8,893**	12,590	11,890
Natural gas liquids *(Bbl/d)*	**4,532**	3,076	1,342
Natural gas *(Mcf/d)*	**113,767**	93,008	71,170
Total *(Boe/d)*	**32,386**	31,168	25,094
Prices, including derivatives			
Oil *($/Bbl)*	**68.88**	84.89	78.13
Natural gas liquids *($/Bbl)*	**22.52**	51.24	72.45
Natural gas *($/Mcf)*	**3.25**	4.52	3.70
Total *($/Boe)*	**33.70**	53.00	51.63
Operating netback *($/Boe)*	**18.45**	31.38	29.54
Total assets	**1,198,623**	1,939,706	1,403,344
Bank loan	**582,588**	611,717	423,553
Net debt[1]	**675,024**	739,598	452,155
Non-current financial liabilities, excluding bank loan	**69,592**	68,230	3,876

[1] *See Non-GAAP Measures section*

[2] *Excludes $228.8 million paid for the Deep Basin asset acquisition on May 30, 2014*

Reserves

The Company engaged Sproule Associates Limited ("Sproule") to provide an evaluation of the Company's proved and proved plus probable reserves as at December 31, 2015. The reserves estimates set forth below are based upon Sproule's reserve report dated March 9, 2016. The reserves estimates summarized below represent Long Run's gross reserves, which are the Company's interest before deduction of royalties and without including any of its royalty interests. Reserves estimates are based on forecast prices and costs at December 31, 2015.

The reserves estimates were prepared in accordance with National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). Under NI 51-101, proved reserves are classified as reserves with a 90% probability that the actual reserves recovered will equal or exceed proved reserve estimates. Probable reserves are classified as reserves with 50% probability that the quantities actually recovered in the future will equal or exceed the proved plus probable reserve estimates.

Long Run's proved plus probable reserves at December 31, 2015 were 147,084 MBoe compared to 170,625 MBoe in 2014. The decrease in reserves was primarily attributable to the lower commodity price forecasts at December 31, 2015 and the Company's reduced capital program in 2015.

December 31, 2015 Reserves[1]

	Oil *(MBbl)*	NGLs *(MBbl)*	Natural Gas *(MMcf)*	Total *(MBoe)*
Proved				
Proved producing	11,865	6,577	162,367	45,502
Proved non-producing	111	208	11,818	2,288
Proved undeveloped	10,121	6,590	110,699	35,161
Total Proved	22,096	13,374	284,884	82,951
Probable	12,809	9,632	250,153	64,133
Total Proved Plus Probable	34,905	23,006	535,038	147,084

[1] *Amounts may not add due to rounding*

Reserves Reconciliation[1]

(MBoe)	Proved	Probable	Proved plus Probable
December 31, 2014	103,544	67,081	170,625
Infill drilling	599	1,729	2,328
Improved recoveries	-	207	207
Technical revisions	3,657	(6,131)	(2,474)
Dispositions	(724)	(438)	(1,162)
Economic factors	(12,302)	1,685	(10,618)
Production	(11,821)	-	(11,821)
December 31, 2015	82,951	64,133	147,084

[1] *Amounts may not add due to rounding*

Reserves Pricing

	2015		2014	
	WTI Oil *(US$/Bbl)*	AECO Gas *(CDN$/Mcf)*	WTI Oil *(US$/Bbl)*	AECO Gas *(CDN$/Mcf)*
2015	-	-	64.17	3.38
2016	45.00	2.25	76.67	3.83
2017	60.00	2.95	83.33	4.06
2018	70.00	3.42	87.08	4.41
2019 – 2022	80.00 – 83.65	3.91 – 4.35	90.67 – 98.36	4.76 – 5.36
2023 – 2026	84.91 – 88.79	4.43 – 4.67	100.18 – 105.80	5.54 – 5.90
Remainder	+1.5%/yr	+1.5%/yr	+1.8%/yr	+1.8%/yr

Forecast prices, inflation and exchange rates utilized by Sproule in its evaluation were based on rates published by Sproule as at December 31, 2015.

Significant Properties

Key development areas within our property portfolio include the Peace River Montney, the Redwater Viking and the Deep Basin. The Peace River Montney is focused on Montney light oil development at Normandville and Girouxville. The Redwater Viking property, located near Edmonton, Alberta, is focused on light oil development from the Viking formation.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, Falher and Bluesky formations. The Company also owns a significant low decline shallow gas property at Boyer in northern Alberta producing from the Bluesky formation.

In the Peace River Montney area, Long Run invested $19.8 million in 2015, which included drilling 5.0 net Montney wells with a 100% success rate. Production for 2015 averaged 8,136 Boe/d (55% oil and NGLs). The Company operates, transports and processes the majority of its production within the Peace River area.

In the Redwater Viking area, Long Run invested $18.3 million in 2015, which included drilling 12.0 net wells with a 100% success rate. Production for 2015 averaged 3,264 Boe/d (87% oil and NGLs). The Company operates, transports and processes substantially all of its production within the Redwater area.

In the Deep Basin - Edson area, Long Run invested $23.0 million in 2015, which included drilling 3.0 net wells with a 100% success rate. Production for 2015 averaged 6,779 Boe/d (41% oil and NGLs).

In the Deep Basin - Kakwa/Elmworth area, Long Run invested $21.6 million in 2015, which included drilling 3.0 net wells with a 100% success rate and the investment in plant and battery equipment. Production for 2015 averaged 5,048 Boe/d (21% oil and NGLs).

Capital Investment

Capital Expenditures, Acquisitions & Dispositions

($000s)	**2015**	2014
Drilling and completion	**59,747**	203,423
Plant and facilities	**23,783**	86,486
Geological and geophysical	**834**	7,432
Other assets	**6,675**	6,690
Capital expenditures	**91,039**	304,031
Acquisitions – land	**1,815**	5,838
– properties	**823**	240,204
Dispositions	**(31,012)**	(45,949)
Net capital expenditures	**62,665**	504,124

Drilling Activity

		2015 Wells		2014 Wells		Success Rate *(net wells)*	
		Gross	**Net**	Gross	Net	**2015**	2014
Peace River	– Montney	**5.0**	**5.0**	42.0	41.5	**100%**	100%
	– Other	**-**	**-**	2.0	2.0	**-**	100%
Redwater	– Viking	**12.0**	**12.0**	45.0	44.0	**100%**	100%
	– Other	**-**	**-**	2.0	1.0	**-**	100%
Deep Basin	– Edson	**3.0**	**3.0**	5.0	5.0	**100%**	100%
	– Kakwa/Elmworth	**3.0**	**3.0**	6.0	6.0	**100%**	100%
Other		**-**	**-**	1.0	1.0	**-**	100%
		23.0	**23.0**	103.0	100.5	**100%**	100%

Capital Expenditures

Capital expenditures were $91.0 million in 2015 compared to $304.0 million in 2014. The decrease was attributable to the decline in commodity prices during 2015, as low commodity prices reduced funds flow from operations available for capital spending.

Capital expenditures in 2015 of $91.0 million included $19.8 million (22%) in the Peace River Montney, $18.3 million (20%) in the Redwater Viking, $23.0 million (25%) in the Deep Basin at Edson and $21.6 million (24%) in the Deep Basin at Kakwa/Elmworth. The Company drilled 23.0 (23.0 net) wells during the year, with a 100% success rate.

Capital expenditures in 2014 of $304.0 million included $141.0 million (46%) in the Peace River Montney, $71.9 million (24%) in the Redwater Viking, $22.7 million (7%) in the Deep Basin at Edson and $35.2 million (12%) in the Deep Basin at Kakwa/Elmworth. The Company drilled 103.0 (100.5 net) wells with a 100% success rate.

Acquisitions and Dispositions

During 2015, proceeds of $31.0 million were received for the dispositions of minor non-core properties and a pipeline. The dispositions included the sale of a Redwater property in September for $18.3 million producing approximately 600 Boe/d and the sale of a pipeline in April for $8.1 million. Proceeds from the dispositions were directed towards debt repayment.

Disposition proceeds received in 2014 of $45.9 million related primarily to three non-core asset sales in Peace River, Lloydminster and Edson.

Acquisitions in 2014 included the Deep Basin asset acquisition for $228.8 million, which closed on May 30, 2014. The acquisition included development and exploration assets located primarily in the Kakwa/Elmworth and Edson areas. Other acquisitions during the year included a minor property tuck-in at Redwater.

On August 6, 2014, Long Run closed the corporate acquisition of Crocotta Energy Inc. (“Crocotta”) for $346.9 million, through the issuance of $231.4 million in share capital and the assumption of $115.5 million of net debt. The acquisition enhanced the new Deep Basin core area by providing exploration and development opportunities and adding ownership of gathering and processing infrastructure in Edson.

Enhanced Oil Recovery

Enhanced oil recovery (“EOR”) remains a key part of the Company’s strategic development plans. Long Run’s first EOR project was in our Peace River Montney area where the Company had two active EOR expansion projects. The EOR project at Normandville covers 5 sections (16 horizontal producers, 8 horizontal injection wells, 1 vertical injection well) and became operational in December 2014. A similar EOR project 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 the Company’s reservoir models, with signs of reservoir response beginning to show in both areas over recent months. This response has come in the form of stabilizing and increasing fluid and oil rates, as well as a downward trend in gas-oil ratios, in certain areas within the projects. 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 EOR project in the north part of this field in December 2013. This initial project included 2 horizontal injection wells, 6 producers and covered an area of 0.5 sections. A third horizontal injection well was later converted within this project area. A second complementary EOR project, located in the south part of the field, began injection in early December 2014. Together these projects cover an area of 1.125 sections and include 11 horizontal Viking producers, 5 vertical Viking producers and 5 horizontal injection wells. Signs of response have recently begun to show in parts of the reservoir. This response has come in the form of stabilizing fluid and oil rates, as well as a downward trend in gas-oil ratios.

Successful EOR implementation has the potential to improve recoveries, reduce production declines and improve capital efficiencies.

Production

Average Production by Product

	2015	2014
Liquids *(Bbl/d)*		
Light oil	**8,572**	11,979
Heavy oil	**321**	611
NGLs	**4,532**	3,076
Total	**13,425**	15,666
Natural Gas *(Mcf/d)*	**113,767**	93,008
Total *(Boe/d)*	**32,386**	31,168

Average Production by Area

		2015				2014			
		Oil *(Bbl/d)*	**NGLs** *(Bbl/d)*	**Natural Gas** *(Mcf/d)*	**Total** *(Boe/d)*	Oil *(Bbl/d)*	NGLs *(Bbl/d)*	Natural Gas *(Mcf/d)*	Total *(Boe/d)*
Peace River	– Montney	**4,224**	**258**	**21,924**	**8,136**	5,840	260	23,760	10,060
	– Other	**721**	**114**	**8,277**	**2,215**	990	133	11,907	3,108
Redwater	– Viking	**2,785**	**45**	**2,601**	**3,264**	4,430	57	3,896	5,136
	– Other	**565**	**97**	**14,198**	**3,028**	939	147	11,515	3,006
Deep Basin	– Edson	**537**	**2,226**	**24,097**	**6,779**	356	1,024	10,888	3,194
	– Kakwa/Elmworth	**59**	**994**	**23,971**	**5,048**	35	540	8,950	2,067
Boyer		**2**	**1**	**15,572**	**2,598**	-	1	17,149	2,859
Other		**-**	**797**	**3,127**	**1,318**	-	914	4,943	1,738
		8,893	**4,532**	**113,767**	**32,386**	12,590	3,076	93,008	31,168

During 2015, production averaged 32,386 Boe/d compared to 31,168 Boe/d in 2014. The production increase resulted primarily from the Deep Basin acquisitions in 2014, partially offset by the impact of reduced capital spending during 2015. Production in 2015 was also reduced approximately 700 Boe/d due to outages, shut-in of high operating cost wells and minor non-core dispositions.

Peace River Montney production for 2015 averaged 8,136 Boe/d compared to 10,060 Boe/d in 2014. The lower production volumes were primarily a result of reduced capital spending in the area. In 2015, Long Run drilled 5.0 net wells compared to 41.5 net wells in 2014, investing $19.8 million compared to $141.0 million in 2014.

Redwater Viking production for 2015 averaged 3,264 Boe/d compared to 5,136 Boe/d in 2014. The lower production volumes reflect the impact of reduced capital spending in the area. In 2015, Long Run drilled 12.0 net wells compared to 44.0 net wells in 2014, investing $18.3 million compared to $71.9 million in 2014.

Deep Basin production for 2015 averaged 11,827 Boe/d compared to 5,261 Boe/d in 2014. The production increase reflects a full year of production in 2015 and the results of our successful drilling in the area subsequent to the acquisition of the area in 2014. In 2015, Long Run drilled 6.0 net wells compared to 11.0 net wells in 2014, investing $44.6 million compared to $57.9 million in 2014.

Commodity Pricing

	2015	2014
Benchmark pricing		
WTI *(US$/Bbl)*	**48.76**	92.92
Edmonton Light Sweet *(CDN$/Bbl)*	**57.20**	94.46
AECO *($/Mcf)*	**2.70**	4.52
US$/CDN$ exchange rate	**1.28**	1.10
Prices, excluding derivatives		
Liquids *($/Bbl)*		
Light oil	**47.63**	85.80
Heavy oil	**41.94**	78.31
Total Oil	**47.43**	85.44
NGLs	**22.52**	51.24
Total	**39.02**	78.72
Natural Gas *($/Mcf)*	**2.83**	4.67
Total *($/Boe)*	**26.37**	53.70
Prices, including derivatives		
Liquids *($/Bbl)*		
Oil	**68.88**	84.89
NGLs	**22.52**	51.24
Total	**53.23**	78.29
Natural Gas *($/Mcf)*	**3.25**	4.52
Total *($/Boe)*	**33.70**	53.00

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 2015 was $47.43/Bbl, a decrease of $38.01/Bbl from 2014. The decrease resulted from lower West Texas Intermediate benchmark pricing, partially offset by an increase in the U.S dollar exchange rate.

Long Run's average NGLs price during 2015 was $22.52/Bbl, a decrease of $28.72/Bbl over 2014. The decrease was a result of lower market prices as well as the change in our NGLs product mix due to the Deep Basin acquisitions in 2014.

Our average natural gas price during 2015 was $2.83/Mcf, a decrease of $1.84/Mcf from 2014. The decrease was due to 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 due to the volatility of commodity prices. During 2015, our oil price of $68.88/Bbl included a realized gain on derivatives of $21.45/Bbl. The Company's natural gas price of $3.25/Mcf included a realized gain on derivatives of $0.42/Mcf.

Operating Results

Operating Netback & Funds Flow from Operations

	2015		2014	
	$000s	**$/Boe**	$000s	$/Boe
Revenues	**311,770**	**26.37**	610,896	53.70
Royalties	**(22,700)**	**(1.92)**	(70,276)	(6.18)
	289,070	**24.45**	540,620	47.52
Realized gain (loss) on derivatives	**86,593**	**7.33**	(7,963)	(0.70)
Transportation costs	**(18,207)**	**(1.54)**	(21,993)	(1.93)
Operating costs	**(139,357)**	**(11.79)**	(153,730)	(13.51)
Operating netback	**218,099**	**18.45**	356,934	31.38
General and administration	**(31,167)**	**(2.64)**	(38,193)	(3.36)
Interest	**(35,200)**	**(2.98)**	(26,027)	(2.29)
Exploration expenses	**(4)**	**-**	(858)	(0.08)
Capital and other taxes	**(92)**	**(0.01)**	-	-
Funds flow from operations[1]	**151,636**	**12.82**	291,856	25.65

[1] See Non-GAAP Measures section

During 2015, funds flow from operations was $151.6 million, a decrease of $140.2 million from 2014 due primarily to the following:

- Lower commodity prices, excluding derivatives, decreased revenue by $217.6 million. Of this total, $123.7 million was attributable to lower oil prices, $62.3 million to lower natural gas prices and $32.2 million to lower NGLs prices;
- Lower oil production decreased revenue by $115.0 million, reflecting the impact of reduced capital spending in 2015 at Peace River and Redwater; and
- Interest expense was $9.2 million higher in 2015, due to a higher average outstanding debt balance and an increased interest rate during the period. The effective interest rate including fees averaged approximately 6% in 2015.

Partially offset by:

- Higher natural gas and NGLs production increased revenue by $33.4 million. Higher production volumes were attributable to the Deep Basin acquisitions in 2014 and our successful Cardium drilling programs subsequent to the acquisitions. Of the total revenue increase, natural gas production contributed $21.5 million and NGLs production contributed $12.0 million;
- Royalties were $47.6 million lower in 2015, averaging 7% of revenue compared to 12% in 2014. Lower royalties resulted from lower commodity prices and lower oil production volumes;
- The realized gain on financial derivative contracts of $86.6 million compares to a loss of $8.0 million in 2014. During 2015, Long Run realized gains on oil derivative contracts of $69.6 million and on natural gas derivative contracts of $17.4 million;
- Operating costs were $14.4 million lower in 2015. Operating costs averaged $11.79/Boe compared to $13.51/Boe in 2014, reflecting the addition of the lower cost Deep Basin assets in 2014 and lower fuel, maintenance and chemical costs; and

- General and administration expense decreased $7.0 million in 2015. In 2015, general and administration expense included transaction costs of $3.0 million related to the Arrangement and a proposed private placement compared to $6.5 million in 2014 related to the Deep Basin acquisitions. Excluding transaction costs, general and administration expense in 2015 decreased to $2.38/Boe from $2.79/Boe in 2014 due to lower employee costs.

Other Income & Expenses

($000s)	**2015**	2014
Unrealized gain (loss) on derivatives	**(48,170)**	83,538
Share-based compensation	**(3,560)**	(2,262)
Accretion	**(10,623)**	(10,508)
Financing fees	**(2,823)**	-
Depletion and depreciation	**(218,516)**	(234,829)
Gain (loss) on disposal of assets	**(951)**	20,610
Impairments	**(350,000)**	(400,000)
Deferred income tax recovery (expense)	**(162,025)**	61,200
	(796,668)	(482,251)
Funds flow from operations[1]	**151,636**	291,856
Net earnings (loss)	**(645,032)**	(190,395)

[1] See Non-GAAP Measures section

In comparing the year ended December 31, 2015 to the year ended December 31, 2014:

- An unrealized loss on financial derivative contracts of $48.2 million compares to a gain of $83.5 million in 2014. In 2015, an unrealized loss of $42.5 million was recognized on our oil derivative contracts and $5.5 million on our natural gas derivative contracts.

- Depletion and depreciation expense of $218.5 million decreased $16.3 million from 2014 due to a lower depletion rate partially offset by increased production volumes. The depletion rate for 2015 was $18.50/Boe compared to $20.65/Boe in 2014. The lower depletion rate results from the impact of impairments taken in 2014 and 2015.

- The loss on disposal of assets was $1.0 million compared to a gain of $20.6 million in 2014. The loss in 2015 related to the dispositions of minor non-core properties. The gain in 2014 related primarily to the disposition of three non-core assets in Peace River, Lloydminster and Edson.

- Impairments of $350.0 million in 2015 and $400.0 million in 2014 were recorded due to the decline in future commodity price forecasts. In 2015, impairments were recorded at Peace River of $125.0 million, Redwater of $74.0 million, Deep Basin of $123.0 million and Kaybob of $28.0 million. In 2014, impairments were recorded at Deep Basin of $160.0 million, Redwater of $132.0 million, Peace River of $61.0 million and Kaybob of $47.0 million.

- In 2015, Long Run recorded a provision against the $162.0 million deferred income tax asset recognized at December 31, 2014. In addition, a deferred income tax recovery was not recognized on the Company’s 2015 net loss before tax. Decreased commodity prices negatively impacted the estimated realization of Long Run’s tax pools. At December 31, 2015, the Company had an unrecognized deferred income tax asset of $300.0 million. In 2014, a deferred income tax recovery of $61.2 million was recognized on a loss before tax of $251.6 million.

Summary of Quarterly Results

($000s, except per share or unless otherwise noted)	**2015**				2014			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Funds flow from operations [1]	**30,277**	35,477	45,924	39,958	68,178	80,199	73,429	70,050
Per share, basic [1]	**0.16**	0.18	0.24	0.21	0.35	0.45	0.55	0.56
Per share, diluted [1]	**0.16**	0.18	0.24	0.21	0.35	0.45	0.54	0.56
Net earnings (loss)	**(267,020)**	(305,058)	(50,136)	(22,818)	(258,652)	40,644	20,842	6,771
Per share, basic	**(1.38)**	(1.58)	(0.26)	(0.12)	(1.34)	0.23	0.16	0.05
Per share, diluted	**(1.38)**	(1.58)	(0.26)	(0.12)	(1.34)	0.23	0.15	0.05
Revenues, before royalties	**64,739**	72,271	93,436	81,324	133,354	166,978	158,678	151,886
Capital expenditures	**17,587**	19,367	8,770	45,315	70,094	75,759	57,330	100,848
Net divestitures [2]	**462**	(17,914)	(9,530)	(1,392)	(1,797)	(8,147)	(15,051)	(3,679)
Net capital expenditures [2]	**18,049**	1,453	(760)	43,923	68,297	67,612	42,279	97,169
Production								
Oil *(Bbl/d)*	**7,641**	7,990	9,429	10,557	12,130	13,071	12,476	12,684
Natural gas liquids *(Bbl/d)*	**3,998**	4,277	4,659	5,210	5,609	3,031	2,038	1,584
Total Liquids *(Bbl/d)*	**11,639**	12,267	14,088	15,767	17,739	16,102	14,514	14,268
Natural gas *(Mcf/d)*	**103,250**	110,799	122,214	119,007	112,576	112,161	78,524	68,071
Total *(Boe/d)*	**28,847**	30,733	34,457	35,602	36,502	34,795	27,602	25,613
Prices, including derivatives								
Oil *($/Bbl)*	**70.45**	68.27	72.03	65.34	79.35	84.66	89.59	85.89
Natural gas liquids *($/Bbl)*	**22.21**	20.74	24.48	22.50	30.02	57.98	72.76	86.87
Total Liquids *($/Bbl)*	**53.88**	51.69	56.31	51.18	63.75	79.64	87.23	85.99
Natural gas *($/Mcf)*	**3.20**	3.34	3.30	3.17	4.15	4.23	4.61	5.53
Total *($/Boe)*	**33.37**	32.81	35.04	33.45	43.92	50.75	59.13	62.67
Operating netback *($/Boe)*	**18.45**	18.55	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 asset acquisition on May 30, 2014*

Fourth Quarter 2015 compared to Fourth Quarter 2014

Funds flow from operations for the fourth quarter of 2015 of $30.3 million compared to $68.2 million in 2014. The decrease reflects lower commodity prices and production, partially offset by a higher gain on financial derivatives, lower royalties and lower operating costs.

The net loss for the fourth quarter of 2015 was $267.0 million compared to a net loss of $258.7 million in 2014. The 2015 net loss was primarily due to the provision recorded against the $168.8 million deferred tax asset and a non-cash impairment charge of $65.0 million, both attributable to lower commodity price forecasts at December 31, 2015. The 2014 net loss primarily resulted from year end after tax impairment charges of $300.0 million due to the decline in future commodity price forecasts at December 31, 2014.

Capital expenditures of $17.6 million in the fourth quarter of 2015 included 2.0 net wells drilled in the Deep Basin at Kakwa. Fourth quarter 2014 capital expenditures of $70.1 million included Deep Basin facility costs, and the drilling of 10.0 net wells, with 1.0 net well in the Peace River Montney, 1.0 net well in the Redwater Viking and 8.0 net wells in the Deep Basin Cardium.

Production in the fourth quarter of 2015 averaged 28,847 Boe/d (40% oil and NGLs) compared to 36,502 Boe/d (49% oil and NGLs) in 2014. The decrease in production reflects the impact of reduced capital spending in 2015.

The operating netback of $18.45/Boe and corporate netback of $11.41/Boe in the fourth quarter of 2015, compare to an operating netback of $25.04/Boe and corporate netback of $20.33/Boe in 2014. The decreases reflect lower commodity prices partially offset by a realized gain on financial derivatives and lower royalties.

Long Run's oil price excluding derivatives in the fourth quarter of 2015 decreased to $43.14/Bbl from $66.62/Bbl in 2014, reflecting weaker WTI oil benchmark prices, partially offset by an increase in the U.S. dollar exchange rate. Including a gain on derivatives of $27.31/Bbl, our 2015 realized oil price was $70.45/Bbl. Our NGLs price decreased to $22.21/Bbl from $30.02/Bbl in 2014 as a result of reduced market prices for NGLs in 2015. Our natural gas price excluding derivatives decreased to $2.69/Mcf from $4.13/Mcf in 2014, primarily attributable to weaker benchmark AECO natural gas prices. Including a gain on derivatives of $0.51/Mcf, our 2015 realized natural gas price was $3.20/Mcf.

Operating costs in the fourth quarter averaged $12.03/Boe, improving from $12.71/Boe in 2014 as costs have reduced in the low commodity price environment. Fourth quarter general and administration expense averaged $3.46/Boe compared to $2.32/Boe in 2014. Excluding transaction costs, general and administration expense averaged $2.80/Boe in 2015 compared to $2.32/Boe in 2014, attributable to lower production in 2015.

Liquidity and Capital Resources

Net Debt

($000s)	December 31, 2015	December 31, 2014
Bank loan, excluding bank fees – current	**582,588**	100,000
– long-term	**-**	511,717
	582,588	611,717
Working capital deficiency	**17,436**	52,881
Convertible debentures – face value	**75,000**	75,000
Net debt[1]	**675,024**	739,598

[1] See Non-GAAP Measures section

The Company's net debt at December 31, 2015 decreased $64.6 million from December 31, 2014, primarily due to proceeds from dispositions and funds flow from operations exceeding capital expenditures.

The capital intensive nature of the Company's activities generally results in the Company carrying a working capital deficit, as reflected in the net debt calculation. At December 31, 2015, Long Run had drawn $582.6 million against the Company's credit facilities and had letters of credit outstanding totaling $9.6 million, leaving $17.8 million of borrowing capacity available.

Credit Facilities

At December 31, 2014, the Company had credit facilities of $695.0 million, consisting of a $655.0 million revolving syndicated facility and a $40.0 million operating facility.

On May 29, 2015, the Company completed a semi-annual review of its credit facilities. The total credit facilities were maintained at $695.0 million, consisting of a $410.0 million revolving syndicated facility, a $40.0 million operating facility and a $245.0 million non-revolving syndicated facility. The $245.0 million non-revolving facility was due May 29, 2016. Long Run's financial covenants were relaxed to provide increased financial flexibility given the decrease in commodity prices.

On November 30, 2015, the Company completed its second semi-annual review of its credit facilities with its bank syndicate. Credit facilities were amended to $650.0 million, consisting of a $270.0 million revolving syndicated facility, a $30.0 million revolving operating facility and a $350.0 million non-revolving syndicated facility. The non-revolving syndicated facility was due in three tranches with $100.0 million due on January 31, 2016, $125.0 million due on May 29, 2016 and $125.0 million due on November 30, 2016. The $100.0 million due in January 2016 was expected to be funded by proceeds from the proposed private placement ("Proposed Private Placement") with Maple Marathon Investments Limited ("Maple Marathon") and MIE Holdings Corporation ("MIEH") pursuant to an agreement that was entered into on November 8, 2015. The November 30, 2015 credit facility amendments also included an event of default if the Proposed Private Placement was terminated.

On December 18, 2015, Long Run, Maple Marathon and MIEH mutually agreed to terminate the Proposed Private Placement, which constituted an event of default under the Company's credit facilities. On December 20, 2015, Long Run entered into the Arrangement Agreement with the Purchaser and Guarantor.

On December 24, 2015, Long Run entered into an interim forbearance and amending agreement with its bank syndicate. During the interim forbearance period, which was extended to January 29, 2016, the Company's credit facilities were reduced to $610.0 million, of which $582.6 million was outstanding at December 31, 2015 (December 31, 2014 - $611.7 million). During the interim forbearance period, credit facility margins increased by 2.0%.

On January 29, 2016, the Company entered into an amending credit facilities agreement with its bank syndicate that reflects the proposed Arrangement. The Company's credit facilities were amended to $620.0

million, comprised of a $240.0 million revolving syndicated facility, a $30.0 million operating facility and a $350.0 million non-revolving syndicated facility. The credit facilities terminate six months following the close of the proposed Arrangement, which is consistent with the Purchaser's plan to repay the credit facilities in due course following completion of the Arrangement. Until closing of the Arrangement, the additional 3.50% charged on the Company's non-revolving syndicated facility and the financial covenants have been removed.

The terms of the credit agreement were amended and restated to include additional events of default including: (i) the failure to receive the approval of the Arrangement by Long Run securityholders as required; (ii) the closing date of the Arrangement not occurring on or before the earlier of: (a) April 30, 2016 provided that if the only conditions precedent to the completion of the Arrangement that have not been satisfied by such date are the required approvals under the *Investment Canada Act* and/or the *Competition Act* (Canada), then such later outside date as agreed to by Long Run and the Purchaser in accordance with the Arrangement Agreement and (b) July 30, 2016; or (iii) termination of the Arrangement Agreement for any reason. Long Run securityholder approval was received at a special meeting of securityholders held on February 29, 2016. The Court approved the Arrangement on March 2, 2016. Long Run and the Purchaser are working together toward the completion of the additional required Canadian regulatory approvals, including under the *Investment Canada Act* and the *Competition Act* (Canada).

The terms of the credit facilities have also been amended to restrict the Company from making any payment of interest or other amounts on the convertible debentures, including the semi-annual interest payable on February 1, 2016. The bank syndicate has agreed to forbear from exercising any rights or remedies that arise as a result of Long Run's failure to pay interest on the convertible debentures as provided in the amended credit facilities agreement.

Security for the credit facilities at December 31, 2015 included a demand debenture for $1.5 billion which provides for a first ranking security interest and floating charge over all of the assets and property of the Company.

During 2015, the credit facilities beared interest at the prime rate or Libor rate, plus a margin, and in respect of banker's acceptances, required the payment of a stamping fee equal to a margin. The margins applicable to the borrowing base facilities ranged 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 expense 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 were based upon the borrowing base facility margins plus 3.50%.

Prior to their removal from the credit agreement on January 29, 2016, the bank covenants required the 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 (December 31, 2015 – 3.17:1). The interest coverage ratio, defined as Bank EBITDA to interest expense, was required to be greater than 2.75x until June 30, 2016 (December 31, 2015 – 5.31:1). The convertible debentures issued in January 2014 were not considered debt for the debt to Bank EBITDA ratio calculations under the credit agreement. Commodity hedges were 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 were permitted up to 75% of the total debt balance. Long Run was in compliance with the bank covenants at December 31, 2015. Further details on the calculations of the covenants can be found in the Company's credit facility agreement and amendments thereto filed on SEDAR at www.sedar.com on June 3, 2015, December 2, 2015, February 1, 2016 and February 8, 2016 under the Company's profile.

Convertible Debentures

On January 28, 2014, the Company issued $75.0 million face value of convertible unsecured subordinated debentures at par. The convertible debentures bear an annual interest rate of 6.40%, payable semi-annually in arrears. Prior to maturity on January 31, 2019, the debentures are convertible into Common Shares at a conversion price of $7.40 per Common Share, subject to adjustment in certain events.

Under the terms of the January 29, 2016 amendment to the credit facilities, the Company is restricted from making any payment of interest or other amounts on the convertible debentures, including the semi-annual

interest payable on February 1, 2016. Under the terms of the proposed Arrangement, the Purchaser has agreed to acquire, subject to the conditions contained in the Arrangement Agreement, the outstanding convertible debentures for cash consideration of $750 per $1,000 principal amount of debentures plus accrued and unpaid interest.

Share Capital

# of units (000s)	**March 9, 2016**	**December 31, 2015**	December 31, 2014
Common Shares	**193,498**	**193,498**	193,498
Options	**7,540**	**7,558**	8,879
Restricted Awards	**4,599**	**4,614**	-

Under the terms of the proposed Arrangement, the Purchaser agreed to acquire all of the outstanding Common Shares for cash consideration of $0.52 per share.

In January 2015, a total of 5.2 million restricted awards were granted. Each restricted award entitles the holder to a Common Share or the value of a Common Share (subject to certain adjustments, including 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.

The first vesting of the restricted awards occurred on January 5, 2016. The payment of these awards has been deferred as holders of the restricted awards were in a black-out period. Successful completion of the Arrangement will cause the payment dates applicable to all outstanding awards to be accelerated such that the value attaching to outstanding awards will be settled upon closing of the Arrangement.

Dividends

No dividends were declared or paid to shareholders since the first quarter of 2015. The monthly dividend was suspended in February 2015 as the Company focused on improving its capital structure. During the year ended December 31, 2015, $3.4 million in dividends had been declared and paid (December 31, 2014 - $66.2 million in dividends were declared, of which $59.4 million were paid in 2014 and $6.8 million were paid in 2015).

Capital Structure

The Company's primary capital management objective is to strengthen our financial position and improve 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. At December 31, 2015, the Company's net debt to funds flow from operations was 5.6 times and the debt to debt plus equity ratio was 0.90. Both measures reflect the impact of the decreased commodity prices experienced in 2015.

During 2015, Long Run examined strategic and financial options to improve its capital structure given the low commodity price environment. As a result of this process, the Company entered into the proposed Arrangement which will provide certainty of value for securityholders and improve the Company’s capital structure. The Company’s net debt to funds flow from operations and debt to debt plus equity targets for 2016 will be revaluated subsequent to the closing of the Arrangement.

Contractual Obligations and Contingencies

Contractual Obligations

($000s)	2016	2017	2018	2019	2020	Thereafter	Total
Operating leases	5,042	6,600	7,968	7,618	7,382	43,395	78,005
Processing	5,413	6,118	6,118	6,118	6,118	32,628	62,513
Transportation	13,484	14,243	10,099	4,734	3,156	6,466	52,182
Fractionation	2,843	2,653	650	-	-	-	6,146
Capital	6,182	6,182	254	-	-	-	12,618
Commitments	32,964	35,796	25,089	18,470	16,656	82,489	211,464
Bank loan [1]	582,588	-	-	-	-	-	582,588
Convertible debentures [2,3]	-	-	-	75,000	-	-	75,000
Total	615,552	35,796	25,089	93,470	16,656	82,489	869,052

[1] *Excludes bank fees*

[2] *Face value with maturity on January 31, 2019*

[3] *Under the terms of the proposed Arrangement, the Purchaser will acquire Long Run's outstanding convertible debentures for cash consideration of $750 per $1,000 principal amount of debentures plus accrued and unpaid interest*

At December 31, 2015, the Company was committed under operating leases for office space, contracts related to the processing of natural gas, transportation of oil, natural gas and NGLs, fractionation of natural gas liquids and capital commitments for drilling rig services. Commitments increased by $19.8 million from December 31, 2014 primarily as a result of an increase in natural gas processing 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, 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 its 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.

For a further and more in-depth discussion of risk management, see the Company's annual financial statements and the Company's annual information form for the year ended December 31, 2015.

Commodity Price

Oil and natural gas prices have been and are expected to remain volatile due to market uncertainties over the supply and demand of these commodities due to various factors including OPEC actions, the current state of world economies and ongoing credit and liquidity concerns. Depressed commodity prices have had and will continue to have a significant effect on the Company's revenue, funds flow from operations available for capital expenditures and repayment of indebtedness and other matters.

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 December 31, 2015, the Company had contracts for oil volumes of 1,000 Bbl/d contracted for 2016. At December 31, 2015, the Company had contracts for natural gas volumes of approximately 42.6 MMcf/d contracted for 2016. Further details on the derivative contracts can be found in Note 17 of the annual financial statements for the year ended December 31, 2015.

In 2015, the Company realized an $86.6 million gain as a result of its commodity price risk management. The realized gain included a $69.6 million gain on oil financial derivative contracts and a $17.4 million gain on natural gas contracts. In 2015, the Company recognized an unrealized loss on oil financial derivative contracts of $42.5 million and an unrealized loss on natural gas contracts of $5.5 million. At December 31, 2015, the fair value of oil derivatives was an asset of $7.4 million and the fair value of natural gas derivatives was an asset of $9.9 million.

Third Party Credit Risk

Credit risk is the risk that a customer or counterparty will fail to perform an obligation or fail to pay amounts due, causing a financial loss. The Company may be exposed to third party credit risk through its contractual arrangements with current or future industry partners, marketers of its production, counterparties to financial derivative contracts and other parties. In the event such entities fail to meet their contractual obligations to the Company, such failures may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

In addition, poor credit conditions in the industry and of industry partners may impact a partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until the Company finds a suitable alternative partner.

Credit risk is managed through credit assessments before contract initiation and by ensuring product sales and delivery contracts are diversified among well-known and financially strong oil and natural gas marketers. Additional security such as parental guarantees or letters of credit may be obtained. Financial derivative contracts are entered into with counterparties who are major Canadian financial institutions having investment grade credit ratings.

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.

At December 31, 2015, $582.6 million was drawn against the Company's credit facilities, with $17.8 million of borrowing capacity available.

The Company's current credit facilities terminate six months following the close of the proposed Arrangement, which is consistent with the Purchaser's plan to repay the credit facilities in due course following completion of the Arrangement.

Failure to complete the Arrangement will result in an event of default under the Company's credit facilities, which could accelerate the repayment of amounts outstanding. The Company's ability to continue as a going concern and discharge its obligations would be dependent on obtaining alternative equity, debt financing and/or proceeds from asset sales. In addition, the Arrangement Agreement provides for a mutual non-completion fee of $20 million under which Long Run may be required to pay the amount to the Purchaser in certain circumstances. Though management has been successful in securing sufficient financing in the past, doing so in the currently depressed commodity price cycle is expected to be challenging.

Operational Risks

Long Run is engaged in the development, exploration, and production of oil and natural gas. The oil and gas business is inherently risky and there is no assurance that hydrocarbon reserves will be discovered and economically produced. Operational risks include estimation of oil and gas reserves, estimation of the value of acquisitions, reservoir performance uncertainties, pipeline restrictions, facility capacity restrictions and operational risk related to non-operated properties. Long Run operates within a highly competitive area, and may face competition for acquisition of reserves and undeveloped land, access to supplier services and for qualified personnel.

Long Run mitigates these risks by employing qualified personnel and management, utilizing current technology for reserve identification and estimation, utilizing independent engineering consultants and maintaining operational control over the majority of our operations.

Regulatory, Environmental and Safety Risks

The Company is subject to regulation pursuant to a variety of federal, provincial and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material.

All phases of the oil and natural gas business present environmental and safety risks and hazards that can result in damage to property and the environment, and which may cause personal injury. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. Additional regulatory risks arise from uncertainties in obtaining regulatory approvals.

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations, often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment.

Long Run mitigates these risks by employing qualified personnel and management, utilizing third party specialists as required and by maintaining an acceptable level of property loss and business interruption insurance. The Company has a health and safety program which provides training and education to field employees, operators and contractors.

Implementation of strategies for reducing greenhouse gases to meet the limits required could have a material impact on the nature of oil and gas operations, including those of the Company. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on the Company and its operations and financial condition.

Critical Accounting Judgments, Estimates and Accounting Policies

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.

Oil and Natural Gas Accounting

All expenditures incurred, after the Company has obtained the legal right to explore, associated with the exploration for and development of oil and gas properties are capitalized whether successful or not. Exploration and evaluation costs are capitalized and accumulated pending determination of technical feasibility and commercial viability. Exploration and evaluation assets are not depleted. For property and equipment, the aggregate of net capitalized costs and estimated future development costs is amortized using the unit-of-production method based on estimated proved and probable oil and gas reserves.

Oil and gas accounting relies on the estimated proved and probable reserves believed to be recoverable from the oil and gas properties. Determination of reserves is a complex process involving judgments, estimates and decisions based on available geological, engineering, production and other relevant economic data. These estimates are subject to change as economic conditions change and ongoing production and development activities provide new information. The Company’s reserves are evaluated annually by an independent firm and by the Company on a quarterly basis. Reserve estimates are critical to the following accounting estimates:

- Calculation of unit of production depletion. Proved and probable reserve estimates are used to determine the depletion rate applied to each unit of production; and
- Impairment of oil and gas assets. Estimated future cash flows are determined using proved and probable reserve estimates.

An increase (decrease) in estimated proved and probable oil and gas reserves would result in a reduction (increase) in depletion expense. A decrease (increase) in estimated future development costs would result in a reduction (increase) in depletion expense.

The calculation of proved and probable reserves is affected by events, including the following:

- Changes to commodity prices;
- Production performance of wells;
- Changes to reservoir performance and pressures;
- New geological and geophysical data;
- Competitor production practices; and
- Changes to government regulations.

As circumstances change and additional data becomes available, revisions are made to these estimates.

Property and equipment may be excluded from depletion until capable of operating in the manner intended. The estimated fair value of these assets is included in impairment calculations.

Impairment Calculations

The Company is required to test the carrying value of exploration and evaluation assets for impairment if facts and circumstances suggest the carrying amount exceeds the recoverable amount, and when these assets are transferred to property and equipment. The Company is required to test the carrying value of oil and natural gas assets for impairment when indications of impairment exist.

The recoverable amount of an asset is the greater of its value in use and its fair value less costs to sell. The recoverable amount is determined for an individual asset, unless the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets. If this is the case, the recoverable amount is determined for the cash-generating unit to which the asset belongs. The amount by which the carrying value exceeds the recoverable amount of an asset is charged to earnings. An impairment recognized in prior periods for an asset other than goodwill is reversed if there has been a change in facts and circumstances since the last impairment loss was recognized.

The recoverable amount of an oil and gas asset is based on estimates of fair value, reserves, production rates, oil and natural gas prices, future costs, recent market transactions and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. As well, the cash generating unit to which an asset belongs is subject to the judgment of management.

A decrease in estimated proved and probable oil and gas reserves values could reduce the recoverable amount of a cash generating unit and result in an impairment. A subsequent increase in estimated proved oil and gas reserves values could increase the recoverable amount of a cash generating unit and reverse the impairment, net of the depletion that would have been recognized had the impairment not been recognized.

Business Combinations

Business acquisitions are accounted for using the acquisition method. Under this method, the consideration transferred is allocated to the assets acquired and the liabilities assumed based on their fair values at the time of acquisition. In determining the fair value of the assets and liabilities, Long Run is often required to make assumptions and estimates, such as reserves, future commodity prices, fair value of undeveloped land, discount rates, decommissioning liabilities and possible outcomes of any assumed contingencies.

Decommissioning Liabilities

The Company is required to provide for future abandonment and site restoration costs. The Company must estimate these costs in accordance with existing laws, contracts or other policies. These estimated costs are capitalized to exploration and evaluation assets or property and equipment, as applicable. The costs capitalized to property and equipment are depleted into earnings based on units of production. The estimate of future removal and site restoration costs involves a number of estimates related to timing of abandonment, determination of economic life of the asset, costs associated with abandonment and site restoration and review of potential abandonment methods.

Increases in the estimated decommissioning costs increase the corresponding charges of accretion and depletion to net earnings. A decrease in discount rates increases the decommissioning liability, which decreases the accretion charged to net earnings. Actual expenditures incurred are charged against the accumulated decommissioning liability.

Fair Value of Financial Derivatives

The fair value of financial derivatives is based on fair values provided by the counterparties with whom the transactions were completed. By their nature, these estimates and assumptions are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future years could be significant.

Income Tax Accounting

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment subsequent to the financial statement reporting period. The recognition of income tax assets requires a determination of the likelihood that they will be realized from future taxable earnings. Accordingly, the actual income tax asset or liability may differ significantly from that estimated and recorded by management.

Future Accounting Pronouncements

As required by IFRS, Long Run will be required to adopt IFRS 11 *Joint Arrangements* on January 1, 2016 and IFRS 9 *Financial Instruments* on January 1, 2018. Both standards are not expected to have a material impact on the Company's financial statements. Long Run will also be required to adopt IFRS 15 *Revenue from Contracts with Customers* on January 1, 2018 and IFRS 16 *Leases* on January 1, 2019. The Company has not yet determined the impact of these standards on its financial statements.

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. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's disclosure controls and procedures at the financial year end of the Company and have concluded that the Company's disclosure controls and procedures are effective at the financial year end of the Company for the foregoing purposes.

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. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal controls over financial reporting at the financial year end of the Company and have concluded that the Company's internal controls over financial reporting are effective at the financial year end of the Company for the foregoing purposes.

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 fourth quarter of 2015, Long Run recorded property impairment charges of $65.0 million at Redwater and the Deep Basin. The Company also recorded a provision against the $168.8 million of deferred tax asset recognized at September 30, 2015. The impairment and provision charges were a result of the drop in forecast commodity prices at December 31, 2015.

- During the third quarter of 2015, Long Run recorded property impairment charges of $285.0 million at Peace River, Redwater, Deep Basin and Kaybob. The impairment charges were a result of the drop in forecast commodity prices at September 30, 2015.

- During the first quarter of 2015, Long Run suspended its monthly dividend.

- 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 acquisition of Crocotta 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			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Funds flow from operations[1] *($000s)*	**30,277**	35,477	45,924	39,958	68,178	80,199	73,429	70,050
Per share, basic[1]	**0.16**	0.18	0.24	0.21	0.35	0.45	0.55	0.56
Per share, diluted[1]	**0.16**	0.18	0.24	0.21	0.35	0.45	0.54	0.56
Net earnings (loss) *($000s)*	**(267,020)**	(305,058)	(50,136)	(22,818)	(258,652)	40,644	20,842	6,771
Per share, basic	**(1.38)**	(1.58)	(0.26)	(0.12)	(1.34)	0.23	0.16	0.05
Per share, diluted	**(1.38)**	(1.58)	(0.26)	(0.12)	(1.34)	0.23	0.15	0.05
Capital *($000s)*								
Drilling and completion	**10,252**	13,434	4,484	31,577	40,928	52,530	34,851	75,114
Plant and facilities	**5,127**	4,487	1,967	12,202	26,935	19,740	16,441	23,370
Geological and geophysical	**-**	14	42	778	247	1,951	4,295	939
Other assets	**2,208**	1,432	2,277	758	1,984	1,538	1,743	1,425
Capital expenditures	**17,587**	19,367	8,770	45,315	70,094	75,759	57,330	100,848
Net acquisitions (dispositions)	**462**	(17,914)	(9,530)	(1,392)	(1,797)	(8,147)	213,716	(3,679)
Capital investment	**18,049**	1,453	(760)	43,923	68,297	67,612	271,046	97,169
Wells drilled *(net)*								
Peace River - Montney	**-**	-	-	5.0	1.0	12.0	11.0	17.5
- Other	**-**	-	-	-	-	-	-	2.0
Redwater - Viking	**-**	12.0	-	-	1.0	6.0	10.0	27.0
- Other	**-**	-	-	-	-	-	1.0	-
Deep Basin - Edson	**-**	-	-	3.0	2.0	3.0	-	-
- Kakwa/Elmworth	**2.0**	-	-	1.0	6.0	-	-	-
Other	**-**	-	-	-	-	-	-	1.0
Total	**2.0**	12.0	-	9.0	10.0	21.0	22.0	47.5
Production								
Liquids *(Bbl/d)*								
Light oil	**7,319**	7,711	9,059	10,242	11,895	12,708	11,808	11,491
Heavy oil	**322**	279	370	315	235	363	668	1,193
NGLs	**3,998**	4,277	4,659	5,210	5,609	3,031	2,038	1,584
	11,639	12,267	14,088	15,767	17,739	16,102	14,514	14,268
Natural Gas *(Mcf/d)*	**103,250**	110,799	122,214	119,007	112,576	112,161	78,524	68,071
Total *(Boe/d)*	**28,847**	30,733	34,457	35,602	36,502	34,795	27,602	25,613
Production by area *(Boe/d)*								
Peace River - Montney	**6,791**	7,497	8,767	9,527	10,661	10,918	9,340	9,294
- Other	**1,999**	2,046	2,170	2,651	2,650	3,054	3,160	3,579
Redwater - Viking	**3,077**	2,942	3,295	3,749	4,451	5,122	5,617	5,365
- Other	**2,817**	2,903	3,124	3,279	3,242	3,196	2,758	2,819
Deep Basin - Edson	**5,843**	6,430	7,366	7,498	7,665	4,654	338	19
- Kakwa/Elmworth	**4,698**	4,854	5,706	4,942	3,579	3,207	1,433	-
Boyer	**2,492**	2,717	2,659	2,523	2,727	2,929	3,046	2,733
Other	**1,130**	1,344	1,370	1,433	1,527	1,715	1,910	1,804
Total	**28,847**	30,733	34,457	35,602	36,502	34,795	27,602	25,613

[1] *See Non-GAAP Measures section*

	2015				2014			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Benchmark pricing								
WTI *(US$/Bbl)*	**42.17**	46.44	57.96	48.57	73.12	97.21	102.98	98.68
Edmonton Light Sweet (*CDN$/Bbl)*	**52.93**	56.27	67.73	51.85	75.65	97.18	105.62	99.83
AECO *($/Mcf)*	**2.56**	2.84	2.66	2.76	3.75	4.02	4.69	5.72
US$/CDN$ exchange rate	**1.33**	1.31	1.23	1.24	1.13	1.09	1.09	1.10
Prices, excluding derivatives								
Liquids *($/Bbl)*								
Light oil	**43.51**	45.78	58.53	42.32	66.73	88.08	97.50	91.24
Heavy oil	**34.55**	40.59	53.33	37.36	60.71	81.47	81.79	78.90
NGLs	**22.21**	20.74	24.48	22.50	30.02	57.98	72.76	86.87
Total	**35.95**	36.93	47.13	35.67	55.04	82.26	93.30	89.72
Natural Gas *($/Mcf)*	**2.69**	2.95	2.89	2.80	4.13	4.29	4.89	5.96
Total *($/Boe)*	**24.39**	25.56	29.80	25.38	39.71	52.16	63.17	65.89
Prices, including derivatives								
Oil *($/Bbl)*	**70.45**	68.27	72.03	65.34	79.35	84.66	89.59	85.89
NGLs *($/Bbl)*	**22.21**	20.74	24.48	22.50	30.02	57.98	72.76	86.87
Natural Gas *($/Mcf)*	**3.20**	3.34	3.30	3.17	4.15	4.23	4.61	5.53
Total *($/Boe)*	**33.37**	32.81	35.04	33.45	43.92	50.75	59.13	62.67
Netback *($/Boe)*								
Revenues	**24.39**	25.56	29.80	25.38	39.71	52.16	63.17	65.89
Royalties	**(1.38)**	(2.23)	(2.04)	(1.97)	(4.42)	(6.05)	(7.01)	(8.01)
Realized gain (loss) on derivatives	**8.98**	7.25	5.24	8.07	4.21	(1.42)	(4.04)	(3.22)
Transportation costs	**(1.51)**	(1.41)	(1.53)	(1.69)	(1.75)	(1.65)	(2.10)	(2.41)
Operating costs	**(12.03)**	(10.62)	(11.55)	(12.85)	(12.71)	(11.63)	(14.98)	(15.70)
Operating Netback	**18.45**	18.55	19.92	16.94	25.04	31.41	35.04	36.55
G&A	**(3.46)**	(2.71)	(2.53)	(2.00)	(2.32)	(3.92)	(3.64)	(3.79)
Interest	**(3.58)**	(3.25)	(2.75)	(2.46)	(2.39)	(2.36)	(2.19)	(2.13)
Corporate Netback	**11.41**	12.59	14.64	12.48	20.33	25.13	29.21	30.63
Funds flow from operations[1] *($000s)*								
Revenues	**64,739**	72,271	93,436	81,324	133,354	166,978	158,678	151,886
Royalties	**(3,667)**	(6,312)	(6,400)	(6,321)	(14,835)	(19,377)	(17,598)	(18,466)
Realized gain (loss) on derivatives	**23,830**	20,486	16,432	25,845	14,145	(4,529)	(10,157)	(7,422)
Transportation costs	**(4,007)**	(3,995)	(4,785)	(5,421)	(5,891)	(5,272)	(5,287)	(5,543)
Operating costs	**(31,935)**	(30,031)	(36,206)	(41,184)	(42,684)	(37,238)	(37,614)	(36,194)
	48,960	52,419	62,477	54,243	84,089	100,562	88,022	84,261
G&A	**(9,178)**	(7,654)	(7,929)	(6,406)	(7,793)	(12,537)	(9,134)	(8,729)
Interest	**(9,505)**	(9,196)	(8,624)	(7,875)	(8,038)	(7,566)	(5,507)	(4,916)
Other	**-**	(92)	-	(4)	(80)	(260)	48	(566)
	30,277	35,477	45,924	39,958	68,178	80,199	73,429	70,050

[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			
($000s)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Cash flow from operating activities	**38,144**	28,057	37,585	48,832	80,866	78,006	67,280	59,781
Change in non-cash working capital	**(8,910)**	5,338	7,975	(11,491)	(18,865)	(996)	5,452	8,923
Abandonment costs	**1,043**	2,082	364	2,617	6,177	3,189	697	1,346
Funds flow from operations	**30,277**	35,477	45,924	39,958	68,178	80,199	73,429	70,050
Weighted average outstanding shares *(000s)*								
- Basic	**193,498**	193,498	193,498	193,498	193,497	176,318	134,291	125,730
- Diluted	**193,498**	193,498	193,498	193,498	193,497	177,003	135,437	126,129
Funds flow from operations per share *($/share)*								
- Basic	**0.16**	0.18	0.24	0.21	0.35	0.45	0.55	0.56
- Diluted	**0.16**	0.18	0.24	0.21	0.35	0.45	0.54	0.56

($000s)	**2015**	2014
Cash flow from operating activities	**152,618**	285,933
Change in non-cash working capital	**(7,088)**	(5,486)
Abandonment costs	**6,106**	11,409
Funds flow from operations	**151,636**	291,856
Weighted average outstanding shares *(000s)*		
- Basic	**193,498**	157,697
- Diluted	**193,498**	157,697
Funds flow from operations per share *($/share)*		
- Basic	**0.78**	1.85
- Diluted	**0.78**	1.85

Net Debt

($000s)	**December 31, 2015**	December 31, 2014
Bank loan, excluding bank fees	**582,588**	611,717
Working capital deficiency		
Accounts payable and accrued liabilities	**64,611**	132,439
Accounts receivable	**(38,315)**	(65,135)
Prepaid expenses and deposits	**(8,860)**	(14,423)
Convertible debentures – face value	**75,000**	75,000
Net Debt	**675,024**	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, closing of the proposed Arrangement, ability to secure additional financing, potential impact of EOR implementation in the Montney and ultimate expanse on full field implementation, expected timing of the repayment of the Company's credit facilities and payment of outstanding restricted awards upon closing of the Arrangement Agreement. 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 satisfaction of conditions precedent to completion of the Arrangement, including 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.

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, ability to access sufficient capital from internal and external sources and risks that the Arrangement is not completed as a result of non-satisfaction of the conditions precedent to completion thereof, or otherwise. 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. The Company's light oil production also includes a mix of minor medium oil production.

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. Operating netback and corporate netback are commonly used metrics in the oil and gas industry; however, as these metrics do not have a standardized meaning, they may not be comparable to these metrics as reported by other companies.

Abbreviations

Oil and Natural Gas Liquids

Bbl	Barrels
MBbl	thousand barrels
MMBbl	million barrels
Bbl/d	barrels per day
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

Natural Gas

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

Additional Information

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

LONG RUN EXPLORATION LTD.

Financial Statements

December 31, 2015

Management's Responsibility for Financial Reporting

The accompanying financial statements and all information in this report are the responsibility of management. Management has prepared the financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. In the opinion of management, the financial statements have been prepared within acceptable limits of materiality and, when necessary, management has made informed judgments and estimates in accounting for transactions that were not complete at the statement of financial position date. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances as indicated in the notes to the financial statements. Financial information contained elsewhere in this report has been prepared and reviewed by management to ensure it is consistent with the financial statements.

Management has established systems of 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 International Financial Reporting Standards.

The Audit and Reserves Committees are appointed by the Board of Directors, and are comprised of directors that are not employees of the Company. The Audit Committee meets regularly with management, as well as the external auditors, to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each party is discharging its responsibilities, and to review the financial statements and the external auditors' report. The Board of Directors has approved the financial statements.

(signed)
William E. Andrew
Chair and Chief Executive Officer

(signed)
Corine Bushfield
Senior Vice President and
Chief Financial Officer

March 9, 2016

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Long Run Exploration Ltd.

We have audited the accompanying financial statements of Long Run Exploration Ltd. which comprise the statements of financial position as at December 31, 2015 and December 31, 2014, and the statements of earnings (loss), comprehensive income (loss), changes in shareholders' equity and cash flows for the years ended December 31, 2015, and December 31, 2014, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Long Run Exploration Ltd. as at December 31, 2015 and December 31, 2014, and its financial performance and its cash flows for the years ended December 31, 2015, and December 31, 2014, in accordance with International Financial Reporting Standards.

Ernst & Young LLP

Chartered Professional Accountants
Calgary, Canada
March 9, 2016

Statement of Financial Position

($000s)	**December 31, 2015**	December 31, 2014
ASSETS		
CURRENT		
Accounts receivable	**38,315**	65,135
Deposits and prepaid expenses	**8,860**	14,423
Fair value of financial derivatives *(note 17)*	**17,253**	65,438
	64,428	144,996
Exploration and evaluation assets *(note 7)*	**-**	5,635
Property and equipment *(note 8)*	**1,134,195**	1,627,050
Deferred income tax asset *(note 15)*	**-**	162,025
	1,198,623	1,939,706
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	**64,611**	132,439
Bank loan *(note 10)*	**579,406**	100,000
Fair value of financial derivatives *(note 17)*	**406**	336
	644,423	232,775
Bank loan *(note 10)*	**-**	511,717
Convertible debentures *(note 11)*	**69,592**	68,145
Decommissioning liabilities *(note 9)*	**412,207**	411,209
Fair value of financial derivatives *(note 17)*	**-**	85
	1,126,222	1,223,931
SHAREHOLDERS' EQUITY		
Share capital *(note 12)*	**1,006,799**	1,006,799
Equity component of convertible debentures *(note 11)*	**3,483**	3,483
Contributed surplus *(note 12)*	**31,204**	26,160
Retained earnings (deficit)	**(969,085)**	(320,667)
	72,401	715,775
	1,198,623	1,939,706

Commitments and contingencies *(note 19)*

See accompanying notes to the financial statements.

Approved on behalf of the Board of Directors:

(signed)
William Stevenson
Director

(signed)
Brad Munro
Director

Statement of Earnings (Loss) and Comprehensive Income (Loss)

($000s, except per share amounts)	Year ended December 31 2015	2014
INCOME		
Petroleum and natural gas revenue	**311,770**	610,896
Royalties	**(22,700)**	(70,276)
	289,070	540,620
Gain (loss) on financial derivatives *(note 17)*		
- realized	**86,593**	(7,963)
- unrealized	**(48,170)**	83,538
	327,493	616,195
EXPENSES		
Operating	**139,357**	153,730
Transportation	**18,207**	21,993
General and administration *(note 14)*	**31,167**	38,193
Share-based compensation *(note 12)*	**3,560**	2,262
Interest	**38,023**	26,027
Accretion *(note 9, 11)*	**10,623**	10,508
Depletion and depreciation *(note 8)*	**218,516**	234,829
Exploration	**4**	858
(Gain) loss on disposal of assets *(note 8)*	**951**	(20,610)
Impairments *(note 8)*	**350,000**	400,000
	810,408	867,790
EARNINGS (LOSS) BEFORE TAX	**(482,915)**	(251,595)
Income taxes		
Capital and other taxes	**92**	-
Deferred income tax expense (recovery) *(note 15)*	**162,025**	(61,200)
	162,117	(61,200)
NET EARNINGS (LOSS) AND COMPREHENSIVE INCOME (LOSS)	**(645,032)**	(190,395)
NET EARNINGS (LOSS) AND COMPREHENSIVE INCOME (LOSS) PER SHARE *(note 12)*		
Basic	**(3.33)**	(1.21)
Diluted	**(3.33)**	(1.21)

See accompanying notes to the financial statements.

Statement of Changes in Shareholders' Equity

($000s)	Share Capital	Equity Component of Convertible Debentures	Contributed Surplus	Retained Earnings (Deficit)	Total
	(note 12)	*(note 11)*	*(note 12)*		
January 1, 2014	657,666	-	23,377	(64,066)	616,977
Issuance of common shares	346,317	-	-	-	346,317
Share-based compensation	-	-	3,440	-	3,440
Options exercised	2,816	-	(657)	-	2,159
Comprehensive income (loss)	-	-	-	(190,395)	(190,395)
Dividends declared *(note 12)*	-	-	-	(66,206)	(66,206)
Convertible debentures issued	-	3,483	-	-	3,483
December 31, 2014	1,006,799	3,483	26,160	(320,667)	715,775
Share-based compensation	-	-	5,044	-	5,044
Comprehensive income (loss)	-	-	-	(645,032)	(645,032)
Dividends declared *(note 12)*	-	-	-	(3,386)	(3,386)
December 31, 2015	**1,006,799**	**3,483**	**31,204**	**(969,085)**	**72,401**

See accompanying notes to the financial statements.

Statement of Cash Flows

($000s)	Year ended December 31 **2015**	2014
Cash provided by (used in):		
OPERATING ACTIVITIES		
Net earnings (loss)	**(645,032)**	(190,395)
Items not requiring cash:		
Unrealized (gain) loss on financial derivatives *(note 17)*	**48,170**	(83,538)
Share-based compensation *(note 12)*	**3,560**	2,262
Accretion and other *(note 9, 11)*	**13,446**	10,508
Depletion and depreciation *(note 8)*	**218,516**	234,829
(Gain) loss on disposal of assets *(note 8)*	**951**	(20,610)
Impairments *(note 8)*	**350,000**	400,000
Deferred income tax expense (recovery) *(note 15)*	**162,025**	(61,200)
Abandonment costs *(note 9)*	**(6,106)**	(11,409)
Change in non-cash working capital *(note 18)*	**7,088**	5,486
	152,618	285,933
INVESTING ACTIVITIES		
Capital expenditures *(note 7, 8)*	**(91,039)**	(304,031)
Acquisitions *(note 6, 8)*	**(2,638)**	(246,042)
Dispositions *(note 8)*	**31,012**	45,949
Change in non-cash working capital *(note 18)*	**(44,661)**	21,380
	(107,326)	(482,744)
FINANCING ACTIVITIES		
Bank loan issuance (repayment) *(note 10)*	**(29,129)**	69,327
Bank fees paid *(note 10)*	**(6,005)**	-
Issuance of convertible debentures, net of costs *(note 11)*	**-**	71,566
Dividends declared *(note 12)*	**(3,386)**	(66,206)
Issuance of common shares *(note 12)*	**-**	122,162
Share issue costs *(note 12)*	**-**	(6,810)
Change in non-cash working capital *(note 18)*	**(6,772)**	6,772
	(45,292)	196,811
CHANGE IN CASH	**-**	-
CASH, BEGINNING OF YEAR	**-**	-
CASH, END OF YEAR	**-**	-
SUPPLEMENTAL INFORMATION		
Interest paid	**34,833**	23,651

See accompanying notes to the financial statements.

1. REPORTING ENTITY

Long Run Exploration Ltd. (“Long Run” or the “Company”) is incorporated under the *Business Corporations Act* (Alberta).

The Company is in the business of development, exploration and production of oil and natural gas in western Canada.

The principal address of the Company is located at 400, 250 2nd Street SW, Calgary, Alberta, T2P 0C1. Long Run’s outstanding common shares and convertible debentures are listed on the Toronto Stock Exchange under the symbols “LRE” and “LRE.DB”, respectively.

2. PROPOSED PLAN OF ARRANGEMENT

On December 20, 2015, Long Run entered into an arrangement agreement (the “Arrangement Agreement”) with Calgary Sinoenergy Investment Corp. (the “Purchaser”) and Qingdao Sinoenergy Capital Corporation (the “Guarantor”). On January 29, 2016, in connection with amending Long Run’s credit facilities, the Arrangement Agreement was amended and restated to reflect the revised credit agreement terms (see Note 10).

Pursuant to the proposed plan of arrangement (the “Arrangement”), the Purchaser agreed to acquire: i) all of the outstanding common shares of Long Run (“Common Shares”) for cash consideration of $0.52 per share, and ii) all of the Long Run outstanding convertible debentures for cash consideration of $750 per $1,000 principal amount of debentures plus accrued and unpaid interest.

Completion of the Arrangement is subject to various closing conditions including receipt of Long Run securityholder approval, court and regulatory approvals in Canada and regulatory approvals required by the Purchaser in China. Long Run securityholder approval was received at a special meeting held on February 29, 2016. The Court of Queen's Bench of Alberta approved the Arrangement on March 2, 2016. Long Run and the Purchaser are working together toward the completion of the required Canadian regulatory approvals, including under the *Investment Canada Act* and the *Competition Act* (Canada). The Purchaser has confirmed it has completed its applicable filings with and is in receipt of required approvals from the National Development and Reform Commission, Ministry of Commerce Qingdao Branch and the State Administration of Foreign Exchange in China. The Arrangement is currently expected to close in late April 2016 following the receipt of Canadian regulatory approvals.

3. BASIS OF PRESENTATION

These financial statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”). The financial statements have been prepared on the historical cost basis except where noted in the accounting policies. The financial statements are presented in Canadian dollars.

The financial statements have been prepared in accordance with IFRS applicable to a going concern, which contemplate the realization of assets and the settlement of liabilities in the normal course of business as they become due. Continuing as a going concern is dependent upon the Company’s ability to repay its credit facilities, which is expected to be achieved through the completion of the proposed Arrangement. Failure to complete the Arrangement would result in an event of default under Long Run’s credit facilities, which could accelerate the repayment of amounts outstanding. The Company’s ability to continue as a going concern and discharge its obligations would be dependent on obtaining alternative equity, debt financing and/or proceeds from asset sales. Though management has been successful in securing sufficient financing in the past, doing so in the current low commodity price environment is expected to be challenging. These financial statements do not reflect adjustments to

the amounts and classification of assets and liabilities that would be necessary if the going concern assumption is not appropriate. Such adjustments could be material.

The financial statements were authorized for issue by the Board of Directors on March 9, 2016.

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Estimates, assumptions and judgments

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

The amounts recorded for exploration and evaluation assets, property and equipment, depletion and depreciation and impairment testing are based on estimates of proven and probable reserves, production rates, oil and natural gas prices, future costs, future prices and other relevant assumptions. As well, the cash generating unit (“CGU”) to which an asset belongs is subject to the judgment of management.

Assumptions that are valid at the time of reserves estimation may change significantly when new information becomes available. Changes in forward price estimates, production costs or recovery rates may change the economic status of reserves. Changes in the economic environment could result in significant changes to the discount rate used to calculate net present values.

Business combinations are accounted for using the acquisition method. Under this method, the consideration transferred is allocated to the assets acquired and the liabilities assumed based on the fair values at the time of acquisition. In determining the fair value of the assets and liabilities, Long Run is often required to make assumptions and estimates for items such as reserves, future commodity prices, fair value of undeveloped land, discount rates, decommissioning liabilities and the possible outcome of any assumed contingencies.

The provision for decommissioning liabilities is based on estimates of costs and expected plans for remediation. Actual costs may differ from those estimated due to changes in laws and regulations, technology, market and other conditions.

Accruals for revenue, royalties and costs are prepared based on estimates when actual amounts are not yet known. Share-based compensation amounts are determined using certain assumptions (see Note 12).

The fair value of financial derivatives is based on fair values provided by the counterparties with whom the transactions were completed. By their nature, these estimates and assumptions are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future years could be significant.

The provision for income and other tax liabilities, requiring the interpretation of complex laws and regulations which are subject to change, is subject to measurement uncertainty. The recognition of income tax assets requires a determination of the likelihood that they will be realized from future taxable earnings.

Cash and cash equivalents

Cash and cash equivalents may include highly liquid short-term investments with initial maturities of three months or less. They are recorded at cost which approximates fair market value.

Financial instruments

All financial assets excluding derivatives are classified as loans or receivables and are accounted for on an amortized cost basis. All financial liabilities excluding derivatives are classified as other liabilities and are accounted for on an amortized cost basis. Financial instruments recognized on the Company's statement of financial position are deemed to approximate their estimated fair values.

Convertible debentures are separated into their liability and equity components. The liability component accretes to the principal balance at maturity using the effective interest rate method. The equity component will be reclassified to share capital upon conversion. Any balance in equity that remains after the settlement of the liability is transferred to contributed surplus. The equity portion is recognized net of deferred income taxes and issuance costs.

Financial derivatives that have not been designated as accounting hedges are classified as fair value through profit or loss. Financial derivatives are recorded and carried on the statement of financial position at fair value with actual amounts received or paid on the settlement of the financial derivative instrument recorded in income.

At each reporting date, the Company determines whether transfers have occurred between levels in the fair value hierarchy by reassessing the level of classification for each financial asset and financial liability measured or disclosed at fair value in the financial statements. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy.

Joint operations

The Company's petroleum and natural gas activities may be conducted jointly with others. Joint operations, whereby the jointly controlling parties have rights to the assets and obligations for the liabilities of the arrangement, are accounted for using proportionate consolidation. The financial statements reflect only the Company's proportionate interest in such activities.

Exploration and evaluation assets

Expenditures incurred before the Company has obtained the legal right to explore are expensed in the statement of earnings as exploration expense.

Exploration and evaluation assets reflect expenditures for an area where technical feasibility and commercial viability has not yet been determined. Expenditures, including land acquisition, geological and geophysical, drilling and completion costs are capitalized and accumulated pending determination of technical feasibility and commercial viability. Evaluation and exploration assets are not depleted. When assets are determined to be technically feasible and commercially viable, the accumulated costs are assessed for impairment within the CGU and the recoverable amount is transferred to property and equipment.

Exploration and evaluation assets are also assessed for impairment if facts and circumstances suggest the carrying amount exceeds the recoverable amount.

Property and equipment

Property and equipment are stated at cost less accumulated depletion and depreciation and accumulated impairments.

Petroleum and natural gas properties

Property and equipment includes transfers of exploration and evaluation assets, property acquisitions, facilities, directly attributable overhead and share-based compensation expense, as well as land acquisition, geological and geophysical, drilling and completion costs incurred within an area considered to be technically feasible and commercially viable.

Property and equipment is depleted on the unit of production method using estimated gross proven and probable petroleum and natural gas reserves, determined annually by independent professional engineers. Petroleum and natural gas reserves are converted to a common unit of measure on an energy equivalent basis of six mcf of gas to one barrel of oil. Estimated future development costs necessary to bring the reserves into production are included in the depletion calculation. Assets may be excluded from depletion until capable of operation. Undeveloped land is amortized into the depletable base over the term of the leases.

Reserves are the remaining quantities of oil, natural gas and related substances from known accumulations estimated to be recoverable from a given date forward. The estimates of reserves are determined from drilling, geological, geophysical and engineering data based on established technology and specified economic conditions. The guidelines for the determination and classification of reserves are outlined in the Canadian Oil and Gas Evaluation Handbook.

Proven plus probable reserve estimate is defined as a “best estimate” of the remaining recoverable quantities of oil, natural gas and related substances. This estimate should best represent the expected outcome with no optimism or conservatism. In probabilistic terms, there should be at least a 50 percent probability that the quantities actually recovered in the future will equal or exceed the proven plus probable reserve estimate.

Property and equipment is tested for impairment when indications of impairment exist.

Assets held for sale

Non-current assets, or disposal groups consisting of assets and liabilities, are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is met when the sale is highly probable and the asset is available for immediate sale in its present condition.

Assets classified as held for sale are measured at the lower of the carrying amount and fair value less costs to sell, with impairments recognized in net earnings in the period measured. Assets and disposal groups held for sale are presented in current assets and liabilities on the statement of financial position.

Disposals

Any gain or loss on the disposal of assets, including oil and natural gas properties, determined as the difference between the net disposal proceeds and the carrying amount of the asset, is recognized in the statement of earnings.

Non-monetary transactions

Non-monetary transactions for the acquisition or disposal of property and equipment are measured at fair value, unless the transaction lacks commercial substance or fair value cannot be reliably measured.

Goodwill

Goodwill, at the time of acquisition, represents the excess of the purchase price of a business over the fair value of net assets acquired. When the excess is negative, it is recognized immediately in the statement of earnings.

Goodwill, measured at cost less accumulated impairments, is tested for impairment annually. For purposes of impairment testing, goodwill acquired in a business combination is allocated to the CGUs that are expected to benefit from the synergies of the combination and tested for impairment at the operating segment level. An impairment of goodwill is not reversed.

Business combinations

Transactions for the purchase of assets, where the assets acquired are deemed to constitute a business, are accounted for as business combinations. Using the acquisition method, identifiable assets acquired and liabilities assumed are measured at their fair values on the acquisition date. Transaction costs related to the acquisition are expensed in the statement of earnings.

Impairments

The recoverable amount of an asset is the greater of its value in use and its fair value less costs to sell. If the recoverable amount is less than the carrying value, the asset is considered to be impaired. The recoverable amount is determined for an individual asset, unless the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets. If this is the case, the recoverable amount is determined for the CGU to which the asset belongs.

In assessing value in use, estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from proven and probable reserves.

Fair value less costs to sell is the amount obtainable from the sale of an asset in an arm’s length transaction between knowledgeable and willing parties, less the costs of disposal. Available fair value indicators, such as recent market transaction information and appropriately discounted cash flow valuation models, are used in determining fair value less costs to sell.

An impairment is recognized in the statement of earnings. An impairment recognized in respect of a CGU is allocated first to reduce the carrying amount of any goodwill allocated to the CGU and subsequently to other assets in the CGU. An impairment recognized in prior periods for an asset other than goodwill is reversed if there has been a change in facts and circumstances used to determine the asset’s recoverable amount since the last impairment was recognized, such that the impairment no longer exists or has decreased. An impairment is only reversed to the extent that the asset’s carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment had been recognized.

Leases

The Company’s leases are classified as either finance or operating. Finance leases are those which transfer substantially all the benefits and risks of ownership to the lessee. Assets acquired under finance leases are depleted along with property and equipment. Obligations recorded under finance leases are reduced by the principal portion of lease payments as incurred and the imputed interest portion of finance lease payments is charged to interest expense. Payments under operating leases are expensed as incurred.

Decommissioning liabilities

Decommissioning liabilities arise from the legal obligation to abandon and reclaim property, plant and equipment incurred upon acquisition, construction, development and normal use of the asset. The initial liability is measured at the discounted value of the estimated costs to reclaim and abandon using a risk free rate, subsequently adjusted for the accretion of discount and changes in expected costs. The decommissioning cost is capitalized as part of exploration and evaluation assets or property and equipment, as applicable. The costs capitalized to property and equipment are depleted into earnings

based on units of production. Actual costs incurred upon settlement of the obligations are charged against the liability.

Revenue recognition

Petroleum and natural gas sales are recognized when delivery of the product has been completed and the risks and rewards have passed to an external party.

Share-based compensation

The grant date fair values of share-based compensation awards are recognized over the vesting periods of the awards, with an offsetting credit to contributed surplus. The Black-Scholes option pricing model is used to calculate the fair value of stock awards granted. The estimated forfeiture rate is adjusted to reflect the actual number of awards that vest. Consideration paid by the award holders on the exercise of stock awards is credited to share capital, together with the related share-based compensation previously included in contributed surplus.

Cash settled compensation

From time to time, the Company may choose to award employees, directors and other service providers with incentive awards whose value is derived from the performance of the Company's share price. If such plans are to be settled in cash, the awards are measured at fair value at the end of each reporting period, where fair value is the amount at which the liability could be settled. The liability is recorded on the statement of financial position with changes in fair value included in the statement of earnings.

Income taxes

Income tax expense is recognized in the statement of earnings, except to the extent it relates to items recognized directly in equity, in which case the related income tax is also recognized in equity.

Deferred tax is recognized using the statement of financial position method. Under this method, deferred income tax assets and liabilities are recognized based on differences between the financial reporting and tax bases of assets and liabilities, and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period in which the change is substantively enacted. Deferred income tax assets and liabilities are presented as non-current.

Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is neither a business combination nor an event resulting in income or expense. Deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. A deferred tax asset is recognized only to the extent it is probable that future taxable profits will be available against which the asset can be utilized.

Flow-through shares

The Company may finance a portion of its exploration and development activities through the issuance of flow-through shares. Under the terms of the flow-through share agreements, the tax attributes of the related expenditures are renounced to subscribers. To recognize the foregone tax benefits to the Company, a deferred tax expense is recognized in the statement of earnings when the expenditures are incurred and the renouncement has been filed. The deferred tax expense recognized is offset by the premium received for the flow-through shares, with the premium being initially recorded as a liability in the statement of financial position.

Earnings per share

Basic earnings per share amounts are calculated by dividing the net earnings by the weighted average number of common shares outstanding during the period. Diluted earnings per share is determined by

adjusting the earnings and the weighted average number of common shares outstanding using the treasury stock method for the effects of dilutive instruments such as outstanding stock options.

Provisions

A provision is recognized if, as a result of a past event, the Company has a present, legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are measured using the best estimate of the expenditure required to settle the obligation.

5. CHANGES IN ACCOUNTING POLICIES

Future Accounting Pronouncements

- IFRS 11, *Joint Arrangements,* was amended regarding the accounting for the acquisition of an interest in a joint operation that constitutes a business. The amendment must be adopted January 1, 2016. The adoption of this amendment is not expected to have a material impact on the Company's financial statements.

- IFRS 9, *Financial Instruments*, clarifies guidance on the classification and measurement of financial assets, including impairment, and supplements the hedge accounting principles published in 2013. The IFRS must be adopted January 1, 2018. The adoption of this standard is not expected to have a material impact on the Company's financial statements.

- IFRS 15, *Revenue from Contracts with Customers*, clarifies the principles for recognizing revenue from contracts with customers and provides a model for the recognition and measurement of sales of certain non-financial assets. The IFRS must be adopted January 1, 2018. The Company is currently assessing the impact of this standard on the Company's financial statements.

- IFRS 16, *Leases*, provides guidance on the recognition of leases on the statement of financial position. The IFRS must be adopted January 1, 2019. The Company has not yet assessed the impact of this standard on the Company's financial statements.

6. BUSINESS COMBINATIONS

a) Acquisition of oil and natural gas properties in the Deep Basin

On May 30, 2014, the Company closed the acquisition of assets in the Deep Basin area of Alberta focused on development of the Cardium for $228.8 million. A $120.0 million bought deal equity financing was closed in conjunction with the acquisition (see Note 12). Details of the transaction are as follows:

($000s)	
Property and equipment	258,079
Decommissioning liabilities	(29,312)
Fair value of net assets	228,767
Cash consideration paid	228,767

Following the acquisition, property and equipment and the decommissioning liabilities were increased by $32.3 million, reflecting the calculation of decommissioning liabilities using a risk free discount rate. The credit adjusted discount rate was used to determine fair value. Transaction costs of $2.0 million were included in the statement of earnings as general and administration expense.

b) Acquisition of Crocotta Energy Inc.

On August 6, 2014, the Company acquired all of the issued and outstanding common shares of Crocotta Energy Inc. (“Crocotta”) pursuant to a plan of arrangement under the *Business Corporations Act* (Alberta). Under the arrangement, Crocotta shareholders received a combination of Common Shares of Long Run, as well as common shares and warrants of a newly established exploration company (“ExploreCo”). ExploreCo assets, including assets in northeast British Columbia and northwest Alberta, were excluded from Long Run’s acquisition of Crocotta.

For each Crocotta share held, shareholders of Crocotta received 0.415 of a Common Share of Long Run, one common share of ExploreCo and 0.2 arrangement warrants of ExploreCo. Long Run issued 43.8 million Common Shares based on the exchange ratio and assumed $115.5 million of net debt, defined as bank debt, net of cash, less working capital. Details of the transaction are as follows:

($000s)	
Property and equipment	406,738
Working capital	3,359
Risk management contracts	(750)
Decommissioning liabilities	(13,164)
Bank debt, net of cash	(118,837)
Deferred income tax liabilities	(45,927)
Fair value of net assets	231,419
Share consideration paid (43.8 million shares @ $5.28 per share)	231,419

Following the acquisition, property and equipment and the decommissioning liabilities were increased by $15.8 million, reflecting the calculation of decommissioning liabilities using a risk free discount rate. The credit adjusted discount rate was used to determine fair value. Transaction costs of $4.5 million were included in the statement of earnings as general and administration expense.

7. EXPLORATION AND EVALUATION ASSETS

($000s)	December 31, 2015	December 31, 2014
Balance, beginning of year	**5,635**	10,758
Additions	**157**	27
Transfers to property and equipment	**(2,556)**	(5,150)
Disposals	**(3,236)**	-
Balance, end of year	**-**	5,635

8. PROPERTY AND EQUIPMENT

($000s)	December 31, 2015	December 31, 2014
Property and equipment cost	**2,858,769**	2,808,959
Accumulated depletion, depreciation and impairments	**(1,724,574)**	(1,181,909)
Net book value	**1,134,195**	1,627,050

Property and Equipment Cost

($000s)	December 31, 2015	December 31, 2014
Balance, beginning of year	**2,808,959**	1,769,893
Additions	**97,761**	311,488
Acquisitions, including decommissioning costs	**2,638**	753,297
Transfers from exploration and evaluation assets	**2,556**	5,150
Transfers to assets held for sale	**-**	(6,000)
Change in decommissioning liabilities estimate (*note 9*)	**9,912**	52,022
Disposals	**(63,057)**	(76,891)
Balance, end of year	**2,858,769**	2,808,959

Accumulated Depletion, Depreciation and Impairments

($000s)	December 31, 2015	December 31, 2014
Balance, beginning of year	**(1,181,909)**	(585,542)
Depletion and depreciation expense	**(218,516)**	(234,829)
Disposals	**25,851**	38,462
Impairments	**(350,000)**	(400,000)
Balance, end of year	**(1,724,574)**	(1,181,909)

During 2015, proceeds of $31.0 million were received for the dispositions of minor non-core properties and a pipeline (2014 - $45.9 million). The dispositions included the sale of a Redwater property for $18.3 million in September and the sale of a pipeline for $8.1 million in April. The pipeline had been held for sale at December 31, 2014, with $6.0 million included in deposits and prepaids on the statement of financial position. During 2015, a loss on the disposal of the minor properties of $1.0 million was recognized (2014 - $20.6 million gain).

At December 31, 2015, undeveloped land of $15.5 million was excluded from costs subject to depletion (December 31, 2014 - $32.6 million). Future development costs of $1.2 billion were added into costs subject to depletion (December 31, 2014 - $1.3 billion).

During 2015, the Company recorded property and equipment impairments totalling $350.0 million resulting from a decline in oil and natural gas price forecasts (Peace River – $125.0 million; Deep Basin – $123.0 million; Redwater – $74.0 million; and Kaybob – $28.0 million). The recoverable amounts of the Company's CGUs were estimated at fair value less costs to sell, based on the net present value of after-tax cash flows from oil and natural gas reserves, using reserve values estimated by external reserve evaluators and the estimated fair value of undeveloped land. Within the fair value hierarchy, these inputs would be considered Level 3.

At December 31, 2015, in calculating the net present values of cash flows from oil and natural gas reserves, the Company used an after-tax discount rate of approximately 9% (December 31, 2014 – 10%), an average CDN$ to US$ exchange rate of CDN$0.83 to US$1.00 (December 31, 2014 – CDN$0.87 to US$1.00), and the following forward commodity price estimates:

	2015		2014	
	WTI Oil ***(US$/Bbl)***	**AECO Gas** ***(CDN$/Mcf)***	WTI Oil *(US$/Bbl)*	AECO Gas *(CDN$/Mcf)*
2015	**N/A**	**N/A**	64.17	3.38
2016	**45.00**	**2.25**	76.67	3.83
2017	**60.00**	**2.95**	83.33	4.06
2018	**70.00**	**3.42**	87.08	4.41
2019	**80.00**	**3.91**	90.67	4.76
2020	**81.20**	**4.20**	94.30	4.97
2021	**82.42**	**4.28**	96.59	5.18
2022	**83.65**	**4.35**	98.36	5.36
2023	**84.91**	**4.43**	100.18	5.54
2024	**86.18**	**4.51**	102.02	5.70
2025	**87.48**	**4.59**	103.88	5.80
2026	**88.79**	**4.67**	105.80	5.90
Remainder	**+1.5%/yr**	**+1.5%/yr**	+1.8%/yr	+1.8%/yr

At December 31, 2015, a one percent change in the after-tax discount rate is estimated to change the impairment by approximately $27.0 million. A $1.00/Bbl change in the price of oil is estimated to change the impairment by approximately $17.0 million. A $0.10/Mcf change in the price of natural gas is estimated to change the impairment by approximately $23.0 million.

In 2014, the Company recorded property and equipment impairments of $400.0 million, resulting from a decline in oil and natural gas price forecasts (Deep Basin - $160.0 million; Redwater - $132.0 million; Peace River - $61.0 million; and Kaybob - $47.0 million).

9. DECOMMISSIONING LIABILITIES

($000s)	**December 31, 2015**	December 31, 2014
Balance, beginning of year	**411,209**	254,413
Accretion expense	**9,176**	9,286
Liabilities acquired	**-**	113,681
Liabilities incurred	**2,495**	6,306
Disposal of liabilities	**(14,479)**	(13,090)
Settlement of liabilities	**(6,106)**	(11,409)
Change in estimates	**9,912**	52,022
Balance, end of year	**412,207**	411,209

The Company's decommissioning liabilities result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems, pipelines and processing facilities. The change in estimates in 2015 is primarily attributable to a change in the period end risk-free rate, partially offset by the decrease in the inflation rate. The change in estimates in 2014 is primarily attributable to a change in the period end risk-free rate. At December 31, 2015, the Company estimated the total undiscounted amount of cash flows required to settle its decommissioning liabilities was approximately $546.0 million, which will be incurred over the next 45 years (December 31, 2014 - $560.0 million). At December 31, 2015, the Company used a risk free rate of 2.0% and an inflation rate of 1.8% to calculate the present value of the decommissioning liabilities (December 31, 2014 - risk free rate of 2.25% and inflation rate of 2.0%).

10. AVAILABLE CREDIT FACILITIES

At December 31, 2014, the Company had credit facilities of $695.0 million, consisting of a $655.0 million revolving syndicated facility and a $40.0 million operating facility.

On May 29, 2015, the Company completed a semi-annual review of its credit facilities. The total credit facilities were maintained at $695.0 million, consisting of a $410.0 million revolving syndicated facility, a $40.0 million operating facility and a $245.0 million non-revolving syndicated facility. The $245.0 million non-revolving facility was due May 29, 2016. Long Run's financial covenants were relaxed to provide increased financial flexibility given the decrease in commodity prices.

On November 30, 2015, the Company completed its second semi-annual review of its credit facilities with its bank syndicate. Credit facilities were amended to $650.0 million, consisting of a $270.0 million revolving syndicated facility, a $30.0 million revolving operating facility and a $350.0 million non-revolving syndicated facility. The non-revolving syndicated facility was due in three tranches with $100.0 million due on January 31, 2016, $125.0 million due on May 29, 2016 and $125.0 million due on November 30, 2016. The $100.0 million due in January 2016 was expected to be funded by proceeds from a proposed private placement (the "Proposed Private Placement") with Maple Marathon Investments Limited ("Maple Marathon") and MIE Holdings Corporation ("MIEH") pursuant to an agreement that was entered into on November 8, 2015. The November 30, 2015 credit facility amendments also included an event of default if the Proposed Private Placement was terminated.

On December 18, 2015, Long Run, Maple Marathon and MIEH mutually agreed to terminate the Proposed Private Placement, which constituted an event of default under the Company's credit facilities. On December 20, 2015, Long Run entered into the Arrangement Agreement with the Purchaser and Guarantor.

On December 24, 2015, Long Run entered into an interim forbearance and amending agreement with its bank syndicate. During the interim forbearance period, which was extended to January 29, 2016, the Company's credit facilities were reduced to $610.0 million, of which $582.6 million was outstanding at December 31, 2015 (December 31, 2014 - $611.7 million). During the interim forbearance period credit facility margins increased by 2.0%.

At December 31, 2015, the Company had letters of credit outstanding totalling $9.6 million (December 31, 2014 – $4.5 million).

During 2015, the credit facilities beared interest at the prime rate or Libor rate, plus a margin, and in respect of banker's acceptances, required the payment of a stamping fee equal to a margin. The margins applicable to the borrowing base facilities ranged 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 expense, 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 were based upon the borrowing base facility margins plus 3.50%.

For the year ended December 31, 2015, the effective interest rate, including standby and other fees, was 5.5% (December 31, 2014 – 4.5%). Bank fees for 2015 related to the credit facilities totalled $6.0 million, of which $3.2 million were offset against bank debt on the statement of financial position at December 31, 2015.

Security for the credit facilities at December 31, 2015 included a demand debenture for $1.5 billion which provides for a first ranking security interest and floating charge over all of the assets and property of the Company.

On January 29, 2016, Long Run entered into an amending credit facilities agreement with its bank syndicate that reflected the proposed Arrangement. The Company's credit facilities were amended to $620.0 million, comprised of a $240.0 million revolving syndicated facility, a $30.0 million operating facility and a $350.0 million non-revolving syndicated facility. The credit facilities terminate six months following the close of the proposed Arrangement, which is consistent with the Purchaser's plan to repay the credit facilities in due course following completion of the Arrangement. Until closing of the Arrangement, the additional 3.50% charged on the Company's non-revolving syndicated facility and the financial covenants have been removed. The terms of the credit agreement have been amended to include events of default relating to the completion of the Arrangement.

The terms of the credit facilities have also been amended to restrict the Company from making any payment of interest or other amounts on the debentures, including the semi-annual interest payable on February 1, 2016 (see Note 11). The bank syndicate agreed to forbear from exercising any rights or remedies that arise as a result of Long Run's failure to pay interest on the debentures as provided in the amended credit facilities agreement.

11. CONVERTIBLE DEBENTURES

On January 28, 2014, the Company issued $75.0 million face value of convertible unsecured subordinated debentures at par. The debentures bear an annual interest rate of 6.40%, payable semi-annually in arrears. Prior to maturity on January 31, 2019, the debentures are convertible into Common Shares at a conversion price of $7.40 per Common Share, subject to adjustment in certain events.

The fair value of the debt portion of the debentures was calculated using a similar instrument without a conversion feature. The residual between the face value of the debentures and the fair value of the liability was classified as equity. The book value of the liability is being accreted to the face value of $75.0 million over the term of the debentures, using the effective rate interest method.

Below is a summary of the debt and equity balances:

($000s)	Convertible Debentures Liability	Equity Component of Convertible Debentures	Total
Balance, January 1, 2014	-	-	-
Issued	70,137	4,863	75,000
Issuance costs	(3,214)	(220)	(3,434)
Deferred income taxes	-	(1,160)	(1,160)
Accretion expense	1,222	-	1,222
Balance, December 31, 2014	68,145	3,483	71,628
Accretion expense	1,447	-	1,447
Balance, December 31, 2015	**69,592**	**3,483**	**73,075**

Under the terms of the January 29, 2016 amendment to the credit facilities, the Company is restricted from making any payment of interest or other amounts on the debentures, including the semi-annual interest payable on February 1, 2016. Under the terms of the proposed Arrangement, the Purchaser has agreed to acquire, subject to the conditions of the Arrangement Agreement, the outstanding convertible debentures for cash consideration of $750 per $1,000 principal amount of debentures plus accrued and unpaid interest (see Note 2).

12. SHAREHOLDERS' EQUITY

The Company is authorized to issue an unlimited number of Common Shares, Common Non-Voting Shares, Non-Voting Convertible Shares and First Preferred Shares without nominal or par value.

Common Shares

	December 31, 2015		December 31, 2014	
(000s)	**Number of shares**	**Amount $**	Number of shares	Amount $
Balance, beginning of year	**193,498**	**1,006,799**	110,143	551,403
Issuance of common shares	**-**	**-**	23,530	120,003
Issuance of common shares upon business combination *(note 6)*	**-**	**-**	43,829	231,419
Issued on conversion of Non-Voting Convertible Shares	**-**	**-**	15,513	106,263
Issued on exercise of stock options	**-**	**-**	483	2,159
Share issue costs, net of deferred tax of $1.7 million	**-**	**-**	-	(5,105)
Transfer from contributed surplus on exercise of stock options	**-**	**-**	-	657
Balance, end of year	**193,498**	**1,006,799**	193,498	1,006,799

Under the terms of the proposed Arrangement (see Note 2), the Purchaser agreed to acquire all of the outstanding Common Shares for cash consideration of $0.52 per share. Closing of the Arrangement is anticipated to occur in April 2016.

On April 30, 2014, the Company closed an equity issuance of 23.5 million subscription receipts at $5.10 per subscription receipt for gross proceeds of $120 million. On May 30, 2014, in conjunction with the closing of the acquisition of Deep Basin properties, holders of the subscription receipts received one Common Share for each subscription receipt held.

On May 28, 2014, all of the Company's outstanding Non-Voting Convertible Shares were converted to Common Shares of the Company.

On August 6, 2014, the Company issued 43.8 million Common Shares at $5.28 per share in connection with the acquisition of Crocotta.

Non-Voting Convertible Shares

	December 31, 2015		December 31, 2014	
(000s)	**Number of shares**	**Amount $**	Number of shares	Amount $
Balance, beginning of year	**-**	**-**	15,513	106,263
Conversion to Common Shares	**-**	**-**	(15,513)	(106,263)
Balance, end of year	**-**	**-**	-	-

On May 28, 2014, all of the Non-Voting Convertible Shares were converted to Common Shares. The holders of the Non-Voting Common Shares were entitled to receive dividends declared thereon equally, on a share-for-share basis, with the holders of Common Shares. The holders of Non-Voting Convertible Shares were entitled to attend meetings of shareholders, but were not entitled to vote. In

the event of liquidation, dissolution or winding up of the affairs of the Company, the holders of the Non-Voting Convertible Shares were entitled to receive an amount per share equal to the fair market value of any property received as consideration by the Company for the issuance of the shares, before any amount was distributed to the holders of the Common Shares. The Non-Voting Convertible Shares could not be transferred to a control person, meaning a person or company holding more than 20% of the voting securities of the Company. Holders of Non-Voting Convertible Shares could convert each share into one Common Share, provided the holder would not become a control person of the Company after the conversion, or upon a change in control of the Company, and were automatically converted on a transfer of the share to a person that would not be a control person of the Company after giving effect to such transfer. The Company had the right to require holders of the Non-Voting Convertible Shares to convert all issued and outstanding shares to Common Shares after June 30, 2014.

Dividends

Dividends declared are subject to approval by the Board of Directors on a monthly basis. In February 2015, the monthly dividend was suspended by the Board of Directors. During the year ended December 31, 2015, $3.4 million in dividends were declared and paid (December 31, 2014 - $66.2 million in dividends declared, of which $59.4 million were paid in 2014 and $6.8 million were paid in 2015).

Warrants

# of Warrants (000s)	**December 31, 2015**	December 31, 2014
Balance, beginning of year	**-**	2,300
Expired	**-**	(2,300)
Balance, end of year	**-**	-

At January 1, 2014, each warrant entitled the holder to acquire 0.4167 Common Shares at an exercise price of $3.10 per 0.4167 of a share until September 15, 2014. The exchange ratio and exercise price were subject to adjustment upon the payment of dividends by the Company. At June 30, 2014, each warrant entitled the holder to acquire 0.4329 Common Shares at an exercise price of $2.98 per 0.4329 of a share. All outstanding warrants expired unexercised on September 15, 2014.

Contributed Surplus

($000s)	**December 31, 2015**	December 31, 2014
Balance, beginning of year	**26,160**	23,377
Share-based compensation cost	**5,044**	3,440
Transfer to share capital on exercise of options	**-**	(657)
Balance, end of year	**31,204**	26,160

Share Option Plan

The Company has a share option plan which provides for the grant of options to purchase Common Shares. The exercise price of each option may not be less than the closing price of the Common Shares on the trading day immediately preceding the date of grant. Compensation expense is recognized as the options vest. Unless otherwise determined by the Board of Directors, vesting occurs one third on each of the next three anniversaries of the date of the grant. The options expire five years from the date of grant. The maximum number of Common Shares issuable on exercise of options outstanding is limited to 10% of the issued and outstanding Common Shares.

	December 31, 2015		December 31, 2014	
	Number of Options *(000s)*	**Weighted Average Exercise Price ($)**	Number of Options *(000s)*	Weighted Average Exercise Price ($)
Outstanding, beginning of year	**8,879**	**4.50**	10,266	4.50
Forfeited	**(1,321)**	**4.48**	(904)	4.52
Exercised	**-**	**-**	(483)	4.47
Outstanding, end of year	**7,558**	**4.50**	8,879	4.50

At December 31, 2015, option exercise prices ranged from $4.03 to $5.30 per option for the 7.6 million options outstanding. The weighted average exercise price was $4.50 per option and the weighted average remaining life of the options was 2.0 years. At December 31, 2015, there were 6.8 million options exercisable, with a weighted average exercise price of $4.50 per option. The Company has not issued options since December 31, 2013.

For the year ended December 31, 2015, $0.9 million was recognized as share-based compensation (December 31, 2014 - $3.4 million), of which $0.7 million was expensed (December 31, 2014 - $2.3 million).

Under the proposed Arrangement, outstanding options would be terminated for $nil consideration.

Restricted and Performance Award Incentive Plan

Number of Restricted Awards (000s)	**December 31, 2015**	December 31, 2014
Outstanding, beginning of year	**-**	-
Granted	**5,196**	-
Forfeited	**(582)**	-
Outstanding, end of year	**4,614**	-

Under the Restricted and Performance Award Incentive Plan, grantees will receive either cash or Common Shares, at the discretion of the Company, in relation to the value of a specified number of underlying Common Shares. The Company 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. The maximum number of Common Shares issuable is limited to 5% of the issued and outstanding Common Shares. During 2015, a total of 5.2 million restricted awards were granted. Each restricted award entitles the holder to a Common Share or the value of a Common Share (subject to certain adjustments, including for dividends paid on the Common Shares) on the vesting date.

The grant date fair values of share-based compensation awards are recognized over the vesting periods of the awards, with an offsetting credit to contributed surplus. The estimated forfeiture rate is

adjusted to reflect the actual number of awards that vest. The related share-based compensation expense previously included in contributed surplus is credited to share capital on the exercise of the stock awards.

The fair value of awards under the Company's incentive plan is determined using a Black-Scholes pricing model. The following assumptions were made during the year ended December 31, 2015: risk-free interest rate of 1.0 - 1.4%; dividend yield of 1.2%; volatility factor of the market price of the Common Shares of 43 - 54%; and expected award lives of one to three years. Restricted share awards granted during the year ended December 31, 2015 had an average fair value of $1.47 per award.

For the year ended December 31, 2015, $4.1 million was recognized as share-based compensation (December 31, 2014 - $nil), of which $2.9 million was expensed (December 31, 2014 - $nil). At December 31, 2015, there were 4.6 million restricted share awards outstanding with a weighted average remaining life of 2.0 years. At December 31, 2015, none of the restricted share awards were exercisable.

The first vesting of the restricted share awards occurred on January 5, 2016. The payment of these awards has been deferred as holders of the restricted awards were in a black-out period. Successful completion of the Arrangement will cause the payment dates applicable to outstanding restricted share awards to be accelerated such that the value attaching to outstanding awards will be settled upon closing of the Arrangement. Future share-based compensation expense of $2.7 million relating to unvested awards at December 31, 2015 would also be accelerated.

Earnings (Loss) Per Share

	Year ended December 31	
	2015	2014
Net earnings (loss) *($000s)*	**(645,032)**	(190,395)
Weighted average number of shares *(000s)*		
Shares outstanding, beginning of year	**193,498**	125,656
Share options exercised	**-**	344
Equity issuance of Common Shares	**-**	31,697
Weighted average shares outstanding - basic	**193,498**	157,697
Weighted average shares outstanding - diluted	**193,498**	157,697
Basic earnings (loss) per share	**(3.33)**	(1.21)
Diluted earnings (loss) per share	**(3.33)**	(1.21)

The diluted weighted average number of shares is calculated by assuming the proceeds that arise from the exercise of outstanding and in the money options are used to purchase Common Shares at the average market price during the period. As the Company incurred a net loss for the years ended December 31, 2015 and 2014, all options, all restricted awards and the effect of the conversion of convertible debentures were excluded from the calculations of diluted loss per share.

13. CAPITAL RISK MANAGEMENT

The Company's primary capital management objective is to strengthen our financial position and improve 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. Both measures reflect the impact of the decreased commodity prices experienced in 2015.

During 2015, Long Run examined strategic and financial options to improve its capital structure given the low commodity price environment. As a result of this process, the Company entered into the proposed Arrangement (see Note 2) which will provide certainty of value for securityholders and improve the Company’s capital structure.

Net Debt to Funds Flow from Operations

($000s, except ratios)	**December 31, 2015**	December 31, 2014
Net Debt		
Bank loan, excluding bank fees	**582,588**	611,717
Accounts payable and accrued liabilities	**64,611**	132,439
Accounts receivable	**(38,315)**	(65,135)
Deposits and prepaid expenses	**(8,860)**	(14,423)
Convertible debentures - face value	**75,000**	75,000
Net Debt	**675,024**	739,598
Funds Flow from Operations - Quarter Ended		
Petroleum and natural gas revenue	**64,739**	133,354
Royalties	**(3,667)**	(14,835)
Gain on financial derivatives - realized	**23,830**	14,145
Operating expense	**(31,935)**	(42,684)
Transportation expense	**(4,007)**	(5,891)
General and administration expense	**(9,178)**	(7,793)
Interest	**(9,505)**	(8,038)
Exploration expense	**-**	(86)
Capital and other taxes	**-**	6
Funds Flow from Operations - Quarter Ended	**30,277**	68,178
Funds Flow from Operations - Annualized *(Quarterly x 4)*	**121,108**	272,712
Net Debt to Funds Flow from Operations	**5.6**	2.7

Debt to Debt plus Equity

($000s, except ratios)	**December 31, 2015**	December 31, 2014
Debt		
Bank loan, excluding bank fees	**582,588**	611,717
Convertible debentures - face value	**75,000**	75,000
Debt	**657,588**	686,717
Debt plus Equity		
Debt	**657,588**	686,717
Shareholders' equity	**72,401**	715,775
Debt plus Equity	**729,989**	1,402,492
Debt to Debt plus Equity	**0.90**	0.49

14. GENERAL AND ADMINISTRATION

	Year ended December 31	
($000s)	**2015**	2014
Salary and employee	**28,906**	36,417
Other	**20,050**	22,734
Gross expense	**48,956**	59,151
Capitalized cost	**(11,610)**	(16,001)
Operating recoveries	**(6,179)**	(4,957)
General and administration	**31,167**	38,193

During the year ended December 31, 2015, general and administration expense included $3.0 million (December 31, 2014 – $6.5 million) of transaction costs primarily related to the Arrangement and terminated Proposed Private Placement. Transaction costs for 2014 primarily related to the Deep Basin and Crocotta acquisitions.

Long Run has determined that the key management personnel of the Company consist of its directors and vice-presidents. Key management personnel compensation is comprised of the following:

	Year ended December 31	
($000s)	**2015**	2014
Salaries and short-term benefits	**4,162**	4,794
Directors fees	**483**	627
Termination benefits	**1,587**	975
Included in general and administration	**6,232**	6,396
Total share-based compensation	**930**	1,035
	7,162	7,431

15. INCOME TAXES

The provision for income tax differs from the amount that would have been expected if the reported earnings (loss) had been subject only to the statutory Canadian income tax rate of 26.0% (2014 – 25.0%). The Alberta provincial tax rate increased from 10% to 12% effective July 1, 2015.

	Year ended December 31	
($000s)	**2015**	2014
Earnings (loss) before income tax	**(482,915)**	(251,595)
Corporate tax rate	**26.0%**	25.0%
Expected tax expense (recovery)	**(125,558)**	(62,899)
Increase (decrease) in taxes resulting from:		
Share-based compensation	**1,258**	782
Statutory tax rate changes	**(16,377)**	-
Unrecognized deferred income tax asset	**300,202**	-
Other	**2,500**	917
Deferred income tax expense (recovery)	**162,025**	(61,200)

The components of the deferred income tax asset were as follows:

($000s)	**December 31, 2015**	December 31, 2014
Property and equipment	**203,849**	82,990
Decommissioning liabilities	**44,361**	43,927
Non-capital losses	**41,208**	34,786
Alberta royalty tax deduction	**1,657**	1,380
Investment tax credits	**13,255**	13,649
Convertible debentures *(note 11)*	**(1,460)**	(1,714)
Share issue costs	**1,881**	3,261
Financial derivatives	**(4,549)**	(16,254)
Unrecognized deferred income tax asset	**(300,202)**	-
Deferred income tax asset	**-**	162,025

Movements in the deferred tax asset during the year were as follows:

	Year ended December 31	
($000s)	**2015**	2014
Balance, beginning of year	**162,025**	146,207
Share issue costs *(note 12)*	**-**	1,705
Convertible debentures *(note 11)*	**-**	(1,160)
Acquisition of Crocotta *(note 6)*	**-**	(45,927)
Current year recovery (expense)	**(162,025)**	61,200
Balance, end of year	**-**	162,025

Deferred tax assets are recognized to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax losses can be utilized. At December 31, 2015, the Company recorded a provision against the deferred income tax asset as a result of the significant decrease in commodity prices.

The amount and timing of reversals of temporary differences will be dependent upon a number of factors, including the Company's future operating results.

At December 31, 2015 the Company has non-capital loss carry forward balances of approximately $152.6 million (December 31, 2014 – $129.2 million). The non-capital losses expire as follows: 2021 – $0.7 million, 2022 – $8.1 million, 2023 – $20.5 million, 2024 – $38.6 million, 2025 – $11.8 million and thereafter $72.9 million.

Investment tax credit balances expire as follows: 2019 – $1.3 million, 2020 – $3.0 million, 2021 – $3.8 million, 2022 – $3.1 million, 2023 – $3.5 million and 2024 – $3.5 million.

16. RELATED PARTY TRANSACTIONS

A director of the Company and the corporate secretary are partners of the Company's legal counsel, Burnet, Duckworth & Palmer LLP ("BDP"). For the year ended December 31, 2015, general and administration expense included amounts totalling $1.2 million charged to the Company by BDP (December 31, 2014 - $1.5 million). As at December 31, 2015, a payable of $0.4 million was owing to BDP (December 31, 2014 - $0.1 million).

17. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

Fair Value of Financial Assets and Liabilities

Fair value is defined as the price that would be received upon selling an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

The Company's financial instruments recognized in the statement of financial position consist of accounts receivable, accounts payable, bank loan, convertible debentures and financial derivatives. The carrying values of accounts receivable and accounts payable approximate their fair values due to their short-term nature. The carrying value of the bank loan approximates fair value due to the floating interest rate on the facilities. At December 31, 2015, the fair value of the convertible debentures was $33.8 million, based on Level 1 inputs as the debentures are traded in an active market.

Financial Derivative Contracts

The Company enters into financial derivative contracts for the purpose of protecting cash flows generated from operations from the volatility of commodity prices and changes in interest and electricity rates.

The Company had the following commodity financial contracts in place as at December 31, 2015:

	Volume	Pricing
Crude Oil		
Fixed Price		
January 1, 2016 – December 31, 2016	500 Bbl/d	WTI CDN $77.55/Bbl
January 1, 2016 – December 31, 2016	500 Bbl/d	WTI CDN $77.50/Bbl
Natural Gas		
Fixed Price		
January 1, 2016 – December 31, 2016	30,000 GJ/d	$3.00/GJ
January 1, 2016 – December 31, 2016	10,000 GJ/d	$3.05/GJ
January 1, 2016 – December 31, 2016	5,000 GJ/d	$2.98/GJ
Electricity		
January 1, 2016 – December 31, 2016	3.0 MW/h	$49.50 MW/h

Financial Derivative Contracts Financial Statement Recognition

The Company recognizes the fair value of its financial derivative contracts on the statement of financial position each reporting period, with the change in fair value recognized as an unrealized gain or loss on the statement of earnings.

The Company determines fair value using a hierarchy that prioritizes inputs depending upon the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

- Level 1 - inputs represent quoted prices in active markets for identical assets or liabilities. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 - inputs other than quoted prices used in Level 1 that are observable, either directly or indirectly as of the reporting date. Level 2 valuations are based on inputs which can be observed or corroborated in the market place from sources such as the New York Mercantile Exchange and the Natural Gas Exchange.
- Level 3 - inputs that are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value.

The fair values of the Company's financial derivatives were determined using an income valuation approach based upon Level 3 inputs. The valuations, which were provided by the counterparties with whom the transactions were completed, were reviewed by the Company for reasonableness, giving consideration to factors such as the commodity forward price strips and historical volatilities. There have been no transfers between the hierarchy levels during the period.

($000s)	December 31, 2015	December 31, 2014
Assets - Fair value of financial derivatives		
Current	**17,253**	65,438
Liabilities - Fair value of financial derivatives		
Current	**406**	336
Long-term	**-**	85
	406	421
Net Asset	**16,847**	65,017

($000s)	Crude Oil	Natural Gas	Other	Total
Year ended December 31, 2015				
Realized (gain) loss on financial derivatives	(69,639)	(17,377)	423	(86,593)
New contracts	188	3,117	-	3,305
Change in value	26,977	8,716	(575)	35,118
Unrealized loss on financial derivatives	(42,474)	(5,544)	(152)	(48,170)
December 31, 2014 - Net Asset (Liability)	49,844	15,427	(254)	65,017
December 31, 2015 - Net Asset (Liability)	**7,370**	**9,883**	**(406)**	**16,847**
Year ended December 31, 2014				
Realized loss on financial derivatives	2,492	5,165	306	7,963
New contracts	(358)	(3,066)	-	(3,424)
Change in value	65,211	14,130	(342)	78,999
Unrealized gain (loss) on financial derivatives	67,345	16,229	(36)	83,538
Business combination	(398)	(352)	-	(750)
December 31, 2013 - Net Liability	(17,103)	(450)	(218)	(17,771)
December 31, 2014 - Net Asset (Liability)	49,844	15,427	(254)	65,017

Market risk

Market risk includes uncertainty arising from possible movements in commodity prices and interest rates and the impact of such movements on the future performance of the business. Commodity price and interest rate movements could adversely affect the value of the Company's financial assets, liabilities and expected future cash flows.

To partially mitigate exposure to commodity price risk, the Company enters into various financial derivative instruments. The instruments currently outstanding are described above. To mitigate exposure to interest rate risk, the Company carries debt at both fixed and floating interest rates. The Company may also manage interest rate risk through the use of interest rate swaps. The Company's bank debt facilities have a floating interest rate that fluctuates based on prevailing market conditions.

When assessing the potential impact of price changes on financial derivative contracts outstanding at December 31, 2015, it is estimated that a $1.00/Bbl change in the price of oil would change the unrealized loss by approximately $0.4 million. A $0.10/GJ change in the price of natural gas would change the unrealized loss by approximately $1.8 million. Based on the bank debt outstanding as at December 31, 2015, a one percent change in the interest rate would impact annual interest expense

by approximately $5.8 million. The Company's convertible debentures bear interest at a fixed annual interest rate of 6.4%.

Credit risk

Credit risk is the risk that a customer or counterparty will fail to perform an obligation or fail to pay amounts due, causing a financial loss. The Company's accounts receivable are with customers and partners in the oil and natural gas industry and are subject to normal credit risks. A portion of the Company's production is currently sold through partners under normal industry sale and payment terms.

During the year ended December 31, 2015, three third party purchasers each marketed more than 10% of the Company's petroleum and natural gas revenue. At December 31, 2015, approximately 27% of the accounts receivable balance is due from three customers.

Accounts Receivable *($000s)*	**December 31, 2015**	December 31, 2014
Less than 90 days	**33,999**	58,019
Greater than 90 days	**4,316**	7,116
Total	**38,315**	65,135

When determining whether amounts that are past due are collectible, the Company assesses the creditworthiness and past payment history of the counterparty, as well as the nature of the past due amount. Long Run generally considers amounts greater than 90 days to be past due.

The Company's allowance for doubtful accounts at December 31, 2015 was $0.3 million (December 31, 2014 – $0.3 million). During the year ended December 31, 2015, the Company expensed $0.5 million of accounts receivable not considered collectible (December 31, 2014 - $nil).

Counterparties to the Company's financial derivative contracts are major Canadian financial institutions, having investment grade credit ratings.

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.

At December 31, 2015, $582.6 million was drawn against the Company's credit facilities, with $17.8 million of borrowing capacity available.

The Company's current credit facilities terminate six months following the close of the proposed Arrangement, which is consistent with the Purchaser's plan to repay the credit facilities in due course following completion of the Arrangement (see Note 2 and Note 10). Failure to complete the Arrangement will result in an event of default under the Company's credit facilities, which could accelerate the repayment of amounts outstanding. The Company's ability to continue as a going concern and discharge its obligations would be dependent on obtaining alternative equity, debt financing and/or proceeds from asset sales. In addition, the Arrangement Agreement provides for a mutual non-completion fee of $20.0 million under which Long Run may be required to pay the amount to the Purchaser in certain circumstances.

18. SUPPLEMENTAL CASH FLOW INFORMATION

Net Change in Non-Cash Working Capital

	Year ended December 31	
($000s)	**2015**	2014
Source (use) of cash:		
Accounts receivable	**26,820**	(11,702)
Deposits and prepaid expenses	**(437)**	(852)
Accounts payable and accrued liabilities	**(70,728)**	42,833
Business combination	**-**	3,359
	(44,345)	33,638
Related to:		
Operating activities	**7,088**	5,486
Investing activities	**(44,661)**	21,380
Financing activities	**(6,772)**	6,772
	(44,345)	33,638

19. COMMITMENTS AND CONTINGENCIES

Commitments

($000s)	2016	2017	2018	2019	2020	Thereafter	Total
Operating leases	5,042	6,600	7,968	7,618	7,382	43,395	78,005
Processing	5,413	6,118	6,118	6,118	6,118	32,628	62,513
Transportation	13,484	14,243	10,099	4,734	3,156	6,466	52,182
Fractionation	2,843	2,653	650	-	-	-	6,146
Capital	6,182	6,182	254	-	-	-	12,618
Total	32,964	35,796	25,089	18,470	16,656	82,489	211,464

At December 31, 2015, the Company is committed under operating leases for office space, contracts related to the processing of natural gas, transportation of oil, natural gas and NGLs, fractionation of natural gas liquids and capital commitments for drilling rig services.

Litigation

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