LONG RUN EXPLORATION LTD.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2015

LONG RUN EXPLORATION

March 9, 2016

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See "Abbreviations" and "Certain Definitions" for abbreviations and definitions used herein.

BACKGROUND

Long Run is engaged in the development, exploration and production of oil and natural gas in western Canada. Specifically, the Company is focused on controlled exploitation and strategic acquisitions within the Western Canadian Sedimentary Basin.

The head office of the Company is located at Suite 400, 250-2nd Street SW, Calgary, Alberta T2P 0C1 and its registered office is located at 2400, 525-8th Avenue SW, Calgary, Alberta T2P 1G1.

The Company was incorporated under the ABCA on September 14, 1999. See "*General Development of the Business – Material Amendments to the Articles of Incorporation*".

The Company has no subsidiaries.

The Common Shares and Convertible Debentures trade on the TSX under the symbols "LRE" and "LRE.DB", respectively.

GENERAL DEVELOPMENT OF THE BUSINESS

Three-Year History

The following is a summary of significant events in the general development of the business of Long Run during the last three completed financial years and changes to the business in the current financial year.

2015

On February 9, 2015, the Company announced, as a result of a volatile and uncertain commodity price environment, that the Board of Directors had suspended Long Run's monthly dividend.

On May 29, 2015, the Company completed the semi-annual review of its credit facilities with its bank syndicate and maintained its total credit facilities at $695 million. The amended credit facilities consisted of a $410 million revolving syndicated facility, a $40 million operating facility and a $245 million non-revolving syndicated facility. The revolving syndicated facility and the operating facility, which comprised the Company's borrowing base facilities, were to be reviewed semi-annually and were to terminate on May 31, 2017. The non-revolving syndicated facility was due on May 29, 2016.

On August 4, 2015, the Company announced that it had entered into an investment agreement with Maple Marathon and MIEH which contemplated a private placement to Maple Marathon of 155 million units of the Company at a price of $1.30 per unit for total gross proceeds to Long Run of approximately $200 million. On November 9, 2015, the Company announced that it entered into an amended and restated investment agreement with Maple Marathon and MIEH which amended the terms of the private placement to Maple Marathon to consist of 125 million units of the Company at a price of $0.80 per unit for total gross proceeds to Long Run of approximately $100 million (the "Proposed Private Placement"). Long Run also announced that it had commenced a strategic asset rationalization process of both core and non-core assets as a potential means of improving its capital structure (the "Asset Rationalization Process").

On November 30, 2015, the Company completed the second semi-annual review of its credit facilities with its bank syndicate. Credit facilities were amended to $650 million from $695 million. The amended credit facilities consisted of a $270 million revolving syndicated facility, a $30 million revolving operating facility and a $350 million non-revolving syndicated facility. The non-revolving syndicated facility was due in three tranches with $100 million due on January 31, 2016, $125 million due May 29, 2016 and $125 million due on November 30, 2016. The $100 million due in January 2016 was expected to be funded by proceeds from the Proposed Private Placement with Maple Marathon and MIEH pursuant to the 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 21, 2015, the Company announced that it had entered into an arrangement agreement (the "Arrangement Agreement") with the Purchaser and the Guarantor. Pursuant to the proposed plan of arrangement contemplated by the Arrangement Agreement (the "Arrangement"), the Purchaser agreed to acquire: (i) all of the outstanding Common Shares for cash consideration of $0.52 per share; and (ii) all of the outstanding Convertible Debentures for cash consideration of $750 per $1,000 principal amount of Convertible Debentures plus accrued and unpaid interest up to but excluding the effective date of the Arrangement. Long Run also announced, on December 21, 2015, the mutual termination of the Proposed Private Placement, which constituted an event of default under the Company's credit facilities, as well as the termination of the Asset Rationalization Process.

On January 29, 2016, Long Run entered into an amending credit facilities agreement with its bank syndicate that reflected, among other matters, the proposed Arrangement. The Company's credit facilities were amended to $620 million, comprised of a $240 million revolving syndicated facility, a $30 million operating facility and a $350 million non-revolving syndicated facility. The credit facilities terminate six months following the close of the proposed Arrangement. The terms of the credit agreement have also been amended to include events of default relating to the completion of the Arrangement. Additionally, the terms of the credit facilities were also amended to restrict the Company from making any payment of interest or other amounts on the Convertible Debentures, including the semi-annual interest that was payable on February 1, 2016. The bank syndicate agreed to forbear from exercising any rights or remedies that arise as a result of Long Run's failure to pay such interest on the Convertible Debentures as provided for in the amended credit facilities agreement.

On February 29, 2016, Long Run securityholder approval was received for the Arrangement at a special meeting. 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. The 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* (Canada) 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. See *"Risk Factors".*

2014

On January 28, 2014, the Company closed a public offering of $75 million principal amount of Convertible Debentures for gross proceeds of $75 million. The Convertible Debentures were issued pursuant to the Debenture Indenture and bear interest at an annual rate of 6.40%, payable semi-annually in arrears. Prior to maturity on January 31, 2019, the Convertible Debentures are convertible into Common Shares at a conversion price of $7.40 per Common Share, subject to adjustment in certain events. See "*Description of Capital Structure – Convertible Debentures*".

On May 21, 2014, the Company and Sprott Resource Corp. ("SRC") announced the completion of a secondary offering of 12.7 million Common Shares by SRC at a price of $5.35 per Common Share, for gross proceeds of $67.7 million to SRC (the "Secondary Offering"). Long Run received no proceeds from this transaction and the total number of outstanding Common Shares did not change. See "*Interest of Management and Others in Material Transactions*".

On May 30, 2014, Long Run completed the acquisition of assets located in the Cardium in the Deep Basin area of Alberta (the "Deep Basin Property Acquisition"), for a purchase price of $228.8 million. Production from the properties averaged approximately 5,200 Boe/d from May 30 through December 31, 2014. In connection with the Deep Basin Property Acquisition, the Company revised its dividend policy by increasing the monthly dividend to $0.035 per Common Share per month effective with the June 2014 dividend paid on July 15, 2014.

The Deep Basin Property Acquisition was financed in part through the issuance of 23.5 million subscription receipts of the Company ("Subscription Receipts") at a price of $5.10 per Subscription Receipt for gross proceeds of $120 million. Each Subscription Receipt was converted into one Common Share in connection with the closing of the Deep Basin Property Acquisition.

On August 6, 2014, Long Run acquired all of the issued and outstanding common shares of Crocotta pursuant to a plan of arrangement under the ABCA (the "Crocotta Acquisition"). In connection with the Crocotta Acquisition, shareholders of Crocotta received 0.415 of a Common Share of Long Run for each issued and outstanding common share of Crocotta. Shareholders of Crocotta also received a combination of common shares and warrants of a newly established exploration company ("ExploreCo"). The assets of ExploreCo, including assets in northeast British Columbia and northwest Alberta, were excluded from Long Run's acquisition of Crocotta. The assets of Crocotta acquired by Long Run pursuant to the Crocotta Acquisition were prospective for the Cardium and Bluesky formations and included light oil production and facilities infrastructure. Production from the properties averaged approximately 6,200 Boe/d from August 6 through December 31, 2014.

On December 15, 2014, Long Run announced that it would be decreasing its monthly dividend to $0.0175 per Common Share, starting with the dividend declared payable to holders of record as of January 30, 2015 and paid on February 13, 2015.

2013

On October 16, 2013, Long Run completed the acquisition of assets located in the Redwater and Peace River areas of Alberta, for a cash purchase price of approximately $50 million. The effective date of the acquisition was April 1, 2013. The assets were prospective for the Viking formation and included light oil production and facilities infrastructure. At the time of closing, production was approximately 1,350 Boe/d.

On November 6, 2013, the Company established an initial dividend policy of paying monthly dividends at an expected rate of $0.0335 per Common Share and per Non-Voting Convertible Share per month with the first dividend declared payable to holders of record as of January 31, 2014 and paid on February 14, 2014.

On December 12, 2013, Long Run completed the acquisition of assets located in the Redwater area of central Alberta, for a cash purchase price of approximately $45 million. The effective date of the acquisition was December 1, 2013. The assets were prospective for the Viking formation and, at the time of closing, were producing approximately 450 Boe/d.

Significant Acquisitions

Long Run did not complete any significant acquisitions during its most recently completed financial year for which disclosure is required under Part 8 of NI 51-102.

Material Amendments to the Articles of Incorporation

The Company was incorporated under the ABCA on September 14, 1999 under the name 845818 Alberta Ltd. On May 17, 2005, the Company filed Articles of Amendment to change its name to "WestFire Energy Ltd.". On December 13, 2007, WestFire filed Articles of Amendment to remove the "private company" restrictions including restrictions on transfer of shares and limits on the number of shareholders. On January 1, 2009, WestFire filed Articles of Amalgamation whereby WestFire amalgamated with its wholly-owned subsidiaries, WF Resources Ltd. and Racing Resources Ltd. On December 24, 2010, WestFire filed Articles of Amalgamation whereby WestFire amalgamated with its wholly-owned subsidiary, Exceed Energy Inc. On June 30, 2011, WestFire filed Articles of Amendment to create the Non-Voting Convertible Shares. Subsequently on June 30, 2011, WestFire amalgamated with Orion Oil and Gas Company (“Orion”) and continued under the name of "WestFire Energy Ltd.". On October 23, 2012, WestFire filed Articles of Amendment to create a class of First Preferred Shares and subsequently amalgamated with Guide Exploration Ltd. (”Guide”). Following the amalgamation, the Articles of WestFire were amended to change the name of WestFire to "Long Run Exploration Ltd.". On August 7, 2014, the Company filed Articles of Amalgamation whereby Long Run amalgamated with Crocotta.

DESCRIPTION OF THE BUSINESS

Corporate Strategy

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

Long Run has assembled a large land position and oil and natural gas infrastructure in its 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, the Company continued to examine strategic and financial options to improve the capital structure of the Company. As part of this process, Long Run entered into the Arrangement Agreement with the Purchaser and the Guarantor on December 20, 2015. Pursuant to the Arrangement, the Purchaser agreed to acquire all of the outstanding Common Shares for cash consideration of $0.52 per share and all of the outstanding Convertible Debentures for cash consideration of $750 per $1,000 principal amount of Convertible Debentures plus accrued and unpaid interest up to but excluding the effective date of the Arrangement.

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 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* (Canada) 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. See *"Risk Factors – Completion of the Arrangement".*

Commodity Prices

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 action or inaction by OPEC, 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.

Specialized Skills and Knowledge

Drawing on significant experience in the oil and gas business, Long Run's management team has a demonstrated track record of bringing together all of the key components to a successful development and acquisition company: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows Long Run to effectively identify, evaluate and execute on value added initiatives. The Company's management team has strong industry experience in producing areas in western Canada.

Competitive Conditions

Companies operating in the petroleum industry must manage risks which are beyond the direct control of company personnel. Among these risks are those associated with exploration, environmental damage, commodity prices, foreign exchange rates and interest rates.

The oil and natural gas industry is intensely competitive and Long Run is required to compete with a substantial number of other entities which may have greater technical or financial resources. With the maturing nature of the Western Canadian Sedimentary Basin, the access to new prospects is becoming more competitive and technically challenging.

Long Run attempts to enhance its competitive position by operating in areas where its technical personnel are able to reduce some of the risks associated with exploration, production and marketing because they are familiar with the areas of operation. See "*Risk Factors – Competition*".

Cycles

The Company's business is generally cyclical. Commodity prices tend to be cyclical in nature with variations in pricing adding additional risk. See "*Risk Factors - Prices, Markets and Marketing"*. The exploration and development of oil and natural gas reserves is dependent on access to areas where drilling is to be conducted. Seasonal weather variation, including freeze up and break up affect access in certain circumstances. See "*Risk Factors – Seasonality*".

Environmental Protection

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation can require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on earnings and overall competitiveness. See "*Industry Conditions – Environmental Regulation*" and *"Risk Factors – Environmental"*.

Environmental, Health and Safety Policies

Environmental protection and employee health and safety are core values recognized and supported by the Company. The Company actively supports these areas by integrating the essential principles and practices through its environmental management systems and employee occupational health and safety programs. The Company ensures policies and procedures are fully integrated with and within all operating units by advising and educating employees, suppliers and contractors in the safe use, transportation, storage and disposal of products and materials. The Company promotes and enhances safety and environmental awareness and protection through the implementation and communication of the Company's environmental management and employee occupational health and safety programs policies and procedures. Effective committee structures are established in the Company's operations to allow for employee participation and development of corporate policies and programs which provide employees with job orientation, training, instruction and supervision necessary to assist them in conducting their activities in an environmentally responsible and safe manner.

The Company develops emergency response teams and preparedness plans in conjunction with local authorities, emergency services and the communities it operates in, in order to ensure prompt response to an environmental incident should it arise. Environmental assessments are undertaken for new projects or when acquiring new properties or facilities to identify, assess and minimize environmental risks and operational exposures. The Company conducts audits of operations to confirm compliance with internal standards and to stimulate improvement in practices where needed. Accurate documentation is maintained to support internal accountability and measure operational performance against recognized industry indicators to ensure the objectives of the policies and programs are achieved.

The Company also faces environmental, health and safety risks in the normal course of its operations due to the handling and storage of hazardous substances. The Company's environmental and occupational health and safety management systems are designed to identify, prevent and control such risks in the Company's business and ensure immediate action is taken to mitigate the extent of any environmental, health or safety impacts from such operations. A key aspect of these systems is the performance of annual environmental and occupational health and safety audits.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "Statement") is dated March 9, 2016. The effective date of the Statement is December 31, 2015 and the preparation date of the Statement is March 9, 2016.

Disclosure of Reserves Data

The Company engaged Sproule to provide an evaluation of the Company's proved and proved plus probable reserves as at December 31, 2015. The reserves data set forth below (the "Reserves Data") is based upon the Sproule Report. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Company and the net present values of future net revenue for these reserves using forecast prices and costs. The Sproule Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. The Reserves Committee of the Board of Directors has reviewed and approved the Sproule Report. The *Report of Management and Directors on Oil and Gas Disclosure* and the *Report on Reserves Data by the Independent Qualified Reserves Evaluator or Auditor* are attached as Schedules "A" and "B" hereto, respectively.

All of the Company's reserves are in Canada and specifically in the provinces of Alberta and Saskatchewan.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserves estimates of the Company's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.

Reserves Data (Forecast Prices and Costs)

Summary of Oil and Gas Reserves
December 31, 2015
(Forecast Prices and Costs)

	RESERVES									
	LIGHT AND MEDIUM CRUDE OIL *(MBbl)*		HEAVY CRUDE OIL *(MBbl)*		CONVENTIONAL NATURAL GAS *(MMcf)*		NATURAL GAS LIQUIDS *(MBbl)*		TOTAL *(MBoe)*	
	Gross	*Net*	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*
Proved Developed										
Producing	11,578	10,207	287	265	162,367	142,168	6,577	4,715	45,502	38,881
Non-Producing	70	67	41	34	11,818	9,682	208	131	2,288	1,846
Proved Undeveloped	9,956	9,056	165	139	110,699	92,488	6,590	4,951	35,161	29,561
Total Proved	21,604	19,331	492	437	284,884	244,337	13,374	9,797	82,951	70,287
Probable	12,618	10,779	191	166	250,153	212,421	9,632	6,968	64,133	53,317
Total Proved plus Probable	34,222	30,110	683	603	535,038	456,758	23,006	16,765	147,084	123,604

Net Present Values of Future Net Revenue
December 31, 2015
(Forecast Prices and Costs)

	BEFORE INCOME TAXES DISCOUNTED AT *(%/year; $M)*					AFTER INCOME TAXES DISCOUNTED AT *(%/year; $M)*					UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year
	0	5	10	15	20	0	5	10	15	20	($/Boe)
Proved Developed											
Producing	601,422	516,768	445,951	390,109	346,036	601,422	516,768	445,951	390,109	346,036	11.47
Non-Producing	11,935	11,031	9,639	8,349	7,243	11,935	11,031	9,639	8,349	7,243	5.22
Proved Undeveloped	303,426	181,269	99,211	43,950	6,177	303,426	181,269	99,211	43,950	6,177	3.36
Total Proved	916,783	709,068	554,801	442,409	359,456	916,783	709,068	554,801	442,409	359,456	7.89
Probable	963,084	627,377	423,944	297,259	214,675	913,639	602,343	410,708	289,991	210,550	7.95
Total Proved plus Probable	1,879,867	1,336,445	978,744	739,667	574,131	1,830,422	1,311,411	965,508	732,400	570,006	7.92

Total Future Net Revenue
December 31, 2015
(Forecast Prices and Costs, Undiscounted; $M)

	REVENUE	ROYALTIES	OPERATING COSTS	DEVELOPMENT COSTS	ABANDONMENT AND RECLAMATION COSTS	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
Total Proved	3,335,794	403,384	1,267,644	563,169	184,814	916,783	-	916,783
Total Proved plus Probable	6,043,999	783,514	2,085,074	1,031,375	264,169	1,879,867	49,446	1,830,422

Future Net Revenue by Production Group
December 31, 2015
(Forecast Prices and Costs)

RESERVES CATEGORY	PRODUCTION TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES *(discounted at 10%/year; $M)*	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	327,104	10.40 $/Bbl
	Heavy Crude Oil (including solution gas and other by-products)	9,772	13.60 $/Bbl
	Conventional Natural Gas (including by-products but excluding solution gas from oil wells)	215,874	0.95 $/Mcf
	Other Income	2,051	
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	572,658	11.73 $/Bbl
	Heavy Crude Oil (including solution gas and other by-products)	13,561	13.68 $/Bbl
	Conventional Natural Gas (including by-products but excluding solution gas from oil wells)	392,665	0.89 $/Mcf
	Other Income	(140)	

Notes to Reserves Data Tables Above

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserves estimates presented in the Sproule Report were prepared in accordance with NI 51-101 and the COGE Handbook.

3. Forecast Costs and Price Assumptions

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. The forecast price and cost assumptions assume the continuance of current laws and regulations. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by Sproule in the Sproule Report as at December 31, 2015 were as follows:

	Oil							
	WTI Cushing Oklahoma *($US/Bbl)*	Canadian Light Sweet 40° API *($Cdn/Bbl)*	Hardisty Heavy 12° API *($Cdn/ Bbl)*	Natural Gas Alberta Spot Gas Price *($Cdn/Mcf)*	Pentanes Plus Edmonton *($Cdn/Bbl)*	Butanes Price Edmonton *($Cdn/Bbl)*	Inflation Rates(i) %/Year	Exchange Rate(ii) *($US/$Cdn)*
2016	45.00	55.20	41.40	2.25	59.10	39.09	0.0	0.75
2017	60.00	69.00	53.13	2.95	73.88	51.43	0.0	0.80
2018	70.00	78.43	60.39	3.42	83.98	58.46	1.5	0.83
2019	80.00	89.41	68.85	3.91	95.73	66.64	1.5	0.85
2020	81.20	91.71	70.62	4.20	98.19	68.35	1.5	0.85
2021	82.42	93.08	71.67	4.28	99.66	69.38	1.5	0.85
2022	83.65	94.48	72.75	4.35	101.16	70.42	1.5	0.85
2023	84.91	95.90	73.84	4.43	102.68	71.48	1.5	0.85
2024	86.18	97.34	74.95	4.51	104.22	72.55	1.5	0.85
2025	87.48	98.80	76.07	4.59	105.78	73.64	1.5	0.85
2026	88.79	100.28	77.21	4.67	107.37	74.74	1.5	0.85
2027+	Escalated oil, gas and product prices at 1.5% per year thereafter							

(i) Inflation rates for forecasting prices and operating costs. Capital costs inflation is forecasted to be 0.0% for 2016, 4.0%/yr for 2017-2019 and 1.5%/yr thereafter.
(ii) Exchange rates used to generate the benchmark reference prices in this table.

4. Weighted average historical prices realized, before transportation and financial derivative contracts, by the Company for the year ended December 31, 2015, were $47.63/Bbl for light and medium crude oil, $41.94/Bbl for heavy oil, $22.52/Bbl for NGLs and $2.83/Mcf for natural gas.

5. Abandonment and reclamation costs have only been included for wells (both existing and undrilled wells) with reserves attributed. No allowance was made, however, for the abandonment and reclamation costs in respect of any pipelines or facilities or for wells with no attributed reserves. See "*Additional Information Concerning Abandonment and Reclamation Costs*".

6. The extent and character of all factual data supplied to Sproule were accepted by Sproule as represented. No field inspection was conducted.

7. The after-tax net present value of the Company's properties reflects the tax burden on the properties on a stand-alone basis and utilizing the Company's tax pools. It does not consider the business-entity-level tax situation, or tax planning. It does not provide an estimate of the value at the level of the business entity, which may be significantly different. The financial statements and the management's discussion and analysis of the Company should be consulted for information at the level of the business entity. Furthermore, the tax methodology used assumes that all tax pools are utilized to the maximum depreciation rate as currently permitted.

8. The reserves of the Company and the estimated net present value of the future net revenue of the Company's reserves set forth in the tables above reflect the royalty regime in place for the Province of Alberta as of the effective date of the Sproule Report being December 31, 2015 and do not reflect the Modernized Royalty Framework released by the Government of Alberta on January 29, 2016 as the Modernized Royalty Framework was not in force nor applicable as of December 31, 2015. See "*Industry Conditions – Royalties and Incentives – Alberta*".

Reconciliations of Changes in Gross Reserves

December 31, 2015
(Forecast Prices and Costs)

	LIGHT AND MEDIUM CRUDE OIL (MBbl)			HEAVY CRUDE OIL (MBbl)		
	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable
December 31, 2014	26,105	13,415	39,521	533	183	716
Extensions	-	-	-	-	-	-
Infill Drilling	169	110	280	-	-	-
Improved Recovery	-	119	119	-	-	-
Technical Revisions	347	(844)	(498)	89	12	101
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	(629)	(364)	(993)	-	-	-
Economic Factors	(1,247)	181	(1,065)	(26)	(4)	(30)
Production	(3,142)	-	(3,142)	(104)	-	(104)
December 31, 2015	21,604	12,618	34,222	492	191	683

	NATURAL GAS LIQUIDS (MBbl)			CONVENTIONAL NATURAL GAS (MMcf)			TOTAL (MBoe)		
	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable
December 31, 2014	16,516	11,731	28,247	362,336	250,508	612,844	103,544	67,081	170,625
Extensions	-	-	-	-	-	-	-	-	-
Infill Drilling	156	593	749	1,643	6,152	7,795	599	1,729	2,328
Improved Recovery	-	6	6	-	492	492	-	207	207
Technical Revisions	(164)	(2,260)	(2,424)	20,312	(18,234)	2,078	3,657	(6,131)	(2,474)
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(2)	(3)	(5)	(563)	(429)	(992)	(724)	(438)	(1,162)
Economic Factors	(1,477)	(437)	(1,914)	(57,319)	11,664	(45,655)	(12,302)	1,685	(10,618)
Production	(1,654)	-	(1,654)	(41,525)	-	(41,525)	(11,821)	-	(11,821)
December 31, 2015	13,374	9,632	23,006	284,884	250,153	535,037	82,951	64,133	147,084

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the remaining proved undeveloped reserves and the remaining probable undeveloped reserves, each by product type, attributed to the Company's assets for the years ended December 31, 2015, 2014 and 2013 based on forecast prices and costs.

Proved Undeveloped Reserves

	LIGHT AND MEDIUM CRUDE OIL *(MBbl)*		HEAVY CRUDE OIL *(MBbl)*		CONVENTIONAL NATURAL GAS *(MMcf)*		NATURAL GAS LIQUIDS *(MBbl)*	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2013	6,843	11,050	200	236	12,956	61,368	172	812
2014	2,234	11,004	-	167	98,409	174,910	7,179	7,899
2015	169	9,956	-	165	1,643	110,699	156	6,590

Probable Undeveloped Reserves

	LIGHT AND MEDIUM CRUDE OIL *(MBbl)*		HEAVY CRUDE OIL *(MBbl)*		CONVENTIONAL NATURAL GAS *(MMcf)*		NATURAL GAS LIQUIDS *(MBbl)*	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2013	4,086	8,846	95	184	6,245	78,239	116	874
2014	2,001	8,722	-	81	120,631	185,550	8,471	9,240
2015	110	9,066	-	80	6,152	200,972	593	7,870

In general, once proved and/or probable reserves are identified, they are included in Long Run's development plans. Normally, the Company plans to develop the majority of its proved and probable undeveloped reserves within four years, however these locations will continue to be re-evaluated to assess their relative economic merits when compared to other projects available to the Company. A number of factors that could result in delayed or cancelled development (including the delay or development of the undeveloped reserves beyond two years from the date such undeveloped reserves are first attributed) may include:

- impact of commodity prices as a substantial and extended decline in the price of oil and natural gas would have an adverse effect on, among other things, the Company's revenues and financial condition and consequently, its ability to finance the development of its undeveloped reserves);
- other changing economic conditions (due to royalties, operating and capital expenditure fluctuations);
- changing technical conditions (production anomalies (such as water breakthrough, accelerated depletion));
- multi-zone developments (such as a prospective formation completion may be delayed until the initial completion is no longer economic);
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and
- surface access issues (landowners, weather conditions, regulatory approvals).

See *"Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Principal Properties"* and *"Statement of Reserves Data and Other Oil and Gas Information – Additional*

Information Relating to Reserves Data – Future Development Costs" for a description of the Company's exploration and development plans and expenditures.

Significant Factors or Uncertainties Affecting Reserves Data

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserves estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability and pricing of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserves estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserves estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

With regard to the particular components of the Reserves Data, the Company does not anticipate any unusually high development costs or operating costs, nor does the Company have any contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

See "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Additional Information Concerning Abandonment and Reclamation Costs*" for the Company's anticipated abandonment and reclamation costs as determined for the purposes of the Sproule Report and the Company's decommissioning liabilities as recorded in the Company's financial statements. See also *"Risk Factors – Reserves Estimates".*

Future Development Costs

The following table sets forth development costs deducted in the estimation of the Company's future net revenue attributable to the reserve categories noted below:

(Forecast Prices and Costs; $MM)	Proved Reserves	Proved Plus Probable Reserves
2016	77	96
2017	210	313
2018	159	245
2019	74	240
2020	42	100
Thereafter	1	38
Total Undiscounted	563	1,031

During 2015, the Company entered into the Arrangement which is anticipated to provide funding for future development costs. The cost of funding is not expected to have any effect on disclosed reserves or future net revenue nor make the development of a property uneconomic for the Company.

Other Oil and Gas Information

Principal Properties

The Company is engaged in the onshore development, acquisition, exploration and production of crude oil and natural gas in western Canada. The Company's current operations are primarily in the province of Alberta.

The following is a description of the Company's oil and natural gas properties as at December 31, 2015, unless otherwise stated. The reserve amounts stated are gross reserves as at December 31, 2015 based on forecast costs and prices as evaluated in the Sproule Report (see *"Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data – Reserves Data (Forecast Prices and Costs)"*). The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2015.

Peace River Area – Northwest Alberta

The Peace River area is located in Townships 69 to 89 and Ranges 17W5M to 12W6M, approximately 80 kilometers northeast of the city of Grande Prairie, Alberta.

In addition to several minor properties, this area includes the Normandville and Girouxville Montney oil projects. These projects are characterized by a large, regional oil and gas accumulation with thick pay intervals of up to 30 meters, at approximately 950 meters vertical depth. Long Run has identified, delineated and initiated development of a fairway that is approximately 50 kilometers long and 15 kilometers wide. Development is expected to occur via horizontal drilling with a density of between four and eight wells per section, targeting oil. Enhanced recovery potential also exists in this field, with waterflood initiated in 2013. Approximately 90% of this area is year-round accessible for drilling, seismic and construction projects.

Within Peace River, the Normandville EOR project expansion became operational in early December 2014. This project 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. Successful EOR implementation in the Montney area has the potential to improve recoveries, reduce production declines and improve capital efficiencies. Full field implementation of EOR at Normandville and Girouxville could ultimately cover approximately 30 net sections.

Long Run operates, transports and processes the majority of its production in the Peace River area.

During 2015, Long Run invested $20.2 million into the Peace River area, drilling 5.0 (5.0 net) wells with a 100% success rate. Average production was 10,351 Boe/d.

At December 31, 2015, the Sproule Report assigned total proved plus probable reserves of 18.9 MMBbls of oil and NGLs and 102.1 Bcf of natural gas within the Peace River area. The Company held an interest in 313,006 gross acres (276,352 net acres) of undeveloped land in the area.

Redwater Area – East Central Alberta

The Redwater area is located in Townships 26 to 60 and Ranges 2W4M to 9W5M. Although this area contains several projects with exploration and development potential, Long Run’s recent activity has been focused on development of light oil in the Viking formation, approximately 50 kilometers northeast of the city of Edmonton, Alberta.

Viking development is occurring using horizontal drilling at a density of up to 16 wells per section. The Viking play at Redwater is the site of Long Run’s 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.

Long Run processes, operates and transports the majority of its production in the Redwater area.

During 2015, Long Run invested $21.3 million into the Redwater area, drilling and casing 12.0 (12.0 net) wells with a 100% success rate. Average production was 6,292 Boe/d.

At December 31, 2015, the Sproule Report assigned total proved plus probable reserves of 15.6 MMBbls of oil and NGLs and 33.9 Bcf of natural gas within the Redwater area. The Company held an interest in 362,140 gross acres (322,229 net acres) of undeveloped land in the area.

Deep Basin

During 2015, Long Run invested $44.6 million into the Deep Basin area, drilling 6.0 (6.0 net) wells with a 100% success rate. Average production was 11,827 Boe/d.

Deep Basin – Edson Area – West Central Alberta

The Edson area is located in Townships 50 to 56 and Ranges 15W5M to 19W5M, immediately north of the town of Edson, Alberta.

The majority of Long Run's production in the Edson area is oil, natural gas, natural gas liquids and condensate from the Cardium and Bluesky formations at depths of 2,000 meters and 2,600 meters, respectively. Long Run has identified, delineated and initiated development of a fairway that is approximately 32 kilometers long and 16 kilometers wide. Development is expected to occur via horizontal drilling with an initial density of 4 wells per section, targeting oil in the Cardium formation and natural gas in the Bluesky formation. Approximately 90% of this area is year-round accessible for drilling, seismic and construction projects.

Long Run owns and operates the oil and gas facilities that handle the majority of the Company’s production in the Edson area.

During 2015, Long Run drilled and cased 3.0 (3.0 net) wells within the Edson area with a 100% success rate.

At December 31, 2015, the Sproule Report assigned total proved plus probable reserves of 10.3 MMBbls of oil and NGLs and 87.2 Bcf of natural gas within the Edson area. The Company held an interest in 108,400 gross acres (90,831 net acres) of undeveloped land in the area.

Deep Basin – Kakwa Area – West Central Alberta

The Kakwa area is located in Townships 57 to 65 and Ranges 1W6M to 7W6M, approximately 70 kilometers south of the city of Grande Prairie, Alberta.

The majority of Long Run's production in the Kakwa area is natural gas, natural gas liquids and condensate from both the Cardium formation at a depth of approximately 1,600 meters and from the Falher formation, at depths of approximately 2,500 meters. Development is expected to occur via horizontal drilling with an initial density of 4 wells per section, targeting natural gas and natural gas liquids in the Cardium formation.

Long Run owns and operates the natural gas compression that handles the majority of the natural gas, all of which is processed by third party gas plants in the area.

During 2015, Long Run drilled and cased 3.0 (3.0 net) wells within the Kakwa area with a 100% success rate.

At December 31, 2015, the Sproule Report assigned total proved plus probable reserves of 3.1 MMBbls of oil and NGLs and 91.4 Bcf of natural gas within the Kakwa area. The Company held an interest in 14,785 gross acres (10,485 net acres) of undeveloped land in the area.

Deep Basin – Elmworth Area – West Central Alberta

The Elmworth area is located in Townships 65 to 70 and Ranges 7W6M to 12W6M, approximately 45 kilometers southwest of the city of Grande Prairie, Alberta.

The majority of Long Run's production in the Elmworth area is natural gas, natural gas liquids and condensate from the Cardium at a depth of approximately 1,000 meters. Development is expected to occur via horizontal drilling with an initial density of 4 wells per section, targeting natural gas and natural gas liquids in the Cardium formation.

Long Run owns and operates the natural gas compression that handles the majority of the natural gas, all of which is processed by third party gas plants in the area.

During 2015, Long Run did not drill any new wells within the Elmworth area.

At December 31, 2015, the Sproule Report assigned total proved plus probable reserves of 8.2 MMBbls of oil and NGLs and 109.4 Bcf of natural gas within the Elmworth area. The Company held an interest in 17,200 gross acres (14,459 net acres) of undeveloped land in the area.

Boyer Area – Northwest Alberta

The Boyer area is located in Townships 100 to 109 and Ranges 20W5M to 5W6M, immediately south of the town of High Level, Alberta.

In the Boyer area, Long Run produces natural gas from the Cretaceous Bluesky and Gething formations, at depths ranging from 200 meters to 600 meters. Long Run's holdings cover a fairway that is approximately 90 kilometers long and 40 kilometers wide. Average drilling density is currently less than 2 vertical wells per section. Opportunity exists to continue development of this field with further infill drilling.

During 2015, Long Run invested $1.3 million into the Boyer area. Long Run did not drill any wells in this area during 2015. Average production was 2,598 Boe/d. Significant drilling activity could be undertaken with an improvement in natural gas prices.

At December 31, 2015, the Sproule Report assigned total proved plus probable reserves of 102.9 Bcf of natural gas within the Boyer area. The Company held an interest in 88,145 gross acres (85,541 net acres) of undeveloped land in the area.

Capital Expenditures

The following table summarizes capital expenditures related to the Company's activities for the year ended December 31, 2015:

($M)	
Property acquisition costs	
Proved properties	823
Undeveloped properties	1,815
Exploration costs	834
Development costs	89,029
Dispositions	(31,012)
Other	1,176
Net Capital Expenditures	62,665

Long Run plans to incur minimal capital expenditures prior to closing of the Arrangement.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Company participated during the year ended December 31, 2015:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Light and Medium Crude Oil	-	-	20.0	20.0
Heavy Crude Oil	-	-	-	-
Conventional Natural Gas	-	-	3.0	3.0
Dry	-	-	-	-
Service/Other	-	-	-	-
Stratigraphic Test	-	-	-	-
	-	-	23.0	23.0

Land Holdings Including Properties with No Attributed Reserves

The following table sets out the Company's developed and undeveloped land holdings as at December 31, 2015.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	1,622,096	1,368,191	910,397	803,697	2,532,493	2,171,888
Saskatchewan	17,519	17,519	11,037	11,037	28,556	28,556
Total	1,639,615	1,385,710	921,434	814,734	2,561,049	2,200,444

Long Run calculates both its gross and net acres on a per lease basis.

The Company expects that rights to explore, develop and exploit 245,087 net acres of its undeveloped land holdings will expire by December 31, 2016, a portion of which may be continued by drilling. Long Run plans to drill or submit applications to continue selected portions of the above acreage.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

Changes in future commodity prices could have a negative impact on the development of the Company's properties with no attributed reserves. See *"Risk Factors"* in this AIF for further discussion of economic and risk factors relevant to Long Run's properties with no attributed reserves.

The Company does not anticipate any significant abandonment and reclamation costs or any unusually high development or operating costs that have affected or are reasonably expected to affect the anticipated development or production activities on the Company's properties which have no attributed reserves, nor does the Company have any contractual obligations to produce or sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

Oil and Gas Wells

The following table sets forth the number and status of oil and gas wells in which the Company had a working interest as at December 31, 2015:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	910	813	433	364	1,666	1,519	775	617
Saskatchewan	-	-	6	6	-	-	46	46
Total	910	813	439	370	1,666	1,519	821	663

Note:

(1) This table does not include water source wells, injection wells, abandoned wells or wells which have never produced. Producing wells are based on public data status.

(2) Long Run has attributed reserves to less than 6% of its non-producing oil wells and to approximately 2% of its non-producing natural gas wells. The reserves attributed to these non-producing wells represent less than 3% of Long Run's total proved (net) reserves. Each of Long Run's non-producing wells are located within three kilometers of existing pipeline and/or facility infrastructure. The period for which these non-producing wells have been off of production varies from one month to several years.

(3) The non-producing wells currently capable of production that are not currently producing will be considered to be placed on production, from time to time, with respect to future product prices, proximity to facility infrastructure, design of future exploration and development programs and access to capital.

Additional Information Concerning Abandonment and Reclamation Costs

The Company uses its internal historical costs to estimate its abandonment and reclamation costs when available. The costs are estimated on an area by area basis. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements.

The abandonment and reclamation obligation included in the Company's financial statements differs from the amount deducted in the reserves evaluation, as the Sproule Report forecasts abandonment and reclamation costs only for existing and undrilled wells that have been attributed reserves. No allowance was made for the abandonment and reclamation of any facilities in the Sproule Report. The following table sets forth abandonment costs deducted in the estimation of the Company's future net revenue as provided in the Sproule Report:

(Forecast Prices and Costs; $M)	Total Proved Abandonment Costs	Total Proved plus Probable Abandonment Costs
2016	-	-
2017	-	-
2018	-	-
Thereafter	184,814	264,169
Total Undiscounted	184,814	264,169
Total Discounted @ 10%	39,112	38,621

The decommissioning liabilities recorded in the Company's financial statements result from net ownership interests in petroleum and natural gas assets including well sites, pipelines, gathering systems and processing facilities. The estimated total undiscounted amount of cash flows required to settle the Company's decommissioning liability is approximately $546 million ($171 million discounted at 10%), which will be incurred over the next 45 years.

Forward Contracts

At December 31, 2015, the Company held certain financial derivative contracts which are described in Note 17 of the Company's audited financial statements for the year ended December 31, 2015.

Tax Horizon

The Company does not expect to pay current income tax for the 2016 fiscal year. Depending on production, commodity prices and capital spending levels, management believes that, based on its current business plan, the Company will not begin paying current income taxes for a number of years.

Production Estimates

The following tables disclose the total volume of the Company's gross 2016 production estimated by Sproule in the estimates of future net revenue from gross proved and gross probable reserves disclosed under *"Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data – Reserves Data (Forecast Prices and Costs)".*

2016 Production from Gross Proved Reserves

	Light and Medium Crude Oil *(Bbl/d)*	Heavy Crude Oil *(Bbl/d)*	Conventional Natural Gas *(Mcf/d)*	Natural Gas Liquids *(Bbl/d)*	Boe *(Boe/d)*	%
Peace River	4,093	-	18,839	258	7,491	30.2
Redwater	1,802	-	7,135	38	3,029	12.2
Deep Basin - Edson	396	-	18,086	1,748	5,158	20.8
Deep Basin - Kakwa/Elmworth	37	-	22,739	1,044	4,871	19.7
Boyer	-	-	10,683	-	1,781	7.2
Other	66	221	8,366	757	2,438	9.8
Total	6,394	221	85,848	3,845	24,768	100.0

2016 Production from Gross Probable Reserves

	Light and Medium Crude Oil *(Bbl/d)*	Heavy Crude Oil *(Bbl/d)*	Conventional Natural Gas *(Mcf/d)*	Natural Gas Liquids *(Bbl/d)*	Boe *(Boe/d)*	%
Peace River	677	-	3,626	46	1,327	62.2
Redwater	202	-	351	3	264	12.3
Deep Basin - Edson	39	-	822	76	252	11.8
Deep Basin - Kakwa/Elmworth	1	-	615	25	129	6.0
Boyer	-	-	221	-	37	1.7
Other	13	15	451	24	127	6.0
Total	932	15	6,086	174	2,135	100.0

Production History

The following tables summarize certain information in respect to the Company's production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	Q4 2015	Q3 2015	Q2 2015	Q1 2015
Average Daily Production[1]				
Light and Medium Crude Oil *(Bbl/d)*	7,319	7,711	9,059	10,242
Heavy Crude Oil *(Bbl/d)*	322	279	370	315
Conventional Natural Gas *(Mcf/d)*	103,250	110,799	122,214	119,007
NGLs *(Bbl/d)*	3,998	4,277	4,659	5,210
Combined *(Boe/d)*	28,847	30,733	34,457	35,602
Average Price Received (net of transportation)				
Light and Medium Crude Oil *($/Bbl)*	41.56	43.83	56.39	39.60
Heavy Crude Oil *($/Bbl)*	31.50	37.47	49.78	33.65
Conventional Natural Gas *($/Mcf)*	2.45	2.73	2.66	2.57
NGLs *($/Bbl)*	23.20	21.43	25.71	23.31
Combined *($/Boe)*	22.88	24.15	28.27	23.69
Royalties				
Light and Medium Crude Oil *($/Bbl)*	3.51	4.88	3.17	4.64
Heavy Crude Oil *($/Bbl)*	3.87	(5.57)	7.87	6.74
Conventional Natural Gas *($/Mcf)*	(0.06)	0.10	0.08	0.06
NGLs *($/Bbl)*	4.71	5.19	6.23	2.65
Combined *($/Boe)*	1.38	2.23	2.04	1.97
Operating Expenses				
Light and Medium Crude Oil *($/Bbl)*	12.68	10.86	12.23	13.33
Heavy Crude Oil *($/Bbl)*	14.55	11.71	23.82	13.23
Conventional Natural Gas *($/Mcf)*	2.07	1.85	1.95	2.21
NGLs *($/Bbl)*	8.89	7.99	8.57	10.25
Combined *($/Boe)*	12.03	10.62	11.55	12.85
Netback[2]				
Light and Medium Crude Oil *($/Bbl)*	25.37	28.09	40.99	21.63
Heavy Crude Oil *($/Bbl)*	13.08	31.33	18.09	13.68
Conventional Natural Gas *($/Mcf)*	0.43	0.78	0.63	0.30
NGLs *($/Bbl)*	9.60	8.25	10.91	10.41
Combined *($/Boe)*	9.47	11.30	14.68	8.87

Notes:

(1) Before deduction of royalties.
(2) Netbacks are calculated by subtracting royalties and operating costs from revenues, net of transportation costs.

The following table indicates the Company's average daily production by area for the year ended December 31, 2015:

	Light and Medium Crude Oil *(Bbl/d)*	Heavy Crude Oil *(Bbl/d)*	Conventional Natural Gas *(Mcf/d)*	NGLs *(Bbl/d)*	Boe *(Boe/d)*
Peace River	4,945	-	30,201	372	10,351
Redwater	3,029	321	16,799	142	6,292
Deep Basin – Edson	537	-	24,097	2,226	6,779
Deep Basin – Kakwa/Elmworth	59	-	23,971	994	5,048
Boyer	2	-	15,572	1	2,598
Other	-	-	3,127	797	1,318
Total	8,572	321	113,767	4,532	32,386

For the year ended December 31, 2015, the Company's production was 26% light and medium quality oil, 1% heavy oil, 59% natural gas and 14% NGLs. For 2015, approximately 49% of the Company's gross revenue was derived from oil (2014 – 64%), 38% was derived from natural gas (2014 – 26%) and 13% was derived from NGLs (2014 – 10%).

DESCRIPTION OF CAPITAL STRUCTURE

The Company is authorized to issue an unlimited number of Common Shares, an unlimited number of Common Non-Voting Shares, an unlimited number of Non-Voting Convertible Shares and an unlimited number of First Preferred Shares, issuable in one or more series. The following is a description of the rights, privileges, restrictions and conditions attaching to the share capital of the Company. As at March 9, 2016, there were an aggregate of 193,498,465 Common Shares issued and outstanding. There are no Common Non-Voting Shares, Non-Voting Convertible Shares or First Preferred Shares outstanding. The Company has $75.0 million principal amount of Convertible Debentures outstanding.

Common Shares

The holders of Common Shares are entitled to one vote for each Common Share held on all matters to be voted on by such holders and are entitled to receive such dividends as may be declared by the Board of Directors on such shares subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes of shares of the Company ranking in priority thereto in respect of dividends. Holders of Common Shares are entitled, in the event of any liquidation, dissolution or winding-up of the Company, whether voluntarily, or in the event of other distribution of the assets of the Company among the shareholders for the purpose of winding-up its affairs and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of the Company ranking in priority to the Common Shares in respect of return of capital on dissolution, to share ratably, together with the holders of the Common Non-Voting Shares and of any shares of any other class ranking equally with the Common Shares in respect of return of capital on dissolution, in such assets of the Company as are available for distribution.

Common Non-Voting Shares

The holders of Common Non-Voting Shares are entitled to receive notice and attend shareholder meetings provided that, except as required by law, shall not be entitled to vote on any matter. The holders of Common Non-Voting Shares are entitled to receive such dividends as may be declared by the Board of Directors on the Common Non-Voting Shares subject to prior satisfaction of all preferential rights to dividends attached to shares of other classes of shares of the Company ranking in priority to the Common Non-Voting Shares, provided that no dividend may be declared in respect of, or any other benefit conferred upon holders of, Common Shares unless concurrently therewith the same dividend in respect of, or the same benefits conferred upon holders of, Common Non-Voting Shares. The holders of the Common Non-Voting Shares are entitled, in the event of any liquidation, dissolution or winding-up of the Company, whether voluntary or involuntary, or in the event of other distribution of assets of the Company among the shareholders for the purpose of winding-up its affairs and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of the Company ranking in priority to the Common Non-Voting Shares in respect of return of capital on dissolution, to share ratably, together with the holder of the Common Shares and of any shares of any other class ranking equally with the Common Non-Voting Shares in respect of return of capital on dissolution, in such assets of the Company as are available for distribution

Neither the Common Shares nor the Common Non-Voting Shares may be subdivided, consolidated, reclassified or otherwise changed unless concurrently therewith, the shares of such classes are subdivided, consolidated, reclassified or otherwise changed in the same proportion and in the same manner.

Subject to certain exceptions noted below and applicable law, in the event of an Offer, each outstanding Common Non-Voting Share shall be redeemed by the Company at the Redemption Price per Common Non-Voting Share at the option of the holder during the Redemption Period and such redemption shall be subject to completion of the Offer. The redemption right may be exercised by notice in writing to the Company together with the certificate(s) representing the Common Non-Voting Shares. The Company shall issue a cheque for the aggregate Redemption Price to be paid to such holder (less any tax required to be withheld and paid by such holder) upon completion of the offer (the "Redemption Date"). If the Offer is not completed, the Company shall return any share certificates representing Common Non-Voting Shares to the holders thereof.

The redemption right noted above shall not come into effect if, subject to certain notification requirements: (i) one or more shareholders of the Company who did not make or act in concert with the person or persons making the Offer and who, in the aggregate, beneficially own, directly or indirectly, or exercise control or direction over, not less than 50% of the outstanding Common Shares, determine within five business days after the Offer Date that he or they will continue to so own or exercise control or direction over, in the aggregate, 50% or more of the outstanding Common Shares; (ii) contemporaneously with the Offer, an offer is made to the holders of Common Non-Voting Shares upon the same terms and conditions as those contained in the Offer, including the consideration to be paid to the holders of Common Shares and the offer is for the same percentage of Non-Voting Shares as the percentage of Common Shares sought to be acquired under the Offer, excluding in each case the number of shares then owned by the offeror; (iii) the Board of Directors determines within five business days after the Offer Date that the Offer is not bona fide or is made primarily for the purpose of causing the redemption right to come into effect and not primarily for the purpose of acquiring Common Shares; or (iv) the Offer is not completed in accordance with its terms.

From and after a Redemption Date, all Common Non-Voting Shares which are redeemed in accordance with their terms shall cease to be entitled to dividends and the Common Non-Voting Shares shall be deemed to be returned to the authorized but unissued capital of the Company.

Non-Voting Convertible Shares

The holders of Non-Voting Convertible Shares are entitled to receive notice of and to attend at any meeting of the shareholders of the Company but are not entitled to vote at any such meeting, except with respect to such matters and in the manner as to which voting rights are accorded to the holders of specified classes of shares pursuant to the provisions of the ABCA.

The holders of the Non-Voting Convertible Shares are entitled to receive dividends if, as and when declared by the Board of Directors equally, on a share-for-share basis, with the holders of Common Shares.

In the event of liquidation, dissolution or winding-up of the affairs of the Company, whether voluntary or involuntary, or in the event of any other distribution of assets of the Company among its shareholders for the purpose of winding up its affairs, or in the event of a reduction or redemption of the capital stock of the Company, the holders of the Non-Voting Convertible Shares are entitled to receive an amount per share equal to that amount that is the fair market value of any property received by the Company as consideration for the issuance of such Non-Voting Convertible Shares divided by the number of Non-Voting Convertible Shares issued, in lawful money of Canada, the whole before any amount will be paid by the Company or any assets of the Company will be distributed to holders of Common Shares. After payment to the holders of the Non-Voting Convertible Shares of the amount so payable to them in accordance with the foregoing, they will not be entitled to share in any further distribution of property or assets of the Company.

Each holder of Non-Voting Convertible Shares has the right to transfer to any Person all or any of the holder's Non-Voting Convertible Shares, provided (i) the transferee would not be a Control Person of the Company after giving effect to the transfer and (ii) such transfer was made in compliance with all applicable securities laws.

Each holder of Non-Voting Convertible Shares has the right to convert all or any of the holder's Non-Voting Convertible Shares into Common Shares at the Conversion Ratio in the following circumstances:

(i) at any time, provided that the holder would not be a Control Person of the Company after giving effect to the conversion; or

(ii) upon a Change of Control Transaction, regardless of whether or not such Change of Control Transaction has been approved by the Board of Directors.

Each Non-Voting Convertible Share will be deemed to convert into Common Shares at the Conversion Ratio immediately upon the sale, transfer, conveyance or other disposition of such Non-Voting Convertible Share, whether by way of a sale, transfer, conveyance or other disposition that is exempt from the prospectus requirements under applicable securities laws, or a distribution to the public or a secondary offering completed by way of prospectus, provided that the transferee would not be a Control Person of the Company after giving effect to the sale, transfer, conveyance or other disposition and the conversion of such Non-Voting Convertible Shares.

The Company has the right, following the date that is three years after the issuance date of the Non-Voting Convertible Shares, at its sole option to require that holders of Non-Voting Convertible Shares convert all issued and outstanding Non-Voting Convertible Shares held by them into Common Shares.

The Conversion Ratio shall be adjusted proportionately if the Common Shares are subdivided or consolidated.

First Preferred Shares

Long Run is authorized to issue an unlimited number of First Preferred Shares issuable in series, each series consisting of such number of shares and having such rights, privileges, restrictions and conditions as may be determined by the Board of Directors prior to the issuance thereof. With respect to the payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding up of Long Run, whether voluntary or involuntary, the First Preferred Shares of each series shall rank on a parity with the First Preferred Shares of each other series and are entitled to preference over any other shares ranking junior to the First Preferred Shares from time to time and may also be given such other preferences over the Common Shares and any other shares ranking junior to the first preferred shares as may be determined at the time of creation of such series.

Convertible Debentures

The Convertible Debentures are issued under and pursuant to the provisions of the Debenture Indenture. A summary description of the Convertible Debentures is set forth under the heading "Details of the Offering" in the short form prospectus of the Company dated January 21, 2014 (the "January 2014 Prospectus"). Such section of the January 2014 Prospectus, together with the definitions under the heading "Definitions and Abbreviations" in the January 2014 Prospectus used in such section, are incorporated herein by reference. The January Prospectus was filed and is available on SEDAR at www.sedar.com. The description of the Convertible Debentures included in such summary is subject to detailed provisions of the Debenture Indenture and is qualified in its entirety by reference to the Debenture Indenture which was filed and is available on SEDAR at www.sedar.com.

Under the terms of the amendment to the Company's credit facilities made on January 29, 2016, the Company is restricted from making any payment of interest or other amounts on the Convertible Debentures, including the semi-annual interest that was 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 Convertible Debentures plus accrued and unpaid interest up to but excluding the effective date of the Arrangement.

DIVIDENDS

Dividend Policy

On November 6, 2013, the Company established an initial dividend policy of paying monthly dividends at a rate of $0.0335 per Common Share and per Non-Voting Convertible Share per month with the first dividend declared payable to holders of record as of January 31, 2014 and paid on February 14, 2014. On May 6, 2014, the Board of Directors revised the dividend policy, increasing the monthly dividend payable to $0.035 per Common Share per month with the first revised dividend declared payable to holders of record as of June 30, 2014 and paid on July 15, 2014. On December 15, 2014, Long Run lowered the amount of the monthly dividend to $0.0175 per share, starting with the dividend declared payable to holders of record as of January 30, 2015 and paid on February 13, 2015. As a result of a volatile and uncertain commodity price environment, the monthly dividend was suspended in February 2015.

The payment and the amount of dividends declared in any month will be subject to the discretion of the Board of Directors and will depend on the Board of Director's assessment of Long Run's outlook for capital expenditure requirements, growth, funds flow from operations, potential acquisition opportunities, debt position and other conditions that the Board of Directors may consider relevant at such future time. The amount of future cash dividends, if any, may also vary depending on a variety of factors, including production, current and future commodity prices, commodity hedging, foreign exchange rates, acquisition opportunities and the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends.

Payment of dividends is restricted under the Company's credit facility if there is a borrowing base shortfall or a default or an event of default thereunder that has occurred and is continuing at the time or will occur as a result of, or may be expected to result from, such dividend.

Dividends Paid

The following monthly cash dividends were declared and paid by the Company for the years ending December 31, 2015 and December 31, 2014. The Company did not declare or pay any dividends during the year ended December 31, 2013.

Record Date	Dividends per Common Share	Payment Date
2014		
January 31, 2014	0.0335	February 14, 2014
February 28, 2014	0.0335	March 14, 2014
March 31, 2014	0.0335	April 15, 2014
April 30, 2014	0.0335	May 15, 2014
May 30, 2014	0.0335	June 16, 2014
June 30, 2014	0.0350	July 15, 2014
July 31, 2014	0.0350	August 14, 2014
August 29, 2014	0.0350	September 15, 2014
September 30, 2014	0.0350	October 15, 2014
October 31, 2014	0.0350	November 14, 2014
November 28, 2014	0.0350	December 15, 2014
December 31, 2014	0.0350	January 15, 2015
	0.4125	
2015		
January 30, 2015	0.0175	February 13, 2015

During February 2015, the monthly dividend was suspended by the Board of Directors.

MARKET FOR SECURITIES

Trading Price and Volume

Common Shares

The Common Shares are listed and posted for trading on the TSX under the symbol "LRE". The following sets forth the price range and trading volume of the Common Shares on the TSX (as reported by such exchange) for the periods indicated.

	Price Range		
	High *($/share)*	Low *($/share)*	Volume *(000s)*
2015			
January	1.55	0.97	24,234
February	1.39	1.04	31,420
March	1.13	0.66	23,418
April	1.00	0.67	22,074
May	0.97	0.71	14,635
June	0.88	0.70	16,919
July	0.80	0.53	11,633
August	0.87	0.32	14,515
September	0.44	0.29	6,204
October	0.44	0.30	10,267
November	0.37	0.20	16,019
December	0.45	0.12	30,866
2016			
January	0.37	0.27	12,876
February	0.45	0.33	25,677
March 1-8	0.48	0.44	6,249

Convertible Debentures

The Convertible Debentures are listed and posted for trading on the TSX under the symbol "LRE.DB". The following sets forth the price range and trading volume of the Convertible Debentures on the TSX (as reported by such exchange) for the periods indicated.

	Price Range[i]		
	High *($/share)*	Low *($/share)*	Volume[i] *(000s)*
2015			
January	65.00	35.00	26
February	50.00	37.99	47
March	47.50	32.00	26
April	59.00	37.08	16
May	60.02	57.01	10
June	69.00	59.00	18
July	67.50	38.00	9
August	63.00	39.00	16
September	43.00	33.00	9
October	40.00	34.00	7
November	40.00	25.10	19
December	50.00	20.00	32
2016			
January	45.50	28.00	15
February	62.00	38.00	12
March 1-8	67.00	62.00	14

[i] *Per $100 principal amount of Convertible Debentures*

EMPLOYEES

As at December 31, 2015, Long Run had 136 full-time employees and 10 consultants located at its office in Calgary. In addition, Long Run had 91 full-time employees and 62 contract operators in various field locations.

DIRECTORS AND OFFICERS

The names, province and country of residence, positions with the Company and principal occupation of the directors and officers of the Company and their age at year-end are set out below and in the case of directors, the period each has served as a director of the Company.

Name, Province and Country of Residence	Office Held	Principal Occupation	Director Since
William E. Andrew Alberta, Canada Age: 63	Chair & Chief Executive Officer	Chair and Chief Executive Officer of the Company	October 23, 2012
Dale A. Miller Alberta, Canada Age: 55	President, Chief Operating Officer and Director	President and Chief Operating Officer of the Company	October 23, 2012
John A. Brussa(2)(4) Alberta, Canada Age: 58	Director	Partner, Burnet, Duckworth & Palmer LLP (Barristers and Solicitors)	December 13, 2007
Ed Chwyl(2)(3) British Columbia, Canada Age: 72	Director	Independent Businessman	December 13, 2007
Michael M. Graham(1)(2)(4)(5) Alberta, Canada Age: 56	Lead Director	Independent Businessman	October 23, 2012
Brad R. Munro(1)(3)(5) Saskatchewan, Canada Age: 56	Director	President and Chief Executive Officer of Bittercreek Capital Corporation, (a private investment and advisory firm)	October 23, 2012
William Stevenson(1)(4)(5) Alberta, Canada Age: 60	Director	Independent Businessman	May 21, 2014
Steve Yuzpe(3) Ontario, Canada Age: 50	Director	President and Chief Executive Officer of Sprott Resource Corp.	January 29, 2014
Corine R.K. Bushfield Alberta, Canada Age: 41	Senior Vice President and Chief Financial Officer	Senior Vice President and Chief Financial Officer of the Company	N/A
Dale J. Orton Alberta, Canada Age: 43	Senior Vice President, Development	Senior Vice President, Development of the Company	N/A
Devin K. Sundstrom Alberta, Canada Age: 43	Vice President, Production	Vice President, Production of the Company	N/A
C. Steven Cohen Alberta, Canada Age: 60	Secretary	Partner, Burnet, Duckworth & Palmer LLP (Barristers and Solicitors)	N/A

Notes:

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Health, Safety and Environment Committee.
(4) Member of the Human Resources Committee.
(5) Member of the Corporate Governance Committee.

All of the above directors have held their principal occupations or other positions with the same organization as listed above for at least the last five years except as described below and as described under *"Management"* and *"Audit Committee Information – Composition of the Audit Committee"* and other than the following. Mr. Graham served as Executive Vice-President of Encana and served as President of its Canadian Division from April 2005 to February 2012. Mr. Stevenson worked for Encana and its predecessor company for the last 20 years in various management positions, most recently as Executive Vice-President and Chief Accounting Officer until retiring in November 2013. Mr. Yuzpe was appointed President and Chief Executive Officer of Sprott Resource Corp. in October 2013. Prior thereto, he was the Chief Financial Officer of Sprott Resource Corp. since May 2009. The term of office of each director expires at the next annual meeting of shareholders of the Company.

As at March 9, 2016, the directors and executive officers of Long Run, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 3,909,790 Common Shares or approximately 2.0% of the issued and outstanding Common Shares.

Cease Trade Orders

To Long Run's knowledge, no director or executive officer of the Company is, as at the date hereof, or was within 10 years before the date hereof, a director, chief executive officer or chief financial officer of any issuer (including the Company) that: (a) was subject to an order that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer. For the purposes of the above, "order" means a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days.

Bankruptcies

To Long Run's knowledge, other than as disclosed herein, no director or executive officer of the Company, or a shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company: (a) is, as at the date hereof, or has been within the 10 years before the date hereof, a director or executive officer of any issuer (including the Company) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets or (b) has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Mr. Munro presently serves as a director of CERF Inc. and previously served as a director of Winalta, Inc. CERF Inc. combined with Winalta, Inc. during 2014. Winalta Inc. and each of its subsidiaries, (collectively "Winalta") obtained creditor protection under the Companies' Creditors Arrangement Act (Canada) (the "CCAA") pursuant to an order granted on April 26, 2010 by the Court. Deloitte & Touche Inc. was appointed as Winalta's monitor. The CCAA filing follows the receipt on March 31, 2010 by Winalta and its subsidiaries of demands for payment and Notices of Intention to Enforce Security from Winalta's principal lender, HSBC Bank of Canada. On October 22, 2010, Winalta received Court and creditor approval of a plan of arrangement (the "Plan") pursuant to the CCAA under which it amalgamated with certain of its subsidiaries and, effective October 29, 2010, emerged from CCAA protection to begin focused operations on its oilfield services business. The board of directors maintained its usual role during the period while Winalta was under CCAA protection and, together with management, was primarily responsible for formulating the Plan for restructuring Winalta's affairs.

John Brussa resigned as a director of Calmena Energy Services Inc. ("Calmena") on June 30, 2014. On January 19, 2015, a senior lender of Calmena (the "Senior Lender") made an application to the Court to appoint an interim receiver under the Bankruptcy and Insolvency Act (Canada) and trading in the common shares of Calmena was suspended by the TSX. On January 20, 2015, the Senior Lender was granted a receivership order by the Court. Mr. Brussa was also a director of Enseco Energy Services Corp. ("Enseco"), a public oilfield service company, which was placed in receivership on October 14, 2015 and, in connection therewith, a receiver was appointed under the Bankruptcy and Insolvency Act (Canada). Mr. Brussa resigned as a director of Enseco on October 14, 2015. On December 21, 2015, Enseco was assigned into bankruptcy by the receiver.

Penalties or Sanctions

To Long Run's knowledge, no director or executive officer of the Company, or a shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company, has been subject to (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

MANAGEMENT

William E. Andrew, Chair & Chief Executive Officer

Mr. Andrew is a professional engineer with over 40 years of experience in oil and gas exploration and development focused in western Canada. After starting his career with Shell Canada, Mr. Andrew worked for a number of large multi-national oil companies gaining experience in drilling, completions, production, evaluations and reservoir engineering. His management experience includes increasing levels of responsibility in Canadian public and private exploration companies. Mr. Andrew joined Guide in mid-2011, and its successor, Long Run in October 2012. Prior to joining Guide, he was Chief Executive Officer of a large Canadian public oil and gas exploration company. He is active in the community as a director of Ronald McDonald House of Southern Alberta, a director of the Fathers of Confederation Buildings Trust and a director of the Wind Energy Institute of Canada. Mr. Andrew served as Chancellor of the University of Prince Edward Island from 2005 to 2014. Mr. Andrew has a Bachelor of Engineering degree from the Technical University of Nova Scotia with a major in Mining.

Dale A. Miller, President, Chief Operating Officer and Director

Mr. Miller is a professional engineer with over 30 years of oil and natural gas industry experience. Mr. Miller joined Guide in mid-2011, and its successor, Long Run in October 2012. Prior to joining Guide, he acted as Vice President and Chief Operating Officer of an intermediate oil and gas company, Pace Oil and Gas Ltd., from July 2010 to August 2011. Mr. Miller has held various executive and management positions with Midnight Oil Exploration Ltd. from November 2009 to July 2010, Gibraltar Exploration Ltd. from September 2003 to July 2009, as well as a large Canadian public oil and gas exploration company from 1993 to 2003. Mr. Miller is a graduate of the University of Tulsa with a Bachelor of Science degree in Petroleum Engineering and is a Registered Professional Engineer in Alberta.

Corine R. K. Bushfield, Senior Vice President and Chief Financial Officer

Ms. Bushfield is a Chartered Professional Accountant with over 20 years of oil and natural gas industry experience. Prior to joining Long Run in March 2013, Ms. Bushfield worked for Encana for 13 years in positions of increasing responsibility within corporate finance, most recently as Vice President and Assistant Controller. Ms. Bushfield holds a Bachelor of Commerce degree from the University of Calgary and is a member of the Chartered Professional Accountants of Alberta.

Dale J. Orton, Senior Vice President, Development

Mr. Orton is a professional engineer with over 20 years of exploitation, production, operations, business development and acquisition experience. Mr. Orton joined Guide in June 2005 and its successor, Long Run in October 2012. Prior to joining Guide, he held positions of increasing responsibility with Flowing Energy Corporation, KeyWest Energy Corporation, Velvet Exploration Ltd. and Renaissance Energy Ltd. Mr. Orton holds a Bachelor of Engineering degree from the University of Victoria and is a Registered Professional Engineer in Alberta and in Saskatchewan.

Devin K. Sundstrom, Vice President, Production

Mr. Sundstrom is a professional engineer with over 20 years of drilling and completion, exploitation, production operations and acquisition experience. Mr. Sundstrom joined Guide in August 2004 and its successor, Long Run in October 2012. Prior to joining Guide, he held positions with increasing responsibility at Hunt Oil Company, Renaissance Energy Ltd. and Northstar Energy Corporation. Mr. Sundstrom holds a Bachelor of Science Degree in Chemical Engineering from the University of Calgary and is a Registered Professional Engineer in Alberta.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Audit Committee of the Board of Directors is attached hereto as Schedule "C".

Composition of the Audit Committee

The members of the Audit Committee are William A. Stevenson, Michael M. Graham and Brad R. Munro. The members of the Audit Committee are independent (in accordance with National Instrument 52-110) and are financially literate. The following is a description of the education and experience of each member of the Audit Committee.

William A. Stevenson, Chair

Mr. Stevenson was appointed a director of the Company on May 21, 2014. Mr. Stevenson is a professional accountant with over 35 years of experience at several large and intermediate North American oil and gas companies, including Mobil Oil Company, Marathon Petroleum Corporation and Encana. Mr. Stevenson worked for Encana and its predecessor company for the last 20 years in various management positions. Mr. Stevenson was Executive Vice-President and Chief Accounting Officer of Encana from December 1, 2009 until retiring in November 2013. From 2004 to 2009, he was Vice-President and Controller of Encana. Mr. Stevenson is a Chartered Professional Accountant and a member of the Chartered Professional Accountants of Alberta.

Michael M. Graham

Mr. Graham was appointed a director of the Company on October 23, 2012. Mr. Graham is an independent businessman with over 30 years of experience in the oil and natural gas business. Mr. Graham served as Executive Vice-President & President of the Canadian Division with Encana until February 2012. Mr. Graham has held various executive and management positions with Alberta Energy Company, Amber Energy Inc. and Encana. He was a former member of the Board of Governors for the Business Council of British Columbia and the Canadian Association of Petroleum Producers. Mr. Graham is a graduate of the University of Wyoming with a Bachelor of Science degree in Petroleum Engineering and is a member of APEGA and the Society of Petroleum Engineers. Mr. Graham's various senior positions required regular review of financial statements and he currently serves as a director for a number of publicly traded companies.

Brad R. Munro

Mr. Munro was appointed a director of the Company on October 23, 2012. Mr. Munro is the President and Chief Executive Officer of Bittercreek Capital Corporation, a private investment and advisory firm. Through Bittercreek Capital Corporation, Mr. Munro was a contractor to GrowthWorks Capital WV Ltd. and its affiliates in the role of Vice-President, Investments from May 2006 to August 2009. Prior thereto, Mr. Munro was an employee of GrowthWorks Capital Ltd. and its affiliates since September 1991. Mr. Munro presently serves as a director of CERF Inc. (CERF Inc. combined with Winalta Inc. in 2014) and Secure Energy Services Inc. and has extensive experience in corporate finance and investment in oil and gas and other industries. Mr. Munro holds a Bachelor of Commerce degree from the University of Saskatchewan.

Pre-Approval of Non-Audit Services

Long Run has adopted policies and procedures with respect to the pre-approval of non-audit services to be provided by the Company's external auditors. The Audit Committee approves a schedule which summarized the services to be provided that the Audit Committee believes to be typical, recurring or otherwise likely to be provided. The schedule generally covers the period between the adoption of the schedule and the end of the year, but at the option of the Audit Committee, may cover a shorter or longer period. Non-audit services that arise that were not contemplated in the schedule may be pre-approved by the chair of the Audit Committee in respect of fees not in excess of $25,000 between meetings of the Audit Committee and the full Audit Committee is informed of the services at its next meeting.

External Auditor Service Fees

The following table summarizes the fees paid in the last two financial years by the Company to its external auditors Ernst & Young LLP:

Year	Audit Fees[(1)] *($)*	Audit Related Fees[(2)] *($)*	Tax Fees[(3)] *($)*	Other Fees[(4)] *($)*
2015	401,750	60,500	Nil	Nil
2014	366,500	141,300	Nil	Nil

Notes:

(1) Represents the fees for audit services.
(2) Represents the fees for services rendered in connection with financings and acquisitions.
(3) Represents the fees for tax compliance, tax advice and tax planning.
(4) Represents the fees for products and services other than the services reported under items (1), (2) and (3) above.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as described herein, there were no material interests, direct or indirect, of directors or executive officers of the Company, of any shareholder who beneficially owns or controls or directs, directly or indirectly, more than 10% of any class of outstanding voting securities of the Company or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect the Company.

On May 21, 2014, Long Run and SRC announced the completion of the Secondary Offering. Long Run did not receive any proceeds from the Secondary Offering. Immediately following the closing of the Secondary Offering, SRC converted all of its Non-Voting Convertible Shares into 15.5 million Common Shares (the "Conversion"). Upon completion of the Secondary Offering and the Conversion, SRC's ownership interest in Long Run was approximately 18.3%, comprised of a total of 23.0 million Common Shares. Following the conversion of the outstanding 23.5 million Subscription Receipts into Common Shares which occurred on May 30, 2014 in connection with the closing of the Deep Basin Property Acquisition, SRC's ownership interest in Long Run was approximately 15.4%. See "*General Development of the Business – Three-Year History – 2014*". Following the acquisition of Crocotta, SRC's ownership interest in Long Run was approximately 11.9%.

Certain directors and officers of Long Run have participated in private placements and public offerings by Long Run (or its predecessors) on the same basis as other arm's length subscribers to such offerings. During 2014, John Brussa participated in the Subscription Receipt offering, acquiring 20,000 Subscription Receipts on April 30, 2014 at a price of $5.10 per receipt.

CONFLICTS OF INTEREST

The directors or officers of the Company may also be directors or officers of other oil and natural gas companies or otherwise involved in natural resource exploration and development and situations may arise where they are in a conflict of interest with the Company. Conflicts of interest, if any, which arise will be subject to and governed by procedures prescribed by the ABCA which require a director or officer of a Company who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Company disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that Long Run is or was a party to, or that any of its property is or was a subject of, during the last completed financial year, nor are any such legal proceedings known to Long Run to be contemplated, that involves a claim for damages, exclusive of interest and costs, exceeding 10% of the current assets of Long Run.

During the year ended December 31, 2015, there were no (i) penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority; (ii) any other penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements the Company entered into with a court relating to securities legislation or with a securities regulatory authority.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Company has not entered into any material contracts within the most recently completed financial year or prior to the most recently completed financial year which are still in effect, other than the following:

(i) the Arrangement Agreement (see "*General Development of the Business – Three-Year History – 2015*");

(ii) the amended and restated credit agreement between Long Run and its bank syndicate dated May 29, 2015, as amended by the first amending agreement dated November 30, 2015, the interim forbearance and second amending agreement dated December 24, 2015, the consent, interim forbearance extension and amending agreement dated January 22, 2016 and the waiver, consent, forbearance and third amending agreement dated January 29, 2016 and as may be further amended or amended and restated (see "*General Development of the Business – Three-Year History – 2015*");

(iii) the investment agreement dated August 2, 2015 among Long Run, Maple Marathon and MIEH as amended and restated on November 8, 2015 (see "*General Development of the Business – Three-Year History – 2015*");

(iv) the Debenture Indenture (see "*General Development of the Business – Three-Year History – 2014*" and "*Description of Capital Structure – Convertible Debentures*"); and

(v) the investor agreement dated May 11, 2011 entered into by WestFire (now Long Run) and SRC in connection with WestFire's acquisition of all of the common shares of Orion on June 30, 2011 (the "Investor Agreement"). The Investor Agreement provides:

- Certain "drag-along" rights whereby SRC agreed in the event of a bona fide offer from an arm's length party to purchase or otherwise acquire (including, without limitation, by way of take-over bid, plan of arrangements or amalgamation) 90% or more of the aggregate outstanding Common Shares at a price in excess of $7.90 per Common Share (subject to adjustment in connection with any subdivision, re-division, or change of its then outstanding Common Shares into a greater number of shares or any reduction, combination or consolidation of its then outstanding Common Shares into a lesser number of Common Shares) (an "Acquisition Transaction"), upon notice by Long Run that the Board of Directors intends to support the Acquisition Transaction and enter into a binding agreement in respect of the transaction, SRC is required to sell or otherwise transfer its Common Shares (including any Common Shares acquired pursuant to the conversion of SRC's Non-Voting Convertible Shares) upon the same terms and conditions as the Acquisition Transaction; and
- Long Run's agreement to provide SRC with certain information as required by SRC to comply with its reporting obligations under applicable law.

AUDITORS, TRANSFER AGENTS AND REGISTRAR

The auditors of the Company are Ernst & Young LLP, Chartered Professional Accountants, 1000, 444 – 2nd Avenue SW, Calgary, Alberta, T2P 5E9.

CST Trust Company, at its principal offices in Calgary, Alberta and Toronto, Ontario, is the transfer agent and registrar of the Common Shares and of the Convertible Debentures.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Company during, or related to, the Company's most recently completed financial year other than Sproule, the Company's independent engineering evaluators, and Ernst & Young LLP, the Company's auditors. None of Sproule or the "designated professionals" (as defined in Item 16.2(1.1) of Form 51-102F2 of NI 51-102 of Sproule have or are to receive any registered or beneficial interest, direct or indirect, in any of Long Run's securities or other property of Long Run or of Long Run's associates or affiliates, at the time Sproule prepared the report, valuation, statement or opinion. Ernst & Young LLP, Chartered Professional Accountants, the Company's auditors, are independent within the meaning of the Chartered Professional Accountants of Alberta Rules of Professional Conduct.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Company or of any associate or affiliate of the Company.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation and marketing) as a result of legislation enacted by various levels of government with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, and certain other provinces, all of which should be carefully considered by investors in the oil and gas industry. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada.

Pricing and Marketing

Oil

In Canada, the producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which results in the market determining the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the NEB. The NEB is currently undergoing a consultation process to update the regulations governing the issuance of export licenses. The updating process is necessary to meet the criteria set out in the federal Jobs, Growth and Long-term Prosperity Act (Canada) (the "Prosperity Act") which received Royal Assent on June 29, 2012. In this transitory period, the NEB has issued, and is currently following, an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications" under Part VI of the National Energy Board Act (Canada).

Natural Gas

Canada's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system, at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange, Intercontinental Exchange or the New York Mercantile Exchange in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 40 years) or for a larger quantity requires an exporter to obtain an export license from the NEB.

The North American Free Trade Agreement

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are carved out of the working interest owner's interest, from time to time, through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

The federal government has signaled it will, inter alia, phase out subsidies for the oil and gas industry, which include only allowing the use of the Canadian Exploration Expenses tax deduction in cases of successful exploration, implementing more stringent reviews for pipelines and establishing a pan-Canadian framework for combating climate change within 90 days of the 2015 Paris Climate Conference which concluded on December 12, 2015. These changes could affect earnings of companies operating in the oil and natural gas industry.

Alberta

On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "MRF"). The MRF will take effect on January 1, 2017. Wells drilled prior to January 1, 2017 will continue to be governed by the current "Alberta Royalty Framework" for a period of 10 years until January 1, 2027. The MRF is structured in three phases: (i) Pre-Payout, (ii) Mid-Life and (iii) Mature. During the Pre-Payout phase, a fixed 5% royalty will apply until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on depth, length and historical costs). The new royalty rate will be payable on gross revenue generated from all production streams (oil, gas and natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. While the metrics for calculating the Mid-Life phase royalty have yet to be released, the rate will be determined based on commodity prices and are intended, on average, to yield the same internal rate of return as under the current Alberta Royalty Framework. In the Mature phase, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, currently estimated to be 20 bbl/d for oil and 200 mcf/d for gas, the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of 5%. The downward adjustment of the royalty rate in the Mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well. Details of the MRF, including the applicable royalty rates and formulas, are scheduled to be released by March 31, 2016.

Oil sands projects are also subject to Alberta's royalty regime. The MRF does not change the oil sands royalty framework, however, the method and figures by which the royalties are calculated will be released to the public. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% - 9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma. Rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1% - 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher.

Currently, producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Royalties, for wells drilled prior to January 1, 2017 are paid pursuant to "The New Royalty Framework" (implemented by the Mines and Minerals (New Royalty Framework) Amendment Act, 2008) and the "Alberta Royalty Framework" until January 1, 2027. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36%.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the Freehold Mineral Rights Tax Act (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "IETP") has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "Emerging Resource and Technologies Initiative"). These initiatives apply to wells drilled before January 1, 2017, for a 10 year period, until January 1, 2027. Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;
- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;
- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and
- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

While the MRF eliminates the various royalty credits and incentives, outlined above, for wells drilled after December 31, 2016, the Government of Alberta has committed to creating cost allowance programs for both enhanced oil recovery schemes and higher risk experimental drilling. Details of these programs are scheduled to be released simultaneously with the finalization of the MRF prior to March 31, 2016.

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses and permits for varying terms and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Various provinces have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license.

Alberta has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses issued after January 1, 2009 at the conclusion of the primary term of the lease or license.

Production and Operation Regulations

The oil and natural gas industry in Canada is highly regulated and subject to significant control by provincial regulators. Regulatory approval is required for, among other things, the drilling of oil and natural gas wells, construction and operation of facilities, the storage, injection and disposal of substances and the abandonment and reclamation of well-sites. In order to conduct oil and gas operations and remain in good standing with the applicable provincial regulator, the Company must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance with such legislation, regulations, orders, directives or other directions can be costly and a breach of the same may result in fines or other sanctions.

Environmental Regulation

The oil and natural gas industry is currently subject to regulation pursuant to a variety of provincial and federal environmental legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability and the imposition of material fines and penalties.

Federal

Pursuant to the Prosperity Act, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime that came into force on July 6, 2012. The changes to the environmental legislation under the Prosperity Act are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

Alberta

The AER is the single regulator responsible for all energy development in Alberta. The AER ensures the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is efficient, attractive to business and investors and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. The following frameworks, plans and policies form the basis of Alberta's Integrated Resource Management System ("IRMS"). The IRMS method to natural resource management sets out to engage and consult with stakeholders and the public. While the AER is the primary regulator for energy development, several governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the AER, the Alberta Environmental Monitoring, Evaluation and Reporting Agency, the Policy Management Office, the Aboriginal Consultation Office and the Land Use Secretariat.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "ALUF"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

Proclaimed in force in Alberta on October 1, 2009, the Alberta Land Stewardship Act (the "ALSA") provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established under the ALSA are deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, registrations, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("LARP") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometers in size. The region includes a substantial portion of the Athabasca oil sands area, which contains approximately 82% of the province's oil sands resources and much of the Cold Lake oil sands area.

LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oil sands companies' tenure has been (or will be) cancelled in conservation areas and no new oil sands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit surface access.

In July 2014, the Government of Alberta approved the South Saskatchewan Regional Plan ("SSRP") which came into force on September 1, 2014. The SSRP is the second regional plan developed under the ALUF. The SSRP covers approximately 83,764 square kilometers and includes 44% of the provincial population.

The SSRP creates four new and four expanded conservation areas and two new and six expanded provincial parks and recreational areas. Similar to LARP, the SSRP will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, any new petroleum and natural gas tenures sold in conservation areas, provincial parks and recreational areas will prohibit surface access. However, oil and gas companies must minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Freehold mineral rights will not be subject to this restriction.

Liability Management Rating Programs

Alberta

In Alberta, the AER implements the Licensee Liability Rating Program (the "AB LLR Program"). The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The ABOGCA establishes an orphan fund (the "Orphan Fund") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant ("WIP") becomes defunct. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licensees and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER.

Made effective in three phases, from May 1, 2013 to August 1, 2015, the AER implemented important changes to the AB LLR Program (the "Changes") that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. The Changes affect the deemed parameters and costs used in the formula that calculates the ratio of deemed liabilities to deemed assets under the AB LLR Program, increasing a licensee's deemed liabilities and rendering the industry average netback factor more sensitive to asset value fluctuations. The Changes stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

The AER implemented the inactive well compliance program (the "IWCP") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013: Suspension Requirements for Wells ("Directive 013"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within 5 years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: Well Abandonment. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system.

Climate Change Regulation

Federal

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the oil and natural gas industry in Canada. Such regulations, surveyed below, impose certain costs and risks on the industry.

The Government of Canada is a signatory to the United Nations Framework Convention on Climate Change (the "UNFCCC") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing greenhouse gas ("GHG") emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of GHG emissions from 2005 levels. This target is aligned with the United States target. In a report dated October 2013, the federal government stated that this target represents a significant challenge in light of strong economic growth (Canada's economy is projected to be approximately 31% larger in 2020 compared to 2005 levels).

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "Action Plan") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "Updated Action Plan"). The Updated Action Plan outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific basis, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. Representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

On December 12, 2015, the UNFCCC adopted the Paris Agreement, to which Canada is a participant. The Paris Agreement mandates that all countries must work together to limit global temperature rise resulting from GHG emissions to a goal of less than 2° Celsius and to pursue efforts to limit below 1.5° Celsius, through implementing successive nationally determined contributions. Technical details remain unreleased, but the Government of Canada is expected to announce a plan within 90 days of the Paris Agreement, which will significantly increase Canada's GHG emission reduction targets.

Alberta

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the Climate Change and Emissions Management Act (the "CCEMA") enacted on December 4, 2003 and amended through the Climate Change and Emissions Management Amendment Act, which received royal assent on November 4, 2008. The accompanying regulations include the Specified Gas Emitters Regulation ("SGER"), which imposes GHG limits, and the Specified Gas Reporting Regulation, which imposes GHG emissions reporting requirements. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions. The SGER applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year ("Regulated Emitters") and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER.

On June 25, 2015, the Government of Alberta renewed the SGER for a period of two years with significant amendments while Alberta's newly formed Climate Advisory Panel conducted a comprehensive review of the province's climate change policy. In 2015, Regulated Emitters are required to reduce their emissions intensity by 2% from their baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year, 10% of their baseline in the eighth year and 12% of their baseline in the ninth or subsequent years. These reduction targets will increase, meaning that Regulated Emitters in their ninth or subsequent years of commercial operation must reduce their emissions intensity from their baseline by 15% in 2016 and 20% in 2017.

Regulated Emitters can meet their emissions intensity targets through a combination of the following: (1) producing its products with lower carbon inputs, (2) purchasing emissions offset credits from non-regulated emitters (generated through activities that result in emissions reductions in accordance with established protocols), (3) purchasing emissions performance credits from other Regulated Emitters that earned credits through the reduction of their emissions below the 100,000 tonne threshold, (4) cogeneration compliance adjustments and (5) by contributing to the Climate Change and Emissions Management Fund (the "Fund"). Contributions to the Fund are made at a rate of $15 per tonne of GHG emissions, increasing to a rate of $20 per tonne of GHG emissions in 2016 and $30 per tonne of GHG emissions in 2017. Proceeds from the Fund are directed at testing and implementing new technologies for greening energy production.

On November 22, 2015, as a result of the Climate Advisory Panel's Climate Leadership report, the Government of Alberta announced its Climate Leadership Plan which proposes to introduce a carbon tax on all emitters. An economy-wide levy $30 per tonne of GHG emissions will be phased in, starting in January 2017 at $20 per tonne, and increasing to $30 per tonne in January 2018. An oil sands specific approach was proposed to replace the $30 per tonne of GHG emissions to further reduce emissions and promote carbon competitiveness rather than rewarding past intensity levels. A 100 megatonne per year limit for GHG emissions was proposed for oil sands operations, which currently emit roughly 70 megatonnes per year. This cap exempts new upgrading and cogeneration facilities, which are allocated a separate 10 megatonne limit. The existing SGER will be replaced for large industrial facilities with a Carbon Competitiveness Regulation ("CCR"), in which sector specific output-based carbon allocations will be used to ensure competitiveness.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion over 15 years to fund two large-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the Carbon Capture and Storage Statutes Amendment Act, 2010. It deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Company's other public filings before making an investment decision. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Company's business and the oil and natural gas business generally.

Completion of the Arrangement

Each of the Company and Purchaser are currently working toward satisfying the conditions to the completion of the Arrangement, as described in *"General Development of the Business – Three-year History – 2015".* However, certain of the conditions to completion of the Arrangement are outside the control of Long Run and the Purchaser, including obtaining the required regulatory approvals. There is no certainty, nor can Long Run provide any assurance, that these conditions will be satisfied or, if satisfied, when they will be satisfied. Certain costs related to the Arrangement, such as legal and certain financial advisor fees, must be paid by Long Run even if the Arrangement is not completed. Failure to complete the Arrangement could materially negatively impact the market price of the Common Shares and the Convertible Debentures. Moreover, if the Arrangement Agreement is terminated, there is no assurance that the Board of Directors will be able to find a party willing to pay an equivalent or greater price for the Common Shares and Convertible Debentures than the price to be paid pursuant to the terms of the Arrangement Agreement. Termination of the Arrangement Agreement or non-completion of the Arrangement by the specified date constitutes an event of default under the Company's credit facilities agreements (*see "Risk Factors – Credit Facilities Arrangements").*

Each of Long Run and the Purchaser has the right to terminate the Arrangement Agreement in certain circumstances. Accordingly, there is no certainty, nor can either of Long Run or the Purchaser provide any assurance, that the Arrangement will not be terminated by either Long Run or the Purchaser before the completion of the Arrangement.

In the event that the Arrangement is not completed, the Company's ability to continue as a going concern and discharge its obligations will require additional equity or debt financing and/or proceeds from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory to the Company or at all. Similarly, there can be no assurance that the Company will be able to realize any or sufficient proceeds from asset sales to discharge its obligations and continue as a going concern.

Under the Arrangement Agreement, Long Run may be required to pay a termination fee of $20 million to the Purchaser in the event that the Arrangement Agreement is terminated in certain circumstances. In the event that the termination fee becomes payable to the Purchaser by Long Run, Long Run may require additional financing in order to pay the termination fee. Such financing may not be available to Long Run on terms and conditions satisfactory to Long Run or at all. In the event that Long Run is unable to pay the termination fee to the Purchaser when payable, Long Run may become subject to litigation by the Purchaser and Long Run's ability to access additional financing may be further compromised. See also "*Risk Factors – Litigation*" and "*Risk Factors – Additional Funding Requirements*".

Credit Facilities Arrangements

The Company currently has credit facilities and the amount authorized thereunder is dependent on the borrowing base determined by its bank syndicate. The bank syndicate uses the Company's reserves, commodity prices, applicable discount rate and other factors to periodically determine the Company's borrowing base. A further decline in commodity prices could further reduce the Company's borrowing base thereby further reducing the funds available to the Company under the credit facilities. This could result in the requirement to repay a portion, or all, of the Company's bank indebtedness.

The Company is required to comply with covenants under its credit facilities agreements which may, from time to time either affect the availability, or price, of additional funding and in the event that the Company does not comply with these covenants, repayment could be required. Events beyond the Company's control may contribute to the failure of the Company to comply with its covenants and the occurrence of other events also beyond the Company's control could result in an event of default under the credit facilities agreements.

The amendments made to the Company's credit facilities agreements on January 29, 2016 included additional events of default related to the completion of the Arrangement, including termination of the Arrangement Agreement for any reason or non-completion of the Arrangement by a specified date. Upon the occurrence of such an event of default, or any other event of default under the credit facilities agreements, the amount owing by Long Run under the credit facilities agreements may be accelerated and the bank syndicate may proceed to enforce their security or otherwise realize upon the collateral granted to them to secure the indebtedness under the credit facilities agreements. If the Company's bank syndicate requires repayment of all or a portion of the amounts outstanding under its credit facilities for any reason, including failure to complete the Arrangement, there is no certainty that the Company would be in a position to make such repayment. Even if the Company is able to obtain new financing in order to make any required repayment under its credit facilities, it may not be on commercially reasonable terms or terms that are acceptable to the Company.

Weakness in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by OPEC, slowing growth in China and other emerging economies, market volatility and disruptions in Asia and sovereign debt levels in various countries, have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at a federal level and, in case of Alberta, the provincial level and the resultant uncertainty surrounding regulatory, tax and royalty changes that may be implemented by the new governments. In addition, the inability to get the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in western Canada has led to additional uncertainty and reduced confidence in the oil and gas industry in western Canada.

Lower commodity prices may also affect the volume and value of the Company's reserves especially as certain reserves become uneconomic. In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, the Company's cash flow resulting in a reduced capital expenditure budget. As a result, the Company may not be able to replace its production with additional reserves and both the Company's production and reserves could be reduced on a year over year basis. Any decrease in value of the Company's reserves may reduce the borrowing base under its credit facilities, which, depending on the level of the Company's indebtedness, could result in the Company having to repay a portion of its indebtedness.

Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Company may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms. If these conditions persist, the Company's cash flow may not be sufficient to continue to fund its operations and to satisfy its obligations when due and the Company's ability to continue as a going concern and discharge its obligations will require additional equity or debt financing and/or proceeds from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory to the Company or at all. Similarly, there can be no assurance that the Company will be able to realize any or sufficient proceeds from asset sales to discharge its obligations and continue as a going concern.

Prices, Markets and Marketing

Numerous factors beyond the Company's control do, and will continue to, affect the marketability and price of oil and natural gas acquired or discovered by the Company. The Company's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance the Company's reserves are from pipelines, railway lines, processing and storage facilities, operational problems affecting pipelines, railway lines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Company.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Company. These factors include economic conditions in the United States, Canada, Europe, China and emerging markets, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Company's ability to access such markets. Oil prices are expected to remain volatile and may decline in the near future as a result of global excess supply due to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities and OPEC's recent decisions pertaining to the oil production of OPEC member countries, among other factors. A material decline in prices could result in a reduction of the Company's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Company's reserves. The Company might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in the Company's expected net production revenue and a reduction in its oil and natural gas acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Company's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects. See *"Risk Factors – Weakness in the Oil and Gas Industry".*

Reserves Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserves and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- production rates;
- ultimate reserves recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves. Such variations could be material.

In accordance with applicable securities laws, the Company's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Company's oil and natural gas reserves will vary from the estimates contained in the reserves evaluation and such variations could be material. The reserves evaluation is based in part on the assumed success of activities the Company intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the reserves evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserves evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and therefore does not reflect changes in the Company's reserves since that date.

Additional Funding Requirements

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Company may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. Due to the conditions in the oil and gas industry and/or global economic volatility, the Company may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing.

Continued depressed oil and natural gas prices have caused decreases, and may cause further decreases, in the Company's revenues from its reserves, which may affect the Company's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Company's ability to make capital investments and maintain existing assets may be impaired and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Company's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing shareholders. Failure to obtain any financing necessary for the Company's capital expenditure plans may result in a delay in development or production on the Company's properties.

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect the Company's production revenues. Accordingly, exchange rates between Canada and the United States could affect the future value of the Company's reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the United States dollar may positively affect the price the Company receives for its oil production, it could also result in an increase in the price for certain goods used for the Company's operations, which may have a negative impact on the Company's financial results.

To the extent that the Company engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Company may contract.

An increase in interest rates could result in a significant increase in the amount the Company pays to service debt, resulting in a reduced amount available to fund its exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of the Common Shares.

Third Party Credit Risk

The Company may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In addition, the Company may be exposed to third party credit risk from operators of properties in which the Company has a working or royalty interest. 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 joint venture partners may affect a joint venture 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. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Company being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect the Company's financial and operational results.

Substantial Capital Requirements

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Company's ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- the Company's credit rating (if applicable);
- commodity prices;
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and the Company's securities in particular.

Further, if the Company's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. The Company may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business financial condition, results of operations and prospects.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Company's existing reserves, and the production from them, will decline over time as the Company produces from such reserves. A future increase in the Company's reserves will depend on both the ability of the Company to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Company will be able continue to find satisfactory properties to acquire or participate in. Moreover, management of the Company may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that the Company will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells as well as from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, and shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, the Company may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Company.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

As is standard industry practice, the Company is not fully insured against all risks, nor are all risks insurable. Although the Company maintains liability insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event the Company could incur significant costs.

Project Risks

The Company manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Company's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Company's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or the Company's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Company could be unable to execute projects on time, on budget, or at all, and may be unable to market the oil and natural gas that it produces effectively.

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Company's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. Similarly, the market price of the Common Shares could be subject to significant fluctuations in response to variations in the Company's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted.

Income Taxes

The Company files all required income tax returns and believes that it is in full compliance with the provisions of the Income Tax Act (Canada) (“Tax Act”) and all other applicable provincial tax legislation**.** However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Company, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Company. Furthermore, tax authorities having jurisdiction over the Company may disagree with how the Company calculates its income for tax purposes or could change administrative practices to the Company's detriment.

Expiration of Licenses and Leases

The Company's properties are held in the form of licences and leases and working interests in licenses and leases. If the Company or the holder of the license or lease fails to meet the specific requirement of a license or lease, the license or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each license or lease will be met. The termination or expiration of the Company's licenses or leases or the working interests relating to a license or lease may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. 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. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge. Although the Company believes that it will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See *"Industry Conditions".* The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Company's costs, either of which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Company will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that the Company will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, the Company's business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Company's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reserves.

Due to recent seismic activity reported in the Fox Creek area of Alberta, the Alberta Energy Regulator has announced new seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay Zone in the Fox Creek area. These requirements include, among others, an assessment of the potential for seismicity prior to operations, the implementation of a response plan to address potential events and the suspension of operations if a seismic event above a particular threshold occurs. The Alberta Energy Regulator continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

Climate Change

The Company's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Company to comply with GHG emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* (the "UNFCCC") and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020; however, these GHG emission reduction targets are not binding. Some of the Company's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, to which Canada was a participant, the Government of Canada is expected to announce a plan to further reduce its GHG emission reduction targets by March 11, 2016. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is not possible to predict the impact on the Company and its operations and financial condition. See *"Industry Conditions - Climate Change Regulation".*

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Company's earnings and could make future capital investments, or the Company's operations, less economic. On January 29, 2016, the Government of Alberta adopted a new royalty regime which will take effect on January 1, 2017. Details of this new regime are scheduled to be finalized and released before March 31, 2016. See *"Industry Conditions - Royalties and Incentives".*

Liability Management

Alberta and various other provinces have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of the Company's deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. In addition, the liability management system may prevent or interfere with the Company's ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See *"Industry Conditions - Liability Management Rating Programs".*

Hedging

From time to time, the Company may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Company engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Company's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes or prices fall significantly lower than projected;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time the Company may enter into agreements to fix the exchange rate of Canadian to United States dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, the Company will not benefit from the fluctuating exchange rate.

Gathering and Processing Facilities, Pipeline Systems and Rail

The Company delivers its products through gathering and processing facilities and pipeline systems some of which it does not own and by rail. The amount of oil and natural gas that the Company can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines, and in particular the processing facilities, could result in the Company's inability to realize the full economic potential of its production or in a reduction of the price offered for the Company's production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Company's production, operations and financial results. Furthermore, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Company's business and, in turn, the Company's financial condition, results of operations and cash flows. The federal government has signaled that it plans to review the National Energy Board approval process for large projects. This may cause the timeframe for project approvals to increase for current and future applications.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the Safe and Accountable Rail Act which increased insurance obligations on the shipment of crude oil by rail, imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of crude oil by rail.

A portion of the Company's production may, from time to time, be processed through facilities owned by third parties and over which the Company does not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on the Company's ability to process its production and deliver the same for sale.

Geopolitical Risks

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by the Company. Conflicts, or conversely peaceful developments, arising outside of Canada have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of the Company's net production revenue.

In addition, the Company's oil and natural gas properties, wells and facilities could be the subject of a terrorist attack. If any of the Company's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company does not have insurance to protect against the risk from terrorism.

Insurance

The Company's involvement in the exploration for and development of oil and natural gas properties may result in the Company becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Company maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, the Company may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that the Company is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Competition

The petroleum industry is competitive in all of its phases. The Company competes with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Company's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Company. The Company's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, methods and reliability of delivery and storage.

Reliance on Key Personnel

The Company's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company does not have any key person insurance in effect for the Company. The contributions of the existing management team to the immediate and near term operations of the Company are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Company.

Litigation

In the normal course of the Company's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company and as a result, could have a material adverse effect on the Company's assets, liabilities, business, financial condition and results of operations.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities.

Operational Dependence

Other companies operate some of the assets in which the Company has an interest. The Company has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Company's financial performance. The Company's return on assets operated by others depends upon a number of factors that may be outside of the Company's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which the Company has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which the Company has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations the Company may be required to satisfy such obligations and to seek recourse from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Company potentially becoming subject to additional liabilities relating to such assets and the Company having difficulty collecting revenue due from such operators. Any of these factors could materially adversely affect the Company's financial and operational results.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise. The actual interest of the Company in properties may accordingly vary from the Company's records. If a title defect does exist, it is possible that the Company may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Company's title to the oil and natural gas properties the Company controls that could impair the Company's activities on them and result in a reduction of the revenue received by the Company.

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. In addition, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding decreases in the demand for the goods and services of the Company.

Management of Growth

The Company may be subject to growth related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Company to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Company to deal with this growth may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Conflicts of Interest

Certain directors or officers of the Company may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA which require a director or officer of a Company who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Company to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA . See *"Conflicts of Interest".*

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Company may disclose confidential information relating to the business, operations or affairs of the Company. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put the Company at competitive risk and may cause significant damage to its business. The harm to the Company's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Company will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Company considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired businesses may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets may be periodically disposed of so the Company can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Company, if disposed of, may realize less than their carrying value on the financial statements of the Company.

Expansion into New Activities

The operations and expertise of the Company's management are currently focused primarily on oil and gas production, exploration and development in the Western Canada Sedimentary Basin. In the future, the Company may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase the Company's exposure to one or more existing risk factors, which may in turn result in the Company's future operational and financial conditions being adversely affected.

Cost of New Technologies

The petroleum industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Company. There can be no assurance that the Company will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by the Company or implemented in the future may become obsolete. In such case, the Company's business, financial condition and results of operations could be affected adversely and materially. If the Company is unable to utilize the most advanced commercially available technology, its business, financial condition and results of operations could also be adversely affected in a material way.

Alternatives to and Changing Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and energy generation devices could reduce the demand for oil, natural gas and other liquid hydrocarbons. The Company cannot predict the impact of changing demand for oil and natural gas products and any major changes may have a material adverse effect on the Company's business, financial condition, results of operations and cash flows.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in portions of western Canada. The Company is not aware that any claims have been made in respect of its properties and assets. However, if a claim arose and was successful, such claim may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Issuance of Debt

In the event the Arrangement is not completed, the Company may enter into transactions to acquire assets or shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Company's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Company may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Company's articles nor its by-laws limit the amount of indebtedness that the Company may incur. The level of the Company's indebtedness from time to time could impair the Company's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Dividends

The amount of future cash dividends paid by the Company, if any, will be subject to the discretion of the Board of Directors of the Company and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends.

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Company's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risk and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumption and uncertainties are found under the heading *"Forward-Looking Statements"* of this Annual Information Form.

ADDITIONAL INFORMATION

Additional information relating to the Company can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans is contained in the Company's information circular for the Company's most recent annual meeting of shareholders that involved the election of directors. Additional financial information is contained in the Company's financial statements and the related management's discussion and analysis for the Company's most recently completed financial year.

ABBREVIATIONS

Oil and Natural Gas Liquids		**Natural Gas**	
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	MMcf	million cubic feet
Boe/d	barrels of oil equivalent per day	Mcf/d	thousand cubic feet per day
MBbls	thousand barrels	MMcf/d	million cubic feet per day
MMBbls	million barrels	MMcfe/d	million cubic feet equivalent per day
Mstb	1,000 stock tank barrels	MMbtu	million British Thermal Units
Bbl/d	barrels per day	Bcf	billion cubic feet
NGLs	natural gas liquids	GJ	gigajoule
STB	standard tank barrels	MM	Million

Other

AECO	A natural gas storage facility located at Suffield, Alberta.
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
Boe	barrel of oil equivalent of natural gas and crude oil on the basis of 1 Boe for 6 Mcf of natural gas
Boe/d	barrel of oil equivalent per day
m^3	cubic meters
MBoe	1,000 barrels of oil equivalent
$000s	thousands of dollars
$M	thousands of dollars
$MM	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

Disclosure provided herein in respect of Boe's may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Where any disclosure of reserves data is made in this annual information form that does not reflect all reserves of the Company, the reader should note that the estimates of reserves and future net revenue for individual properties or groups of properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

CONVERSIONS

To Convert From	To	Multiply By
Mcf	Cubic meters	28.174
Cubic meters	Cubic feet	35.494
Bbls	Cubic meters	0.159
Cubic meters	Bbls oil	6.290
Feet	Meters	0.305
Meters	Feet	3.281
Miles	Kilometers	1.609
Kilometers	Miles	0.621
Acres (Alberta)	Hectares	0.400
Hectares (Alberta)	Acres	2.500
Acres (British Columbia)	Hectares	0.405
Hectares (British Columbia)	Acres	2.471

CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires:

"**ABCA**" means *Business Corporations Act* (Alberta);

"**AER**" means the Alberta Energy Regulator;

"**APEGA**" means The Association of Professional Engineers and Geoscientists of Alberta;

"**Arrangement**" has the meaning as set forth under *"General Development of the Business – Three-Year History – 2015";*

"**Arrangement Agreement**" has the meaning as set forth under *"General Development of the Business – Three-Year History – 2015";*

"**Asset Rationalization Process**" has the meaning as set forth under *"General Development of the Business – Three-Year History – 2015";*

"**Board of Directors**" means the board of directors of the Company;

"**Change of Control Transaction**" means any of the following**:**

(i) an amalgamation, merger, business combination, consolidation, recapitalization, reorganization, liquidation, dissolution or winding-up in respect of the Company or any other transaction of the Company with another Company or entity, other than a wholly-owned subsidiary, or an arrangement pursuant to the *Business Corporations Act* (Alberta) involving the Company or another transaction pursuant to which a Person, or group of Persons acting jointly or in concert, acquires all the issued and outstanding Common Shares;

(ii) the direct or indirect sale, lease or other disposition (or any long-term supply arrangement, license or other arrangement having the same economic effect as a sale) of all or substantially all of the consolidated assets, revenues or earnings, as applicable, or undertaking of the Company;

(iii) the direct or indirect acquisition by any Person, or group of Persons acting jointly or in concert, of voting control or direction over an aggregate of 50% or more of the outstanding Common Shares, by take-over bid, issuance of Common Shares or otherwise; or

(iv) any similar transaction or series of transactions involving the Company or any of its subsidiaries, directly or indirectly.

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"Common Non-Voting Shares" means the non-voting common shares in the capital of the Company;

"**Common Shares**" means the common voting shares in the capital of the Company;

"**Company**" or **"Long Run"** means Long Run Exploration Ltd. and, for greater certainty, prior to October 23, 2012, "Company" means WestFire;

"**Control Person**" means (a) a person or company who holds more than 20 percent of the voting rights attached to all outstanding voting securities of the Company, or (b) each person or company in a combination of persons or companies, acting in concert by virtue of an agreement, arrangement, commitment or understanding, which holds more than 20 percent of the voting rights attached to all outstanding voting securities of the Company;

"**Conversion Ratio**" means the number of Common Shares issuable upon conversion of each Non-Voting Convertible Share, which shall initially be one Common Share, subject to adjustment in accordance with the terms of the Non-Voting Convertible Shares;

"**Convertible Debentures**" means the 6.40% convertible unsecured subordinated debentures due January 31, 2019 of the Company;

"**Court**" means the Court of Queen's Bench of Alberta;

"**Crocotta**" means Crocotta Energy Inc.;

"**Crocotta Acquisition**" has the meaning as set forth under *"General Development of the Business – Three-Year History – 2014"*;

"**Debenture Indenture**" means the debenture indenture between the Company and CST Trust Company dated as of January 28, 2014 providing for the issue of the Convertible Debentures;

"**Deep Basin Property Acquisition**" has the meaning as set forth under *"General Development of the Business – Three-Year History – 2014"*;

"**Encana**" means Encana Corporation;

"**EOR**" means enhanced oil recovery;

"**Exchange**" means the TSX or, if applicable, such other stock exchange on which the Common Shares are principally traded;

"**ExploreCo**" has the meaning as set forth under "*General Development of the Business – Three-Year History – 2014";*

"First Preferred Shares" means the first preferred shares in the capital of the Company, issuable in series;

"**GHG**" means Greenhouse Gas;

"**gross**" means:

(a) in relation to the Company's interest in production and reserves, its "company gross reserves", which are the Company's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Company;

(b) in relation to wells, the total number of wells in which the Company has an interest; and

(c) in relation to properties, the total area of properties in which the Company has an interest.

"**Guarantor**" means Qingdao Sinoenergy Capital Corporation;

"**Guide**" means Guide Exploration Ltd.;

"**Maple Marathon**" means Maple Marathon Investments Limited;

"**MIEH**" means MIE Holdings Corporation;

"**net**" means:

(a) in relation to the Company's interest in production and reserves, the Company's working interest (operating and non-operating) share after deduction of royalty obligations, plus the Company's royalty interests in production or reserves;

(b) in relation to wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and

(c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

"**NI 51-101**" means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities*;

"**NI 51-102**" means National Instrument 51-102 – *Continuous Disclosure Obligations*;

"Non-Voting Convertible Shares" means the non-voting convertible shares in the capital of the Company;

"**Offer**" means an offer to purchase Common Shares (or an acceptance of an offer to sell Common Shares) which must, by reason of applicable securities legislation or by laws, regulations or policies of a stock exchange on which the Common Shares are listed, be made to each holder of Common Shares whose last address on the records of the Company is in a province or territory of Canada to which the relevant requirement applies;

"**Offer Date**" means the date on which an Offer is made;

"**OPEC**" means the Organization of the Petroleum Exporting Countries;

"**Person**" means an individual, partnership, Company, trust, unincorporated association, joint venture or other entity and includes a group of Persons acting jointly or in concert;

"**Proposed Private Placement**" has the meaning as set forth under *"General Development of the Business – Three-Year History – 2015";*

"**Purchaser**" means Calgary Sinoenergy Investment Corp.*;*

"**Redemption Period**" means the period of time commencing on the seventh business day after the Offer Date and terminating on the last date upon which holders of Common Shares may accept the Offer;

"**Redemption Price**" means the value of the consideration offered under an Offer which, in the case of non cash consideration shall be determined solely by the Board of Directors, acting reasonably;

"**Secondary Offering**" has the meaning as set forth under *"General Development of the Business – Three-Year History – 2014";*

"**Sproule**" means Sproule Associates Limited;

"**Sproule Report**" means the report of Sproule dated March 9, 2016 evaluating, effective December 31, 2015 the crude oil, natural gas liquids and natural gas reserves of the Company;

"**SRC**" means Sprott Resource Corp.;

"**Subscription Receipts**" has the meaning as set forth under *"General Development of the Business – Three-Year History – 2014";*

"**Tax Act**" means the Income Tax Act (Canada);

"**TSX**" means the Toronto Stock Exchange; and

"**WestFire**" means WestFire Energy Ltd.

CONVENTIONS

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

Unless otherwise specified, information in this Annual Information Form is as at the end of the Company's most recently completed financial year, being December 31, 2015.

All dollar amounts herein are in Canadian dollars, unless otherwise stated.

FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, management's assessment of future plans and operations, reserve and production estimates, drilling plans, activities to be undertaken in various property areas, criteria, nature of planned capital expenditures, plans to improve balance sheet strength and the methods thereof, the Arrangement and the anticipated timing for the completion thereof, expected method of funding capital expenditures, tax horizon, future production estimates, timing of development of undeveloped reserves, future development costs, estimated abandonment and reclamation costs and the timing thereof, weighting of production between different commodities, forecast commodity prices, exchange rates and inflation rates, expected land expiries and plans with respect thereto, the potential for enhanced oil recovery on various properties of the Company and timing to implement such plans, the effect of government announcements, proposals and legislation and the expected volatility in commodity prices and stock markets may be forward looking statements which reflect management's expectations regarding future plans and intentions, growth, results of operations, performance and business prospects and opportunities. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions have been used to identify these forward looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward looking statements including, but not limited to, changes in general economic and market conditions, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserves 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 , failure to satisfy the conditions precedent to closing of the Arrangement and risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserves estimates of Long Run's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Long Run 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 Long Run 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 Long Run operates; the timely receipt of any required regulatory approvals; the ability of Long Run 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 Long Run has an interest in to operate the field in a safe, efficient and effective manner; the ability of Long Run to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Long Run to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Long Run operates; and the ability of Long Run to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Long Run's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) and at Long Run's website (www.longrunexploration.com). Although the forward looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward looking statements.

Investors should not place undue reliance on forward looking statements. These forward looking statements are made as of the date hereof and the Company assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward looking statements and other information contained herein concerning the oil and gas industry and the Company's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Company believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Company is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

SCHEDULE "A"
FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Long Run Exploration Ltd. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the board of directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on recommendation of the Reserves Committee, approved

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-102F2 which is the report of the independent qualified reserves evaluator on the reserves data, contingent resources data, or prospective resources data; and

(c) the content and filing of this report.

Because the reserves data is based on judgments regarding future events, actual results will vary and the variations may be material.

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

(signed) Dale J. Orton
Senior Vice President, Development

(signed) Michael M. Graham
Lead Director and Chair of the Reserves Committee

(signed) John A. Brussa
Director and Member of the Reserves Committee

DATED as of this 9th day of March, 2016.

SCHEDULE "B"
FORM 51-101F2
REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the Board of Directors of Long Run Exploration Ltd. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2015, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook"), maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2015, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount rate)			
			Audited	Evaluated	Reviewed	Total
			$M	$M	$M	$M
Sproule	December 31, 2015	Canada				
Total			Nil	978,744	Nil	978,744

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report, entitled "Evaluation of the P&NG Reserves of Long Run Exploration Ltd. (As of December 31, 2015) ".

8. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

EXECUTED as to our report referred to above:

Sproule Associates Limited

Calgary, Alberta

March 9, 2016

(signed) Steven J. Golko, P.Eng.
Vice-President, Field Development & Capital
Strategies and Partner

(signed) Reza M. Saedi, P.Eng.
Senior Petroleum Engineer

(signed) Alexander Minev, P.Geol.
Petroleum Geologist and Associate

(signed) Alec Kovaltchouk, P.Geo.
Vice-President, Geoscience and Partner

(signed) Attila A. Szabo, P.Eng.
Vice-President, Strategic Advisory and Director

SCHEDULE "C"

AUDIT COMMITTEE

MANDATE AND TERMS OF REFERENCE

ROLE AND OBJECTIVE

The Audit Committee (the "Committee") is a committee of the board of directors (the "Board") of Long Run Exploration Ltd. ("Long Run" or the "Corporation") to which the Board has delegated the responsibility for the oversight of the nature and scope of the annual audit, the oversight of internal controls and management's reporting on internal accounting standards and practices, the review of financial information, accounting systems and procedures, financial reporting and financial statements and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

1. to assist directors in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Long Run and related matters;

2. to provide better communication between directors and external auditors;

3. to enhance the external auditor's independence;

4. to increase the credibility and objectivity of financial reports; and

5. to strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

MEMBERSHIP OF COMMITTEE

1. The Committee will be comprised of at least three (3) directors of Long Run or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in National Instrument 52-110 - Audit Committees ("NI 52-110") unless the Board determines that the exemption contained in NI 52-110 is available and determines to rely thereon.

2. The Board may from time to time designate one of the members of the Committee to be the Chair of the Committee.

3. All of the members of the Committee must be "financially literate" (as defined in NI 52-110) unless the Board determines that an exemption under NI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of NI 52-110.

MANDATE AND RESPONSIBILITIES OF COMMITTEE

It is the responsibility of the Committee to:

1. Oversee the work of the external auditors, including the resolution of any disagreements between management and the external auditors regarding financial reporting.

2. Recommending to the Board the nomination and compensation of the external auditors.

3. Satisfy itself on behalf of the Board with respect to Long Run's internal control systems.

4. Review the annual and interim financial statements of Long Run and related management's discussion and analysis ("MD&A") prior to their submission to the Board for approval. The process should include but not be limited to:
    - reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
    - reviewing significant accruals, reserves or other estimates such as the impairment test calculation;
    - reviewing accounting treatment of unusual or non-recurring transactions;
    - ascertaining compliance with covenants under loan agreements;
    - reviewing disclosure requirements for commitments and contingencies;
    - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
    - reviewing unresolved differences between management and the external auditors; and
    - obtain explanations of significant variances with comparative reporting periods.

5. Review the financial statements, prospectuses, MD&A, annual information forms ("AIF") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Long Run's disclosure of all other financial information and will periodically assess the accuracy of those procedures.

6. With respect to the appointment of external auditors by the Board:
    - recommend to the Board the external auditors to be nominated;
    - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;
    - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;

- when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
- review and pre-approve any non-audit services to be provided to Long Run or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre–approve non–audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre-approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.

7. Review with external auditors (and internal auditor if one is appointed by Long Run) their assessment of the internal controls of Long Run, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee will also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Long Run and its subsidiaries.

8. Review risk management policies and procedures of Long Run (i.e. hedging, litigation and insurance).

9. Establish a procedure for:
    - the receipt, retention and treatment of complaints received by Long Run regarding accounting, internal accounting controls or auditing matters; and
    - the confidential, anonymous submission by employees of Long Run of concerns regarding questionable accounting or auditing matters.

10. Review and approve Long Run's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of Long Run.

11. To review Long Run's disclosure controls and procedures to ensure such disclosure controls and procedures provide reasonable assurance that:
    - Long Run's Disclosure Policy is effectively implemented across all business units and corporate functions; and
    - information of a material nature is accumulated and communicated to senior management, including the Chief Executive Officer, President and the Chief Financial Officer, to allow timely decisions on required disclosures and certification.

12. To review the results of Long Run's annual evaluation of the effectiveness of Long Run's disclosure controls and procedures.

The Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Corporation. The Committee will also have the authority to investigate any financial activity of Long Run. All employees of Long Run are to cooperate as requested by the Committee.

The Committee may also retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of Long Run without any further approval of the Board.

MEETINGS AND ADMINISTRATIVE MATTERS

1. At all meetings of the Committee every resolution shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.

2. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.

3. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board unless otherwise determined by the Committee or the Board.

4. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer will attend meetings of the Committee where matters relating to the functions as the Audit Committee are dealt with, unless otherwise excused from all or part of any such meeting by the Chairman.

5. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.

6. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

7. The Committee may invite such officers, directors and employees of the Corporation as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.

8. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

9. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation.

10. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee, each member will hold such office until the Committee is reconstituted.

11. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chairman of the Board by the Committee Chair.

March 9, 2016