LONG RUN EXPLORATION LTD.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2014

March 4, 2015

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

BACKGROUND

Long Run is engaged in the development, acquisition, 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 financial years.

2014

On January 28, 2014, the Company closed a public offering of $75.0 million principal amount of Convertible Debentures for gross proceeds of $75.0 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 Long Run shares outstanding 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 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 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 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 Acquisition.

On August 6, 2014, Long Run acquired all of the issued and outstanding common shares of Crocotta Energy Inc. ("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 Long Run Common Share 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 Montney-focused 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 are 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. As a result of a volatile and uncertain commodity price environment, the monthly dividend was suspended in February 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 are 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 are prospective for the Viking Formation and, at the time of closing, were producing approximately 450 BOE/d.

2012

On October 23, 2012, WestFire Energy Ltd. (“WestFire”) and Guide Exploration Ltd. (“Guide”) completed the WestFire/Guide Arrangement and in connection therewith, WestFire issued an aggregate of 42.6 million Common Shares and assumed Guide's bank debt of $241 million. WestFire and Guide amalgamated pursuant to the WestFire/Guide Arrangement, the Articles of WestFire were amended to change the name to "Long Run Exploration Ltd." and management of Guide became management of Long Run and the board of directors was reconstituted.

On December 14, 2012, Long Run closed the disposition of properties in the Plato area of west central Saskatchewan for cash consideration of $180 million.

Significant Acquisitions

Other than the Crocotta Acquisition described above, 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. Long Run filed a Business Acquisition Report in accordance with Form 51-102F4 for the Crocotta Acquisition.

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 pursuant to the WestFire/Guide Arrangement. 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 Exploration Ltd. 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 Deep Basin Cardium, the Redwater Viking and the Boyer Bluesky.

Long Run has assembled a large land position and is continuing to add oil and natural gas infrastructure in 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.

The Company continues to evaluate its business model in light of prevailing market conditions and opportunities, with the goal of balancing financial flexibility and operational momentum. Long Run is focused on improving its balance sheet strength, through disciplined capital spending and an ongoing asset rationalization program. In looking forward to 2015, the Company recognizes the current uncertainty regarding future commodity prices and believes it has adopted a fiscally prudent and conservative current year plan. Proactive measures, including a revised capital budget and the suspension of the Company’s dividend, are designed to maximize longer term shareholder returns, while prioritizing balance sheet protection.

Specialized Skill 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 and has the capability to expand the scope of Long Run's activities as opportunities arise.

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 will attempt 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. Management believes that Long Run will be able to explore and develop new production and reserves with the objective of increasing its cash flow and reserve base. 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 4, 2015. The effective date of the Statement is December 31, 2014 and the preparation date of the Statement is March 4, 2015.

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, 2014. The reserves data set forth below (the "Reserves Data") is based upon the Sproule Report dated March 4, 2015. 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 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 reserve 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 liquid reserves may be greater than or less than the estimates provided herein.

Reserves Data (Forecast Prices and Costs)

Summary of Oil and Gas Reserves and Net Present Values of Future Net Revenue
December 31, 2014
(Forecast Prices and Costs)

	RESERVES									
	LIGHT AND MEDIUM OIL *(MBbl)*		HEAVY OIL *(MBbl)*		NATURAL GAS *(MMcf)*		NATURAL GAS LIQUIDS *(MBbl)*		TOTAL *(MBOE)*	
	Gross	*Net*	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*
Proved Developed										
Producing	14,840	12,573	324	299	194,693	171,263	7,799	5,506	55,412	46,921
Non-Producing	261	225	43	34	19,975	16,736	818	567	4,451	3,615
Proved Undeveloped	11,004	9,858	167	136	147,669	126,265	7,899	5,912	43,681	36,950
Total Proved	26,105	22,655	533	469	362,336	314,264	16,516	11,985	103,544	87,487
Probable	13,415	11,165	183	155	250,508	209,930	11,731	8,240	67,081	54,547
Total Proved plus Probable	39,521	33,820	716	624	612,844	524,195	28,247	20,225	170,625	142,034

Net Present Values of Future Net Revenue
December 31, 2014
(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	1,121,103	906,484	768,299	670,898	598,224	1,121,103	906,484	768,299	670,898	598,224	16.37
Non-Producing	76,595	57,659	46,135	38,322	32,683	76,595	57,659	46,135	38,322	32,683	12.76
Proved Undeveloped	561,912	328,271	191,059	105,860	50,808	561,912	328,271	191,059	105,860	50,808	5.17
Total Proved	1,759,609	1,292,414	1,005,493	815,081	681,715	1,759,609	1,292,414	1,005,493	815,081	681,715	11.49
Probable	1,517,695	938,937	636,712	458,059	343,584	1,160,266	727,407	500,547	365,311	277,791	11.67
Total Proved plus Probable	3,277,304	2,231,351	1,642,205	1,273,140	1,025,299	2,919,875	2,019,821	1,506,040	1,180,391	959,506	11.56

Total Future Net Revenue
December 31, 2014
(Forecast Prices and Costs, Undiscounted; $M)

	REVENUE	ROYALTIES	OPERATING COSTS	DEVELOPMENT COSTS	WELL ABANDONMENT COSTS	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
Total Proved	5,017,410	598,652	1,844,973	778,831	35,345	1,759,609	0	1,759,609
Total Proved plus Probable	8,532,725	1,098,977	2,883,547	1,208,870	64,026	3,277,304	357,429	2,919,875

Future Net Revenue by Production Group
December 31, 2014
(Forecast Prices and Costs)

RESERVES CATEGORY	PRODUCTION GROUP	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)	583,022	16.50 $/Bbl
	Heavy Oil (including solution gas and other by-products)	13,142	16.95 $/Bbl
	Natural Gas (including by-products but excluding solution gas from oil wells)	421,279	1.37 $/Mcf
	Other Income	-11,951	
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	921,196	17.11 $/Bbl
	Heavy Oil (including solution gas and other by-products)	17,597	16.93 $/Bbl
	Natural Gas (including by-products but excluding solution gas from oil wells)	716,471	1.37 $/Mcf
	Other Income	-13,059	

Notes to Reserves Data Tables Above

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the Sproule Report prepared in accordance with NI 51-101 and the COGE Handbook, which is incorporated by reference.

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. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by Sproule in the Sproule Report were an average of the forecast prices, inflation and exchange rates as published by Sproule, GLJ Petroleum Consultants Ltd., and McDaniel & Associates Consultants Ltd. as at December 31, 2014 (the "Consultants' Average Forecast Prices"). The forecast price and cost assumptions assume the continuance of current laws and regulations. They are as follows:

	Oil							
	WTI Cushing Oklahoma *($US/Bbl)*	Edmonton Oil Price 40° API *($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)*
2015	64.17	67.89	51.86	3.38	73.48	52.02	1.833	0.853
2016	76.67	83.52	63.90	3.83	90.17	63.44	1.833	0.868
2017	83.33	90.96	69.64	4.06	98.20	69.02	1.833	0.868
2018	87.08	95.26	72.93	4.41	102.69	72.35	1.833	0.868
2019	90.67	99.33	76.03	4.76	106.99	75.52	1.833	0.868
2020	94.30	103.80	79.45	4.97	111.73	78.96	1.833	0.868
2021	96.59	106.16	81.25	5.18	114.26	80.74	1.833	0.868
2022	98.36	108.10	82.74	5.36	116.34	82.22	1.833	0.868
2023	100.18	110.09	84.25	5.54	118.47	83.75	1.833	0.868
2024	102.02	112.13	85.85	5.70	120.67	85.33	1.833	0.868
2025	103.88	114.17	87.39	5.80	122.85	86.86	1.833	0.868
2026	105.80	116.26	88.98	5.90	125.10	88.48	1.833	0.868
2027	107.74	118.41	90.63	6.02	127.40	90.11	1.833	0.868
2028	109.74	120.58	92.29	6.12	129.73	91.80	1.833	0.868
2029	111.75	122.81	93.97	6.24	132.12	93.50	1.833	0.868
2030+	Escalated oil, gas and product prices at 1.83% per year thereafter							

(i) Inflation rates for forecasting prices and costs.
(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, 2014, were $85.80/Bbl for light and medium crude oil, $78.31/Bbl for heavy oil, $51.24/Bbl for NGLs and $4.67/Mcf for natural gas.

5. Well abandonment costs have only been included for undeveloped wells with reserves assigned. Additional abandonment costs associated with existing wells and lease reclamation costs and facility abandonment and reclamation expenses have not been included in this analysis.

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.

Reconciliations of Changes in Gross Reserves

December 31, 2014
(Forecast Prices and Costs)

	LIGHT AND MEDIUM OIL (MBbl)			HEAVY OIL (MBbl)		
	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable
December 31, 2013	23,452	12,724	36,176	1,223	490	1,714
Extensions	599	1,044	1,643	-	-	-
Infill Drilling	2,065	644	2,709	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	2,809	(1,642)	1,168	(29)	(40)	(69)
Discoveries	-	-	-	-	-	-
Acquisitions	1,892	890	2,782	-	-	-
Dispositions	(357)	(253)	(610)	(432)	(267)	(699)
Economic Factors	15	7	22	(4)	(0)	(4)
Production	(4,370)	-	(4,370)	(225)	-	(225)
December 31, 2014	26,105	13,415	39,521	533	183	716

	NATURAL GAS LIQUIDS (MBbl)			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, 2013	3,411	1,498	4,909	207,633	121,669	329,302	62,692	34,991	97,683
Extensions	418	920	1,338	6,694	11,706	18,400	2,132	3,916	6,047
Infill Drilling	76	25	101	7,169	2,336	9,505	3,336	1,058	4,394
Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	467	62	529	(5,183)	(15,989)	(21,172)	2,384	(4,285)	(1,902)
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	13,484	9,294	22,778	191,190	133,803	324,993	47,241	32,485	79,726
Dispositions	(191)	(65)	(256)	(6,329)	(2,208)	(8,537)	(2,035)	(953)	(2,988)
Economic Factors	(26)	(2)	(28)	(4,890)	(809)	(5,699)	(830)	(130)	(960)
Production	(1,123)	-	(1,123)	(33,948)	-	(33,948)	(11,376)	-	(11,376)
December 31, 2014	16,516	11,731	28,247	362,336	250,508	612,844	103,544	67,081	170,625

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, 2014, 2013 and 2012 based on forecast prices and costs.

Proved Undeveloped Reserves

	LIGHT AND MEDIUM OIL *(MBbl)*		HEAVY OIL *(MBbl)*		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
2012	5,873	8,942	486	553	38,371	42,908	327	695
2013	6,843	11,050	200	236	12,956	61,368	172	812
2014	2,234	11,004	0	167	98,409	174,910	7,179	7,899

Probable Undeveloped Reserves

	LIGHT AND MEDIUM OIL *(MBbl)*		HEAVY OIL *(MBbl)*		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
2012	6,660	8,727	730	853	33,682	40,435	322	888
2013	4,086	8,846	95	184	6,245	78,239	116	874
2014	2,001	8,722	0	81	120,631	185,550	8,471	9,240

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 its proved and probable undeveloped reserves within three 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 are as follows:

- changing economic conditions (due to pricing, 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 "Principal Properties", "Future Development Costs" and "Other Oil and Gas Information – Capital Expenditures" for a description of the Company's exploration and development plans and expenditures.

Significant Factors or Uncertainties

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 reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve 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, reserve 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 reserve estimates can arise from changes in year end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

The Company does not anticipate any significant abandonment costs and reclamation costs, unusually high development costs or operating costs, the need to build a major pipeline or other major facility before production of reserves can begin, or 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.

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
2015	39	54
2016	195	270
2017	183	276
2018	196	272
2019	106	241
Thereafter	60	96
Total Undiscounted	779	1,209

On an ongoing basis, Long Run will use internally generated cash flow from operations, debt and new equity issues if available on favourable terms to finance its capital expenditure program. 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 development, acquisition, exploration and production of crude oil and natural gas in western Canada. All of 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, 2014, unless otherwise stated. The reserve amounts stated are gross reserves as at December 31, 2014 based on forecast costs and prices as evaluated in the Sproule Report (see "Reserves Data"). 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, 2014.

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 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 and waterflood pilots were initiated in 2013. Approximately 90% of this area is year-round accessible for drilling, seismic and construction projects.

Within Peace River, the Normandville enhanced oil recovery (“EOR”) project expansion became operational in early December 2014. This project encompasses 5 sections and includes 16 horizontal producers, 8 horizontal injection wells and 1 vertical injection well. At Girouxville, a similar EOR project expansion is underway with startup planned for January 2015. This expanded EOR project will cover an area of 1.5 sections and will include 6 horizontal Montney producers with 3 horizontal injection wells. These expanded pilots form the basis from which EOR may be implemented across the rest of the Girouxville and Normandville Montney fields, beginning in early 2016.

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

During 2014, Long Run invested $148.5 million into the Peace River area, drilling 44.0 (43.5 net) wells with a 100% success rate. Average production was 13,168 Boe/d. Long Run plans to drill 5 oil wells in the area in the first half of 2015.

At December 31, 2014, the Sproule Report assigns total proved plus probable reserves of 17.4 MMBbls of oil and NGLs and 90.2 Bcf of natural gas within the Peace River area. The Company held an interest in 508,206 gross acres (456,450 net acres) of undeveloped land in the area.

Deep Basin

During 2014, Long Run invested $57.9 million into the Deep Basin area, drilling 11.0 (11.0 net) wells with a 100% success rate. Average production was 5,261 Boe/d. Long Run plans to drill 4 oil wells in the area in the first half of 2015.

Deep Basin - Pine Creek Area – West Central Alberta

The Pine Creek 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 Pine Creek 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 four 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.

During 2014, Long Run drilled and cased 5.0 wells within the Pine Creek area. Long Run plans to drill up to 3 Cardium oil wells in the area in the first half of 2015.

At December 31, 2014, the Sproule Report assigns total proved plus probable reserves of 10.7 MMBbls of oil and NGLs, and 89.8 Bcf of natural gas within the Pine Creek area. The Company held an interest in 110,800 gross acres (92,911 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 km south of the city of Grande Prairie.

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

Long Run's 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 2014, Long Run drilled and cased 4.0 wells within the Kakwa area. Long Run plans to drill 1 Cardium gas well in the area in the first half of 2015.

At December 31, 2014, The Sproule Report assigns total proved plus probable reserves of 5.1 MMBbls of oil and NGLs, and 96.2 Bcf of natural gas within the Kakwa area. The Company held an interest in 15,425 gross acres (10,484 net acres) of undeveloped land in the area.

Deep Basin - Wapiti Area – West Central Alberta

The Wapiti area is located in Townships 65 to 70 and Ranges 7W6M to 12W6M, approximately 45 km south and west of the city of Grande Prairie.

The majority of Long Run's production in the Wapiti 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 four 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 2014, Long Run drilled and cased 2.0 wells within the Wapiti area.

At December 31, 2014, the Sproule Report assigns total proved plus probable reserves of 9.9 MMBbls of oil and NGLs, and 116.0 Bcf of natural gas within the Wapiti area. The Company held an interest in 20,640 gross acres (17,899 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, approximately 50 kilometers northeast of the city of Edmonton, Alberta.

Long Run's activities in the Redwater area are directed primarily toward light oil in the Viking Formation. Development is occurring using horizontal drilling at a density of up to 16 wells per section. An enhanced recovery pilot scheme was implemented in 2013. Long Run implemented an additional enhanced oil recovery pilot within the Redwater Viking trend during 2014. Analogous Viking pools along this trend have demonstrated good response to enhanced recovery in the form of waterflood.

The Viking play at Redwater is the site of Long Run's second major EOR project. Long Run initiated the first Viking pilot EOR project in the north part of the field in December of 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 pilot project, located in the south part of the trend, began injection in early December 2014. Together these projects cover an area of 0.625 sections and include 8 horizontal Viking producers, 5 vertical Viking producers, and 2 horizontal injection wells.

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

During 2014, Long Run invested $89.8 million into the Redwater area, drilling and casing 47.0 (45.0 net) wells with a 100% success rate. Average production was 8,142 Boe/d. No wells are planned to be drilled in the first half of 2015.

At December 31, 2014, the Sproule Report assigns total proved plus probable reserves of 15.6 MMBbls of oil and NGLs, and 10.8 Bcf of natural gas within the Redwater area. The Company held an interest in 414,377 gross acres (373,070 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 two vertical wells per section. Opportunity exists to continue development of this field with further infill drilling and using horizontal wells.

During 2014, Long Run invested $2.1 million into the Boyer area. Long Run did not drill any wells in this area during 2014.

Significant drilling activity could be undertaken with an improvement in natural gas prices. Average production amounted to 2,859 Boe/d.

At December 31, 2014, the Sproule Report assigns total proved plus probable reserves of 121.5 Bcf of natural gas within the Boyer area. The Company held an interest in 88,145 gross acres (87,081 net acres) of undeveloped land in the area.

Kaybob Area – West Central Alberta

The Kaybob area is located in Townships 60 to 66 and Ranges 19W5M to 22W5M, approximately 220 kilometers northwest of the city of Edmonton, Alberta.

The majority of Long Run's production in the Kaybob area is natural gas, natural gas liquids and condensate from the Devonian Beaverhill Lake Formation, at a depth of 3,200 meters. Long Run holds a 90.7% working interest in the Kaybob South Beaverhill Lake Unit No. 1 ("Unit"), and is the operator of this Unit.

During 2014, Long Run invested $3.1 million into the Kaybob area. Long Run did not drill any wells in this area during 2014. Average production was 1,738 Boe/d. Long Run has identified opportunities to drill additional infill wells within the Unit with an improvement in natural gas prices.

At December 31, 2014, the Sproule Report assigns total proved plus probable reserves of 3.0 MMBbls of oil and NGLs, and 16.1 Bcf of natural gas within the Kaybob area. The Company held an interest in 7,360 gross acres (5,720 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, 2014:

($M)	
Property acquisition costs	
Proved properties	240,204
Undeveloped properties	5,838
Exploration costs	7,432
Development costs	294,955
Dispositions	(45,949)
Other	1,644
Net Capital Expenditures	504,124

Not reflected in the values above is the acquisition of Crocotta on August 6, 2014 for $346.9 million. The acquisition enhances the new Deep Basin core area by providing exploration and development opportunities and adding strategic ownership of gathering and processing infrastructure in Pine Creek. As consideration for Crocotta, Long Run issued 43.8 million Common Shares and assumed $115.5 million of the net debt of Crocotta, defined as bank debt, net of cash, less working capital. Long Run acquired $406.7 million of property and equipment through the acquisition.

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, 2014:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Light and Medium Oil	-	-	96.0	93.5
Heavy Oil	-	-	-	-
Natural Gas	-	-	6.0	6.0
Dry	-	-	-	-
Service/Other	-	-	1.0	1.0
Stratigraphic Test	-	-	-	-
	-	-	103.0	100.5

Land Holdings Including Properties with no Attributable Reserves

The following table sets out the Company's developed and undeveloped land holdings as at December 31, 2014.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	1,632,055	1,371,304	1,166,554	1,043,983	2,885,215	2,415,287
Saskatchewan	17,638	17,578	11,037	11,037	33,952	28,615
Total	1,649,693	1,388,883	1,177,590	1,055,020	2,919,167	2,443,902

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

The Company expects that rights to explore, develop and exploit 232,346 net acres of its undeveloped land holdings will expire by December 31, 2015, 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.

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, 2014:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	1,096	982	303	252	1,886	1,690	756	599
Saskatchewan	-	-	5	5	9	9	17	17
Total	1,096	982	308	257	1,895	1,699	773	616

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 9% of its non-producing oil wells and to less than 6% of its non-producing natural gas wells. The reserves attributed to these non-producing wells represent less than 2% 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 1 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 Company has approximately 4,804 net wells, including water source, injection and standing wells for which it expects to incur abandonment and reclamation costs.

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 costs only for undeveloped wells scheduled to be drilled in the future and no allowance was made for reclamation of existing wellsites or 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
2015	-	-
2016	-	-
2017	-	-
Thereafter	35,345	64,026
Total Undiscounted	35,345	64,026
Total Discounted @ 10%	6,825	7,773

The decommissioning liabilities recorded in the Company's financial statements result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its decommissioning liability is approximately $560 million ($161 million discounted at 10%), which will be incurred over the next 40 years.

Forward Contracts

At December 31, 2014, the Company held certain financial derivative contracts which are described in Note 16 of the Company's audited financial statements for the year ended December 31, 2014.

Tax Horizon

The Company does not expect to pay current income tax for the 2015 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 2015 production estimated by Sproule in the estimates of future net revenue from gross proved and gross probable reserves disclosed under "Disclosure of Reserves Data".

2015 Production from Gross Proved Reserves

	Light and Medium Oil *(Bbl/d)*	Heavy Oil *(Bbl/d)*	Natural Gas *(Mcf/d)*	Natural Gas Liquids *(Bbl/d)*	BOE *(BOE/d)*	%
Peace	4,482	-	19,775	204	7,982	25.8
Redwater	2,583	-	2,469	27	3,020	9.8
Boyer	-	-	13,397	-	2,233	7.2
Kaybob	-	-	4,370	791	1,519	4.9
Other	1,556	256	63,469	3,734	16,124	52.2
Total	8,621	256	103,480	4,755	30,879	100.0

2015 Production from Gross Probable Reserves

	Light and Medium Oil *(Bbl/d)*	Heavy Oil *(Bbl/d)*	Natural Gas *(Mcf/d)*	Natural Gas Liquids *(Bbl/d)*	BOE *(BOE/d)*	%
Peace	427	-	1,747	18	736	33.3
Redwater	301	-	243	2	343	15.5
Boyer	-	-	552	-	92	4.2
Kaybob	-	-	137	25	48	2.2
Other	116	19	3,895	206	990	44.8
Total	844	19	6,573	251	2,209	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 2014	Q3 2014	Q2 2014	Q1 2014
Average Daily Production[(1)]				
Light and Medium Oil *(Bbl/d)*	11,895	12,708	11,808	11,491
Heavy Oil *(Bbl/d)*	235	363	668	1,193
Gas *(Mcf/d)*	112,576	112,161	78,524	68,071
NGLs *(Bbl/d)*	5,609	3,031	2,038	1,584
Combined *(BOE/d)*	36,502	34,795	27,602	25,613
Average Price Received (net of transportation)				
Light and Medium Oil *($/Bbl)*	63.79	86.33	95.31	88.33
Heavy Oil *($/Bbl)*	59.97	79.06	80.22	75.21
Gas *($/Mcf)*	3.92	4.00	4.54	5.61
NGLs *($/Bbl)*	30.53	60.60	74.29	87.35
Combined *($/BOE)*	37.96	50.51	61.07	63.49
Royalties				
Light and Medium Oil *($/Bbl)*	9.85	11.53	14.40	11.64
Heavy Oil *($/Bbl)*	12.24	18.28	13.13	14.94
Gas *($/Mcf)*	0.16	0.24	(0.23)	0.26
NGLs *($/Bbl)*	3.99	10.12	16.23	22.93
Combined *($/BOE)*	4.42	6.05	7.01	8.01
Operating Expenses				
Light and Medium Oil *($/Bbl)*	12.47	11.44	14.15	14.81
Heavy Oil *($/Bbl)*	16.25	15.43	21.12	17.11
Gas *($/Mcf)*	2.29	2.00	2.65	2.81
NGLs *($/Bbl)*	9.69	9.62	11.71	12.98
Combined *($/BOE)*	12.71	11.63	14.98	15.70
Netback[(2)]				
Light and Medium Oil *($/Bbl)*	41.47	63.36	66.77	61.87
Heavy Oil *($/Bbl)*	31.49	45.35	45.97	43.16
Gas *($/Mcf)*	1.47	1.76	2.12	2.55
NGLs *($/Bbl)*	16.85	40.86	46.36	51.44
Combined *($/BOE)*	20.83	32.83	39.08	39.78

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, 2014:

	Light and Medium Oil *(Bbl/d)*	Heavy Oil *(Bbl/d)*	Gas *(Mcf/d)*	NGLs *(Bbl/d)*	BOE *(BOE/d)*
Peace	6,830	-	35,667	393	13,168
Redwater	4,758	611	15,411	204	8,142
Kaybob	-	-	4,943	914	1,738
Deep Basin	391	-	19,838	1,564	5,261
Boyer	-	-	17,149	1	2,859
Total	11,979	611	93,008	3,076	31,168

For the year ended December 31, 2014, the Company's production was 38% light and medium quality oil, 2% heavy oil, 50% natural gas and 10% NGLs. For 2014, approximately 74% of the Company's gross revenue was derived from oil and NGL production and 26% was derived from natural gas production.

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 4, 2015, 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 of the Company 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 of the Company 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 of the Company 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 of the Company 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 of the Company.

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 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 of Long Run 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.

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 have been declared and paid by the Company for the year ending December 31, 2014 and for the months indicated in the year ending December 31, 2015. The Company did not declare or pay any dividends during the years ending December 31, 2013 and December 31, 2012.

	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 31, 2014	0.0335	June 16, 2014
June 30, 2014	0.0350	July 15, 2014
July 31, 2014	0.0350	August 14, 2014
August 31, 2014	0.0350	September 15, 2014
September 30, 2014	0.0350	October 15, 2014
October 31, 2014	0.0350	November 14, 2014
November 30, 2014	0.0350	December 15, 2014
December 31, 2014	0.0350	January 15, 2015
	0.4125	
2015		
January 31, 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 Toronto Stock Exchange (“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)*
2014			
January	5.46	4.92	7,609
February	5.30	4.88	8,159
March	5.33	4.85	19,117
April	5.89	5.26	26,726
May	6.09	5.34	20,361
June	5.82	5.35	15,632
July	5.89	5.41	13,248
August	5.63	5.10	32,703
September	5.26	4.34	28,166
October	4.58	3.14	30,867
November	3.21	2.11	26,458
December	2.13	1.15	51,432
2015			
January	1.55	0.97	24,234
February	1.39	1.04	31,420
March 1-3	1.12	1.00	1,370

Convertible Debentures

The Convertible Debentures commenced trading on the TSX on January 28, 2014 under the symbol "LRE.DB". The following sets for the price range and trading volume of the Convertible Debentures on the TSX (as reported by such exchange) for the period indicated.

	Price Range[1]		
	High *($/share)*	Low *($/share)*	Volume *(000s)*
2014			
January 28-31	99.50	95.25	72
February	99.49	96.20	26
March	101.00	99.10	30
April	104.00	100.13	12
May	106.00	103.50	22
June	104.00	102.16	12
July	104.90	102.75	21
August	106.10	102.50	17
September	104.27	99.75	15
October	100.50	92.10	35
November	92.71	81.96	24
December	82.00	61.01	45
2015			
January	65.00	35.00	26
February	50.00	37.99	47
March 1-3	-	-	-

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

EMPLOYEES

As at December 31, 2014, Long Run had 143 full-time employees and 15 consultants located at its office in Calgary. In addition, Long Run had 83 full-time employees and 86 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: 62	Executive Chairman, Chief Executive Officer	Executive Chair and Chief Executive Officer of the Company	October 23, 2012
Dale A. Miller Alberta, Canada Age: 54	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: 57	Director	Partner, Burnet, Duckworth & Palmer LLP (Barristers and Solicitors)	December 13, 2007
Ed Chwyl(2)(3) British Columbia, Canada Age: 71	Director	Independent Businessman	December 13, 2007
C. Steven Cohen Alberta, Canada Age: 59	Secretary	Partner, Burnet, Duckworth & Palmer LLP (Barristers and Solicitors)	N/A
Michael M. Graham(2)(4)(5) Alberta, Canada Age: 55	Lead Director	Independent Businessman	October 23, 2012
Brad R. Munro(1)(5) Saskatchewan, Canada Age: 55	Director	President and Chief Executive Officer of Bittercreek Capital Corporation, (a private investment and advisory firm)	October 23, 2012
Patricia M. Newson(1)(3) Alberta, Canada Age: 58	Director	Independent Businesswoman	October 23, 2012
William Stevenson(1)(4)(5) Alberta, Canada Age: 59	Director	Independent Businessman	May 21, 2014
Steve Yuzpe(3) Ontario, Canada Age: 49	Director	President and Chief Executive Officer of Sprott Resource Corp.	February 4, 2014
Corine R.K. Bushfield Alberta, Canada Age: 40	Senior Vice President and Chief Financial Officer	Senior Vice-President and Chief Financial Officer of the Company	N/A
Jason W. Fleury Alberta, Canada Age: 44	Vice President, Business Development	Vice-President, Business Development of the Company	N/A
Jana King Alberta, Canada Age: 49	Vice-President, Exploration	Vice-President, Exploration of the Company	N/A
Dale J. Orton Alberta, Canada Age: 42	Senior Vice President, Development	Senior Vice-President, Development	N/A
Devin K. Sundstrom Alberta, Canada Age: 42	Vice-President, Production	Vice-President, Production of the Company	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 an Executive Vice President of Encana Corporation from April 14, 2005 and served as President of its Canadian Division until February 2012. Mr. Yuzpe was appointed President and Chief Operating Officer of Sprott Resources Corp. in October 2013. Prior thereto, he was the Chief Financial Officer of Sprott Resource Corp. since May 2009. Mr. Stevenson worked for Encana Corporation until October 1, 2013 and its predecessor company for the last 20 years in various management positions, most recently as Executive Vice-President and Chief Accounting Officer. The term of office of each director expires at the next annual meeting of shareholders of the Company.

As at March 4, 2015, the directors and executive officers of Long Run, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 3,145,710 Common Shares or approximately 1.6% of the issued and outstanding Common Shares.

Cease Trade Orders

To Long Run's knowledge, other than as disclosed herein, 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 office 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. 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 of Queen's Bench of Alberta (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.

Penalties or Sanctions

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, 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, Executive Chair, Chief Executive Officer and Director

Mr. Andrew is a professional engineer with over 35 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. Prior to joining Guide Exploration Ltd. ("Guide") in mid-2011, he was Chief Executive Officer of Penn West Exploration Ltd. He is active in the community as, Director of Ronald McDonald House of Southern Alberta, Director of the Fathers of Confederation Buildings Trust, and 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. Prior to joining Guide in mid-2011, 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 Accountant with 20 years experience in the oil and natural gas industry. Prior to joining Long Run in March 2013, Ms. Bushfield worked for Encana Corporation 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 a designation as a Chartered Accountant from the Institute of Chartered 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 Long Run on completion of the WestFire/Guide Arrangement. 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 Long Run on completion of the WestFire/Guide Arrangement. Prior to joining Guide, he has 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.

Jana King, Vice President, Exploration

Ms. King has over 25 years of experience in the oil and gas industry. Ms. King's career includes various leadership roles in exploration, development and corporate acquisitions and divestitures with Encana Corporation as well as prior geo-consulting work on numerous regional studies in western Canada. Ms. King holds a Bachelor of Science degree in Geology from the University of Calgary and is affiliated with the Association of Professional Engineers and Geoscientists of Alberta, the Canadian Society of Petroleum Geologists and the American Association of Petroleum Geologists.

Jason W. Fleury, Vice President, Business Development

Mr. Fleury has 10 years of investor relations and capital markets experience. Prior to joining Long Run Exploration Ltd., he worked at a number of oil and natural gas companies in increasingly senior positions. Mr. Fleury holds a Masters of Business Administration from the University of Calgary and a Bachelor of Arts from the University of Regina.

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, Patricia M. Newson 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 35 years of experience at several large and intermediate North American oil and gas companies, including Mobil Oil, Marathon Petroleum, and Encana Corporation. Mr. Stevenson worked for Encana and its predecessor company for 20 years in various management positions, most recently as Executive Vice-President and Chief Accounting Officer. Mr. Stevenson is a Certified Management Accountant and a member of the Society of Management Accountants of Alberta.

Patricia M. Newson

Ms. Newson was appointed a director of the Company on October 23, 2012. Ms. Newson is the chairman of the board of Heritage Gas Ltd., and serves on the boards of Brookfield Residential Properties Inc., the Alberta Electric System Operator, and Quality Urban Energy Systems of Tomorrow (QUEST) Canada, and is a member of the Alberta Securities Commission's Financial Advisory Committee. Ms. Newson was a director and audit committee member of Guide from 2011 to 2012, Brookfield Asset Management Inc. from 2008 to 2010, and the Canadian Gas Association from 2006 to 2011 and a director of AltaGas Utility Group from 2005 to 2009. From 2005 through 2009 she was the President and Chief Executive Officer of AltaGas Utility Group Inc., a natural gas distribution holding company listed on the TSX. Ms. Newson retired in 2011 from AltaGas Ltd. as the President of AltaGas Utility Group Inc. Ms. Newson originally joined AltaGas Income Trust in 1996 and was Senior Vice President, Finance and Chief Financial Officer until 2006 and Senior Vice President through 2008. Prior to joining AltaGas Income Trust, her experience included consulting for utility companies and crown corporations; and positions in financial reporting and merger and acquisition functions with private equity firms and with Olympia and York Enterprises, GW Utilities and Gulf Canada. Ms. Newson holds a Bachelor of Commerce degree (with distinction) in accounting, is a member of the Institute of Chartered Accountants of Alberta, and is an Institute Certified Director (ICD.D).

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 holds a Bachelor of Commerce degree from the University of Saskatchewan and has extensive experience in corporate finance and investment in the oil and gas and other industries. Mr. Munro has held various senior positions requiring regular review of financial statements and has served as an Audit Committee member, including Chairman, for a number of publicly traded companies. Mr. Munro presently serves as a director of CERF Inc. CERF Inc. combined with Winalta, Inc. during 2014, and Secure Energy Services Inc.

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] ($)
2014	331,500	141,300	-
2013	250,500	-	10,000

Notes:

(1) Represents the aggregate fees billed for assurance and related services that are reasonably related to the performance of the audit or review of all of the Company's financial statements.

(2) The services comprising the fees disclosed under this category consisted of services rendered in connection with financings and acquisitions.

(3) The services comprising the fees disclosed under this category consisted of tax consultations and tax compliance services.

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 15,512,858 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 23,000,000 Common Shares. Following the conversion of the outstanding 23,500,000 Subscription Receipts into Common Shares which occurred on May 30, 2014 in connection with the closing of the Deep Basin 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%.

On September 16, 2011, Guide issued an aggregate of 2,300,000 units ("Units") at a price of $2.81 per Unit. Each Unit was comprised of one Class A Share of Guide and one share purchase warrant ("Guide Warrant"), each of which entitled the holder to one Class A Share of Guide at an exercise price of $3.10 for a period of three years from the date of issuance any time after the Class A Shares achieved a 20-day volume weighted average trading price exceeding $5.00 per share. These share purchase warrants were assumed by Long Run as the Warrants pursuant to the WestFire/Guide Arrangement. The Warrants expired unexercised on September 15, 2014. At the time of issuance, the following directors and executive officers of the Company, who were also directors and/or executive officers of Guide, acquired an aggregate of 860,000 Units: William E. Andrew, Executive Chairman and Chief Executive Officer (205,000 Units); Dale A. Miller, President (175,000 Units); V. William Tang Kong, Vice President, Corporate Development (200,000 Units); John A. Brussa, Director (200,000); Dale J. Orton, Vice President, Operations and Engineering (30,000); Devin K. Sundstrom, Vice President, Production (15,000

Units); Shivon M. Crabtree, Vice President, Finance and Chief Financial Officer (15,000 Units); and James D. Iverson, Vice President, Exploration (15,000 Units).

Pursuant to the WestFire/Guide Arrangement, which closed on October 23, 2012, each outstanding common share of Guide was transferred to WestFire in exchange for 0.4167 of a common share of WestFire (being the Common Shares of Long Run), and Guide and WestFire were amalgamated and continued under the name "Long Run Exploration Ltd."

Pursuant to the WestFire/Guide Arrangement, management of Guide assumed management of Long Run and the board of directors of Long Run was reconstituted as disclosed herein (see "*Directors and Officers*" and "*Management*"). As a result, the WestFire executive officers, being Lowell E. Jackson, Frank P. Muller, Jeff Holmgren, Darrin R. Drall, Christopher J. Bennett and Cam King, received severance (being amounts paid in lieu of salary, benefits and bonus) in the amounts of $992,200, $582,600, $556,950, $582,600, $582,600 and $545,100, respectively, and other bonus payments in the amount of $532,574, $439,825, $200,908, $439,825, $240,825 and $240,825, respectively, certain of which were triggered upon the change of control resulting from the WestFire/Guide Arrangement and certain of which were payable in any event. See also "The Arrangement – Interest of Certain Persons and Companies in the Arrangement", in the Joint Information Circular of Guide and WestFire dated September 24, 2012, which section (other than cross references therein to other sections of the Joint Information Circular) is incorporated herein by reference. The Joint Information Circular is available under the Company's profile on SEDAR at www.sedar.com.

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, 2014, 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 described previously, and those 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.

An investor agreement exists dated as of May 11, 2011, (the "Investor Agreement") 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 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 Accountants, 1000, 444 – 2nd Avenue S.W., 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 National Instrument 51-102 of the Canadian Securities Administrators) 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 Accountants, the Company's auditors, are independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

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, British Columbia, and Saskatchewan 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 oil and two years in the case of heavy 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 licence from the NEB. The NEB is currently undergoing a consultation process to update the regulations governing the issuance of export licences. 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

Alberta'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 such as the Alberta "NIT" (Nova Inventory Transfer), 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 (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) 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 m^3/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 25 years) or for a larger quantity requires an exporter to obtain an export licence 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.

Alberta

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

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework", which was implemented in 2010. 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%.

Oil sands projects are also subject to Alberta's royalty regime. 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. In addition, concurrent with the implementation of The New Royalty Framework, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the new royalty regime.

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"). 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.

The Emerging Resource and Technologies Initiative will be reviewed in 2014, and the Government of Alberta has committed to providing the industry with three years notice if it decides to discontinue the program.

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, licences, 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.

Each of the provinces of Alberta, British Columbia and Saskatchewan 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. On March 29, 2007, British Columbia expanded its policy of deep rights reversion for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

Alberta also 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. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied 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 in to 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 regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator (the "AER") assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the *Oil and Gas Conservation Act* ("ABOGCA"). On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development ("AESRD") in respect of the disposition and management of public lands under the *Public Lands Act*. On March 29, 2014, the AER assumed the energy related functions and responsibilities of AESRD in the areas of environment and water under the *Environmental Protection and Enhancement Act* and the *Water Act*, respectively. 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 the transformation to a single regulator is the creation of 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.

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 kilometres in size. The region includes a substantial portion of the Athabasca oil sands area, which contains approximately 82% of the province's oilsands 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 oilsands 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 kilometres 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.

With the implementation of the new Alberta regulatory structure under the AER, AESRD will remain responsible for development and implementation of regional plans. However, the AER will take on some responsibility for implementing regional plans in respect of energy related activities.

Saskatchewan

In May 2011, Saskatchewan passed changes to The Oil and Gas Conservation Act ("SKOGCA"), the act governing the regulation of resource development operations in the province. Although the associated Bill received Royal Assent on May 18, 2011, it was not proclaimed into force until April 1, 2012, in conjunction with the release of The Oil and Gas Conservation Regulations, 2012 ("OGCR") and The Petroleum Registry and Electronic Documents Regulations ("Registry Regulations"). The aim of the amendments to the SKOGCA, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the Registry Regulations and the OGCR, Saskatchewan has implemented a number of operational aspects, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers, and procedural aspects including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

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 the 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.

Effective May 1, 2013, the AER implemented important changes to the AB LLR Program that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. Some of the important changes include:

- a 25% increase to the prescribed average reclamation cost for each individual well or facility (which will increase a licensee's deemed liabilities);

- a $7,000 increase to facility abandonment cost parameters for each well equivalent (which will increase a licensee's deemed liabilities);

- a decrease in the industry average netback from a five-year to a three-year average (which will affect the calculation of a licensee's deemed assets, as the reduction from five to three years means the average will be more sensitive to price changes); and

- a change to the present value and salvage factor, increasing to 1.0 for all active facilities from the current 0.75 for active wells and 0.50 for active facilities (which will increase a licensee's deemed liabilities).

These changes will be implemented over a three-year period. The first phase was implemented in May of 2013, the second phase was implemented in May of 2014 and the final phase will be implemented in May of 2015. The changes to the AB LLR Program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

On July 4, 2014, the AER introduced 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 will be 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.

Saskatchewan

In Saskatchewan, the Ministry of Economy implements the Licensee Liability Rating Program (the "SK LLR Program"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund (the "Oil and Gas Orphan Fund") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities.

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 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.

Alberta

As part of Alberta's 2008 Climate Change Strategy, the province committed to taking action on three themes: (a) conserving and using energy efficiently (reducing GHG emissions); (b) greening energy production; and (c) implementing carbon and capture storage.

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 CCEMA is based on an emissions intensity approach and aims for a 50% reduction from 1990 emissions relative to GDP by 2020. 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 facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions.

The SGER, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year, 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. The SGER distinguishes between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity by 12% of their baseline emissions intensity for 2008 and subsequent years. Generally, the baseline for an Established Facility reflects the average of emissions intensity in 2003, 2004 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the SGER. New Facilities 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 and 10% of their baseline in the eighth year. The CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA provides that regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund at a rate of $15 per tonne of CO_2 equivalent. The funds contributed by industry to the Climate Change and Emissions Management Fund will be used to drive innovation and test and implement new technologies for greening energy production. Emissions credits can also be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta will invest $2 billion into demonstration 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.

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 and Europe, 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. 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 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.

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.

Reserve 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 reserve 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 reserve 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 reserve evaluation, and such variations could be material. The reserve 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 reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve 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.

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 of the Company 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 of the Company will trade cannot be accurately predicted.

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);
- 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. 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 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.

Credit Facility Arrangements

The Company currently has a credit facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Company is required to comply with covenants under its credit facility which may, in certain cases, include certain financial ratio tests, which 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, the Company's access to capital could be restricted or repayment could be required. Events beyond the Company's control may contribute to the failure of the Company to comply with such covenants. A failure to comply with covenants could result in default under the Company's credit facility, which could result in the Company being required to repay amounts owing thereunder. Even if the Company is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Company. If the Company is unable to repay amounts owing under credit facilities, the lenders under the credit facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Company's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Company's credit facility may impose operating and financial restrictions on the Company that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Company's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The Company's lenders use the Company's reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Company's borrowing base. A material decline in commodity prices could reduce the Company's borrowing base, reducing the funds available to the Company under the credit facility. This could result in the requirement to repay a portion, or all, of the Company's bank indebtedness.

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. There is risk that if the economy and banking industry experienced unexpected and/or prolonged deterioration, the Company's access to additional financing may be affected.

Because of global economic volatility, the Company may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such 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. If the Company's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will 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. 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.

Issuance of Debt

From time to time, 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.

Dilution

The Company may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Company which may be dilutive.

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. Depending on these and various other factors, many of which will be beyond the control of the Company, the dividend policy of the Company from time to time and, as a result, future cash dividends could be reduced or suspended entirely.

Income Taxes

The Company files all required income tax returns and believes that it is in full compliance with the provisions of the 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.

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.

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.

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 greenhouse gas ("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. These GHG emission reduction targets are not binding, however. 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. 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. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Company and its operations and financial condition.

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 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.

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 Company'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.

Liability Management

Alberta, Saskatchewan and British Columbia 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' 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. See "*Industry Conditions*".

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, Canadian/United States exchange rates could affect the future value of the Company's reserves as determined by independent evaluators.

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 of the Company.

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. Although pipeline expansions are ongoing, 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. 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 and it is projected to continue in this upward trend. 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.

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. These recommendations include, among others, the imposition of higher standards for all DOT-111 tank cars carrying crude oil and the increased auditing of shippers to ensure they properly classify hazardous materials and have adequate safety plans in place. 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.

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 supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- 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.

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.

Global Financial Markets

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels, have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader United States and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Worldwide crude oil commodity prices are expected to remain volatile in the near future as a result of global excess supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("OPEC"), and ongoing global credit and liquidity concerns. This volatility may affect the Company's ability to obtain equity or debt financing on acceptable terms.

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.

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.

Expiration of Licenses and Leases

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

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 "Directors and Officers – 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.

Expansion into New Activities

The operations and expertise of the Company's management are currently focused primarily on oil and gas production, development and exploration 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 oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil 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.

Intellectual Property Litigation

Due to the rapid development of oil and gas technology, in the normal course of the Company's operations, the Company may become involved in, named as a party to, or be the subject of, various legal proceedings in which it is alleged that the Company has infringed the intellectual property rights of others or commence lawsuits against others who the Company believes are infringing upon its intellectual property rights. The Company's involvement in intellectual property litigation could result in significant expense, adversely affecting the development of its assets or intellectual property or diverting the efforts of its technical and management personnel, whether or not such litigation is resolved in the Company's favour. In the event of an adverse outcome as a defendant in any such litigation, the Company may, among other things, be required to:

- pay substantial damages; cease the development, use, sale or importation of processes that infringe upon other patented intellectual property;
- expend significant resources to develop or acquire non-infringing intellectual property;
- discontinue processes incorporating infringing technology; or
- obtain licences to the infringing intellectual property. However, the Company may not be successful in such development or acquisition or such licences may not be available on reasonable terms. Any such development, acquisition or licence could require the expenditure of substantial time and other/ resources and could have a material adverse effect on the Company's business and financial results.

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

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 consolidated 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

Bbl	barrel
Bbls	barrels
BOE/d	barrels of oil equivalent per day
MBbls	thousand barrels
MMBbls	million barrels
Mstb	1,000 stock tank barrels
Bbl/d	barrels per day
BOPD	barrels of oil per day
NGLs	natural gas liquids
STB	standard tank barrels

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMcfe/d	million cubic feet equivalent per day
MMbtu	million British Thermal Units
Bcf	billion cubic feet
GJ	gigajoule
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 metres
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 BOEs 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 metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	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);

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

"**Business Day**" means a day on which securities may be traded on the floor of the Toronto Stock Exchange or any other stock exchange on which the Common Shares are then listed;

"**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 completion of the WestFire/Guide Arrangement on October 23, 2012 "Company" means WestFire;

"**Control Person**" means (a) a person or company who holds more than 20 per cent 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 per cent 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;

"**Crocotta Acquisition**" has the meaning as set forth under "General Development of the Business – Three-Year History – 2014". On August 6, 2014, Long Run acquired Crocotta Energy Inc. The acquisition was for consideration of $346.9 million, through the issuance of $231.4 million in share capital and the assumption of $115.5 million of net debt;

"**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". On May 30, 2014, Long Run acquired the Deep Basin assets for $228.8 million;

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

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

"**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.

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

"**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;

"**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;

"**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;

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

"**Sproule Report**" means the report of Sproule dated March 4, 2015 evaluating, effective December 31, 2014 the crude oil, natural gas liquids and natural gas reserves of the Company;

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

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

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

"**Units**" has the meaning ascribed thereto under "Interest of Management and Others in Material Transactions";

"**Warrant"** means Common Share purchase warrants of the Company, each of which originally entitled the holder to acquire 0.4167 of a Common Share at an exercise price of $3.10 until September 15, 2014 at any time after the Common Shares have achieved a 20 day volume weighted average trading price on the TSX exceeding $12.00 per Common Share. The exchange ratio and exercise price were subject to adjustment upon the payment of dividends by the Company. At June 30, 2014, each warrant entitled the holder to acquire 0.4329 Common Shares of the Company at an exercise price of $2.98 per 0.4329 of a share. All outstanding warrants expired unexercised on September 15, 2014;

"**WestFire**" means WestFire Energy Ltd. prior to the WestFire/Guide Arrangement; and

"**WestFire/Guide Arrangement**" means the plan of arrangement under Section 193 of the ABCA involving WestFire, Guide and the shareholders of Guide pursuant to which, among other things, each issued and outstanding common share of Guide was acquired by WestFire for 0.4167 of a common share of WestFire and WestFire and Guide amalgamated.

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, 2014.

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 and considerations for acquisitions and divestitures, nature of planned capital expenditures, plans to improve balance sheet strength and the methods thereof, the Company's belief that the 2015 capital expenditure plans are fiscally prudent and conservative, expected method of funding capital expenditures, the Company's dividend policy and factors impacting the payment of any dividends, if any, tax horizon and extent of tax pools, 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 reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserve 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 which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, estimated using forecast prices and costs.

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 the 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; and

(c) the content and filing of this report.

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

DATED as of this 4th day of March, 2015.

(signed) William E. Andrew
Executive Chairman 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

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, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, 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 (the "COGE Handbook"), prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

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 sets forth the estimated 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 by us as of December 31, 2014, 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	Description and Preparation Date of Evaluation Report	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	Evaluation of the P&NG Reserves of Long Run Exploration Ltd., as of December 31, 2014 prepared September 2014 to March 2015	Canada				
Total			Nil	1,642,205	Nil	1,642,205

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are presented 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 the report referred to in paragraph 5 for events and circumstances occurring after its preparation date.

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, dated March 4, 2015.

(signed) Steven J. Golko, P.Eng.
Supervisor, Engineering and Partner

(signed) Robert R. Warholm, P.Eng.
Manager, Quality and Assurance and Partner

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

(signed) Alec Kovaltchouk, P.Geo.
Manager, Geoscience and Partner

(signed) Attila A. Szabo, P.Eng.
Vice-President, Engineering, Canada 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 "Company") 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:

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

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

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

7. 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.

8. 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.

9. 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 Company 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.

10. 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.

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

12. 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.

13. 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.

14. 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.

15. 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 Company. 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 Company 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 Company.

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 4, 2015

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