LONG RUN EXPLORATION LTD.

Financial Statements

December 31, 2014

Management's Responsibility for Financial Reporting

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

Management has established systems of internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with International Financial Reporting Standards.

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

(signed)
Bill Andrew
Chair and Chief Executive Officer

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

March 4, 2015

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Long Run Exploration Ltd.

We have audited the accompanying financial statements of Long Run Exploration Ltd. which comprise the statements of financial position as at December 31, 2014 and December 31, 2013, and the statements of earnings (loss), comprehensive income (loss), changes in shareholders' equity and cash flows for the years ended December 31, 2014, and December 31, 2013, and a summary of significant accounting policies and other explanatory information.

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

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

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

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

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of Long Run Exploration Ltd. as at December 31, 2014 and December 31, 2013, and its financial performance and its cash flows for the years ended December 31, 2014, and December 31, 2013, in accordance with International Financial Reporting Standards.

Ernst & Young LLP

Chartered Accountants
Calgary, Canada
March 4, 2015

Statement of Financial Position

($000s)	**December 31, 2014**	December 31, 2013
ASSETS		
CURRENT		
Accounts receivable	**65,135**	53,433
Deposits and prepaid expenses	**14,423**	7,571
Fair value of financial derivatives *(note 16)*	**65,438**	1,024
	144,996	62,028
Exploration and evaluation assets *(note 6)*	**5,635**	10,758
Property and equipment *(note 7)*	**1,627,050**	1,184,351
Deferred income tax asset *(note 14)*	**162,025**	146,207
	1,939,706	1,403,344
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	**132,439**	89,606
Bank loan *(note 9)*	**100,000**	-
Fair value of financial derivatives *(note 16)*	**336**	14,919
	232,775	104,525
Bank loan *(note 9)*	**511,717**	423,553
Convertible debentures *(note 10)*	**68,145**	-
Decommissioning liabilities *(note 8)*	**411,209**	254,413
Fair value of financial derivatives *(note 16)*	**85**	3,876
	1,223,931	786,367
SHAREHOLDERS' EQUITY		
Share capital *(note 11)*	**1,006,799**	657,666
Equity component of convertible debentures *(note 10)*	**3,483**	-
Contributed surplus *(note 11)*	**26,160**	23,377
Retained earnings (deficit)	**(320,667)**	(64,066)
	715,775	616,977
	1,939,706	1,403,344

Commitments and contingencies *(note 18)*

See accompanying notes to the financial statements.

Approved on behalf of the Board of Directors:

(signed)
Bill Stevenson
Director

(signed)
Brad Munro
Director

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

($000s, except per share amounts)	Year ended December 31 **2014**	2013
INCOME		
Petroleum and natural gas revenue	**610,896**	475,562
Royalties	**(70,276)**	(55,133)
	540,620	420,429
Gain (loss) on financial derivatives *(note 16)*		
- realized	**(7,963)**	(2,689)
- unrealized	**83,538**	(11,735)
	616,195	406,005
EXPENSES		
Operating	**153,730**	126,637
Transportation	**21,993**	20,520
General and administration *(note 13)*	**38,193**	25,349
Share-based compensation *(note 11)*	**2,262**	4,379
Interest	**26,027**	14,790
Accretion *(note 8, 10)*	**10,508**	6,110
Depletion and depreciation *(note 7)*	**234,829**	170,696
Exploration	**858**	247
Gain on disposal of assets *(note 7)*	**(20,610)**	(11,161)
Impairments *(note 7)*	**400,000**	13,000
	867,790	370,567
EARNINGS (LOSS) BEFORE TAX	**(251,595)**	35,438
Income taxes		
Capital and other taxes	**-**	88
Deferred income tax expense (recovery) *(note 14)*	**(61,200)**	11,085
	(61,200)	11,173
NET EARNINGS (LOSS) AND COMPREHENSIVE INCOME (LOSS)	**(190,395)**	24,265
NET EARNINGS (LOSS) AND COMPREHENSIVE INCOME (LOSS) PER SHARE *(note 11)*		
Basic	**(1.21)**	0.19
Diluted	**(1.21)**	0.19

See accompanying notes to the financial statements.

Statement of Changes in Shareholders' Equity

($000s)	Share Capital *(note 11)*	Equity Component of Convertible Debentures *(note 10)*	Contributed Surplus *(note 11)*	Retained Earnings (Deficit)	Total
January 1, 2013	657,455	-	16,558	(88,331)	585,682
Share-based compensation	-	-	6,868	-	6,868
Options exercised	211	-	(49)	-	162
Comprehensive earnings	-	-	-	24,265	24,265
December 31, 2013	657,666	-	23,377	(64,066)	616,977
Issuance of common shares	346,317	-	-	-	346,317
Share-based compensation	-	-	3,440	-	3,440
Options exercised	2,816	-	(657)	-	2,159
Comprehensive loss	-	-	-	(190,395)	(190,395)
Dividends declared *(note 11)*	-	-	-	(66,206)	(66,206)
Convertible debentures issued	-	3,483	-	-	3,483
December 31, 2014	**1,006,799**	**3,483**	**26,160**	**(320,667)**	**715,775**

See accompanying notes to the financial statements.

Statement of Cash Flows

($000s)	Year ended December 31 2014	2013
Cash provided by (used in):		
OPERATING ACTIVITIES		
Net earnings (loss)	**(190,395)**	24,265
Items not requiring cash:		
Unrealized (gain) loss on financial derivatives *(note 16)*	**(83,538)**	11,735
Share-based compensation	**2,262**	4,379
Accretion	**10,508**	6,110
Depletion and depreciation	**234,829**	170,696
Gain on disposal of assets	**(20,610)**	(11,161)
Impairments *(note 7)*	**400,000**	13,000
Deferred income tax expense (recovery)	**(61,200)**	11,085
Abandonment costs *(note 8)*	**(11,409)**	(3,970)
Change in non-cash working capital *(note 17)*	**5,486**	8,117
	285,933	234,256
INVESTING ACTIVITIES		
Capital expenditures *(note 6, 7)*	**(304,031)**	(276,571)
Acquisitions *(note 5, 7)*	**(246,042)**	(125,967)
Dispositions *(note 7)*	**45,949**	17,205
Change in non-cash working capital *(note 17)*	**21,380**	(15,268)
	(482,744)	(400,601)
FINANCING ACTIVITIES		
Issuance of common shares *(note 11)*	**122,162**	162
Share issue costs *(note 11)*	**(6,810)**	-
Issuance of convertible debentures, net of costs *(note 10)*	**71,566**	-
Bank loan issuance	**69,327**	162,380
Dividends declared *(note 11)*	**(66,206)**	-
Change in non-cash working capital *(note 17)*	**6,772**	-
	196,811	162,542
CHANGE IN CASH	**-**	(3,803)
CASH, BEGINNING OF YEAR	**-**	3,803
CASH, END OF YEAR	**-**	-
SUPPLEMENTAL INFORMATION		
Interest paid	**23,651**	15,179

See accompanying notes to the financial statements.

Notes to the Financial Statements
For the year ended December 31, 2014

1. REPORTING ENTITY

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

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

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

2. BASIS OF PRESENTATION

These financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

The financial statements have been prepared on the historical cost basis except where noted in the accounting policies. The financial statements are presented in Canadian dollars.

Certain prior year amounts have been reclassified to conform to current year presentation.

The financial statements were authorized for issue by the Board of Directors on March 4, 2015.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Estimates, assumptions and judgements

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

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

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

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

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

Accruals for revenue, royalties and costs are prepared based on estimates when actual amounts are not yet known. Share-based compensation amounts are determined using certain assumptions (see Note 11).

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

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

Cash and cash equivalents

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

Financial instruments

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

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

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

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

Joint operations

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

Exploration and evaluation assets

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

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

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

Property and equipment

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

Petroleum and natural gas properties

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

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

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

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

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

Assets held for sale

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

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

Disposals

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

Non-monetary transactions

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

Goodwill

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

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

Business combinations

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

Impairments

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

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

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

An impairment is recognized in the statement of earnings. An impairment recognized in respect of a CGU is allocated first to reduce the carrying amount of any goodwill allocated to the CGU and subsequently to other assets in the CGU. An impairment recognized in prior periods for an asset other than goodwill is reversed if there has been a change in facts and circumstances used to

determine the asset's recoverable amount since the last impairment was recognized, such that the impairment no longer exists or has decreased. An impairment is only reversed to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment had been recognized.

Leases

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

Decommissioning liabilities

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

Revenue recognition

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

Share-based compensation

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

Cash settled compensation

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

Income taxes

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

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

change is substantively enacted. Deferred income tax assets and liabilities are presented as non-current.

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

Flow-through shares

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

Earnings per share

Basic earnings per share amounts are calculated by dividing the net earnings by the weighted average number of common shares outstanding during the period. Diluted earnings per share is determined by adjusting the earnings and the weighted average number of common shares outstanding using the treasury stock method for the effects of dilutive instruments such as outstanding stock options.

Provisions

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

4. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2014, the Company adopted the following:

- Amendment to IAS 36, *Impairment of Assets,* which requires additional disclosures if impairments are recognized. The adoption of this amendment did not have a material impact on the Company's financial statements.

- IFRIC 21, *Levies,* which clarifies when the liability for a levy should be recognized. The adoption of this IFRIC did not have an impact on the Company's financial statements.

Future Accounting Pronouncements

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

- IFRS 15, *Revenue from Contracts with Customers,* clarifies the principles for recognizing revenue from contracts with customers, and provides a model for the recognition and measurement of sales of certain non-financial assets. The IFRS must be adopted January 1, 2017. The adoption of this standard is not expected to have a material impact on the Company's financial statements.

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

5. BUSINESS COMBINATIONS

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

On May 30, 2014, the Company closed the acquisition of assets in the Deep Basin area of Alberta focused on development of the Cardium for $228.8 million. A $120.0 million bought deal equity financing was closed in conjunction with the acquisition (see Note 11). Details of the transaction are as follows:

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

Following the acquisition, property and equipment and the decommissioning liabilities were increased by $32.3 million, reflecting the calculation of decommissioning liabilities using a risk free discount rate. The credit adjusted discount rate was used to determine fair value.

The financial statements incorporate the operations of the acquired properties commencing May 30, 2014. During the period May 30, 2014 to December 31, 2014, the Company recorded revenues of $36.3 million and net earnings of $3.5 million in respect of these assets. Acquisition costs of $2.0 million were included in the statement of earnings as general and administration expense.

Had the transaction closed on January 1, 2014, management estimates that for the period January 1, 2014 to May 29, 2014, revenue and net earnings would have increased by an additional $40.8 million and $11.2 million, respectively. In determining these amounts, management assumed the fair values on the date of acquisition would have been the same if the acquisition had occurred on January 1, 2014.

b) Acquisition of Crocotta Energy Inc.

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

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

Details of the transaction are as follows:

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

Following the acquisition, property and equipment and the decommissioning liabilities were increased by $15.8 million, reflecting the calculation of decommissioning liabilities using a risk free discount rate. The credit adjusted discount rate was used to determine fair value.

The purchase price allocation was based on the best estimates of management, giving consideration to cash flows from petroleum and natural gas reserves estimated using independent reserve evaluations. Transaction costs of $4.5 million were included in the statement of earnings as general and administration expense.

The financial statements incorporate the operations of the Crocotta properties commencing August 6, 2014. During the period August 6, 2014 to December 31, 2014, the properties acquired contributed revenues of $30.9 million and net earnings of $4.2 million.

Had the business combination with Crocotta closed on January 1, 2014, management estimates that the corporate activity of Crocotta, adjusted for the property and equipment, deferred tax and decommissioning obligation values determined on August 6, 2014, would have increased revenues by $73.4 million and net earnings by $9.0 million.

6. EXPLORATION AND EVALUATION ASSETS

($000s)	**December 31, 2014**	December 31, 2013
Balance, beginning of year	**10,758**	20,936
Additions	**27**	5,176
Transfers to property and equipment	**(5,150)**	(15,354)
Balance, end of year	**5,635**	10,758

7. PROPERTY AND EQUIPMENT

($000s)	**December 31, 2014**	December 31, 2013
Property and equipment cost	**2,808,959**	1,769,893
Accumulated depletion, depreciation and impairments	**(1,181,909)**	(585,542)
Net book value	**1,627,050**	1,184,351

Property and Equipment Cost

($000s)	**December 31, 2014**	December 31, 2013
Balance, beginning of year	**1,769,893**	1,345,940
Additions	**311,488**	282,326
Acquisitions, including decommissioning costs	**753,297**	169,023
Transfers from exploration and evaluation assets	**5,150**	15,354
Transfers to assets held for sale	**(6,000)**	-
Change in decommissioning liabilities estimate (*note 8*)	**52,022**	(23,765)
Disposals	**(76,891)**	(18,985)
Balance, end of year	**2,808,959**	1,769,893

Accumulated Depletion, Depreciation and Impairments

($000s)	**December 31, 2014**	December 31, 2013
Balance, beginning of year	**(585,542)**	(406,227)
Depletion and depreciation expense	**(234,829)**	(170,696)
Disposals	**38,462**	4,381
Impairments	**(400,000)**	(13,000)
Balance, end of year	**(1,181,909)**	(585,542)

During 2014, the Company acquired lands and oil and natural gas properties for cash consideration of $246.0 million (2013 - $126.0 million), of which $228.8 million was paid for the acquisition of assets in the Deep Basin area (see Note 5). In addition, on August 6, 2014, the Company acquired $406.7 million of oil and natural gas properties through the Crocotta acquisition (see Note 5).

Proceeds of $45.9 million were received for the disposition of minor producing properties during 2014 (2013 - $17.2 million). These dispositions included the sale of the Lloydminster heavy oil property for

proceeds of $12.0 million, the sale of a Pine Creek property for proceeds of $14.8 million, and the sale of a Peace River property for proceeds of $15.0 million. During 2014, a gain on disposal of properties of $20.6 million was recognized (2013 - $11.2 million).

At December 31, 2014, undeveloped land of $32.6 million was excluded from costs subject to depletion (December 31, 2013 - $26.1 million). In addition, future development costs of $1.3 billion were added into costs subject to depletion (December 31, 2013 - $666.7 million).

At December 31, 2014, a $6.0 million pipeline held for sale was included in deposits and prepaids on the statement of financial position.

At December 31, 2014, the Company recorded property and equipment impairments of $400.0 million, resulting from a decline in oil and natural gas price forecasts (Deep Basin - $160.0 million; Redwater - $132.0 million; Peace River - $61.0 million; and Kaybob - $47.0 million). The recoverable amounts of the Company's CGUs were estimated at fair value less costs to sell, based on the net present value of after-tax cash flows from oil and natural gas reserves, using reserve values estimated by independent reserve evaluators, and the estimated fair value of undeveloped land. Within the fair value hierarchy, these inputs would be considered Level 3.

In calculating the net present values of cash flows from oil and natural gas reserves, the Company used an after-tax discount rate of 10%, a CDN$ to US$ exchange rate of 0.87 CDN$ to 1.00 US$, and the following forward commodity price estimates:

	WTI Oil *(US$/bbl)*	AECO Gas *(CDN$/mcf)*
2015	64.17	3.38
2016	76.67	3.83
2017	83.33	4.06
2018	87.08	4.41
2019	90.67	4.76
2020	94.30	4.97
2021	96.59	5.18
2022	98.36	5.36
2023	100.18	5.54
2024	102.02	5.70
2025	103.88	5.80
Remainder	+1.8%/yr	+1.8%/yr

As at December 31, 2014, a one percent change in the after-tax discount rate is estimated to change the impairment by approximately $70.0 million; a $1.00/Bbl change in the price of oil is estimated to change the impairment by approximately $20.0 million; and a $0.10/GJ change in the price of natural gas is estimated to change the impairment by approximately $20.0 million.

In 2013, an impairment charge of $13.0 million was recorded for the Kaybob CGU, resulting primarily from capital spending on facilities that did not result in additional reserves.

8. DECOMMISSIONING LIABILITIES

($000s)	**December 31, 2014**	December 31, 2013
Balance, beginning of year	**254,413**	233,100
Accretion expense	**9,286**	6,110
Liabilities acquired	**113,681**	43,056
Liabilities incurred	**6,306**	8,442
Disposal of liabilities	**(13,090)**	(8,560)
Settlement of liabilities	**(11,409)**	(3,970)
Change in estimates	**52,022**	(23,765)
Balance, end of year	**411,209**	254,413

The Company's decommissioning liabilities result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. Change in estimates is primarily attributable to the change in the period end risk-free rate. At December 31, 2014, the Company estimated the total undiscounted amount of cash flows required to settle its decommissioning liabilities was approximately $560.0 million, which will be incurred over the next 40 years (December 31, 2013 - $404.0 million). At December 31, 2014, the Company used a risk free rate of 2.25% and an inflation rate of 2.0% to calculate the present value of the decommissioning liabilities (December 31, 2013 - risk free rate of 3.0% and inflation rate of 2.0%).

9. AVAILABLE CREDIT FACILITIES

At December 31, 2013, the Company had credit facilities of $475.0 million, of which $423.6 million was drawn. On May 30, 2014, the available borrowing base was increased from $475.0 million to $575.0 million in connection with the Deep Basin acquisition (see Note 5), and the termination date was extended to May 31, 2017. On August 6, 2014, the credit facilities borrowing base was increased from $575.0 million to $695.0 million in conjunction with the acquisition of Crocotta (see Note 5).

The credit facilities of $695.0 million consist of a $655.0 million revolving syndicated facility and a $40.0 million operating facility. At December 31, 2014, $611.7 million was drawn against the credit facilities.

Under the credit facilities, total borrowings cannot exceed the borrowing base, which is determined by the lenders on a semi-annual basis, or upon the occurrence of a material event. The level of the borrowing base is determined by the lenders based upon their review of, among other things, the Company's reserves and the value thereof, utilizing commodity prices determined by the lenders which may be different than those utilized by the Company's independent reserve evaluator.

The $695.0 million borrowing base was confirmed by the lenders on November 25, 2014, upon completion of their semi-annual review. The next annual review will occur prior to May 31, 2015. During 2015, Long Run plans to repay $100.0 million of its bank debt primarily through asset dispositions. As a result, $100.0 million of bank debt has been classified as a current liability.

Security for the credit facilities at December 31, 2014 included a demand debenture for $1.5 billion which provides for a first ranking security interest and floating charge over all of the assets and property of the Company.

The credit facilities bear interest at the prime rate or Libor rate, plus a margin, and in respect of banker's acceptances requires the payment of a stamping fee equal to a margin. The margins range from 1.00% per annum to 3.50% per annum, based upon the Company's debt to earnings before interest, taxes, exploration expenses, and all non-cash items including depletion, depreciation and

amortization ("EBITDA") ratio. For the year ended December 31, 2014, the effective interest rate, including standby and other fees, was 4.5% (December 31, 2013 – 4.4%).

At December 31, 2014, the Company was in compliance with all covenants, obligations and conditions of its credit agreement. The covenants in the facilities relate to debt to EBITDA, interest coverage, permitted dispositions and permitted hedging.

At December 31, 2014, the Company had letters of credit outstanding totalling $4.5 million (December 31, 2013 – $nil).

10. CONVERTIBLE DEBENTURES

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

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

Below is a summary of the debt and equity balances:

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

11. SHAREHOLDERS' EQUITY

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

Share Capital

($000s)	**December 31, 2014**	December 31, 2013
Common Shares	**1,006,799**	551,403
Non-Voting Convertible Shares	**-**	106,263
	1,006,799	657,666

Common Shares

(000s)	December 31, 2014 Number of shares	December 31, 2014 Amount $	December 31, 2013 Number of shares	December 31, 2013 Amount $
Balance, beginning of year	**110,143**	**551,403**	110,107	551,192
Issuance of common shares	**23,530**	**120,003**	-	-
Issuance of common shares upon business combination (*note 5*)	**43,829**	**231,419**		
Issued on conversion of Non-Voting Convertible Shares	**15,513**	**106,263**	-	-
Issued on exercise of stock options	**483**	**2,159**	36	162
Share issue costs, net of deferred tax of $1.7 million	**-**	**(5,105)**	-	-
Transfer from contributed surplus on exercise of stock options	**-**	**657**	-	49
Balance, end of year	**193,498**	**1,006,799**	110,143	551,403

On April 30, 2014, the Company closed an equity issuance of 23.5 million Subscription Receipts at $5.10 per Subscription Receipt for gross proceeds of $120 million. On May 30, 2014, in conjunction with the closing of the acquisition of the Deep Basin properties, holders of the Subscription Receipts received one Common Share of the Company for each Subscription Receipt held. Proceeds were used to pay for a portion of the Deep Basin acquisition cost (see Note 5).

On August 6, 2014, the Company issued 43.8 million Common Shares at $5.28 per share in connection with the acquisition of Crocotta (see Note 5).

Non-Voting Convertible Shares

(000s)	December 31, 2014 Number of shares	December 31, 2014 Amount $	December 31, 2013 Number of shares	December 31, 2013 Amount $
Balance, beginning of year	**15,513**	**106,263**	15,513	106,263
Conversion to Common Shares	**(15,513)**	**(106,263)**	-	-
Balance, end of year	**-**	**-**	15,513	106,263

On May 28, 2014, all of the Non-Voting Convertible Shares were converted to Common Shares of the Company. The holders of the Non-Voting Common Shares were entitled to receive dividends declared thereon equally, on a share-for-share basis, with the holders of Common Shares. The holders of Non-Voting Convertible Shares were entitled to attend meetings of shareholders, but were not entitled to vote. In the event of liquidation, dissolution or winding up of the affairs of the Company, the holders of the Non-Voting Convertible Shares were entitled to receive an amount per share equal to the fair market value of any property received as consideration by the Company for the issuance of the shares, before any amount was distributed to the holders of the Common Shares. The Non-Voting Convertible Shares could not be transferred to a control person, meaning a person or company holding more than 20% of the voting securities of the Company. Holders of Non-Voting Convertible Shares could convert each share into one Common Share, provided the holder would not become a control person of the Company after the conversion, or upon a change in control of the Company, and were automatically converted on a transfer of the share to a person that would not be a control person of the Company after giving effect to such transfer. The Company had the right to require holders of the Non-Voting Convertible Shares to convert all issued and outstanding shares to Common Shares after June 30, 2014.

Dividends

In 2014, the Company began paying a monthly dividend of $0.0335 per share to holders of Common Shares and Non-Voting Convertible Shares. Dividends declared are subject to approval by the Board of Directors on a monthly basis. The first monthly dividend was declared in January 2014 and paid in February 2014. The Company increased its monthly dividend to $0.035 per share starting with the June 2014 dividend payable in July 2014. As at December 31, 2014, $66.2 million in dividends had been declared, of which $59.4 million were paid.

On December 15, 2014, the Company decreased its monthly dividend rate to $0.0175 per share for the January 2015 dividend payable in February 2015. During February 2015, the monthly dividend was suspended by the Board of Directors as a result of the volatile commodity price environment. For the period from January 1, 2015 to March 4, 2015, dividends of $3.4 million were paid.

Warrants

# of Warrants (000s)	**December 31, 2014**	December 31, 2013
Balance, beginning of year	**2,300**	2,300
Expired	**(2,300)**	-
Balance, end of year	**-**	2,300

At December 31, 2013, each warrant entitled the holder to acquire 0.4167 Common Shares of the Company at an exercise price of $3.10 per 0.4167 of a share until September 15, 2014. The exchange ratio and exercise price were subject to adjustment upon the payment of dividends by the Company. At June 30, 2014, each warrant entitled the holder to acquire 0.4329 Common Shares 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.

Contributed Surplus

($000s)	**December 31, 2014**	December 31, 2013
Balance, beginning of year	**23,377**	16,558
Share-based compensation cost	**3,440**	6,868
Transfer to share capital on exercise of options	**(657)**	(49)
Balance, end of year	**26,160**	23,377

Share Option Plan

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

	December 31, 2014		December 31, 2013	
	Number of Options *(000s)*	**Weighted Average Exercise Price ($)**	Number of Options *(000s)*	Weighted Average Exercise Price ($)
Outstanding, beginning of year	**10,266**	**4.50**	8,042	4.49
Forfeited	**(904)**	**4.52**	(679)	4.45
Exercised	**(483)**	**4.47**	(36)	4.49
Granted	**-**	**-**	2,939	4.51
Outstanding, end of year	**8,879**	**4.50**	10,266	4.50

At December 31, 2014, option exercise prices ranged from $4.03 to $5.30 per option for the 8.9 million options outstanding. The weighted average exercise price was $4.50 per option and the weighted average remaining life of the options was 3.0 years. At December 31, 2014, there were 5.0 million options exercisable, with a weighted average exercise price of $4.49 per option.

The fair value of options granted under the Company's share option plan is determined using a Black-Scholes Option Pricing Model. No options were granted during the year ended December 31, 2014.

Restricted and Performance Award Incentive Plan

During 2014, the Company adopted a Restricted and Performance Award Incentive Plan. Grantees will receive either cash or Common Shares, at the discretion of the Company, in relation to the value of a specified number of underlying Common Shares. The awards vest equally over three years, on the first, second and third anniversaries of the grant date. The maximum number of Common Shares issuable is limited to 5% of the issued and outstanding Common Shares. During January 2015, a total of 5.2 million restricted awards were granted. Each restricted award entitles the holder to a Common Share or the value of a Common Share (subject to certain adjustments, including for dividends paid on the Common Shares) on the vesting date.

Earnings (Loss) Per Share

	Year ended December 31	
	2014	2013
Net earnings (loss) *($000s)*	**(190,395)**	24,265
Weighted average number of shares *(000s)*		
Shares outstanding, beginning of period	**125,656**	125,620
Share options exercised	**344**	2
Issuance of Common Shares	**31,697**	-
Weighted average shares outstanding - basic	**157,697**	125,622
Weighted average shares outstanding - diluted	**157,697**	125,778
Basic earnings (loss) per share	**(1.21)**	0.19
Diluted earnings (loss) per share	**(1.21)**	0.19

The diluted weighted average number of shares is calculated by assuming the proceeds that arise from the exercise of outstanding and in the money options are used to purchase Common Shares of

the Company at the average market price during the period. For the year ended December 31, 2014, nil options have been included in the calculation of diluted earnings (loss) per share (December 31, 2013 – 2.9 million options).

12. CAPITAL RISK MANAGEMENT

The Company's primary capital management objective is to strengthen our financial position and financial flexibility. To manage the capital structure, the Company may adjust capital spending, dispose of properties, adjust dividends declared, issue new shares, issue new debt or repay existing debt.

In managing its capital structure, the Company monitors financial metrics as indicators of overall financial strength. The financial metrics the Company currently monitors include net debt to funds flow from operations and debt to debt plus equity.

The Company's objective is to target net debt to funds flow from operations at or below a ratio of 1.5 and debt to debt plus equity at a ratio at or below 0.4. While the Company may exceed these rates from time to time, efforts are made after a period of variation to bring the measures back in line. The net debt to funds flow from operations has been calculated based on fourth quarter funds flow annualized. As a result, the 2014 net debt to funds flow from operations of 2.7 times reflects the lower commodity prices experienced in the fourth quarter. The debt to debt plus equity ratio of 0.49 times includes the impact of the property and equipment impairment of $400 million. Excluding the after-tax effect of the impairment, debt to debt plus equity was 0.40 times. During 2015, the Company plans to repay $100 million of its bank debt to improve its financial position. The repayment is expected to be primarily funded through asset dispositions (see Note 9).

Notes to the Financial Statements
For the year ended December 31, 2014

Net Debt to Funds Flow from Operations

($000s, except ratios)	**December 31, 2014**	December 31, 2013
Net Debt		
Bank loan	**611,717**	423,553
Accounts payable and accrued liabilities	**132,439**	89,606
Accounts receivable	**(65,135)**	(53,433)
Deposits and prepaid expenses	**(14,423)**	(7,571)
Convertible debentures - face value	**75,000**	-
Net Debt	**739,598**	452,155
Funds Flow from Operations - Quarter Ended		
Petroleum and natural gas revenue	**133,354**	124,816
Royalties	**(14,835)**	(18,213)
Gain (loss) on financial derivatives - realized	**14,145**	(1,145)
Operating expense	**(42,684)**	(33,198)
Transportation expense	**(5,891)**	(4,971)
General and administration	**(7,793)**	(7,017)
Interest	**(8,038)**	(4,300)
Exploration expense	**(86)**	(32)
Capital and other taxes	**6**	(6)
Funds Flow from Operations - Quarter Ended	**68,178**	55,934
Funds Flow from Operations - Annualized *(Quarterly x 4)*	**272,712**	223,736
Net Debt to Funds Flow from Operations *(target <= 1.5)*	**2.7**	2.0

Debt to Debt plus Equity

($000s, except ratios)	**December 31, 2014**	December 31, 2013
Debt		
Bank loan	**611,717**	423,553
Convertible debentures - face value	**75,000**	-
Debt	**686,717**	423,553
Debt plus Equity		
Debt	**686,717**	423,553
Shareholders' equity	**715,775**	616,977
Debt plus Equity	**1,402,492**	1,040,530
Debt to Debt plus Equity *(target <= 0.4)*	**0.49**	0.41

13. GENERAL AND ADMINISTRATION EXPENSE

	Year ended December 31	
($000s)	**2014**	2013
Salary and employee	**36,417**	27,067
Other	**22,734**	14,354
Gross expenses	**59,151**	41,421
Capitalized costs	**(16,001)**	(13,691)
Operating recoveries	**(4,957)**	(2,381)
General and administration	**38,193**	25,349

During 2014, general and administration expense included $6.5 million of transaction costs related to the Deep Basin and Crocotta acquisitions (see Note 5).

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

	Year ended December 31	
($000s)	**2014**	2013
Salaries and short-term benefits	**4,794**	4,129
Directors fees	**627**	655
Termination benefits	**975**	768
Included in general and administrative expense	**6,396**	5,552
Total share-based compensation	**1,035**	2,207
	7,431	7,759

14. INCOME TAXES

The provision for income tax differs from the amount that would have been expected if the reported earnings (loss) had been subject only to the statutory Canadian income tax rate of 25.0% (2013 – 25.0%). There have been no significant changes to the relevant Canadian federal or provincial tax rates during the year.

	Year ended December 31	
($000s)	**2014**	2013
Earnings (loss) before income tax	**(251,595)**	35,438
Corporate tax rate	**25.0%**	25.0%
Expected tax expense (recovery)	**(62,899)**	8,859
Increase (decrease) in taxes resulting from:		
Share-based compensation	**782**	1,295
Statutory tax rate changes	**-**	700
Non-deductible transaction costs	**949**	-
Non-deductible items	**145**	225
Deductible capital taxes	**-**	(24)
Other	**(177)**	30
Deferred income tax expense (recovery)	**(61,200)**	11,085

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

($000s)	**December 31, 2014**	December 31, 2013
Property and equipment	**82,990**	57,531
Decommissioning liabilities	**43,927**	43,907
Non-capital losses	**34,786**	24,334
Alberta royalty tax deduction	**1,380**	1,190
Investment tax credits	**13,649**	13,649
Convertible debentures *(note 10)*	**(1,714)**	-
Share issue costs	**3,261**	1,153
Financial derivatives	**(16,254)**	4,443
Deferred income tax asset	**162,025**	146,207

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

	Year ended December 31	
($000s)	**2014**	2013
Balance, beginning of year	**146,207**	157,292
Share issue costs *(note 11)*	**1,705**	-
Convertible debentures *(note 10)*	**(1,160)**	-
Acquisition of Crocotta *(note 5)*	**(45,927)**	-
Current year recovery (provision)	**61,200**	(11,085)
Balance, end of year	**162,025**	146,207

Deferred tax assets are recognized to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax losses can be utilized. The amount and timing of reversals of temporary differences will be dependent upon a number of factors, including the Company's future operating results.

At December 31, 2014 the Company has non-capital loss carry forward balances of approximately $139.1 million (December 31, 2013 – $97.0 million). The non-capital losses expire as follows: 2021 – $4.6 million, 2022 – $2.2 million, 2023 – $21.9 million, 2024 – $37.2 million, 2025 – $19.0 million, and thereafter $54.2 million.

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

15. RELATED PARTY TRANSACTIONS

A director of the Company and the corporate secretary are partners of the Company's legal counsel, Burnet, Duckworth & Palmer LLP ("BDP"). For the year ended December 31, 2014, general and administrative expense and share issue costs included amounts totalling $1.5 million charged to the Company by BDP (December 31, 2013 - $0.5 million). As at December 31, 2014, a payable of $0.1 million was outstanding (December 31, 2013 - $0.1 million).

16. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

Fair Value of Financial Assets and Liabilities

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

The Company's financial instruments recognized in the statement of financial position consist of accounts receivable, accounts payable, bank loan, convertible debentures and financial derivatives. The carrying values of accounts receivable and accounts payable approximate their fair values due to their short-term nature. The carrying value of the bank loan approximates fair value due to the floating interest rate on the facilities. At December 31, 2014, the fair value of the convertible debentures was $50.3 million, based on Level 1 inputs as the debentures are traded in an active market.

Financial Derivative Contracts

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

The Company had the following commodity financial contracts in place as at December 31, 2014:

Crude Oil	Volume	Pricing
Costless Collars		
January 1, 2015 – December 31, 2015	2,500 Bbl/d	WTI US $95.00 - $97.50/Bbl
Fixed Price		
January 1, 2015 – April 30, 2015	1,000 Bbl/d	WTI US $85.00/Bbl
January 1, 2015 – April 30, 2015	1,000 Bbl/d	WTI US $90.00/Bbl
Calls		
January 1, 2015 – December 31, 2015	500 Bbl/d	WTI US $85.00/Bbl

Natural Gas	Volume	Pricing
Costless Collars		
January 1, 2015 – March 31, 2015	13,000 GJ/d	CDN $3.50 - $3.75/GJ
January 1, 2015 – December 31, 2015	5,000 GJ/d	CDN $4.00 - $4.50/GJ
January 1, 2015 – December 31, 2015	5,000 GJ/d	CDN $4.00 - $4.51/GJ
January 1, 2015 – December 31, 2015	20,000 GJ/d	CDN $3.50 - $4.00/GJ
January 1, 2015 – December 31, 2015	11,000 GJ/d	CDN $3.50 - $4.35/GJ

Electricity	Volume	Pricing
January 1, 2015 – December 31, 2016	3.0 MW/h	CDN $49.50 MW/h

Subsequent to December 31, 2014, the Company entered into the following financial derivative contracts:

Crude Oil	Volume	Pricing
Fixed Price		
April 1, 2015 – June 30, 2015	1,000 Bbl/d	WTI US $55.01/Bbl
April 1, 2015 – June 30, 2015	1,500 Bbl/d	WTI US $55.00/Bbl
April 1, 2015 – June 30, 2015	1,000 Bbl/d	WTI CDN $70.42/Bbl
April 1, 2015 – June 30, 2015	500 Bbl/d	WTI CDN $70.55/Bbl

Natural Gas	Volume	Pricing
Fixed Price		
March 1, 2015 – December 31, 2015	5,000 GJ/d	CDN $2.72/GJ
March 1, 2015 – December 31, 2015	10,000 GJ/d	CDN $2.80/GJ
January 1, 2016 – December 31, 2016	10,000 GJ/d	CDN $3.05/GJ

Financial Derivative Contracts Financial Statement Recognition

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

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

- Level 1 - inputs represent quoted prices in active markets for identical assets or liabilities. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

- Level 2 - inputs other than quoted prices used in Level 1 that are observable, either directly or indirectly as of the reporting date. Level 2 valuations are based on inputs which can be observed or corroborated in the market place from sources such as the New York Mercantile Exchange and the Natural Gas Exchange.

- Level 3 - inputs that are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value.

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

($000s)	**December 31, 2014**	December 31, 2013
Assets - Fair value of financial derivatives		
Current	**65,438**	1,024
Liabilities - Fair value of financial derivatives		
Current	**336**	14,919
Long-term	**85**	3,876
	421	18,795
Net Asset (Liability)	**65,017**	(17,771)

Of the total December 31, 2014 financial liability, $0.3 million relates to 2015 and $0.1 million relates to 2016.

($000s)	Crude Oil	Natural Gas	Other	Total
Year ended December 31, 2014				
Realized loss on financial derivatives	2,492	5,165	306	7,963
New contracts	(358)	(3,066)	-	(3,424)
Change in value	65,211	14,130	(342)	78,999
Unrealized gain (loss) on financial derivatives	67,345	16,229	(36)	83,538
Business combination	(398)	(352)	-	(750)
December 31, 2013 - Net Liability	(17,103)	(450)	(218)	(17,771)
December 31, 2014 - Net Asset (Liability)	49,844	15,427	(254)	65,017
Year ended December 31, 2013				
Realized (gain) loss on financial derivatives	11,739	(8,525)	(525)	2,689
New contracts	(4,428)	1,578	-	(2,850)
Cancelled contracts	5,357	(22)	-	5,335
Change in value	(15,861)	(1,715)	667	(16,909)
Unrealized gain (loss) on financial derivatives	(3,193)	(8,684)	142	(11,735)
December 31, 2012 - Net Asset (Liability)	(13,910)	8,234	(360)	(6,036)
December 31, 2013 - Net Liability	(17,103)	(450)	(218)	(17,771)

Market risk

Market risk includes uncertainty arising from possible movements in commodity prices, and the impact of such movements on the future performance of the business. Commodity price movements could adversely affect the value of the Company's financial assets, liabilities and expected future cash flows. To partially mitigate exposure to commodity price risk, the Company enters into various financial derivative instruments. The instruments currently outstanding are described above.

When assessing the potential impact of price changes on financial derivative contracts outstanding at December 31, 2014, it is estimated that a $1.00/Bbl change in the price of oil would change the unrealized gain by approximately $1.3 million. A $0.10/GJ change in the price of natural gas would change the unrealized gain by approximately $1.4 million.

Credit risk

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

During the year ended December 31, 2014, five third party purchasers each marketed more than 10% of the Company's petroleum and natural gas revenue. At December 31, 2014, approximately 31% of the accounts receivable balance is due from five customers.

Accounts Receivable *($000s)*	**December 31, 2014**	December 31, 2013
Less than 90 days	**58,019**	49,528
Greater than 90 days	**7,116**	3,905
Total	**65,135**	53,433

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

Liquidity risk

Liquidity risk arises through excess financial obligations due over available financial assets at any point in time. The Company's objective in managing liquidity risk is to maintain sufficient capital in order to meet its current and future liquidity requirements. The Company believes that it has access to sufficient capital through internally generated cash flows, external equity sources, and credit facilities to meet current spending forecasts. At December 31, 2014, $611.7 million was drawn against the Company's credit facilities, with $78.8 million of borrowing capacity available.

Interest rate risk

The Company is exposed to interest rate risk as changes in interest rates may affect future cash flows and the fair value of its financial instruments. To mitigate exposure to interest rate risk, the Company carries debt at both fixed and floating interest rates. The Company may also manage interest rate risk through the use of interest rate swaps. The Company's bank debt facility has a floating interest rate that will fluctuate based on prevailing market conditions. Cash flows are sensitive to changes in interest rates on this instrument. Based on the bank debt outstanding as at December 31, 2014, a one percent change in the interest rate would be expected to impact interest expense by approximately $6.1 million. The Company's convertible debentures bear interest at a fixed annual interest rate of 6.4%.

17. SUPPLEMENTAL CASH FLOW INFORMATION

Net Change in Non-Cash Working Capital

	Year ended December 31	
($000s)	**2014**	2013
Source (use) of cash:		
Accounts receivable	**(11,702)**	(4,521)
Deposits and prepaid expenses	**(852)**	(415)
Accounts payable and accrued liabilities	**42,833**	(2,215)
Business combination	**3,359**	-
	33,638	(7,151)
Related to:		
Operating activities	**5,486**	8,117
Investing activities	**21,380**	(15,268)
Financing activities	**6,772**	-
	33,638	(7,151)

18. COMMITMENTS AND CONTINGENCIES

Commitments

($000s)	2015	2016	2017	2018	2019	Thereafter	Total
Operating leases	4,790	4,329	6,041	7,753	7,482	50,604	80,999
Processing	4,380	4,380	4,380	4,380	4,380	21,901	43,801
Transportation	9,140	11,713	10,819	8,529	4,470	9,623	54,294
Fractionation	2,224	1,228	233	-	-	-	3,685
Capital	7,079	1,817	-	-	-	-	8,896
Total	27,613	23,467	21,473	20,662	16,332	82,128	191,675

At December 31, 2014, the Company is committed under operating leases for office space, contracts related to the processing of natural gas, transportation of oil, natural gas and NGLs, fractionation of natural gas liquids, and capital commitments for drilling rig services.

Litigation

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

LONG RUN EXPLORATION LTD.

Management's Discussion and Analysis

December 31, 2014

Management's Discussion and Analysis

For the year ended December 31, 2014

This Management's Discussion & Analysis ("MD&A") of financial condition and results of operations of Long Run Exploration Ltd. ("Long Run", the "Company", "its" or "our") should be read in conjunction with the audited financial statements for the years ended December 31, 2014 and 2013.

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

The MD&A contains certain measures that do not have any standardized meaning as prescribed by IFRS and therefore are considered non-Generally Accepted Accounting Principles ("Non-GAAP") measures. Readers are cautioned that the MD&A should be read in conjunction with the disclosure in the Non-GAAP Measures and the Advisory sections located at the end of this document. The Advisory provides information on forward-looking statements and oil and natural gas information.

See the Abbreviations section at the end of this document for abbreviations used throughout.

This document is dated March 4, 2015.

Long Run's Strategy

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

Long Run has assembled a large land position and is continuing to add oil and natural gas infrastructure in our key areas, providing flexibility for future growth and development. Through controlled exploitation, enhanced recovery and selective low risk exploration, Long Run strives to maximize operating and cost efficiencies.

We continue to evaluate our 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 our balance sheet strength, through disciplined capital spending and an ongoing asset rationalization program. In looking forward to 2015, we recognize the current uncertainty regarding future commodity prices and believe we have 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.

Annual Highlights

Highlights for the year ended December 31, 2014 include:

- Established the Deep Basin Cardium core area through two strategic acquisitions for total consideration of $576 million. The Deep Basin transactions provide a key entry point into the Pine Creek, Kakwa and Wapiti areas of Alberta and add ownership of gathering and processing infrastructure.
- Executed a focused development program, drilling 100.5 net wells. Net capital expenditures of $275 million, excluding the Deep Basin acquisitions, concentrated on our Peace River Montney, Deep Basin Cardium and Redwater Viking core areas.
- Averaged 31,168 Boe/d of production, a 24% increase from 25,094 Boe/d in 2013. The production increase resulted from the Deep Basin acquisitions and our 2014 drilling program.
- Increased proved plus probable reserves at December 31, 2014 by 75% to 170,625 MBoe from 97,683 MBoe in 2013, as a result of the Deep Basin acquisitions and Long Run's 2014 drilling program.
- Generated funds flow from operations of $291.9 million, a 27% increase over $230.1 million in 2013. The increase was primarily due to higher production volumes and realized pricing, partially offset by higher royalty expense and higher operating costs associated with increased production volumes.
- Recorded a net loss of $190.4 million compared to net earnings of $24.3 million in 2013. The loss resulted primarily from property impairments of $300 million after tax due to the decline in future commodity price forecasts at December 31, 2014.
- Declared dividends in 2014 totaled $0.41 per share, or $66.2 million, with a basic payout ratio of 23%.
- Issued $75.0 million of convertible debentures to strengthen the balance sheet by providing Long Run with additional financial flexibility through the diversification of indebtedness and interest rate certainty on a portion of its debt. The convertible debentures bear an annual interest rate of 6.40% and are convertible into Long Run Common Shares at conversion price of $7.40 per share.

Annual Results Overview

($000s, except per share or unless otherwise noted)	Year Ended December 31 2014	2013	2012[3]
Funds flow from operations [1]	**291,856**	230,109	128,719
Per share, basic [1]	**1.85**	1.83	1.41
Per share, diluted [1]	**1.85**	1.83	1.41
Net earnings (loss)	**(190,395)**	24,265	(42,652)
Per share, basic	**(1.21)**	0.19	(0.47)
Per share, diluted	**(1.21)**	0.19	(0.47)
Dividends declared	**66,206**	-	-
Per share	**0.41**	-	-
Payout ratio [1]	**23%**	-	-
Revenues, before royalties	**610,896**	475,562	276,605
Capital expenditures	**304,031**	276,571	196,320
Net acquisitions (divestitures) [2]	**(28,674)**	108,762	(164,151)
Production			
Oil *(Bbl/d)*	**12,590**	11,890	7,569
Natural gas liquids *(Bbl/d)*	**3,076**	1,342	1,007
Natural gas *(Mcf/d)*	**93,008**	71,170	27,679
Total *(Boe/d)*	**31,168**	25,094	13,189
Prices, including derivatives			
Oil *($/Bbl)*	**84.89**	78.13	79.84
Natural gas liquids *($/Bbl)*	**51.24**	72.45	71.90
Natural gas *($/Mcf)*	**4.52**	3.70	3.23
Total *($/Boe)*	**53.00**	51.63	58.99
Operating netback *($/Boe)*	**31.38**	29.54	36.33
Total assets	**1,939,706**	1,403,344	1,193,272
Bank loan	**611,717**	423,553	261,173
Net debt[1]	**739,598**	452,155	293,123
Non-current financial liabilities, excluding bank loan	**68,230**	3,876	12,155

[1] *See Non-GAAP measures section*
[2] *Excludes $228.8 million paid for the Deep Basin Acquisition on May 30, 2014*
[3] *On October 23, 2012, the Company completed a plan of arrangement with Guide Exploration Ltd.*

2014 compared to 2013

Funds flow from operations for 2014 was $291.9 million, an increase of $61.8 million from 2013. Funds flow in 2014 was positively impacted by higher production volumes and commodity prices, partially offset by increased royalties on higher revenues, and increased operating costs associated with higher production volumes.

Average production volumes for 2014 increased 6,074 Boe/d, to 31,168 Boe/d from 25,094 Boe/d in 2013. The production increase resulted from the Deep Basin acquisitions and our 2014 drilling program. The production average for the acquired Deep Basin assets was approximately 5,600 Boe/d, excluding new wells drilled on the acquired lands. The increase in our 2014 production was tempered by third party restrictions and plant outages experienced in the latter half of the year which reduced production by approximately 960 Boe/d. In the first quarter of 2015, we expect third party outages to be materially reduced.

Our 2014 average oil price including derivatives increased $6.76/Bbl to $84.89/Bbl from 2013. The oil price increase reflects an increase in the U.S dollar exchange rate and lower differentials, partially offset by a decrease in West Texas Intermediate benchmark pricing. Long Run's NGL price decreased to $51.24/Bbl from $72.45/Bbl in 2013 as a result of the change in our NGL product mix due to the Deep Basin acquisitions and reduced market prices for NGLs in the second half of 2014. Our natural gas price for 2014 including derivatives increased to $4.52/Mcf from $3.70/Mcf in 2013, primarily attributable to a stronger AECO benchmark price.

The net loss for 2014 was $190.4 million, compared to net earnings of $24.3 million in 2013. The loss resulted from year end impairment charges attributable to reduced future commodity price forecasts, and higher depletion expense associated with increased production. These expenses were partially offset by higher funds flow from operations, and an unrealized gain on oil derivatives compared to a loss in 2013.

2015 Plan

Given the current weakness in commodity prices, Long Run has adopted a capital budget of $100 million for 2015, with $50 million being spent in the first half of the year. The capital budget is based on commodity price assumptions of WTI US$52.50/Bbl, AECO $2.60/GJ and an FX CDN/USD of 0.80. This budget is expected to support annual average production of 32,000 Boe/d – 33,000 Boe/d (43% liquids). Given the dramatic change in commodity prices, the Company's 2015 guidance released on December 15, 2014, which was based on an average oil price of WTI US$70/Bbl, has been withdrawn.

The 2015 capital budget will be directed towards oil and liquids rich natural gas development in our Deep Basin Cardium and Peace River Montney core areas. Long Run plans to drill 9 wells in the first quarter of 2015, with 5 in the Peace River Montney, 3 in the Pine Creek Cardium and 1 in the Kakwa Cardium. Long Run expects our capital budget to be fully funded by funds flow from operations.

Long Run is focused on improving our balance sheet strength, through disciplined capital spending and an ongoing asset rationalization program. In looking forward to 2015, we recognize the current uncertainty regarding future commodity prices and believe we have adopted a fiscally prudent and conservative current year plan. As part of this plan, we are targeting a $100 million reduction of our debt, primarily through asset dispositions.

Reserves

The Company engaged Sproule Associates Limited ("Sproule") to provide an evaluation of the Company's proved and proved plus probable reserves as at December 31, 2014. The reserve estimates set forth below are based upon Sproule's reserve report dated March 4, 2015. The reserve estimates represent Long Run's gross reserves, which are the Company's interest before deduction of royalties and without including any of our royalty interests. Reserves estimates are based on forecast prices and costs at December 31, 2014.

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

Long Run's proved plus probable reserves at December 31, 2014 of 170,625 MBoe increased 75% as compared to Long Run's proved plus probable reserves at December 31, 2013, which included a 6% (2,347 MBoe) increase in oil reserves, a 475% (23,338 MBoe) increase in NGLs reserves, and an 86% (283,542 MMcf) increase in natural gas reserves. The increase was the result of the Deep Basin acquisitions, as well as an active drilling program.

December 31, 2014 Reserves[1]

	Oil *(MBbl)*	**NGLs** *(MBbl)*	**Natural Gas** *(MMcf)*	**Total** *(MBoe)*
Proved				
Proved producing	15,164	7,799	194,693	55,412
Proved non-producing	304	818	19,975	4,451
Proved undeveloped	11,171	7,899	147,669	43,681
Total Proved	26,639	16,516	362,336	103,544
Probable	13,598	11,731	250,508	67,081
Total Proved Plus Probable	**40,237**	**28,247**	**612,844**	**170,625**

Reserves Reconciliation[1]

(MBoe)	**Proved**	**Probable**	**Proved plus Probable**
December 31, 2013	62,692	34,991	97,683
Extensions	2,132	3,916	6,047
Infill drilling	3,336	1,058	4,394
Technical revisions	2,384	(4,285)	(1,902)
Discoveries	-	-	-
Acquisitions	47,241	32,485	79,726
Dispositions	(2,035)	(953)	(2,988)
Economic factors	(830)	(130)	(960)
Production	(11,376)	-	(11,376)
December 31, 2014	**103,544**	**67,081**	**170,625**

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

Reserves Pricing

	2014		2013	
	WTI Oil *(US$/Bbl)*	AECO Gas *(CDN$/Mcf)*	WTI Oil *(US$/Bbl)*	AECO Gas *(CDN$/Mcf)*
2014	-	-	95.72	4.01
2015	64.17	3.38	93.62	4.17
2016	76.67	3.83	92.25	4.35
2017	83.33	4.06	96.01	4.81
2018 – 2021	87.08 – 96.59	4.41 - 5.18	96.59 – 100.80	4.99 – 5.38
2022 – 2025	98.36 - 103.88	5.36 - 5.80	102.64 - 108.40	5.48 – 5.80
Remainder	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/yr

Forecast prices, inflation, and exchange rates utilized by Sproule in its evaluation 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.

Significant Properties

Within the Western Canadian Sedimentary Basin, Long Run operates two significant light oil areas, Peace River and Redwater. During 2014, the Company added the Deep Basin as a new core development area focused on oil and liquids rich natural gas. The Company also owns a significant low decline shallow gas property at Boyer in northern Alberta.

Development of the Peace River area, located in northern Alberta, is focused on the Montney oil resource play at Normandville and Girouxville. In 2014, Long Run invested $148.5 million in the Peace River area, drilling 43.5 net wells (41.5 Montney horizontal oil wells) with a 100% success rate. Production in the area averaged 13,168 Boe/d (55% oil and NGLs). Long Run plans to drill 5 net oil wells in the area in the first half of 2015. The Company operates, transports, and processes all of its production within Peace River.

In the Redwater area, located near Edmonton, Alberta, development is focused on the Viking oil resource play. In 2014, Long Run invested $89.8 million, drilling 44.0 net wells with a 100% success rate. Production averaged 8,142 Boe/d (68% oil and NGLs). No wells are planned to be drilled in the first half of 2015. The Company operates, transports, and processes substantially all of its production within the Redwater area.

Following the acquisition of the Deep Basin properties on May 30, 2014 (“Deep Basin Acquisition”) and the Crocotta Energy Inc. (“Crocotta”) acquisition on August 6, 2014, the Company has development and exploration assets located in the Deep Basin at Pine Creek, Kakwa and Wapiti in western Alberta. The development focus is on Cardium liquids rich natural gas and light oil. The Crocotta acquisition added significant ownership of operated gathering infrastructure in the Deep Basin area, comprised of 50 MMcf/d of natural gas handling, oil batteries, pipeline gathering systems and a metering station connected to the Alliance pipeline. The assets also included a working interest in the Edson (Pine Creek) natural gas plant and provide access to increased NGL value through existing marketing arrangements.

During 2014, Long Run invested $57.9 million in the Deep Basin area, drilling 11.0 net wells, with a 100% success rate. Production in the Deep Basin area averaged 5,261 Boe/d, consisting of 1,955 Bbl/d of oil and NGLs and 19.8 MMcf/d of natural gas. Of total production in the Deep Basin area for the year, approximately 2,600 Boe/d was attributed to the seven months of operations from the Deep Basin Acquisition and approximately 2,500 Boe/d was attributed to the five months of operations from the Crocotta properties. Production was tempered by third party restrictions and plant outages experienced in the latter half of the year which reduced production by approximately 680 Boe/d. In the first quarter of 2015, we expect third party outages to be materially reduced. Long Run plans to drill 4 net wells in the Deep Basin in the first half of 2015.

Capital Investment

Capital Expenditures, Acquisitions & Dispositions

($000s)	**2014**	2013
Drilling and completion	**203,423**	203,804
Plant and facilities	**86,486**	64,808
Geological and geophysical	**7,432**	3,260
Other assets	**6,690**	4,699
Capital expenditures	**304,031**	276,571
Acquisitions – land	**5,838**	16,916
– properties	**11,437**	109,051
Dispositions	**(45,949)**	(17,205)
Net capital expenditures excluding the Deep Basin Acquisition	**275,357**	385,333
Deep Basin Acquisition	**228,767**	-
Net capital expenditures	**504,124**	385,333

2014 Drilling Activity

	2014 Wells		2013 Wells		Success Rate *(net wells)*	
	Gross	**Net**	Gross	Net	**2014**	2013
Peace River – Montney	**42.0**	**41.5**	53.0	51.0	**100%**	100%
– Other	**2.0**	**2.0**	3.0	3.0	**100%**	0%
Redwater – Viking	**45.0**	**44.0**	64.0	62.2	**100%**	100%
– Other	**2.0**	**1.0**	8.0	8.0	**100%**	100%
Deep Basin	**11.0**	**11.0**	-	-	**100%**	-
Other	**1.0**	**1.0**	1.0	1.0	**100%**	100%
	103.0	**100.5**	129.0	125.2	**100%**	98%

Capital Expenditures

Capital expenditures in 2014 were $304.0 million, with $148.5 million (49%) in Peace River, $89.8 million (30%) in Redwater and $57.9 million (19%) in the Deep Basin. The Company drilled 103 (100.5 net) wells with a 100% success rate in the period. Capital expenditures included facility costs spent to provide flexibility for future development and to reduce reliance on third party processing.

Capital expenditures in 2013 were $276.6 million, with $152.5 million (55%) in Peace River and $114.1 million (41%) in Redwater. The Company drilled 129 (125.2 net) oil wells with a 98% success rate in 2013.

Acquisitions and Dispositions

During 2014, the active management of our portfolio of assets resulted in net divestitures of $28.7 million, excluding the Deep Basin Acquisition. Acquisitions were $17.3 million, consisting primarily of a minor property tuck-in in Redwater. During 2014, the Company received $45.9 million in disposition proceeds primarily for three non-core asset sales in Peace River, Lloydminster and Pine Creek.

On May 30, 2014, Long Run successfully closed the Deep Basin Acquisition for $228.8 million, which provided a key entry point into the Pine Creek, Kakwa and Wapiti areas of Alberta. A $120.0 million bought

deal equity financing was closed in conjunction with the acquisition. Long Run's credit facility borrowing base was increased by $100 million to $575 million upon closing of the transaction.

Net acquisitions in 2013 were $108.8 million, focusing on the acquisition of properties and infrastructure in the Redwater and Peace River areas.

Corporate Transaction

On August 6, 2014, Long Run successfully closed and integrated the Crocotta acquisition for $346.9 million, through the issuance of $231.4 million in share capital and the assumption of $115.5 million of net debt. The acquisition enhances our new Deep Basin core area by providing exploration and development opportunities and adding ownership of gathering and processing infrastructure in Pine Creek. Crocotta was acquired pursuant to a plan of arrangement under the *Business Corporations Act* (Alberta). For each Crocotta share held, shareholders of Crocotta received 0.415 of a Long Run Common Share, one common share of ExploreCo, and 0.2 arrangement warrants of ExploreCo. 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's credit facility borrowing base was increased by $120.0 million to $695.0 million upon closing of the transaction.

Enhanced Oil Recovery

Long Run's ongoing enhanced oil recovery ("EOR") projects in the Peace River Montney and Redwater Viking were further advanced during 2014. The performance of these projects will continue to be monitored through 2015.

Within Peace River, the Normandville 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 started up in January 2015. This expanded EOR project covers an area of 1.5 sections and includes 6 horizontal Montney producers, with 4 injection wells. These expanded projects 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 initiated a Viking EOR project in the north part of the Redwater field in December of 2013. A second complementary EOR project, located in the south part of the trend, began injection in early December 2014. Together these projects cover an area of 1.125 sections and include 11 horizontal producers, 6 vertical producers, and 5 horizontal injection wells.

Production

Average Production by Product

	2014	2013
Liquids *(Bbl/d)*		
Light oil	**11,979**	10,372
Heavy oil	**611**	1,518
NGLs	**3,076**	1,342
Total	**15,666**	13,232
Natural Gas *(Mcf/d)*	**93,008**	71,170
Total *(Boe/d)*	**31,168**	25,094

Average Production by Area

	2014				2013			
	Oil *(Bbl/d)*	**NGLs** *(Bbl/d)*	**Natural Gas** *(Mcf/d)*	**Total** *(Boe/d)*	Oil *(Bbl/d)*	NGLs *(Bbl/d)*	Natural Gas *(Mcf/d)*	Total *(Boe/d)*
Peace River	**6,830**	**393**	**35,667**	**13,168**	6,020	333	35,832	12,325
Redwater	**5,369**	**204**	**15,411**	**8,142**	5,860	191	11,294	7,934
Deep Basin	**391**	**1,564**	**19,838**	**5,261**	-	-	-	-
Boyer	**-**	**1**	**17,149**	**2,859**	-	2	18,463	3,079
Kaybob	**-**	**914**	**4,943**	**1,738**	10	816	5,581	1,756
	12,590	**3,076**	**93,008**	**31,168**	11,890	1,342	71,170	25,094

During 2014, production averaged 31,168 Boe/d, an increase of 6,074 Boe/d (24%) from 25,094 Boe/d in 2013. The production increase resulted from the Deep Basin acquisitions and our successful development drilling over the past year at Peace River and Redwater.

Production for 2014 increased at Peace River by 843 Boe/d (7%) to 13,168 Boe/d from 12,325 Boe/d in 2013 and at Redwater by 208 Boe/d (3%) to 8,142 Boe/d from 7,934 Boe/d. The Deep Basin property added 5,261 Boe/d of production in the year. Long Run's Deep Basin Acquisition added approximately 3,100 Boe/d of production to the Redwater and Deep Basin properties, and the Crocotta assets added approximately 2,500 Boe/d to the Deep Basin property.

Production was tempered by third party restrictions and plant outages experienced in the latter half of the year which reduced production by approximately 960 Boe/d. These outages were a result of longer than scheduled third party plant turnarounds, third party pipeline repairs and third party unscheduled maintenance. In the first quarter of 2015, we expect third party outages to be materially reduced with the completion of the facility expansion at Kakwa and the pipeline replacement at Cherhill in the Redwater area.

Commodity Pricing

	2014	2013
Benchmark pricing		
WTI *($US/Bbl)*	**92.92**	97.99
Edmonton Light Sweet *($CAD/Bbl)*	**94.46**	93.05
AECO *($/Mcf)*	**4.52**	3.17
Cdn$/US$ exchange rate	**1.10**	1.03
Prices, excluding derivatives		
Liquids *($/Bbl)*		
Light oil	**85.80**	82.58
Heavy oil	**78.31**	68.85
Total oil	**85.44**	80.83
NGLs	**51.24**	72.45
Total	**78.72**	79.98
Natural Gas *($/Mcf)*	**4.67**	3.37
Total *($/Boe)*	**53.70**	51.92
Prices, including derivatives		
Liquids *($/Bbl)*		
Oil	**84.89**	78.13
NGLs	**51.24**	72.45
Total	**78.29**	77.55
Natural Gas *($/Mcf)*	**4.52**	3.70
Total *($/Boe)*	**53.00**	51.63

The Company's financial results are influenced by fluctuations in commodity prices, exchange rates and Canadian price differentials. Our average oil price excluding derivatives for 2014 was $85.44/Bbl, an increase of $4.61/Bbl over 2013. This resulted from an increase in the U.S dollar exchange rate and lower differentials, partially offset by a decrease in West Texas Intermediate benchmark pricing.

Long Run's NGL price in 2014 of $51.24/Bbl decreased $21.21/Bbl from 2013. This reflected the change in our NGL product mix due to the Deep Basin acquisitions and the reduced market prices for NGLs in the latter half of 2014.

In 2014, our natural gas price excluding derivatives was $4.67/Mcf, an increase of $1.30/Mcf over 2013 due to the strengthening of AECO benchmark pricing. AECO pricing was favorably influenced by the reduction in natural gas storage levels, a result of the cold winter experienced in early 2014 in North America. The Company's natural gas price reflected premiums received for the liquids content included in the natural gas production.

The Company enters into financial derivative contracts for the purpose of protecting funds flow from operations from the volatility of commodity prices. During 2014, our oil price of $84.89/Bbl included a realized loss on derivatives of $0.55/Bbl. The Company's 2014 natural gas price of $4.52/Mcf included a realized loss on derivatives of $0.15/Mcf.

Operating Results

Operating Netback & Funds Flow from Operations

	2014		2013	
	$000s	**$/Boe**	$000s	$/Boe
Revenues	**610,896**	**53.70**	475,562	51.92
Royalties	**(70,276)**	**(6.18)**	(55,133)	(6.02)
	540,620	**47.52**	420,429	45.90
Realized loss on derivatives	**(7,963)**	**(0.70)**	(2,689)	(0.29)
Transportation costs	**(21,993)**	**(1.93)**	(20,520)	(2.24)
Operating costs	**(153,730)**	**(13.51)**	(126,637)	(13.83)
Operating netback	**356,934**	**31.38**	270,583	29.54
General and administration	**(38,193)**	**(3.36)**	(25,349)	(2.77)
Interest	**(26,027)**	**(2.29)**	(14,790)	(1.61)
Exploration expenses	**(858)**	**(0.08)**	(247)	(0.03)
Capital and other taxes	**-**	**-**	(88)	(0.01)
Funds flow from operations[1]	**291,856**	**25.65**	230,109	25.12

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

During 2014, funds flow from operations was $291.9 million, an increase of $61.8 million from 2013 due to the following:

- Higher liquids and natural gas production increased revenue by $94.0 million, attributable to the Deep Basin acquisitions and our drilling programs; and
- Higher oil and natural gas prices, excluding derivative contracts, increased revenue by $51.7 million.

Partially offset by:

- Lower NGL prices which decreased revenue by $10.4 million.
- Royalties associated with increased revenue were $15.1 million higher, averaging 11.5% of revenue in 2014 compared to 11.6% in 2013;
- The realized loss on financial derivative contracts of $8.0 million increased $5.3 million compared to 2013. During 2014, there was a realized loss on oil derivative contracts of $2.5 million and a loss on natural gas derivative contracts of $5.2 million due to higher benchmark pricing;
- Operating costs increased $27.1 million primarily resulting from the higher production volumes. Operating costs were $13.51/Boe in 2014, a decrease of $0.32/Boe from 2013, mainly attributed to the acquisition of the lower cost Deep Basin assets;
- General and administration expense increased $12.8 million, due to $6.5 million of transaction costs associated with the Deep Basin acquisitions and higher employee costs. Excluding the transaction costs, general and administration expense averaged $2.79/Boe; and
- Interest expense increased $11.2 million, attributable to a higher average debt balance outstanding, reflecting the Company's recent acquisitions.

Other Income & Expenses

($000s)	**2014**	2013
Unrealized gain (loss) on derivatives	**83,538**	(11,735)
Share-based compensation	**(2,262)**	(4,379)
Accretion	**(10,508)**	(6,110)
Depletion and depreciation	**(234,829)**	(170,696)
Gain on disposal of assets	**20,610**	11,161
Impairments	**(400,000)**	(13,000)
Deferred income tax recovery (expense)	**61,200**	(11,085)
	(482,251)	(205,844)
Funds flow from operations[1]	**291,856**	230,109
Net earnings (loss)	**(190,395)**	24,265

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

In comparing 2014 to 2013:

- There was an unrealized gain on financial derivative contracts of $83.5 million, compared to a loss of $11.7 million in 2013. The unrealized gain of $83.5 million on our oil and natural gas derivative contracts, reflects the decrease in forward prices;

- Depletion and depreciation expense of $234.8 million increased $64.1 million due to increased production volumes and the depletion rate. The depletion rate for 2014 was $20.60/Boe compared to $18.65/Boe in 2013. The increased depletion rate reflected costs associated with the Crocotta acquisition, the development of oil properties, and the properties acquired in late 2013;

- The gain on disposal of assets of $20.6 million increased by $9.4 million from 2013. The gain in 2014 related primarily to the disposition of three non-core assets in Peace River, Lloydminster and Pine Creek;

- Property impairments of $400.0 million in 2014 were recognized at Peace River, Kaybob, Redwater and the Deep Basin. The impairment charges resulted from the drop in commodity price forecasts, as highlighted in the pricing table within Reserves section. A $13.0 million impairment of oil and natural gas properties was recognized at Kaybob, in 2013, due to capital spending on facilities that did not add additional reserves; and

- Deferred income tax recovery of $61.2 million was recorded in 2014 on losses before tax of $251.6 million. A deferred income tax expense of $11.1 million was recognized in 2013 on earnings before tax of $35.4 million.

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

Summary of Quarterly Results

	2014				2013			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Funds flow from operations[1] *($000s)*	68,178	80,199	73,429	70,050	55,934	62,304	63,227	48,644
Per share, basic[1]	0.35	0.45	0.55	0.56	0.45	0.50	0.50	0.39
Per share, diluted[1]	0.35	0.45	0.54	0.56	0.44	0.50	0.50	0.39
Net earnings (loss) *($000s)*	(258,652)	40,644	20,842	6,771	(5,531)	9,524	21,099	(827)
Per share, basic	(1.34)	0.23	0.16	0.05	(0.04)	0.08	0.17	(0.01)
Per share, diluted	(1.34)	0.23	0.15	0.05	(0.04)	0.08	0.17	(0.01)
Dividend *($000s)*	20,318	18,781	14,468	12,639	-	-	-	-
Per share	0.11	0.11	0.10	0.10	-	-	-	-
Payout ratio[1]	30%	23%	20%	18%	-	-	-	-
Revenues, before royalties	133,354	166,978	158,678	151,886	124,816	129,923	117,210	103,613
Capital expenditures	70,094	75,759	57,330	100,848	41,637	93,137	38,878	102,919
Net acquisitions (dispositions)[2]	(1,797)	(8,147)	(15,051)	(3,679)	86,328	3,331	1,158	17,945
Production								
Oil (Bbl/d)	12,130	13,071	12,476	12,684	13,251	11,709	11,471	11,109
NGLs (Bbl/d)	5,609	3,031	2,038	1,584	1,520	1,478	1,116	1,249
Natural Gas *(Mcf/d)*	112,576	112,161	78,524	68,071	73,392	72,634	71,058	67,516
Total *(Boe/d)*	36,502	34,795	27,602	25,613	27,003	25,293	24,431	23,611
Prices, including derivatives								
Oil *($/Bbl)*	79.35	84.66	89.59	85.89	71.14	87.44	81.80	72.77
NGLs *($/Bbl)*	30.02	57.98	72.76	86.87	69.21	76.05	68.91	75.33
Natural Gas *($/Mcf)*	4.15	4.23	4.61	5.53	4.04	3.23	3.89	3.63
Total *($/Boe)*	43.92	50.75	59.13	62.67	49.78	54.29	53.29	49.12
Operating Netback *($/Boe)*	25.04	31.41	35.04	36.55	27.09	30.74	32.57	27.93

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

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

The Company's funds flow from operations is significantly impacted by changes in production volumes, fluctuations in commodity prices and realized gains and losses on financial derivative contracts. In addition to these items, net earnings are impacted by impairments and unrealized gains and losses on financial derivative contracts. Acquisitions and divestitures can also have a significant impact on Long Run's results.

Fourth Quarter 2014 compared to Fourth Quarter 2013

Funds flow from operations for the fourth quarter of 2014 totaled $68.2 million, an increase of 22% from $55.9 million in 2013. The increase was attributable to higher production volumes and a realized gain on financial derivatives, partially offset by lower oil and NGL prices and higher operating costs associated with the increased production volumes. The fourth quarter funds flow from operations for 2014 included the operating and financial results from the Deep Basin acquisitions.

The net loss for the fourth quarter of 2014 was $258.7 million, compared to a net loss of $5.5 million in 2013. The 2014 net loss primarily resulted from year end impairment charges of $300 million after tax due to the decline in future commodity price forecasts at December 31, 2014.

Long Run's operating netback of $25.04/Boe and corporate netback of $20.33/Boe in the fourth quarter reflect lower commodity prices, partially offset by a realized gain on financial derivatives and lower royalties compared to the fourth quarter of 2013.

Long Run's realized oil price excluding derivatives decreased to $66.62/Bbl from $73.72/Bbl in 2013, reflecting the weaker WTI oil benchmark price, partially offset by an increase in the U.S. dollar exchange rate and lower differentials. Including a gain on derivatives of $12.73/Bbl, our 2014 realized oil price was $79.35/Bbl. Our realized NGL price decreased to $30.02/Bbl from $69.21/Bbl in 2013 as a result of the change in our product mix due to the Deep Basin acquisitions and the reduced market prices for NGLs in the second half of 2014. Our realized natural gas price excluding derivatives increased to $4.13/Mcf from $3.73/Mcf in 2013, primarily attributable to stronger benchmark AECO natural gas prices and reflecting the premiums received for the liquids content included in our natural gas production. Including a gain on derivatives of $0.02/Mcf, our 2014 realized natural gas price was $4.15/Mcf.

Operating costs in the fourth quarter averaged $12.71/Boe, improving from $13.36/Boe in 2013 primarily due to the addition of the lower operating cost Deep Basin assets. Fourth quarter general and administrative expense averaged $2.32/Boe. For 2015, we estimate operating costs will be approximately $13.50/Boe and general and administrative expense will be approximately $2.50/Boe.

Fourth quarter production for 2014 averaged 36,502 Boe/d (49% oil and NGLs), which represents an increase of 9,499 Boe/d from 27,003 Boe/d (55% oil and NGLs) in 2013. The production increase resulted from the addition of our Deep Basin acquisition properties and our successful development drilling over the past year. The Deep Basin acquisition properties added approximately 11,400 Boe/d of production in the fourth quarter. Third party outages continued to affect production in the quarter. Extended outages reduced production by approximately 2,200 Boe/d with longer than expected third party outages at both Kakwa and Wapiti as well as extended downtime resulting from a third party gas pipeline replacement at Cherhill. In the first quarter of 2015, we expect third party outages to be materially reduced with the completion of the facility expansion at Kakwa and the infrastructure modifications at Cherhill.

Capital expenditures of $70.1 million in the fourth quarter of 2014 focused on the development of our Deep Basin core area and included $15 million of capital originally planned for the first quarter of 2015. First quarter 2015 net capital expenditures will be reduced accordingly. Fourth quarter 2014 capital included Deep Basin facility costs, spent to provide flexibility for future development and reduce reliance on third party processing. The Company drilled 11.0 wells (10.0 net wells) in the quarter with a 100% success rate, including 8 wells in the Deep Basin Cardium, 1 well in the Peace River Montney and 1 well in the Redwater Viking.

Liquidity and Capital Resources

Net Debt

($000s)	**December 31, 2014**	December 31, 2013
Bank debt	**611,717**	423,553
Working capital deficiency	**52,881**	28,602
Convertible Debentures – face value	**75,000**	-
Net debt[1]	**739,598**	452,155

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

The Company's net debt at December 31, 2014 increased $287.4 million from December 31, 2013, primarily attributable to $115.2 million of the Deep Basin Acquisition being funded with debt and the assumption of $115.5 million of Crocotta net debt.

The capital intensive nature of the Company's activities generally results in the Company carrying a working capital deficit, as reflected in the net debt calculation. The Company maintains sufficient unused credit facilities to satisfy working capital deficiencies. At December 31, 2014, the Company had letters of credit outstanding totaling $4.5 million and had drawn $611.7 million against the Company's credit facilities, leaving $78.8 million of borrowing capacity available.

Credit Facilities

At December 31, 2013, the Company had credit facilities of $475.0 million, of which $423.6 million had been drawn. On May 30, 2014, the available borrowing base was increased from $475.0 million to $575.0 million in connection with the Deep Basin Acquisition, and the termination date was extended to May 31, 2017. On August 6, 2014, the credit facilities borrowing base was increased from $575.0 million to $695.0 million in conjunction with the acquisition of Crocotta.

The credit facilities of $695.0 million consist of a $655.0 million revolving syndicated facility and a $40.0 million operating facility. At December 31, 2014, $611.7 million was drawn against the credit facilities.

Under the credit facilities, total borrowings cannot exceed the borrowing base, which is determined by the lenders on a semi-annual basis, or upon the occurrence of a material event. The level of the borrowing base is determined by the lenders based upon their review of, among other things, the Company's reserves and the value thereof, utilizing commodity prices determined by the lenders, which may be different than those utilized by the Company's independent reserve evaluator. The $695.0 million borrowing base was confirmed by the lenders on November 25, 2014, upon completion of their semi-annual review. The next annual review will occur prior to May 31, 2015. During 2015, the Company plans to repay $100 million of its bank debt to improve its financial position. The repayment is expected to be primarily funded through asset dispositions.

Security for the credit facilities at December 31, 2014 included a demand debenture for $1.5 billion, which provides for a first ranking security interest and floating charge over all of the assets and property of the Company.

The credit facilities bear interest at the prime rate or Libor rate, plus a margin, and in respect of banker's acceptances, requires the payment of a stamping fee equal to a margin. The margins range from 1.00% per annum to 3.50% per annum, based upon the Company's debt to earnings before interest, taxes, exploration expenses, and all non-cash items including depletion, depreciation and amortization ("EBITDA") ratio. For the year ended December 31, 2014, the effective interest rate, including standby and other fees, was 4.5% (December 31, 2013 – 4.4%).

At December 31, 2014, the Company was in compliance with all covenants, obligations, and conditions of its credit agreement. The covenant requirements under the credit facilities have not changed since December 31, 2013. These covenants relate to bank debt and total debt to trailing 12 month EBITDA, interest coverage, permitted dispositions and permitted hedging. EBITDA is defined in the credit facilities as earnings before interest, exploration expenses, taxes, depletion and depreciation, impairments, and other non-cash items. The bank covenants require a senior debt to EBITDA ratio of less than 3:1 (December 31, 2014 – 1.93:1) and a total debt to EBITDA ratio of less than 3.5:1 (December 31, 2014 – 1.93:1). The interest coverage ratio, defined as EBITDA to interest expense, must be at least 3.5:1 (December 31, 2014 – 12.25:1). The convertible debentures issued in January 2014 are not considered debt for the debt to EBITDA ratio calculations under the credit agreement. Dispositions are permitted up to 10% of the borrowing base without formal approval of the lending syndicate. Commodity hedges are permitted on up to 75% of 2015 forecasted oil and NGLs and natural gas production net of royalties (2016 - 75%; 2017 - 50%). Interest rate hedges are permitted up to 75% of the total debt balance. Further details on the calculations of the covenants can be found in the Company's credit facility agreement filed on SEDAR at www.sedar.com on May 5, 2014, June 6, 2014 and August 25, 2014 under the Company's profile.

Convertible Debentures

On January 28, 2014, the Company issued convertible unsecured subordinated debentures (the "convertible debentures") in the principal amount of $75 million at par. The convertible debentures bear interest at an annual rate of 6.40%, payable semi-annually in arrears. Prior to maturity on January 31, 2019, the convertible debentures are convertible into Common Shares at a conversion price of $7.40 per Common Share, subject to adjustments in certain events.

Share Capital

# of units (000s)	**March 4, 2015**	**December 31, 2014**	December 31, 2013
Common Shares	**193,498**	**193,498**	110,143
Options	**8,733**	**8,879**	10,266
Restricted Awards	**5,172**	**-**	-
Non-Voting Convertible Shares[1]	**-**	**-**	15,513
Warrants	**-**	**-**	2,300

[1] *Each Non-Voting Convertible Share was convertible into one Common Share in certain events, including on transfer to a holder that would not be a Control Person (as defined in the share provisions thereof).*

In connection with the Deep Basin Acquisition on April 30, 2014, Long Run closed the offering of 23.5 million subscription receipts ("Subscription Receipts") at a price of $5.10 per Subscription Receipt, for gross proceeds of $120.0 million. The Subscription Receipts were converted to Common Shares on May 30, 2014 upon closing of the Deep Basin Acquisition. The proceeds were used to fund a portion of the acquisition.

On May 21, 2014, Sprott Resource Corp. ("SRC") closed a secondary offering by SRC of 12.7 million Long Run Common Shares on a bought deal basis at a price of $5.35 per share. Long Run received no proceeds from this transaction and the total number of Long Run shares outstanding did not change. Upon completion of the secondary offering, SRC converted their 15.5 million Long Run Non-Voting Convertible Shares into 15.5 million Long Run Common Shares. This also had no impact on the total number of Long Run shares outstanding or Long Run's total shareholders' equity.

On August 6, 2014, upon closing of the Crocotta acquisition, Long Run issued 43.8 million Long Run Common Shares, based on an exchange ratio of 0.415 Long Run Common Shares for each of the 105.6 million Crocotta common shares outstanding.

In 2014, there were 483,000 Long Run Common Shares issued on the exercise of stock options. The Company did not grant stock options in 2014.

During 2014, the Company adopted a Restricted and Performance Award Incentive Plan. Grantees will receive either cash or Long Run Common Shares, at the discretion of the Company, in relation to the value of a specified number of underlying Long Run Common Shares. The awards vest equally over three years,

on the first, second and third anniversaries of the grant date. During January 2015, a total of 5.2 million restricted awards were granted. Each restricted award entitles the holder to a Long Run Common Share or the value if a Long Run Common Share (subject to certain adjustments, including for dividends paid on the Common Shares) on the vesting date.

At December 31, 2013, there were 2.3 million warrants outstanding. Each warrant entitled the holder to acquire 0.4167 Common Shares of the Company at an exercise price of $3.10 per 0.4167 of a share until September 15, 2014. The exchange ratio and exercise price were subject to adjustment upon the payment of dividends by the Company. At June 30, 2014, the warrants 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.

Dividends

In 2014, the Company commenced paying a dividend. Dividends were payable on Long Run Common Shares and Non-Voting Convertible Shares. Long Run initially established a monthly dividend to shareholders of $0.0335 per share ($0.402 per share annualized). Following the completion of the Deep Basin Acquisition, Long Run's monthly dividend was increased to $0.035 per share ($0.42 per share annualized), effective for the June 2014 dividend payable in July 2014. During 2014, dividends of $66.2 million ($0.41 per share) were declared.

On December 15, 2014, Long Run lowered the amount of the monthly dividend to $0.0175 per share, starting with the January 2015 dividend payable in February 2015. As a result of a volatile and uncertain commodity price environment, the monthly dividend was suspended in February 2015.

Capital Structure

The Company's primary capital management objective is to strengthen our financial position and financial flexibility. To manage the capital structure, the Company may adjust capital spending, dispose of properties, adjust dividends declared, issue new shares, issue new debt or repay existing debt.

In managing its capital structure, the Company monitors financial metrics as indicators of overall financial strength. The financial metrics the Company currently monitors include net debt to funds flow from operations and debt to debt plus equity. The Company's objective is to target net debt to funds flow from operations at or below a ratio of 1.5 and debt to debt plus equity at a ratio at or below 0.4. While the Company may exceed these rates from time to time, efforts are made after a period of variation to bring the measures back in line. For the calculation of these metrics, see Note 12 to the annual financial statements for the twelve months ended December 31, 2014.

The net debt to funds flow from operations at December 31, 2014 was calculated based on fourth quarter funds flow annualized. The resulting net debt to funds flow from operations of 2.7 times reflects the lower commodity prices experienced in the fourth quarter. The debt to debt plus equity ratio of 0.49 times includes the impact of the property and equipment impairment of $400 million. Excluding the after-tax effect of the impairment, debt to debt plus equity was 0.40 times. During 2015, the Company plans to repay $100 million of its bank debt to improve its financial position, funded primarily through asset dispositions.

Contractual Obligations and Contingencies

Contractual Obligations

Commitments

($000s)	2015	2016	2017	2018	2019	Thereafter	Total
Operating leases	4,790	4,329	6,041	7,753	7,482	50,604	80,999
Processing	4,380	4,380	4,380	4,380	4,380	21,901	43,801
Transportation	9,140	11,713	10,819	8,529	4,470	9,623	54,294
Fractionation	2,224	1,228	233	-	-	-	3,685
Capital	7,079	1,817	-	-	-	-	8,896
Total	27,613	23,467	21,473	20,662	16,332	82,128	191,675

At December 31, 2014, the Company is committed under operating leases for office space, contracts related to the processing of natural gas, transportation of oil and natural gas and NGLs, fractionation of natural gas liquids, and capital commitments for drilling rig services. Commitments increased by $102.0 million from December 31, 2013, as a result of the Deep Basin acquisitions.

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

Contingencies

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

Risk Management

Long Run is engaged in the development, acquisition, exploration and production of oil and natural gas in western Canada. The Company is exposed to a number of risks, both financial and operational, through the pursuit of its strategic objectives. Actively managing these risks improves the ability to effectively execute our business strategy. Financial risks associated with the petroleum industry include fluctuations in commodity prices, interest rates, currency exchange rates and the cost of goods and services. Financial risks also include third party credit risk and liquidity risk. Operational risks include reservoir performance uncertainties, competition, and regulatory, environment and safety concerns.

For a further and more in-depth discussion of risk management, see the Company's annual financial statements and the Company's Annual Information Form for the year ended December 31, 2014.

Commodity Price

To partially mitigate exposure to commodity price risk, the Company enters into various financial derivative instruments. The Company has entered into oil and natural gas derivative contracts, including costless collars, fixed price contracts, and calls. As at December 31, 2014, the Company had contracts for oil volumes of 3,658 Bbl/d for 2015. At December 31, 2014, the Company had average natural gas volumes of 44.2 MMcf/d contracted for 2015. Further details on the derivative contracts can be found in Note 16 of the annual financial statements for the year ended December 31, 2014.

In 2014, the Company realized an $8.0 million loss as a result of its commodity price risk management. The realized loss included a $2.5 million loss on oil contracts and a $5.2 million loss on natural gas financial derivative contracts. In 2014, the Company recognized an unrealized gain on oil financial derivative contracts of $67.3 million and an unrealized gain on natural gas financial derivative contracts of $16.2

million. At December 31, 2014, the fair value of oil derivatives was an asset of $49.8 million and the fair value of natural gas derivatives was an asset of $15.4 million.

Subsequent to December 31, 2014, the Company entered into additional financial derivative instruments. At March 4, 2015, the Company had contracts for oil volumes of 4,655 Bbl/d for 2015 and for natural gas volumes of 56.8 MMcf/d for 2015 and 10.0 MMcf/d for 2016.

Third Party Credit Risk

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

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

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

Liquidity Risk

Liquidity risk arises through excess financial obligations due over available financial assets at any point in time. The Company is exposed to liquidity risk, as well risks related to the continued availability of debt and equity financing at acceptable terms. 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.

The Company anticipates making substantial capital expenditures for the development and production of oil and natural gas reserves in the future. The Company may also make monthly dividend payments in the future. As future capital expenditures and dividend payments may be financed out of cash generated from operations, borrowings and possible future issuances of equity, 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, tax burdens due to new tax laws, and investor appetite for investments in the energy industry and for the Company's securities in particular. Furthermore, if the Company's revenues or reserves decline, it could result in a reduction of the borrowing base under the credit facility. Under the credit facilities, total borrowings cannot exceed the borrowing base, which is determined by the lenders on a semi-annual basis, or upon the occurrence of a material event. The level of the borrowing base is determined by the lenders based upon their review of, among other things, the Company's reserves and the value thereof, utilizing commodity prices determined by the lenders which may be different than those utilized by the Company's independent reserve evaluator.

There can be no assurance that debt or equity financing, or cash generated by operations, will be available or sufficient to meet the Company's operating or capital requirements. If debt or equity financing is available, there is no assurance that it will be on terms acceptable to the Company.

The Company's objective in managing liquidity risk is to maintain sufficient capital in order to meet its liquidity requirements at any point in time. With the goal of improving liquidity in the current commodity price environment, the Company is currently planning to reduce bank debt by $100.0 million in 2015, through asset rationalization, a reduced capital budget and suspension of the Company's dividend.

Operational Risks

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

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

Regulatory, Environmental and Safety Risks

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

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

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

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

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

Critical Accounting Judgments, Estimates and Accounting Policies

The Company is required to make judgments, estimates and assumptions in the application of accounting policies that could have a significant impact on its financial results. Actual results may differ from those estimates and the differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information.

Oil and Natural Gas Accounting

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

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

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

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

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

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

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

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

Impairment Calculations

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

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

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

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

Business Combinations

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

Decommissioning Liabilities

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

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

Fair Value of Financial Derivatives

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

Income Tax Accounting

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

Adoption of New Accounting Policies

As required by IFRS, the Company adopted IFRIC 21 – *Levies* and the amendment to IAS 36 - *Impairment of Assets* as of January 1, 2014. The adoption of these policies did not have a material impact on the Company's financial results. Further details of these standards can be found in Note 4 of the financial statements for the year ended December 31, 2014.

Future Accounting Pronouncements

As required by IFRS, the Company will be required to adopt the IFRS 11 – *Joint Arrangements* amendments on January 1, 2016, IFRS 15 – *Revenue from Contracts with Customers* on January 1, 2017, and IFRS 9 – *Financial Instruments* on January 1, 2018. The adoptions of these standards are not expected to have a material impact on the Company's financial statements. Further details of these standards can be found in Note 4 of the financial statements for the year ended December 31, 2014.

Control Environment

Disclosure Controls and Procedures

The Company's Chief Executive Officer (“CEO”) and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's disclosure controls and procedures at the financial year end of the Company and have concluded that the Company's disclosure controls and procedures are effective at the financial year end of the Company for the foregoing purposes.

Internal Controls over Financial Reporting

The CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles applicable to the Company. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal controls over financial reporting at the financial year end of the Company and have concluded that the Company's internal controls over financial reporting are effective at the financial year end of the Company for the foregoing purposes.

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

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Detailed Quarterly Results

The Corporation's quarterly funds flow from operations is significantly impacted by changes in production volumes, fluctuations in commodity prices, exchange rates and realized gains and losses on financial derivative contracts. In addition to these items, net earnings are impacted by impairments and unrealized gains and losses on financial derivative contracts. Acquisitions and divestitures can also have a significant impact on Long Run's results. The following significant transactions have impacted the Company's quarterly results:

- During the fourth quarter of 2014, Long Run recorded property impairment charges of $400.0 million ($300.0 million after tax) at Peace River, Kaybob, Redwater and the Deep Basin. The impairment charges are a result of the drop in forecast commodity prices at December 31, 2014.

- During the third quarter of 2014, Long Run completed the Crocotta acquisition on August 6, 2014, for total consideration of $346.9 million. Production from the properties averaged approximately 6,200 Boe/d from August 6 through December 31, 2014, in the Deep Basin area.

- During the second quarter of 2014, Long Run completed the Deep Basin Acquisition on May 30, 2014, for total consideration of $228.8 million. Production from the properties averaged approximately 5,200 Boe/d from May 30 through December 31, 2014, in the Deep Basin and Redwater areas.

- During the fourth quarter of 2013, Long Run completed two significant light oil acquisitions in the Peace River and Redwater areas for total consideration of approximately $95 million, with combined production of approximately 1,800 Boe/d at the closing dates.

	2014				2013			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Funds flow from operations[1] *($000s)*	68,178	80,199	73,429	70,050	55,934	62,304	63,227	48,644
Per share, basic[1]	0.35	0.45	0.55	0.56	0.45	0.50	0.50	0.39
Per share, diluted[1]	0.35	0.45	0.54	0.56	0.44	0.50	0.50	0.39
Net earnings (loss) *($000s)*	(258,652)	40,644	20,842	6,771	(5,531)	9,524	21,099	(827)
Per share, basic	(1.34)	0.23	0.16	0.05	(0.04)	0.08	0.17	(0.01)
Per share, diluted	(1.34)	0.23	0.15	0.05	(0.04)	0.08	0.17	(0.01)
Dividend *($000s)*	20,318	18,781	14,468	12,639	-	-	-	-
Per share	0.11	0.11	0.10	0.10	-	-	-	-
Payout ratio[1]	30%	23%	20%	18%	-	-	-	-
Capital *($000s)*								
Drilling and completion	40,928	52,530	34,851	75,114	30,750	72,746	19,541	80,767
Plant and facilities	26,935	19,740	16,441	23,370	8,760	18,699	17,697	19,652
Geological and geophysical	247	1,951	4,295	939	566	601	779	1,314
Other assets	1,984	1,538	1,743	1,425	1,561	1,091	861	1,186
Capital expenditures	70,094	75,759	57,330	100,848	41,637	93,137	38,878	102,919
Net acquisitions (dispositions)	(1,797)	(8,147)	213,716	(3,679)	86,328	3,331	1,158	17,945
Capital investment	68,297	67,612	271,046	97,169	127,965	96,468	40,036	120,864
Wells drilled *(net)*								
Peace – Montney	1.0	12.0	11.0	17.5	9.5	19.5	4.0	18.0
– Other	-	-	-	2.0	-	-	-	3.0
Redwater – Viking	1.0	6.0	10.0	27.0	1.0	26.6	6.0	28.6
– Other	-	-	1.0	-	-	4.0	2.0	2.0
Deep Basin	8.0	3.0	-	-	-	-	-	-
Other	-	-	-	1.0	1.0	-	-	-
Total	10.0	21.0	22.0	47.5	11.5	50.1	12.0	51.6
Production								
Liquids *(Bbl/d)*								
Light oil	11,895	12,708	11,808	11,491	11,811	10,322	9,802	9,528
Heavy oil	235	363	668	1,193	1,440	1,387	1,669	1,581
NGLs	5,609	3,031	2,038	1,584	1,520	1,478	1,116	1,249
	17,739	16,102	14,514	14,268	14,771	13,187	12,587	12,358
Natural Gas *(Mcf/d)*	112,576	112,161	78,524	68,071	73,392	72,634	71,058	67,516
Total *(Boe/d)*	36,502	34,795	27,602	25,613	27,003	25,293	24,431	23,611
Production by area *(Boe/d)*								
Peace River	13,311	13,972	12,500	12,873	13,669	12,061	11,830	11,726
Redwater	7,693	8,318	8,375	8,184	8,623	8,068	7,901	7,124
Deep Basin	11,244	7,861	1,771	19	-	-	-	-
Boyer	2,727	2,929	3,046	2,733	2,861	3,241	3,274	2,938
Kaybob	1,527	1,715	1,910	1,804	1,850	1,923	1,426	1,823
Total	36,502	34,795	27,602	25,613	27,003	25,293	24,431	23,611

	2014				2013			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Benchmark pricing								
WTI *($US/Bbl)*	73.12	97.21	102.98	98.68	97.46	105.83	94.20	94.37
Edmonton Light Sweet *($CAD/Bbl)*	75.65	97.18	105.62	99.83	86.58	104.98	92.33	88.19
AECO *($/Mcf)*	3.75	4.02	4.69	5.72	3.53	2.43	3.53	3.20
Cdn$/US$ exchange rate	1.13	1.09	1.09	1.10	1.05	1.04	1.02	1.01
Prices, excluding derivatives								
Liquids *($/Bbl)*								
Light oil	66.73	88.08	97.50	91.24	75.06	95.47	83.70	76.69
Heavy oil	60.71	81.47	81.79	78.90	62.69	87.40	71.52	55.10
NGLs	30.02	57.98	72.76	86.87	69.21	76.05	68.91	75.33
Total	55.04	82.26	93.30	89.72	73.25	92.44	80.78	73.79
Natural Gas *($/Mcf)*	4.13	4.29	4.89	5.96	3.73	2.65	3.73	3.37
Total *($/Boe)*	39.71	52.16	63.17	65.89	50.24	55.84	52.72	48.76
Prices, including derivatives								
Oil *($/Bbl)*	79.35	84.66	89.59	85.89	71.14	87.44	81.80	72.77
NGLs *($/Bbl)*	30.02	57.98	72.76	86.87	69.21	76.05	68.91	75.33
Natural Gas *($/Mcf)*	4.15	4.23	4.61	5.53	4.04	3.23	3.89	3.63
Total *($/Boe)*	43.92	50.75	59.13	62.67	49.78	54.29	53.29	49.12
Netback *($/Boe)*								
Revenues	39.71	52.16	63.17	65.89	50.24	55.84	52.72	48.76
Royalties	(4.42)	(6.05)	(7.01)	(8.01)	(7.33)	(6.61)	(4.38)	(5.55)
Realized gain (loss) on derivatives	4.21	(1.42)	(4.04)	(3.22)	(0.46)	(1.54)	0.57	0.36
Transportation costs	(1.75)	(1.65)	(2.10)	(2.41)	(2.00)	(2.50)	(2.36)	(2.11)
Operating costs	(12.71)	(11.63)	(14.98)	(15.70)	(13.36)	(14.45)	(13.98)	(13.53)
Operating Netback	25.04	31.41	35.04	36.55	27.09	30.74	32.57	27.93
G&A	(2.32)	(3.92)	(3.64)	(3.79)	(2.82)	(2.31)	(2.47)	(3.51)
Interest	(2.39)	(2.36)	(2.19)	(2.13)	(1.73)	(1.56)	(1.63)	(1.52)
Corporate Netback	20.33	25.13	29.21	30.63	22.54	26.87	28.47	22.90
Funds flow from operations[1] *($000s)*								
Revenues	133,354	166,978	158,678	151,886	124,816	129,923	117,210	103,613
Royalties	(14,835)	(19,377)	(17,598)	(18,466)	(18,213)	(15,377)	(9,753)	(11,790)
Realized gain (loss) on derivatives	14,145	(4,529)	(10,157)	(7,422)	(1,145)	(3,585)	1,285	756
Transportation costs	(5,891)	(5,272)	(5,287)	(5,543)	(4,971)	(5,816)	(5,250)	(4,483)
Operating costs	(42,684)	(37,238)	(37,614)	(36,194)	(33,198)	(33,614)	(31,083)	(28,742)
	84,089	100,562	88,022	84,261	67,289	71,531	72,409	59,354
G&A	(7,793)	(12,537)	(9,134)	(8,729)	(7,017)	(5,378)	(5,493)	(7,461)
Interest	(8,038)	(7,566)	(5,507)	(4,916)	(4,300)	(3,633)	(3,634)	(3,223)
Other	(80)	(260)	48	(566)	(38)	(216)	(55)	(26)
	68,178	80,199	73,429	70,050	55,934	62,304	63,227	48,644

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

Non-GAAP Measures

The MD&A contains terms commonly used in the oil and natural gas industry, such as funds flow from operations, funds flow from operations per share, net debt and payout ratio. These terms are not defined by IFRS and therefore may not be comparable to similar measures presented by other companies. There are measures commonly used in the oil and gas industry and by Long Run to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. These terms should not be considered an alternative to, or more meaningful than, cash provided by operating activities or net earnings as determined in accordance with IFRS as indicators of Long Run's performance.

Funds Flow from Operations

	2014				2013			
($000s)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Cash flow from operating activities	**80,866**	78,006	67,280	59,781	65,932	61,756	60,835	45,733
Change in non-cash working capital	**(18,865)**	(996)	5,452	8,923	(11,758)	(266)	1,958	1,949
Abandonment costs	**6,177**	3,189	697	1,346	1,760	814	434	962
Funds flow from operations	**68,178**	80,199	73,429	70,050	55,934	62,304	63,227	48,644
Weighted average outstanding shares *(000s)*								
- Basic	**193,497**	176,318	134,291	125,730	125,629	125,620	125,620	125,620
- Diluted	**193,497**	177,003	135,437	126,129	126,245	125,620	125,620	125,620
Funds flow from operations per share *($/share)*								
- Basic	**0.35**	0.45	0.55	0.56	0.45	0.50	0.50	0.39
- Diluted	**0.35**	0.45	0.54	0.56	0.44	0.50	0.50	0.39

($000s)	**2014**	2013
Cash flow from operating activities	**285,933**	234,256
Change in non-cash working capital	**(5,486)**	(8,117)
Abandonment costs	**11,409**	3,970
Funds flow from operations	**291,856**	230,109
Weighted average outstanding shares *(000s)*		
- Basic	**157,697**	125,622
- Diluted	**157,697**	125,778
Funds flow from operations per share *($/share)*		
- Basic	**1.85**	1.83
- Diluted	**1.85**	1.83

Net Debt

($000s)	**December 31, 2014**	December 31, 2013
Bank debt	**611,717**	423,553
Working capital deficiency		
Accounts payable and accrued liabilities	**132,439**	89,606
Accounts receivable	**(65,135)**	(53,433)
Prepaid expenses and deposits	**(14,423)**	(7,571)
Convertible debentures – face value	**75,000**	-
Net Debt	**739,598**	452,155

Payout Ratio

Payout ratio is defined as dividends declared divided by funds flow from operations.

Advisory

Forward-Looking Statements

This document contains forward-looking statements and forward-looking information (collectively "forward-looking information") within the meaning of applicable securities laws relating to the Company's plans and other aspects of Long Run's anticipated future operations, management focus, objectives, strategies, financial, operating and production results and opportunities, including 2015 capital expenditure budget, nature and timing of expenditures and method of funding, drilling and development plans and the timing thereof, and plans and timing regarding EOR projects, expectation that unused credit facilities will be sufficient to satisfy working capital deficiencies, timing of review of credit facilities, plans to reduce credit facility indebtedness primarily through asset dispositions, expectation that completion of facilities will reduce third party outages impact on production. Forward-looking information typically uses words such as "anticipate", "believe", "project", "expect", "goal", "plan", "intend" or similar words suggesting future outcomes, statements that actions, events or conditions "may", "would", "could" or "will" be taken or occur in the future. Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although the Company believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which the Company operates; the timely receipt of any required regulatory approvals; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Company has an interest in to operate the field in a safe, efficient and effective manner; the ability of the Company to obtain financing and access capital on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Company to secure adequate product transportation; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company operates; the ability of the Company to successfully market its oil and natural gas products; expectations and assumptions concerning prevailing and future commodity prices, exchange rates, interest rates, applicable royalty rates and tax laws; future production rates and estimates of operating costs; performance of existing and future wells; reserve and resource volumes; anticipated timing and results of capital expenditures; the success obtained in drilling new wells; the sufficiency of budgeted capital expenditures in carrying out planned activities; the timing, location and extent of future drilling operations; the state of the economy and the exploration and production business; results of operations; business prospects and opportunities; the availability and cost of financing,

labor and services; the impact of increasing competition; and Long Run's ability to integrate the assets acquired pursuant to the Deep Basin Acquisition and the Crocotta acquisition and the effects thereof.

These forward-looking statements sometimes include words to the effect that management believes or expects a stated condition or result. All estimates and statements that describe the Company's objectives, goals or future plans are forward-looking statements. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties including, without limitation, risks associated with oil and natural gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources. The payment of a dividend by the Company is subject to declaration thereof by the board of directors and continuation of the dividend policy will be subject to and dependent on the Company's cash flow and other expenditures, including capital expenditures. As a consequence, Long Run's actual results may differ materially from those expressed in, or implied by, the forward-looking statements.

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

Oil & Natural Gas Information

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

Operating netback per Boe is calculated by subtracting royalties, transportation and operating costs from revenues and dividing by total production. Corporate netback per Boe is calculated as operating netback less interest and general and administration expense and divided by total production.

Abbreviations

Oil and Natural Gas Liquids

Bbl	Barrels
MBbl	thousand barrels
MMBbl	million barrels
Bbl/d	barrels per day
NGL	natural gas liquids
Boe	barrels of oil equivalent
MBoe	thousand barrels of oil equivalent
Boe/d	barrels of oil equivalent per day
Liquids	light oil, heavy oil, and NGLs

Natural Gas

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

Additional Information

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