ENHANCED
Oil Resources Inc.

2014 Third Quarter

Management's Discussion & Analysis

Management's Discussion & Analysis for the Nine Months ended September 30, 2014

DATE AND BASIS OF INFORMATION

Enhanced Oil Resources Inc. ("we", "our" or "the Company") is a natural resource company incorporated in 1980 and is currently engaged in the acquisition, exploration, exploitation, and development of oil and gas properties in the Southwestern United States. The Company's office is headquartered in Houston, Texas. Common shares of the Company are listed for trading on the TSX Venture Exchange ("TSX-V") under the symbol "EOR" and quoted on the OTCQX ("Over the Counter" qualified stock exchange) under the symbol "EORIF". Additional information relating to the Company can be found on the SEDAR website at www.sedar.com.

Basis of Presentation

The following management's discussion and analysis ("MD&A") is dated November 14, 2014 and should be read in conjunction with the Company's unaudited condensed interim consolidated financial statements for the nine months ended September 30, 2014 and related notes as well as the audited consolidated financial statements and notes for the year ended December 31, 2013. The referenced unaudited consolidated financial statements for the nine months ended September 30, 2014 have been prepared by management and approved by the Company's Board of Directors as of the above date. Unless otherwise noted, all financial information and the referenced unaudited condensed interim consolidated financial statements presented herein has been prepared in accordance with International Financial Reporting Standards ("IFRS"), specifically with regard to International Accounting Standard 34, "Interim Financial Reporting".

All financial information referencing $ are in US dollars and references to C$ are in Canadian dollars.

Conversions & Abbreviations – See Appendix A attached hereto.

Cautionary & Forward Looking Statements. See Appendix B attached hereto.

Non-IFRS Financial Measures

Certain financial measures in this MD&A, namely netback, cash flow from operations, lifting costs, and EBITDA are not prescribed and do not have a standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures by other companies.

Netbacks are used by the Company as a key measure of performance and are not intended to represent operating profit nor should they be viewed as an alternative to cash flow provided by operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. A netback is a per barrel (or mcf) computation determined by deducting royalties, production expenses, transportation and selling expenses from the oil or gas sales price to measure the average net cash received from the barrels or mcf sold.

Lifting costs include all production costs necessary to produce oil or gas, however exclude severance taxes.

EBITDA refers to income (loss) before interest, income taxes, depletion, depreciation, amortization and accretion and is often referred to as 'cash flow from operations'.

Management's Discussion & Analysis for the Nine Months ended September 30, 2014

OVERALL PERFORMANCE

Consolidated Statements of Operations and Comprehensive Income (Loss):

(In thousands of US dollars)	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Revenues				
Oil and gas gross sales	$ 2,420	$ 3,935	$ 7,296	$ 10,088
Less royalties	(515)	(809)	(1,519)	(2,065)
	1,905	3,126	5,777	8,023
Expenses				
Production costs and taxes	655	875	2,043	2,691
Workover expenses	131	191	3,423	574
Field expenses	315	359	993	964
General and administrative	654	909	2,360	2,754
Loss on disposition of assets	-	-	1,082	-
Depreciation, depletion and amortization	360	533	1,219	1,505
Financing costs and other, net	168	225	488	589
Stock-based compensation	-	15	-	125
(Gain) loss on financial instruments	(407)	314	(42)	463
Foreign currency translation (gain) loss	5	(3)	6	(2)
	1,881	3,418	11,572	9,663
Income (loss) before income taxes	24	(292)	(5,795)	(1,640)
Income tax provision	-	-	-	-
Net comprehensive income (loss) for the period	$ 24	$ (292)	$ (5,795)	$ (1,640)
Income (loss) per share - basic and diluted	$ 0.00	$ (0.00)	$ (0.04)	$ (0.01)

Results of operations for the nine months ended September 30, 2014, included crude oil and natural gas sales revenues of $7.3 million, and a net loss of $5.8 million, compared to revenues of $10.1 million and a net loss of $1.6 million for the same time period during 2013. In addition, loss per share results (basic and fully diluted) were $0.04 and $0.01 for the nine months ended September 30, 2014 and 2013, respectively. The increase in net loss of $4.2 million was principally related to the sidetrack-drilling and workover costs associated with the Crossroads #202 well and decreases in crude oil production associated with the sale of oil and gas fields in 2014 (See Disposition of Oil and Gas Properties below), other well workovers and production declines in each field. In addition, the Company recognized a loss on disposition of assets of $1.1 million related to exploration and evaluation assets in Texas (See Disposition of Oil and Gas Properties below). The $0.04 million gain on derivative agreements resulted from decreases in crude oil prices compared to a $0.5 million loss in 2013.

Management's Discussion & Analysis for the Nine Months ended September 30, 2014

Results for the three months ended September 30, 2014 included crude oil and natural gas sales revenues of $2.4 million and a net income of $0.02 million, compared to revenues of $3.9 million and a net loss of $0.3 million for the same period in 2013. In addition, per share results (basic and fully diluted) were each nil for the three months ended September 30, 2014 and 2013. As discussed above, the decrease in revenue was attributable to the decrease in production resulting from the property dispositions and a decrease in crude oil prices. Although, revenue decreased significantly in 2014 for the comparative quarters, net loss did not change significantly due to decreases in all operating costs and general administrative costs. The $0.4 million gain on derivative agreements resulted from decreases in crude oil prices compared to a $0.3 million loss in 2013.

Operating Netback Analysis

Operating Netback Per Gross Boe:

(In US dollars)		Three Months Ended, September 30, 2014	Three Months Ended, September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Oil & Gas Sales Volumes					
Oil equivalent	*Boe's*	28,535	38,907	82,609	111,979
Average prices [1]					
Oil equivalent	*$/Boe*	$ 84.81	$ 101.13	$ 88.32	$ 90.09
Less:					
Royalties, net [3]	*$/Boe*	(18.17)	(18.06)	(18.43)	(16.53)
Production taxes	*$/Boe*	(5.65)	(8.37)	(5.89)	(7.41)
Production costs	*$/Boe*	(16.15)	(15.50)	(18.29)	(18.60)
Workover expense	*$/Boe*	0.09	(5.08)	(40.80)	(4.77)
Operating Netback [2]	*$/ Boe*	$ 44.93	$ 54.12	$ 4.92	$ 42.77
Operating Netback by Field					
Crossroads Field		$ 53.20	$ 67.13	$ (3.96)	$ 54.89
Milnesand Field		$ 45.15	$ 37.56	$ 36.06	$ 27.96
Chaveroo Field		$ (13.97)	$ 19.52	$ 8.83	$ 8.73

[1] Average prices are after deduction of transportation costs and do not include net realized losses of $0.03 million and $0.3 million on financial instruments for the nine months ended September 30, 2014 and 2013, respectively.

[2] Operating netback equals crude oil and natural gas sales less royalties, operating costs and transportation costs calculated on a Boe basis. Operating netback does not have a standardized measure prescribed by IFRS and therefore may not be comparable with the calculations of similar measures for other companies.

[3] Net of related production taxes.

Operating Performance

During the third quarter of 2014 the Company announced the sale by its wholly-owned subsidiaries, Ridgeway Arizona Oil Corp. and EOR Operating Company of all of the Company's rights, title and interest in the Crossroads oilfield, located in Lea County, New Mexico to an unrelated third party group consisting of Desert Production, Inc. of Midland, Texas and Penroc Oil Corporation of Hobbs, New Mexico for $10.0 million cash, subject to certain post-closing adjustments and conditions. Riviera-Ensley Energy Advisors, an arm's length full service acquisition and divestiture transaction advisor serving the energy sector for over 20 years, acted as the marketing agent and broker for the Company in connection with the sale and was paid a fee of $210,000 in cash for conducting the marketing and solicitation of bids for the property interests. The sale of the Crossroads field was completed on October 16, 2014, upon acceptance for filing of the transaction by the TSX Venture Exchange. Earlier in February 2014, the Company sold certain non-core property interests in Texas for approximately $0.4 million. With the decrease in production resulting from these property dispositions, the Company is limiting its operations to those that are necessary to sustain production, has postponed certain remedial operations, and has reduced personnel and overhead in order to adjust to reduced cash flows.

DISCUSSION OF OPERATIONS

Revenues

Gross sales of crude oil and natural gas in the first nine months of 2014 decreased $2.8 million or 27.7% compared to a 26.2% decrease in sales volumes in the same period. Oil and gas sales decreased in each field in 2014 with declines in the Crossroads field (13,600 Boes), in the Milnesand field (7,600 Boes), in the Chaveroo field (3,400 Boes) and sales associated with certain Texas properties sold in February 2014 (4,800 Boes). An average price of $88.32 per gross Boe was received in 2014 compared to an average price of $90.09 per gross Boe received for the same period during 2013.

Gross crude oil and natural gas sales for the third quarter of 2014 decreased $1.5 million to $2.4 million when compared to the same period in 2013. The 38.5% decrease was due to lower sales volumes (26.7% decrease under 2013) as well as lower average selling prices ($16.32 per Boe decrease over the comparable prior quarter).

Production Costs, Workover Expense and Field Expense

Production Costs: Production costs for the first nine months of 2014 decreased 24.1% compared to the prior year due to a reduction in water disposal costs in the Crossroads field. Prior to August 2013, the Company had a single injection well to return produced water to the Devonian formation. As a result of increasing the number of producing wells in the field from one well in 2008 to seven producing wells, the Company reached the limit of that single injection well's capacity to handle additional water production. As a result, two producing wells were shut-in at Crossroads in early February 2013 in order to reduce water disposal costs. In July 2013, the Company converted a productive oil well, the Crossroads #106, to a water injector in order to increase field wide injection capacity and to return the two shut-in oil wells to production. Although total production costs decreased in 2014, per equivalent barrel costs decreased only slightly ($18.29 vs. $18.60) as a result of fixed costs related to lower production in 2014. Production costs for the third quarter 2014 decreased $0.2 to $0.7 million when compared to the same period in 2013, although per barrel costs were higher ($16.15 vs. $15.50 quarter to quarter) as a result of fixed costs related to lower production in 2014.

Workover Expenses: Workover expenses increased significantly ($2.8 million), for the first nine months of 2014, primarily related to the re-drilling of the Crossroads #202 well. In 2012, a similar submersible pump failure in the Crossroads #303 well required approximately $1.9 million to re-drill and recover its production. In both wells, the depth, the age and the condition of very narrow wellbores presented significant and costly drilling and workover problems. In each case, the depth of the Crossroads field wells (approximately 12,000 feet) was the principal determinant of workover cost. In an effort to overcome the risk associated with small wellbore diameters, the Company installed two "slimhole" design submersible pumps at Crossroads in January and March 2014. In older fields such as Crossroads, it is anticipated that, from time to time, the Company may be required to engage in untimely similar operations, which may be at substantial financial cost. Third quarter 2014 workover expenses decreased $0.06 million over the comparable quarter in 2013.

Netback – As a result of the workover expense in the first nine months of 2014, the operating netback for the period decreased to $4.92 per Boe compared to $42.77 per Boe for the same period in 2013.

Field Expenses: Field expenses for the nine months ended September 30, 2014 and 2013 were $1.0 million. As result of the first quarter's operating performance the Company has reduced its field activities. Field expenses for the third quarter 2014 decreased $0.04 million to $0.3 million when compared to the same period in 2013.

General & Administrative

General and administrative costs decreased $0.4 million to $2.4 million for the nine months ended September 30, 2014 when compared to the same period in 2013. Due to the first quarter's operating performance of 2014, the Company made it a priority to reduce its general and administrative personnel costs and third party contractors. As a result, general and administrative costs during the third quarter of 2014 decreased $0.3 million under the same period in 2013 to $0.7 million, a reduction of 28.1%.

Disposition of Oil and Gas Properties

The Company sold certain oil and gas interests located in three Texas counties for cash proceeds of $0.4 million and purchaser assumption of asset retirement liabilities of $0.3 million in February 2014. The Company acquired these interests in July 2011 for $1.6 million including $0.6 million of asset retirement obligations.

At December 31, 2013 the Crossroads Field had estimated proved developed producing reserves of approximately $14.8 million (PV10 based on forecast future pricing) from 411,000 net barrels of crude oil and proved developed non-producing reserves of approximately $10.7 million (PV10 based on forecast future pricing) from 441,000 net barrels of crude oil.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization expense decreased approximately $0.3 million for the first nine months of 2014, compared to 2013. The decrease in depletion expense for 2014 was due to the decrease in production. Depreciation, depletion, and amortization expense for the three months ended September 30, 2014 and 2013 were $0.4 million and $0.5 million, respectively.

Gain (Loss) on Financial Instruments

Decreasing crude oil prices in 2014 resulted in a realized a loss of $0.03 million related to its crude oil derivative contracts for the nine months ended September 30, 2014 compared to a loss of $0.3 million for the same period in 2013. For the same reason, an estimated unrealized gain on the future settlements of the remaining derivative contracts was $0.1 million at September 30, 2014 compared to an estimated unrealized loss of $0.2 million at

September 30, 2013. In October 2014, the Company sold the remainder of its collar derivative contract (November 2014 – April 2015) representing 36,200 Bbls to Shell Trading Risk Management, LLC for approximately $278,000.

Financing Costs and Other, net

Financing costs were $0.5 million and $0.6 million the nine months ended September 30, 2014 and 2013, respectively, primarily representing accretion of asset retirement obligations. The $0.1 million decrease in 2014 over 2013, is related to amortization of letter of credit fees during 2013.

EBITDA Reconciliation

In thousands	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Net income (loss) before tax	$ 24	$ (292)	$ (5,795)	$ (1,640)
Adjustments:				
Loss on disposition of assets	-	-	1,082	-
Depreciation , depletion, and amortization	360	533	1,219	1,505
Foreign currency translation (gain) loss	5	(3)	6	(2)
Stock-based compensation	-	15	-	125
Unrealized loss (gain) on financial instruments	(378)	90	(70)	207
Financing costs and other, net	168	225	488	589
EBITDA	**$ 179**	**$ 568**	**$ (3,070)**	**$ 784**

LIQUIDITY AND CAPITAL RESOURCES

As of September 30, 2014, the Company had cash balances of approximately $5.7 million (including restricted cash of $5.5 million). Two submersible pump failures in the Crossroads field required the costly sidetrack drilling of the #202 well and replacement of equipment in the #302 well in the first quarter of 2014. The cost to recover the Crossroads #202 well was $3.4 million, which seriously affected the Company's financial condition and ultimately required the sale of the field. The financial impact limited the Company's ability to fund any well servicing and maintenance activities normally required to sustain remaining production. On October 16, 2014, the Company sold its interests in the Crossroads field for net proceeds of $9.7 million (see Subsequent Event footnote in the Notes to Consolidated Condensed Interim Financial Statements for the Nine Months Ended September 30, 2014). The proceeds were used to pay the outstanding payables arising from the costs incurred on the Crossroads #202 well. The Company will continue to manage cash and working capital to (i) complete further regulatory compliance work in our oil fields as required, (ii) to resume its infill drilling program at the Milnesand field, when and if appropriate, and (iii) to evaluate strategic joint ventures, acquisitions and dispositions.

Accordingly, the timing of development drilling in the Milnesand field, originally expected to commence in January of 2014, was delayed until the Company completes one or more of the following: a financing arrangement or a third party joint venture drilling arrangement. On September 18, 2014, the Company announced that it has entered into a Letter of Intent with Schlumberger Technology Corporation (Schlumberger) whereby Schlumberger, at its own cost, will conduct an in-depth technical evaluation of the potential redevelopment of the Milnesand and Chaveroo oil fields, located in Chaves and Roosevelt Counties, New Mexico. Schlumberger will utilize in-house experts in primary, secondary and tertiary recovery with the ultimate goal of deciding the best way forward, if appropriate, to recover additional oil reserves contained within these fields. Definitive agreements would be completed following the completion of a field study, engineering and the election by Schlumberger to commence joint development. An agreement would include, among other things, provisions where the co-venture partner would earn an interest in the Company's Milnesand or Chaveroo field development projects in exchange for funding the Company's share of the drilling and completion cost of the initial wells. The Company sold certain property interests in Texas for approximately $0.4 million, effective January 15, 2014.

In order to provide the necessary funds to develop its projects, the Company is considering all available sources of financing to develop its projects, including equity, bank and mezzanine debt, asset sales and joint venture arrangements. The Company expects that drilling activities will require higher cost debt financing and will require that the development of these fields command a high rate of return on investment. The Company will continue to focus on operations activities that further its objectives of positive operating cash flows and further its strategic objective of increasing production in one or more of its oil fields.

Derivative Financial Instruments – Average prices received are net of transportation costs. The current derivative contracts in place for crude oil settlements subsequent to September 30, 2014 are as follow:

Barrels	Commodity	Type	Price	Term
42,400	WTI Crude Oil	Costless Collar	$ 88.00 to $ 97.50	Oct 2014 - Apr 2015
45,700	WTI Midland-Cushing Differential	Swap	($3.50)	Oct 2014 - Dec 2015

In October 2014, the Company sold the remainder of its collar derivative contract (November 2014 – April 2015) representing 36,200 Bbls to Shell Trading Risk Management, LLC for approximately $278,000.

QUARTERLY RESULTS OF OPERATIONS AND SELECT FINANCIAL DATA

Summary of Quarterly Information:

Quarterly Revenue, Loss and Earnings Per Share:

(In thousands except per share amounts)	2012	2013				2014		
	Fourth	First	Second	Third	Fourth	First	Second	Third
Revenues	$ 3,935	$ 2,977	$ 3,176	$ 3,935	$ 3,048	$ 2,366	$ 2,510	$ 2,420
Net comprehensive income (loss)	$ (292)	$ (989)	$ (358)	$ (292)	$ (492)	$ (4,554)	$ (1,267)	$ 24
Per share - basic	$ (0.01)	$ (0.01)	$ -	$ -	$ -	$ (0.03)	$ (0.01)	$ 0.00
Per share - diluted	$ (0.00)	$ (0.01)	$ -	$ -	$ -	$ (0.03)	$ (0.01)	$ 0.00

Revenue varies directly with the average price of oil received and production volumes achieved. The following table summarizes the average received prices and gross production for the three month periods indicated:

Quarterly Average Prices Received and Sales Volumes:

	2012	2013				2014		
	Fourth	First	Second	Third	Fourth	First	Second	Third
Average price received	$ 79.19	$ 80.09	$ 88.48	$ 101.13	$ 91.94	$ 90.00	$ 90.33	$ 84.81
Sales volume	37,461	37,170	35,902	38,907	33,152	26,290	27,784	28,535

The quarterly table reflects more operational activity arising from planned and unplanned activities, such as regulatory requirements, changes in prices, availability of oil field services and/or weather related downtime, thereby affecting the level of workover and maintenance activity in each of the oilfields. The increase in crude oil sales volume during the second quarter of 2014 was due to the increase in production from wells that were offline during the prior quarter. The decrease in production in the first quarter of 2014 was associated with wells off production in the Crossroads field. The decrease in crude oil sales volumes in the fourth quarter of 2013 was principally due to severe weather conditions causing the Company to shut-in multiple wells during the latter part of the quarter coupled with the loss of crude oil production of the Crossroads #202 well starting at the beginning of October. In addition to the increase in third quarter 2013 oil prices, production also increased in the quarter as a result of returning two shut-in wells to production in the Crossroads field following the addition of a second water injection well in the field. The decrease in sales volumes in the second quarter of 2013 is due to two producing wells being shut-in at the Crossroads oilfield in early February in order to reduce water disposal costs until the conversion of another well to a water injector was complete. Sales volumes increased in the third quarter of 2012 due to the completion of three wells in the Milnesand field drilling program.

The decrease in revenue in the third quarter 2014 is due to the decrease in the average received price. Revenue increased in the 2Q of 2014 primarily due to an increase in crude oil sales volume. Revenue decreased in the first quarter 2014 principally due to decreased production. Net loss increased in the first quarter of 2014 principally related to increased workover expenses and loss on sale of assets. Fourth quarter 2013 net loss increased $0.2 million over the third quarter of 2013 principally due a 14.8% reduction in sales volumes related to the Crossroads #202, colder weather and a decrease in average sales prices. The decrease in the second quarter of 2013 net loss as compared to the first quarter of 2013 was principally due to an increase in revenue of $0.2 million, reflecting increased crude oil prices, as well as a decrease in production costs of $0.3 million, general and administrative expenses of $0.1 million, loss on financial instruments of $0.3 million and financing costs of $0.1 million offset by increase in workover and field expenses of $0.4 million. In the first quarter of 2013, decreases in production costs, workover expenses, and field expenses of $1.0 million compared to the fourth quarter of 2012 related to decreased operations activity; increases in stock based compensation, losses on financial instruments, and financing costs of $0.6 million related to changes in financial instruments; and were offset by an increase in general and administrative expenses of $0.2 million related to an increase in personnel. The increase in the third quarter of 2012 net loss was principally associated with increased workover costs of $2.8 million associated with expenditures at the Crossroads field of approximately $2.1 million and compliance related workover costs of $0.7 million in the Milnesand Unit and the Chaveroo field. Although the fourth quarter of 2012 loss was not as large as the third quarter, this loss is reflective of increased workover costs of an additional $0.5 million when compared to the second quarter as well as other expenses incurred related to an increase in general and administrative expenses of $0.4 million and increases in production costs for the quarter of $0.9 million.

Kinder Morgan CO_2 Gas Purchase Contract

In March 2010, the Company executed a cancellable five-year CO_2 purchase and delivery agreement with Kinder Morgan CO_2 Company, L.P. (Kinder Morgan) for the purchase of CO_2 by the Company for use in the Company's tertiary oil projects in the Permian Basin. The contract represents a take or pay commitment for a total of 27.4 bcf of CO_2 to be purchased over a five year period commencing no later than January 1, 2018 (as amended February 28, 2014). The maximum daily rate required to be purchased under the contract is 20 million cubic feet per day during the third year. The purchase commitment and obligation to pay, as amended, is cancellable on or before December 31, 2017, with no termination penalty. The cost of CO_2 will fluctuate based on the price of oil plus transportation tariffs.

Regulatory Compliance in New Mexico

The Company's operating subsidiaries, primarily Ridgeway and EOR Operating, conduct their operations under the oversight of multiple federal and state agencies. The Company's Chaveroo field, because of the age and condition of its production facilities and wells, is operated by Ridgeway, which is both the federal and State of New Mexico operator of record. The Company's other principal oil fields are operated by EOR Operating Company, which is both the federal and State of New Mexico operator of record.

DISCLOSURE OF CONTROLS, PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

As a TSX-Venture issuer, the Company's officers are not required to certify the design and evaluation of operating effectiveness of the Company's disclosure controls and procedures ("DC&P") or its internal controls over financial reporting ("ICFR"). The Company maintains DC&P designed controls to ensure that information required to be disclosed in reports filed or submitted is accumulated and communicated to management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In addition, the Chief Executive Officer and the Chief Financial Officer have designed controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles. Due to its size, the small number of employees, the scope of its current operations, its limited liquidity and capital resources, there are inherent limitations on the Company's ability to design and implement on a cost effective basis the DC&P and ICFR procedures, the effect of which may result in additional risks related to the quality, reliability, transparency and timeliness of its interim filings and other reports. There have been no changes in ICFR during the nine months ended September 30, 2014.

OFF-BALANCE SHEET ARRANGEMENTS

The Company does not have any special purpose entities nor is it party to any arrangements that would be excluded from the consolidated balance sheet.

RELATED PARTY TRANSACTIONS

There were no related party transactions for the periods ended September 30, 2014 and 2013, respectively.

CRITICAL ACCOUNTING ESTIMATES

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are reviewed and for any future years affected. Significant judgments, estimates and assumptions made by management in these consolidated financial statements are outlined below:

Oil and natural gas reserves **-** Certain depletion, depreciation, and impairment and asset retirement obligation charges are measured based on the Company's estimate of oil and gas reserves and resources. The estimation of proved and probable reserves and resources is an inherently complex process and involves the exercise of professional judgment. Oil and natural gas reserves have been evaluated at December 31, 2013 and December 31, 2012 by independent petroleum engineers in accordance with National Instruments 51-101 "*Standards of Disclosure for Oil and Gas Activities*".

Oil and natural gas reserve estimates are based on a range of geological, technical and economic factors, including projected future rates of production, estimated commodity prices, engineering data, and the timing and amount of future expenditures, all of which are subject to uncertainty. Assumptions reflect market and regulatory conditions existing at the reporting date, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves and resources.

Impairment of assets **-** The Company evaluates its assets for possible impairment at the CGU level. The determination of CGUs requires judgment in defining the smallest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs have been determined based on similar geological structure, shared infrastructure, geographical proximity, commodity type, the existence of active markets, similar exposure to market risks, and the way in which management monitors the operations.

The recoverable amounts of CGUs and individual assets have been determined based on the higher of fair value less costs to sell model and value in-use model. The key assumptions the Company uses in estimating future cash flows for recoverable amounts are: anticipated future commodity prices, expected production volumes, future operating and development costs, estimates of inflation on costs and expenditures, expected income taxes and discount rates. In addition, the Company considers the current environmental, social and governance issues affecting its property interests and operations, including the current legislative and regulatory activity affecting the permitting and approval of its projects and operations. Changes to these assumptions will affect the estimated recoverable amounts attributed to a CGU or individual assets and may then require a material adjustment to their related carrying value.

Asset retirement obligations **-** The Company estimates and recognizes liabilities for future asset retirement obligations and restoration of exploration and evaluation assets, and for oil and gas development and producing assets. These provisions are based on estimated costs, which take into account the anticipated method and extent of restoration, technological advances and the possible future use of the asset. Actual costs are uncertain and estimates can vary as a result of changes to relevant laws and regulations, the emergence of new restoration techniques, operating experience and prices. The expected timing of future retirement and restoration may change due to these factors, as well as affect the estimates of reserve life. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented. Effective with the transition to

IFRS, the Company made a policy choice available under existing standards to use a risk-free rate for discounting asset retirement obligations.

NEW AND FUTURE CHANGES IN ACCOUNTING POLICIES

IFRS 9

IFRS 9, "Financial Instruments", is the first phase of the IASB's project to replace IAS 39, "Financial Instruments: Recognition and Measurement". IFRS 9 replaces the current multiple classification and measurement models for financial assets with a single model that has only two classification categories: amortized cost and fair value, and provides additional guidance for financial liabilities. The standard is required to be adopted in 2015. The Company has not yet assessed the impact of the standard or determined whether it will adopt the standard early.

IFRIC 21

In May 2013, the ISAB issued IFRIC Interpretation 21, "Levies", which provides clarification on accounting for levies imposed by a government in accordance with legislation and confirms that a liability is recognized only when the triggering event specified in the legislation occurs. The Company adopted the interpretation on January 1, 2014., which did not have a material impact on the Company's financial statements.

IAS 32

In January 2012, the IASB issued an amendment IAS 32, "Financial Instruments: Presentations", to establish principles for presenting financial instruments as either liabilities or equity and for offsetting financial assets and financial liabilities. The amendment was adopted and applied on January 1, 2014, and did not have a material impact on the Company's financial statements.

IAS 36

In May 2013, the IASB issued Amendments to IAS 36, "Recoverable Amount Disclosures for Non-Financial Assets", which reduce the circumstances in which the recoverable amount of CGUs is required to be disclosed and clarify the disclosures required when an impairment loss has been recognized or reversed in the period. The Company adopted and applied the amendment on January 1, 2014. The retrospective application did not have a material impact on the financial statements.

POTENTIAL RISKS AND UNSCERTAINTIES

The resource industry is highly competitive and, in addition, exposes the Company to a number of risks. Resource exploration and development involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. It is also highly capital intensive and the ability to complete a development project may be dependent on the Company's ability to raise additional capital. In certain cases, this may be achieved only through joint ventures or other relationships, which would reduce the Company's ownership interest in the project. There is no assurance that development operations will prove successful.

OTHER MD&A NOT DISCLOSED ELSEWHERE

Disclosure of Share Capital

Authorized capital:

25 million preference shares of no par value
Unlimited common shares of no par value

Issued and outstanding at November 14, 2014:

1,000 preference shares (held by a wholly-owned subsidiary of the Company)
160,186,319 common shares issued

Since no additional warrant activity has occurred through November 14, 2014, the table depicted in 1.9 "Equity Placements" represents all remaining warrant obligations to date.

Common stock options outstanding at November 14, 2014 were as follows:

Stock Options Outstanding - Common Stock:

Number Authorized	Date of Agreement	Exercise or Issue Price	Expiry Date
2,025,000	June 7, 2010	$0.30	June 7, 2015
250,000	November 17, 2010	$0.22	November 17, 2015
1,475,000	April 14, 2011	$0.25	April 14, 2016
200,000	May 3, 2011	$0.25	May 3, 2016
850,000	February 15, 2012	$0.16	February 15, 2017
75,000	August 1, 2012	$0.15	August 1, 2017
1,800,000	January 14, 2013	$0.10	January 14, 2018
575,000	March 19, 2013	$0.11	March 19, 2018
7,250,000			

APPENDIX A - ABBREVIATIONS

Crude Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
BBls/d	barrels per day
BOEPD	barrel of oil equivalent per day
MMbbls	million barrels
Mbbls	thousand barrels

Carbon Dioxide and Natural Gas

Bcf	billion cubic feet
CO_2	carbon dioxide
Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
Tcf	trillion cubic feet

API	American Petroleum Institute
Boe	Barrel of oil equivalent of natural gas and crude oil on the basis of one Boe for six mcf of natural gas and one Boe for forty- two gallons of plant products (these conversion factor are an industry accepted norm and is not based on either energy content or current prices)
Contingent resource	Those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable.
COG	Cost Generating Unit
DOE	United States Department of Energy
EBITDA	Income before income taxes, depletion, depreciation, amortization and accretion and often referred to as ‘cash flow from operations’
EOR	Enhanced oil recovery, typically any method of economically removing oil incremental to that produced by primary or conventional improved-recovery methods
MBoe	1,000 barrels of oil equivalent
Net revenue	Gross revenue less all taxes, royalties and lease operating expenses
NI 51-101	National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities adopted by the Canadian Securities Administrators
Primary recovery	Production in which only existing natural energy sources in the reservoir provide for movement of well fluids.
Permian Basin	A large crude oil and natural gas producing area representing a sedimentary basin dating from the Permian geologic period and covering an area extending from West Texas to eastern New Mexico
PV10	the present value of estimated future cash flows from oil & gas Reserves that can be calculated using costs and pricing consistent with NI 51-101 and discounted at the rate of 10%.
Reserves	Estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward based on (i)

	analysis of drilling, geophysical and engineering data; (ii) the use of established technology; (iii) specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed; and (iv) a remaining reserve life of 50 years. These definitions and disclosures are in accordance with the definitions, procedures and standards contained in the Canadian Oil and Gas Evaluation (COGE) Handbook and the Canadian Securities Administrators NI 51-101.
Secondary recovery	Any method by which an essentially depleted reservoir is restored to producing status by the injection of liquids or gases (from external sources) into the formation, thereby effecting a restoration of reservoir energy which moves the unrecoverable secondary reserves through the reservoir to the wellbore.
Tertiary recovery	Any of various methods, chiefly reservoir drive mechanisms and enhanced recover techniques, designed to improve the flow of hydrocarbons from the reservoir to the wellbore to recover more oil after the primary and secondary methods (water and gas floods) are uneconomic.
$	United States dollars
C$	Canadian dollars

APPENDIX B Forward-Looking Statements

Forward-Looking Statements – See Appendix B for discussion of forward-looking statements contained in this MD&A

Certain statements contained in this MD&A and in certain documents incorporated by reference into this MD&A, contain estimates and assumptions which management are required to make regarding future events and may constitute forward-looking statements within the meaning of applicable securities laws. Management's assessment of future operations, drilling and development plans and timing thereof, other capital expenditures and timing thereof, methods of financing capital expenditures and the ability to fund financial liabilities, expected commodity prices and the impact on the Company, and the impact of the adoption of future changes in accounting standards may constitute forward-looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, the flexibility of capital funding plans and the source of funding therefore; production, marketing and transportation, loss of markets, volatility of commodity prices, the effect of the Company's risk management program, including the impact of derivative financial instruments; 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, the inability to fully realize the benefits of the acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources.

All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" "continue", "upside" and similar other expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company believes that the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this MD&A should not be unduly relied upon. These statements speak only as of the date of this MD&A, as the case may be. The Company does not intend, and does not assume an obligation, to update these forward-looking statements, except as required by securities law.

In particular, this MD&A and the documents incorporated by reference include, but are not limited to, forward-looking statements pertaining to the following:

- the quantity of reserves and contingent resources;
- crude oil, natural gas, CO_2 and helium operations and production levels;
- capital expenditure programs, including drilling programs and pipeline construction projects, and the timing and method of financing thereof;
- projections of market prices and costs;
- supply, demand and pricing for crude oil, natural gas, and CO_2;
- expectations regarding the Company's ability to raise capital and to continually add to reserves through acquisitions and development
- drilling inventory, drilling plans and timing of drilling, re-completion and tie-in of wells;

- plans for production facilities construction and completion and the timing and method of funding thereof;
- productive capacity of wells, anticipated or expected production rates and anticipated dates of commencement of production;
- drilling, completion and facilities costs;
- results of various projects of the Company;
- timing of receipt of regulatory approvals;
- effect of production increases on operating costs per Boe;
- ability to lower cost structure in certain projects of the Company;
- growth expectations within the Company;
- timing of development of undeveloped reserves;
- the tax horizon and taxability of the Company;
- supply and demand for oil, natural gas liquids and natural gas;
- the performance and characteristics of the Company's oil and natural gas properties;
- The Company's acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived therefrom;
- the impact of federal and state governmental regulation on the Company relative to other oil and gas issuers of similar size;
- realization of the anticipated benefits of acquisitions and dispositions;
- weighting of production between different commodities;
- projections of commodity prices and costs;
- expected levels of royalty rates, operating costs, general and administrative costs, costs of services and other costs and expenses;
- capital expenditure programs; and
- treatment under government regulation and taxation, including carbon taxation regimes

Although the Company believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. The Company cannot guarantee future results, levels of activity, performance, or achievements. Moreover, neither the Company nor any other person assumes responsibility for the outcome of the forward-looking statements. Many of the risks and other factors are beyond the Company's control, which could cause actual results to differ materially from those anticipated in these forward-looking statements as a result of risk factors as set forth, but not limited to, those below and elsewhere in this MD&A:

- volatility in market prices for oil, natural gas, and CO_2;
- liabilities and risks inherent in oil and natural gas operations;
- uncertainties associated with estimating reserves;
- competition for capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- incorrect assessments of the recoverability of asset costs and investments;
- geological, technical, drilling and processing problems; and
- governmental, regulatory and taxation regimes.