2014 Second Quarter

Management's Discussion & Analysis

Management's Discussion & Analysis for the Six Months Ended June 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 August 27 2014 and should be read in conjunction with the Company's unaudited condensed interim consolidated financial statements for the six months ended June 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 six months ended June 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 Six Months Ended June 30, 2014

OVERALL PERFORMANCE

Consolidated Statements of Operations and Comprehensive Loss:

(In thousands of US dollars)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Revenues				
Oil and gas gross sales	$ 2,510	$ 3,176	$ 4,876	$ 6,153
Less royalties	(516)	(646)	(1,004)	(1,256)
	1,994	2,530	3,872	4,897
Expenses				
Production costs and taxes	746	747	1,388	1,816
Workover expenses	548	379	3,292	383
Field expenses	313	329	678	605
General and administrative	638	872	1,706	1,845
Loss on disposition of assets	57	-	1,085	-
Depreciation, depletion and amortization	440	469	859	972
Financing costs and other, net	157	141	320	373
Stock-based compensation	-	32	-	109
(Gain) loss on financial instruments	365	(77)	365	149
Foreign currency translation (gain) loss	(3)	(2)	1	(7)
	3,261	2,890	9,694	6,245
Loss before income taxes	(1,267)	(360)	(5,822)	(1,348)
Income tax provision	-	-	-	-
Net comprehensive loss for the period	$ (1,267)	$ (360)	$ (5,822)	$ (1,348)
Loss per share - basic and diluted	$ (0.01)	$ (0.00)	$ (0.04)	$ (0.01)

Results of operations for the six months ended June 30, 2014, included crude oil and natural gas sales revenues of $4.9 million, and a net loss of $5.8 million, compared to revenues of $6.2 million and a net loss of $1.3 million for the same time period during 2013. In addition, per share results (basic and fully diluted) were $0.4 and $0.01 losses for the six months ended June 30, 2014 and 2013, respectively. The increase in net loss of $4.5 million was principally related to the workover costs associated with the Crossroads #202 well, which was side tracked and re-drilled after an equipment failure in September 2013. The Company recognized a loss on disposition of assets of $1.1 million related to exploration and evaluation assets in Texas. In addition, crude oil sales decreased by approximately 19,000 Boes primarily due to production declines as well as the lost production from the Crossroads #202 well, which previously averaged approximately 58 BOPD. Production for the year to date in the Milnesand Field decreased approximately 5,300 Bbls compared to the first quarter of 2013, primarily from two wells (drilled in the second half of 2012), which had steep initial declines.

Results for the three months ended June 30, 2014 included crude oil and natural gas sales revenues of $2.5 million and a net loss of $1.3 million, compared to revenues of $3.2 million and a net loss of $0.4 million for the same period in 2013. In addition, per share results (basic and fully diluted) were a $0.01 loss and nil for the three months ended June 30, 2014 and 2013, respectively. The increase in net loss of $0.9 million can be primarily attributed to the decrease in sales in comparison to 2013 coupled with higher workover expenses related to the replacement of submersible pumps in the Crossroads #101 and #202 wells. In addition, the Company experienced a $0.4 million loss ($57,000 realized loss) on derivative agreements in place during the period compared to a $0.1 million gain (net of a $32,000 realized loss) in 2013.

Operating Netback Analysis

Operating Netback Per Gross Boe:

(In US dollars)		Three Months Ended, June 30, 2014	Three Months Ended, June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Oil & Gas Sales Volumes					
Oil equivalent	*Boe's*	27,784	35,902	54,074	73,072
Average prices [1]					
Oil equivalent	*$/Boe*	$ 90.33	$ 88.48	$ 90.17	$ 84.21
Less:					
Royalties, net [3]	*$/Boe*	(18.57)	(17.00)	(18.56)	(15.73)
Production taxes	*$/Boe*	(5.42)	(7.29)	(5.69)	(6.92)
Production costs	*$/Boe*	(19.27)	(14.49)	(19.20)	(19.25)
Workover expense	*$/Boe*	(13.56)	(8.39)	(59.90)	(4.28)
Operating Netback [2]	*$/ Boe*	$ 33.51	$ 41.31	$ (13.18)	$ 38.03
Operating Netback by Field					
Crossroads Field		$ 35.86	$ 58.17	$ (30.17)	$ 40.27
Milnesand Field		$ 24.72	$ 15.71	$ 31.31	$ 34.73
Chaveroo Field		$ 34.12	$ (3.97)	$ 20.45	$ 14.11

[1] Average prices are after deduction of transportation costs and do not include net realized losses of $0.06 and $0.03 million on financial instruments for the six months ended June 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 1st Half of 2014

In the second quarter of 2014, the Company endeavored to recover from the costly sidetrack operation on the Crossroads #202 well. The well was returned to production in April 2014 and is currently producing at approximately half the rate of its prior performance in 2013. The financial impact of restoring the Crossroads #202 to production was $3.0 million, including the replacement of production equipment. In addition, the Company determined that it would be unable to complete a proposed financing on terms acceptable to the Company to fund its development drilling in the Milnesand Field. After an extended period of reviewing proposals and draft loan documents and an extended diligence period, management determined that the lenders selected in November 2013 could not complete the required financing without substantial additional costs and delays or on terms otherwise acceptable to the Company. The substantial cost of the workover operation coupled with the costs incurred on the financing effort seriously affected the Company's financial condition which continued through the second quarter of 2014. The Company is continuing efforts to complete one or more of either a debt financing, enter into some form of joint venture and/or sell assets in order to fund its operations and development activities. The Company sold certain non-core property interests in Texas for approximately $0.4 million in February 2014 and is continuing to market the Crossroads field in a private transaction. At December 31, 2013 the Crossroads Field represented proved developed producing reserves of approximately $14.8 million (PV10) from 411,000 net barrels of crude oil and proved developed non-producing reserves of approximately $10.7 million (PV10) from 441,000 net barrels of crude oil. As a result, the Company has restricted its current operations to those matters necessary to sustain production, reduced personnel and overhead and postponed certain remedial operations. In addition, the Company as structured certain extended payment arrangements with vendors pending the completion of additional funding arrangements.

DISCUSSION OF OPERATIONS

Revenues

Gross sales of crude oil and natural gas in the first six months of 2014 decreased $1.3 million or 20.1% compared to a 26.0% decrease in sales volumes in the same period. The percentage difference reflects the increase in average oil prices received in 2014 over 2013. An average price of $90.17 per gross Boe was received in 2014 compared to an average price of $84.21 per gross Boe received for the same period during 2013.

Gross crude oil and natural gas sales for the second quarter of 2014 decreased $0.7 million to $2.5 million when compared to the same period in 2013. The 21.0% decrease was due to lower sales volumes (22.6% decrease under 2013) and was partially offset by higher average selling prices ($1.85 per Boe increase over the prior year).

Production Costs, Workover Expense and Field Expense

Production Costs: Production costs for the first six months of 2014 decreased 25.8% 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 were approximately the same ($19.20 vs. $19.25) as a result of lower production in 2014. Second quarter 2014 and 2013, production costs were $0.7 million in each of the quarters and reflected a higher per barrel cost ($19.47 vs. $14.49 quarter to quarter) due to lower production in 2014.

Workover Expenses: Workover expenses increased significantly ($2.9 million) for the first six month of 2014, primarily related to the re-drilling of the Crossroads #202 well. At year-end 2013, the well represented $4.5 million

(PV10) or 14.7% of proved developed reserves and approximately 8.5% of 2013 production. 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 slim hole 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 will be required to engage in untimely similar operations, which may be at substantial financial cost.

Second quarter 2014 workover expenses increased $0.2 million over the comparable quarter in 2013. The increase can be primarily attributed to the replacement of equipment in the Crossroads #101 and #202 wells.

Netback – As a result of the workover expense in the first six months of 2014, the operating netback for the period was a $13.45 loss per Boe compared to $38.03 income per Boe for the same period in 2013. The $55.61 increase in workover cost per Boe in 2014 was partially offset by higher average oil prices ($5.96 increase per Boe over 2013).

Operating netback for the quarter ended June 30, 2014 was $32.98 income per Boe compared to $41.31 income for the same period in 2013. The decrease can be attributed to higher per barrel production costs and workover expenses ($5.31 and $5.16 per Boe increases over 2013, respectively), partially offset by higher average oil prices ($1.85 increase per Boe over prior year).

Field Expenses: Field expenses for the six months ended June 30, 2014 increased $0.1 million when compared to the same period in 2013 due to an increase in personnel costs. As result of the first quarter's operating performance the Company has reduced its field activities. In February 2014, the Company sold, for proceeds of $0.4 million, certain property interests in three Texas counties, which will allow it to reduce field overhead. Field expenses for the quarters ended June 30, 2014 and 2013 were $0.3 million.

General & Administrative

General and administrative costs decreased $0.1 million to $1.7 million for the six months ended June 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 second quarter of 2014 decreased $0.3 million under the same period in 2013 to $0.6 million, a reduction of 33%.

Loss on Disposition of Assets

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.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization expense decreased approximately $0.1 million for the first six 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 June 30, 2014 and 203 were $0.4 million and $0.5 million, respectively.

Gain (Loss) on Financial Instruments

The Company realized a loss of $0.06 million related to its crude oil derivative contracts for the six months ended June 30, 2014 compared to a loss of $0.03 million for the same period in 2013. Estimated unrealized losses on the future settlements of the remaining derivative contracts were $0.3 million and $0.1 million at June 30, 2014 and 2013, respectively.

Financing Costs and Other, net

Financing costs were $0.4 million for each of the six months ended June 30, 2014 and 2013, representing accretion of asset retirement obligations. Financing costs for the three months ended June 30, 2014 and 2013 were $0.2 million and $0.1 million, respectively.

EBITDA Reconciliation

In thousands	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	**2013**	**2014**	**2013**
Net loss before tax	$ (1,267)	$ (360)	$ (5,822)	$ (1,348)
Adjustments:				
Loss on disposition of assets	57	-	1,085	-
Depreciation , depletion, and amortization	440	469	859	972
Foreign currency translation (gain) loss	(3)	(2)	1	(7)
Stock-based compensation	-	32	-	109
Unrealized loss (gain) on financial instruments	308	208	308	208
Financing costs and other, net	157	141	320	373
EBITDA	**$ (308)**	**$ 488**	**$ (3,249)**	**$ 307**

LIQUIDITY AND CAPITAL RESOURCES

As of June 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 $2.7 million, which seriously affected the Company's current financial condition. In the circumstances, the Company must either, complete one or more debt or equity financings, enter into some form of development joint venture or sell assets in order to fund its operations and development activities. Accordingly, the timing of development drilling in the Milnesand field, originally expected to commence in January of 2014, has been delayed until the Company completes one or more of the following: a financing arrangement, a third party joint venture drilling arrangement or sells assets. The Company is continuing to negotiate the drilling of three wells in the

Milnesand field with one or more potential joint venture partners. Definitive agreements would be completed following the completion of a field study and engineering by the potential partners. The agreements would include 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. On August 8, 2014, the Company executed a letter of intent to sell its interests in the Crossroads field for cash proceeds of $10.0 million (see Subsequent Event footnote in the Notes to Consolidated Condensed Interim Financial Statements for the Six Months Ended June 30, 2014). 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 acquisitions and dispositions. Subject to financing these activities, the Company may continue its horizontal infill drilling program in the Milnesand field in late 2014 and 2015.

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. As discussed above, the Company may consider the sale of some or all of its oil fields to accelerate cash flows for use on other projects. 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 June 30, 2014 are as follow:

Barrels	Commodity	Type	Price	Term
72,000	WTI Crude Oil	Costless Collar	$ 88.00 to $ 97.50	May 2014 - Apr 2015
57,900	WTI Midland-Cushing Differential	Swap	($3.50)	Jun 2014 - Dec 2015

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	
	Third	Fourth	First	Second	Third	Fourth	First	Second
Revenues	$ 3,108	$ 3,176	$ 2,977	$ 3,176	$ 3,935	$ 3,048	$ 2,366	$ 2,510
Net comprehensive income (loss)	$ (3,197)	$ (360)	$ (989)	$ (358)	$ (292)	$ (492)	$ (4,554)	$ (1,267)
Per share - basic	$ (0.02)	$ (0.01)	$ (0.01)	$ -	$ -	$ -	$ (0.03)	$ (0.01)
Per share - diluted	$ (0.02)	$ (0.00)	$ (0.01)	$ -	$ -	$ -	$ (0.03)	$ (0.01)

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	
	Third	Fourth	First	Second	Third	Fourth	First	Second
Average price received	$ 82.84	$ 79.19	$ 80.09	$ 88.48	$ 101.13	$ 91.94	$ 90.00	$ 90.33
Sales volume	37,497	37,461	37,170	35,902	38,907	33,152	26,290	27,784

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 2Q 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.

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 six months ended June 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 June 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 August 27, 2014:

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

Common stock options outstanding at August 27, 2014 were as follows:

Stock Options Outstanding - Common Stock:

Number Authorized	Date of Agreement	Exercise or Issue Price	Expiry Date
334,000	April 16, 2009	$0.44	September 16, 2014
350,000	August 29, 2009	$0.30	August 29, 2014
2,025,000	September 15, 2009	$0.25	September 15, 2014
200,000	November 2, 2009	$0.28	November 2, 2014
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
10,159,000			

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.
CGU	Cash 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
IASB	International Accounting Standards Board
IFRIC	International Financial Reporting Interpretations Committee
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

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.