# Enhanced Oil Resources Inc.

# Management's Discussion & Analysis

# Year Ended December 31, 2015

## DATE AND BASIS OF INFORMATION

Enhanced Oil Resources Inc. is a natural resource company incorporated in British Columbia, Canada in 1980 and is engaged, through its wholly-owned U.S. subsidiaries (collectively referred to as the "Company", "we", or "our"), in the acquisition, development, operation and exploitation of crude oil and natural gas properties in the Permian Basin.

The Company's corporate headquarters are located in Houston, Texas. Common shares of the Company are listed 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". The address of the registered office of the Company is 940, 1040 West Georgia Street, Vancouver, British Columbia, V6E 4H1. 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 April 29, 2016 and should be read in conjunction with the Company's consolidated financial statements and related notes for the year ended December 31, 2015, as well as the consolidated financial statements and related notes, and MD&A for the year ended December 31, 2014. The referenced consolidated financial statements have been prepared by management and approved by the Company's Board of Directors. Unless otherwise noted, all financial information presented herein has been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

All financial information is in US dollars, unless otherwise indicated.

### Non-IFRS Financial Measures

Certain financial measures in this MD&A, namely netback, cash flow from operations, lifting costs and EBITDA are not prescribed, do not have a standardized meaning defined 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 income taxes, depletion, depreciation, amortization and accretion and is often referred to as 'cash flow from operations'.

There is an abbreviations section at the end of this document that lists abbreviations and definitions commonly referred to in the energy business and may be used in this MD&A.

## BUSINESS OVERVIEW

### Overview of Year Ended 2015

**Change in Management.** Following a complete change in the Board of Directors of the Company in December 2014, including the appointment of Andrew Hromyk as Chief Executive Officer and President, a new Board was elected by a majority of the shareholders at the annual general meeting held January 15, 2015. Currently, management is undertaking a substantial restructuring of objectives and operating actions to facilitate raising new capital and/or financing arrangements for the reactivation and development of the Company's oilfields. With the continued decline of crude oil prices during 2015 through 2016, management took steps to reduce overhead and personnel, closed our Midland, Texas office and relocated our corporate office in Houston to smaller premises.

**Crude Oil and Natural Gas Business Segment.** The Company has one reportable business segment; crude oil and natural gas production and development, with all activities located in the United States of America. As such, we produce oil and gas from Permian Basin crude oilfields located in eastern New Mexico. The New Mexico fields were purchased in 2007 ("Chaveroo Field" and "Milnesand Field") because they represented excellent candidates for future development based on estimates of substantial remaining original-oil-in-place ("OOIP"). The OOIP associated with these fields represents more than 300 million barrels, of which some estimates project as much as 20% of OOIP could still be recoverable. The Company's net proved reserves at December 31, 2015 and 2014, respectively, were 6.2 million and 4.8 million barrels of equivalents with a net present value of $180.2 million and $54.2 million using a 10% discount rate for both periods. This represents a 29.2% increase in reserves.

**Subsidiaries and Operations.** The operations of the Company include Enhanced Oil Resources Inc. ("the Parent Company") and its wholly-owned subsidiary, Ridgeway Petroleum (Florida), Inc. ("RF"). RF includes the results of its wholly-owned subsidiaries, Enhanced Oil Resources USA Inc. and Arizona Resources Industries, Inc. ("ARI"). ARI includes the results of its wholly-owned subsidiaries, Ridgeway Arizona Oil Corp., EOR Operating Company, St. Johns Dome Operating Company and Phoenix Energy Inc. Ridgeway Arizona Oil Corp. includes the results of its wholly-owned subsidiary, Ridgeway SPV Inc.

## RESULTS OF OPERATIONS

**Consolidated Statements of Operations and Comprehensive Loss:**

| *(In thousands of US dollars)* | Three Months Ended December 31, 2015 | Three Months Ended December 31, 2014 | Year Ended December 31, 2015 | Year Ended December 31, 2014 |
|---|---|---|---|---|
| **Revenues** | | | | |
| Oil and gas gross sales | $ 325 | $ 705 | $ 1,358 | $ 8,001 |
| Less royalties | (75) | (146) | (293) | (1,665) |
| | 250 | 559 | 1,065 | 6,336 |
| **Expenses** | | | | |
| Operating costs, production costs and taxes | 161 | 752 | 1,393 | 3,788 |
| Workover expenses | 249 | 41 | 809 | 3,464 |
| General and administrative | 788 | 1,392 | 2,613 | 3,752 |
| Gain on disposition of assets | (106) | (1,188) | (42) | (106) |
| Depreciation, depletion and amortization | 540 | 290 | 959 | 1,509 |
| Accretion | 93 | 143 | 427 | 608 |
| Other, net | - | - | 9 | 23 |
| Loss (gain) on derivative financial instruments, net | (28) | (214) | 75 | (256) |
| Foreign currency translation gain | (23) | (13) | - | (7) |
| | 1,674 | 1,203 | 6,243 | 12,775 |
| Loss before income taxes | (1,424) | (644) | (5,178) | (6,439) |
| Income tax provision | - | - | - | - |
| Net comprehensive loss for the period | $ (1,424) | $ (644) | $ (5,178) | $ (6,439) |
| *Loss per share - basic and diluted* | $ (0.09) | $ (0.04) | $ (0.32) | $ (0.40) |

The Company's crude oil sales revenues for the year ended December 31, 2015, decreased $6.6 million (or 83.0%) to $1.4 million, compared to $8.0 million in 2014. In addition, net loss for the period decreased by $1.2 million (or 19.6%) to $5.2 million, compared to a $6.4 million net loss for the year ended December 31, 2014. Per share results (basic and fully diluted) were net losses of $0.32 and $0.40 for the years ended December 31, 2015 and 2014, respectively. Cash used in operating activities for the year ended December 31, 2015 was $4.3 million compared to $6.2 million in 2014, a decrease of $1.9 million. The decrease in net loss and operating cash used was principally related to the decrease in operating expenses due to the sale of the Crossroads field in October of 2014 (see "Disposition of Oil and Gas Properties" below) coupled with lower general and administrative expenses from the closing of the Midland office, personnel reductions and the relocation to smaller corporate office in the first quarter of 2015. The decrease in expenses were partially offset by the loss of both commodity production and commodity sales from the Crossroads field combined with declining crude oil prices and the realized $0.1 million loss on derivative contracts used as hedges ($0.3 million realized gain in 2014).

Results of operations for the three months ended December 31, 2015, included crude oil revenues of $0.3 million, and a net loss of $1.4 million, compared to $0.7 million and $0.6 million, respectively, for the three months ended December 31, 2014. In addition, loss per share results (basic and fully diluted) were $0.09 and $0.04 for the three months ended December 31, 2015 and 2014, respectively. The decrease in revenue was primarily related to low oil prices. In addition, both workover costs and depletion expense increased by $0.2 million (due to lease requirements in the Chaveroo field) and $0.2 million (due to the transfer of exploration and evaluation assets to property and equipment), respectively, over the prior year.

Net losses for the period were $1.4 million compared to $0.6 million for the prior year, or an increase of $0.8 million. The increase in net loss was primarily due to a decrease of $1.1 million in gains on disposition of assets from the sale of the Crossroads field in October 2014 offset by a $0.6 million reduction in general and administrative expenses.

## Revenue

In 2015, crude oil sales revenue decreased by $6.6 million (or 83.0%) to $1.4 million, compared to $8.0 million in 2014. The decrease was due to both a 61,699 Boe (or 66.4%) reduction in crude oil sales volumes (31,175 gross Boe's in 2015 compared to 92,874 gross Boe's in 2014) and a 49.4% lower average sales prices ($43.57 in 2015 compared to $86.15 in 2014).

Sales of crude oil decreased by $0.4 million (or 53.9%) to $0.3 million for the fourth quarter in 2015 compared to $0.7 million in 2014. The decrease was due to both a 1,560 Boe (or 15.2%) reduction in crude oil sales volumes (8,704 gross Boe's in the fourth quarter 2015 compared to 10,264 gross Boe's in the fourth quarter 2014) and a 45.5% lower average sales prices ($37.43 in the fourth quarter 2015 compared to $68.70 in the fourth quarter 2014).

## Operating Costs, Production Costs and Workover Expenses

Our efforts have been focused on increasing oil recovery from legacy oil fields, which normally reflect higher operating costs than fields with newly established production. Since all of the Company's properties are older oil fields, we expect that operating costs will always be relatively higher due to the higher frequency of workovers, increasing compliance costs associated with increased regulatory activity and higher maintenance costs pending additional field development.

*Operating and Production Costs*: Operating and production costs for the year ended December 31, 2015 decreased by $2.4 million (or 63.2%) to $1.4 million, compared to $3.8 million for 2014. The decrease in costs is primarily due to the sale of the Crossroads field ($1.1 million expense savings in 2015) in October of 2014 coupled with the closing of the Midland office and personnel reductions ($1.0 million expense savings in 2015).

*Workover Expenses*: Workover expenses for the year ended December 31, 2015 decreased significantly, by approximately $2.7 million (or 76.6%). This represents a $12.66 per gross Boe decrease in workover expenses to $24.80 per gross Boe. The decrease is primarily related to the re-drilling of the Crossroads #202 well during the first half of 2014.

*Netback*: As a result of the decrease in oil prices coupled with decreases in commodity production and the disproportionate decrease in workover costs, the operating netback for the twelve months ended December 31, 2015 decreased to a $22.51 loss per Boe compared to $5.68 income per Boe for the same period in 2014.

Operating netback for the quarter ending December 31, 2015 was a $22.76 loss compared to a $10.74 income for the same period in 2014, primarily due to reduced operations from the sale of the Crossroads field.

## General & Administrative

General and administrative expenses for the year ended December 31, 2015, decreased $1.1 million (or 30.4%) to $2.6 million when compared to 2014. General and administrative expenses increased in the fourth quarter of 2014 due to severance costs associated with the departure of the prior Chief Executive Officer and a Vice President. During 2015, the Company significantly reduced its general and administrative expenses, reduced its overall headcount to four employees and subleased its corporate office in Houston and moved to smaller premises.

### Disposition of Oil and Gas Properties

On October 16, 2014, the Company sold all of its 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. The Company recognized a gain on the disposition of $1.2 million, including a broker's fee of $210,000. In addition, the Company sold certain non-core property interests in Texas for approximately $0.4 million in February 2014, and recognized a loss of $1.1 million. As a result of the decrease in crude oil production associated with these dispositions and declining oil prices, the Company's operations are limited to those that are necessary to sustain production and as a result, the Company has limited its remedial operations, and has reduced personnel and overhead in order to adjust to reduced cash flows.

### Depreciation, Depletion & Amortization

Depreciation, depletion and amortization expense for the year ended December 31, 2015, decreased by approximately $0.5 million (or 36.4%) to $1.0 million, when compared to the same period in 2014. The decrease in depletion expense for 2015 was due to the decrease in production related to the oilfield dispositions discussed above. Depreciation, depletion, and amortization expense for the three months ended December 31, 2015 and 2014 were $0.5 million and $0.3 million, respectively (discussed above).

### Accretion

Accretion expense was $0.4 million and $0.6 million for the years ended December 31, 2015 and 2014, respectively. Accretion expense for the three months ended December 31, 2015 and 2014 was each $0.1 million.

### Gain (Loss) on Financial Instruments

The Company realized a loss of $0.1 million on NYMEX WTI settlements related to its crude oil derivative contracts for the year ended December 31, 2015. This compared to a $0.3 million realized gain for the comparable period in 2014. In October 2014, following the sale of the Crossroads field, the Company sold the remainder of its collar derivative contract (November 2014 – April 2015) representing 36,200 barrels, to Shell Trading Risk Management, LLC for approximately $0.3 million. At December 31, 2014, the remaining crude oil derivative contract represented an unrealized loss of $0.04 million. During the current period, all outstanding agreements expired leaving no derivative contracts in place at December 31, 2015.

### Foreign Exchange Gain (Loss)

The Company's functional currency and presentational currency, as determined under International Accounting Standard ("IAS") 21, *The Effects of Changes in Foreign Exchange Rates*, is the United States dollar. All of the Company's operating expenses and capital expenditures are paid in the United States dollar except for general and administrative expense of the Canadian parent entity and all historical equity issuances of the Canadian parent which are denominated in Canadian dollars. There will continue to be an impact from currency translation and exchange gains and losses, but we believe this translation will have a small impact on our financial results. The average Canadian/US dollar exchange rate was $0.78 and $0.91 for the years ended December 31, 2015 and 2014, respectively.

**Earnings before Interest, Taxes, Depreciation, Depletion and Amortization (EBITDA) Reconciliation**

| *In thousands* | Three Months Ended December 31, 2015 | Three Months Ended December 31, 2014 | Year Ended December 31, 2015 | Year Ended December 31, 2014 |
|---|---|---|---|---|
| Net loss before tax | $ (1,424) | $ (644) | $ (5,178) | $ (6,439) |
| *Adjustments:* | | | | |
| (Gain) loss on disposition of assets | (106) | (1,188) | (42) | (106) |
| Depreciation , depletion, and amortization | 540 | 290 | 959 | 1,509 |
| Foreign currency translation gain | (23) | (13) | - | (7) |
| Unrealized (gain) loss on financial instruments | (62) | (378) | (39) | 39 |
| Financing costs and other, net | - | - | 9 | 23 |
| **EBITDA** | **$ (1,075)** | **$ (1,933)** | **$ (4,291)** | **$ (4,981)** |

**Operating Netback and Production**

The table below summarizes the operating netback for the comparable periods in the aggregate for the years ended December 31, 2015 and 2014.

**Operating Netback Per Gross Boe:**

| *(In US dollars)* | | Three Months Ended December 31, 2015 | Three Months Ended December 31, 2014 | Year Ended December 31, 2015 | Year Ended December 31, 2014 |
|---|---|---|---|---|---|
| **Oil & Gas Sales Volumes** | | | | | |
| Oil equivalent | *Boe's* | 8,704 | 10,264 | 31,175 | 92,874 |
| **Average prices** [1] | | | | | |
| Oil equivalent | *$/Boe* | $ 37.43 | $ 68.70 | $ 43.57 | $ 86.15 |
| **Less:** | | | | | |
| Royalties, net [2] | *$/Boe* | (6.93) | (12.63) | (7.94) | (15.72) |
| Production taxes | *$/Boe* | (3.08) | (5.61) | (3.72) | (7.21) |
| Production costs | *$/Boe* | (22.36) | (33.96) | (29.62) | (20.08) |
| Workover expense | *$/Boe* | (27.83) | (5.76) | (24.80) | (37.46) |
| **Operating Netback** [3] | *$/ Boe* | $ (22.76) | $ 10.74 | $ (22.51) | $ 5.68 |

[1] Average prices are after deduction of transportation costs.

[2] Net of related production taxes.

[3] 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.

Operating netback for the year ended December 31, 2015, decreased $28.19 per gross Boe (or 496.3%) to a $22.51 loss, compared to $5.68 per gross Boe income for the same period in 2014. The decrease is principally due to declining crude prices, the disposition of producing property interests and operating costs decreasing disproportionately to the decrease in commodity production due to the sale of the Crossroads field. For the same reasons, fourth quarter netbacks in 2015 decreased $33.50 per gross Boe (or 311.9%) to a $22.76 loss, compared to $10.74 income per gross Boe realized in the fourth quarter of 2014.

## LIQUIDITY AND CAPITAL RESOURCES

As of December 31, 2015, the Company had unrestricted cash of $1.3 million and restricted cash balances of $4.3 million. On April 9, 2015, the Company announced a private placement of approximately $5.5 million, management's estimate of the additional funds necessary for limited activities in 2015 and 2016. During 2015, the Company received $0.3 million in private placement funding. The private placement is anticipated to close in the second quarter of 2016.

On January 11, 2016, the remaining $1.25 million was released from escrow by Kinder Morgan (discussed below under "Commitments").

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 financing of drilling activities will require dilution of equity interests or 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 increasing production in one or more of its oil fields.

## 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)* | 2014 | | | | 2015 | | | |
|---|---|---|---|---|---|---|---|---|
| | First | Second | Third | Fourth | First | Second | Third | Fourth |
| Revenues | $ 2,366 | $ 2,510 | $ 2,420 | $ 705 | $ 267 | $ 394 | $ 372 | $ 325 |
| Net comprehensive income (loss) | $ (4,554) | $ (1,267) | $ 24 | $ (644) | $ (1,320) | $ (1,335) | $ (1,099) | $ (1,424) |
| Per share - basic | $ (0.28) | $ (0.08) | $ - | $ (0.04) | $ (0.08) | $ (0.08) | $ (0.07) | $ (0.09) |
| Per share - diluted | $ (0.28) | $ (0.08) | $ - | $ (0.04) | $ (0.08) | $ (0.08) | $ (0.07) | $ (0.09) |

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

**Quarterly Average Prices Received and Sales Volumes:**

| | 2014 | | | | 2015 | | | |
|---|---|---|---|---|---|---|---|---|
| | First | Second | Third | Fourth | First | Second | Third | Fourth |
| Average price received | $ 90.00 | $ 90.33 | $ 84.81 | $ 68.70 | $ 41.96 | $ 52.28 | $ 43.34 | $ 37.43 |
| Sales volume | 26,291 | 27,784 | 28,535 | 10,264 | 6,365 | 7,535 | 8,571 | 8,704 |

The changes in the results in the above quarterly table reflects more or less 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 volumes in the second, third and fourth quarters of 2015 was due to the reactivation of numerous wells in both the Milnesand and the Chaveroo fields. The decrease in crude oil sales volume in the fourth quarter 2014 is principally due to the sale of the Crossroads field on October 16, 2014. The Crossroads field was the Company's largest producing field. 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, principally at the

Crossroads field. The decrease in production in the first quarter of 2014 was associated with wells off production in the Crossroads field.

Revenue decreased in the third and fourth quarters of 2015 due to lower commodity prices received from oil sales. Revenue increased in the second quarter of 2015 due to higher sales volume coupled with higher oil prices. Revenue decreases in the fourth quarter 2014 related to the significant decrease in sales volumes as well as a decrease in sales price of $16.11 (or 19.0 %) to $68.70 per Boe. The decrease in revenue in the third quarter 2014 is due to the decrease in the average received price. Revenue increased in the second quarter of 2014 primarily due to an increase in crude oil sales volume.

## Selected Annual Information

The following information is presented from annual information in the Company's audited financial statements for the periods indicated and prepared on the basis of the accounting principles effective for such period, as indicated:

**Three Year Select Financial Data:**

| ***(In thousands except per share amounts)*** | **Year Ended December 31, [1]** | | |
|---|---|---|---|
| | **2015** | **2014** | **2013** |
| Revenues | $ 1,358 | $ 8,001 | $ 13,136 |
| Net comprehensive loss | $ (5,178) | $ (6,439) | $ (21,131) |
| Net loss per common share [2] | $ (0.32) | $ (0.40) | $ (1.32) |
| Loss per share basic and fully diluted [2] | $ (0.32) | $ (0.40) | $ (1.32) |
| Total assets | $ 46,572 | $ 58,588 | $ 65,575 |
| Total non-current financial liabilities | $ 18,977 | $ 24,972 | $ 23,074 |

[1] The selected annual information was prepared in accordance with IFRS. Amounts are denominated in US dollars, which the Company determined under International Accounting Standard (IAS) 21 is its functional currency.

[2] In January of 2015, the Company issued a ten-to-one reverse stock split for all common shares outstanding at the time of the split. In order to be consistent across all reporting periods presented, the Company treated the transaction as if it occurred on the first day of the earliest period reported.

Revenues decreased in 2015 primarily due to the lost production from the sale of the Crossroads field (37,915 gross Boe's sold in the prior year) coupled with the decrease in the average price received for crude oil sales. Revenue decreases in 2014 were associated with the declining crude oil prices and crude oil production. Losses in 2014 were associated with large workover costs associated with the Crossroads field, which was sold in October 2014.

## Equity Placements

The Company has not completed any equity placements since 2010. There were no outstanding share purchase warrants at December 31, 2015. On April 9, 2015, the Company announced a private placement of approximately $5.5 million that is anticipated to be competed in 2016, subject to approval of the TSX Venture Exchange.

### Share Consolidation

Effective January 21, 2015, the Company implemented a share consolidation of one post-consolidation common share for every ten pre-consolidation common shares. The Company's shares began trading on the post-consolidation basis on January 21, 2015, and according all references to the outstanding shares of the Company have been restated to give effect to the consolidation as if the number of shares were consolidated effective December 31, 2013 (see the Company's consolidated financial statements for the year ended December 31, 2015, Note 12 – *Equity Instruments*).

### Commitments

In February 2014, the Company amended its $CO_2$ Purchase Agreement with Kinder Morgan $CO_2$ Company, L.P. ("Kinder Morgan"), which the Company entered into in order to provide the source of $CO_2$ for use in tertiary oil recovery projects in the Permian Basin. The contract, as amended, requires the Company to take or pay for the purchase of 27.4 billion cubic feet of $CO_2$ over a five-year period commencing no later than January 1, 2018. The maximum daily rate to be purchased under the contract is 20 million cubic feet per day during year three and the cost of $CO_2$ will fluctuate based on the price of oil and transportation tariffs. The Company would be required to construct a pipeline, currently estimated to be a distance of approximately 32 miles, to the pipeline operated by Kinder Morgan. The purchase commitment and obligation to pay, as amended, is cancellable before January 1, 2017, with no termination penalty.

In connection with the sale of certain assets to Kinder Morgan in 2012, the Company agreed to be contingently responsible for up to $5.0 million of future appraisal drilling costs to evaluate helium in certain areas of the St. Johns Dome field ("Drilling Costs"). The obligation was secured in part by $2.5 million placed into escrow at closing of the sale. On September 4, 2015, approximately $1.25 million of the Company's restricted cash was released from escrow by Kinder Morgan. In January 2016, the remaining sum of approximately $1.25 million was released to the Company (see the Company's consolidated financial statements for the year ended December 31, 2015 and 2014, Note 22 – *Subsequent Events*). The remaining obligation of $2.5 million expires in January of 2024. The Company's obligations to fund Drilling Costs are contingent on both (i) all permits being issued, and (ii) all steel being purchased to construct a pipeline to the St. Johns Dome field.

### Regulatory Compliance in New Mexico

The Company's operating subsidiaries, primarily Ridgeway Arizona Oil Corp. (Ridgeway) and EOR Operating Company, 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 field, the Milnesand field, is 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 Exchange 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 year ended December 31, 2015.

## 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

During 2014, the Company paid a $0.05 million due diligence fee to a company controlled by the Company's Chief Executive Officer in connection with a proposed credit facility.

During 2015, the Company paid approximately $0.34 million in management fees to an entity controlled by the Company's Chief Executive Officer.

## 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, 2015 and December 31, 2014 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 cash generating unit (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

There are no new standards or amendments to existing standards effective January 1, 2015.

The following new standards and amendments to standards and interpretations are effective for annual periods beginning after January 1, 2016, and have not been applied in preparing these financial statements.

*IFRS 9: Financial Instruments*

The complete version of *IFRS 9* was issued in July 2014. It replaced guidance in *IAS 39* that relates to the classification and measurement of financial instruments. *IFRS 9* retains but simplifies the mixed measurement model and establishes three primary measurement categories for financial assets: amortized cost, fair value through OCI and fair value through profit and loss. The basis of classification depends on the entity's business model and the contractual cash flow characteristics of the financial asset. Investments in equity instruments are required to be measured at fair value through profit or loss with the irrevocable option at inception to present changes in fair value in OCI not recycling. There is now a new expected credit losses model that replaces the incurred loss impairment model used in *IAS 39*. For financial liabilities there were no changes to classification and measurement except for the recognition of changes in own credit risk in other comprehensive income, for liabilities designated at fair value through profit or loss. *IFRS 9* relaxes the requirements for hedge effectiveness by replacing the bright line hedge effectiveness tests. It requires an economic relationship between the hedged item and hedging instrument and for the "hedged ratio" to be the same as the one management actually uses for risk management purposes. Contemporaneous documentation is still required but is different to that currently prepared under *IAS 39.* The standard is effective for accounting periods beginning on or after January 1, 2018. Early adoption is permitted. The Company has not fully assessed the impact of *IFRS 9.*

*IFRS 15: Revenue from Contracts with Customers*

IFRS 15 deals with revenue recognition and establishes principles for reporting useful information to users of financial statements about the nature, amount, timing and uncertainty of revenue and cash flows arising from an entity's contracts with customers. Revenue is recognized when a customer obtains control of a good or service and thus has the ability to direct the use and obtain the benefits from the good or service. The standard replaces *IAS 18 Revenue* and *IAS 11 Construction Contracts* and related interpretations. The standard is effective for annual periods beginning on or after January 1, 2018, and earlier application is permitted. The Company has not fully assessed the impact of *IFRS 15*.

*IFRS 16: Leases*

In January 2016, the IASB issued *IFRS 16 Leases*. It replaces the existing leasing standard (*IAS 17 Leases*) and provides transparency on companies' lease assets and liabilities by removing off balance sheet lease financing and will improve comparability between companies that lease and those that borrow to buy. *IFRS 16* is effective January 1, 2019, with earlier application permitted. The Company is currently assessing the impact of this standard.

*IAS 1: Presentation of Financial Statements*

In December 2014, the IASB issued amendments to *IAS 1*, clarifying guidance on the concepts of materiality and aggregation of items in the financial statements, the use and presentation of subtotals in the statement of operations and the statement of comprehensive income or loss, and providing additional flexibility in the structure and disclosures of the financial statements to enhance understandability. The amendments to *IAS 1* may be applied immediately, and become mandatory for annual periods beginning on or after January 1, 2016. The Company does not expect that the impact of the amendments to *IAS 1* will have a material effect on the Company's consolidated financial statements.

There are no other IFRS or IFRIC interpretations that are not yet effective that would be expected to have a material impact on the Company.

## POTENTIAL RISKS AND UNCERTAINTIES

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.

### Exploration, Drilling and Operational Risks

The business of exploration for and production of oil, gas and other resources involves a high degree of risk. In particular, the operations of the Company may be disrupted, curtailed or cancelled by a variety of risks and hazards which are beyond the control of the Company, including environmental hazards, industrial accidents, occupational and health hazards, technical failures, labor disputes, unusual or unexpected rock formations, flooding and extended interruptions due to inclement or hazardous weather conditions, mechanical difficulties, shortage or delays in the delivery of rigs and/or other equipment, compliance with governmental requirements, explosions and other accidents. These risks and hazards could also result in damage to, or destruction of, production facilities, personal injury, environmental damage, business interruptions, monetary losses and possible legal liability.

### Political Risks

The Company's principal licenses are located in New Mexico, USA. Future operations may be affected in varying degrees by government regulations with respect to, but not limited to, restrictions on production, price controls, export controls, currency remittance, income taxes, foreign investment, maintenance of licenses, environmental legislation, land use, land claims of local people, water use and well safety.

Failure to comply strictly with applicable laws, regulations and local practices relating to exploration and evaluation assets could result in loss, reduction or expropriation of entitlements. The occurrence of these various factors and uncertainties cannot be accurately predicted and could have an adverse effect on the Company's consolidated results of operations and financial condition.

### Additional Financing

To the extent that external sources of capital, including the issuance of additional common shares, become limited or unavailable, the Company's ability to make necessary capital investments to maintain or expand its oil and gas exploration and development activities will be impaired.

### Dependence on Key Personnal

The Company has a small management team and the loss of a key individual or the inability to attract suitably qualified personnel in the future could materially and adversely affect the Company's business.

### Foreign Investments

The Company expects that its oil and gas exploration activities will take place principally outside of Canada for the foreseeable future. As such, the Company's operations are subject to a number of risks over which it has no control. These risks may include risks related to economic, social or political instability or change, terrorism, hyperinflation, currency non-convertibility or instability, changes of laws affecting foreign ownership, government participation, taxation, working conditions, rates of exchange, exchange control, exploration licensing, petroleum and export licensing and export duties as well as government control over domestic oil and gas pricing. The Company endeavors to operate in such a manner in order to minimize and mitigate its exposure to these risks. However, there can be no assurance that the Company will be successful in protecting itself from the impact of all of these risks.

### Environmental Regulation

The oil and gas industry is subject to environmental regulation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of the Company or its properties. Such legislation may be changed to impose higher standards and potentially costlier obligations. The Company endeavors to operate in such a manner to ensure it conforms to the standards and government regulations required for each jurisdiction in which it operates.

### Government Regulations

The Company's oil and gas concessions are subject to various federal and local governmental regulations. Matters subject to regulation include discharge permits for drilling operations, drilling and abandonment bonds, reports concerning operations, the spacing of wells, and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and gas wells below actual production capacity in order to conserve supplies of oil and gas. The production, handling, storage, transportation and disposal of oil and gas, by-products thereof, and other substances and materials produced or used in connection with oil and gas operations are also subject to regulation under federal and local laws and regulations relating primarily to the protection of human health and the environment. The Company incurs expenditures related to complying with these laws, and for remediation of existing environmental contamination. The requirements imposed by such laws and regulations are frequently changed and subject to interpretation, and the Company is unable to predict the ultimate cost of compliance with these requirements or their effect on its operations.

### General Economic Conditions

There has been a high level of volatility in the world financial markets over the past few years. This volatility has caused investors to become less willing to provide debt or equity financing to most companies and in particular to junior resource companies. This will potentially make completing financings for the Company difficult in the foreseeable future.

### Market Risks

The Company is subject to normal market risks including fluctuations in foreign exchange rates and interest rates. While the Company manages its operations in order to minimize exposure to these risks, the Company has not entered into any derivatives or contracts to hedge or otherwise mitigate this exposure.

## OTHER MD&A INFORMATION 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 April 29, 2016:

1,000 preference shares (held by a wholly-owned subsidiary of the Company).

16,008,810 common shares issued. Common stock options outstanding were as follows:

**Stock Options Outstanding – Common Shares**

| Number Authorized | Date of Agreement | Exercise or Issue Price (C$) | Expiration Date |
|---|---|---|---|
| 10,000 | February 15, 2012 | $1.60 | February 15, 2017 |
| 20,000 | January 14, 2013 | $1.00 | January 14, 2018 |
| 30,000 | | | |

## FORWARD-LOOKING STATEMENTS

Certain statements contained in this Management's Discussion and Analysis and in certain documents incorporated by reference into this Management's Discussion and Analysis, 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" 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, asset retirement and abandonment activities 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;
- timing and effect of production increases and the related effect and timing 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 tax related implications 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, either directly or 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;
- expected levels of royalty rates, production and workover costs, office field expenses, general and administrative costs, costs of services and other costs and expenses; and
- benefits or costs related to settlement of financial instruments
- 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.

## ABBREVIATIONS AND DEFINITIONS

**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. |
| DD&A | Depreciation, depletion and amortization |
| 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. |
| 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 |

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|---|---|
| | 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 |