MANAGEMENT'S DISCUSSION AND ANALYSIS

For the Year Ended December 31, 2016

Date of Report: March 22, 2017

INTRODUCTION

The Company was incorporated under the laws of Ontario, Canada, on March 29, 1968 under the name "Dejour Mines Limited". By articles of amendment dated October 30, 2001, the issued common shares were consolidated on the basis of one (1) new share for every fifteen (15) old shares and the name of the company was changed to Dejour Enterprises Ltd. On June 6, 2003, the shareholders approved a resolution to complete a one new share for three old share consolidation, which became effective on October 1, 2003. In 2005, the Company was continued into the province of British Columbia under the *Business Corporations Act* (British Columbia). On March 9, 2011, the Company changed its name from Dejour Enterprises Ltd. to Dejour Energy Inc. On October 27, 2015, the Company changed its name from Dejour Energy Inc. to DXI Energy Inc.

The head office of DXI Energy is located at 598 – 999 Canada Place, Vancouver, British Columbia, V6C 3E1, and its registered and records office is located at 25th Floor, 700 West Georgia Street, Vancouver, British Columbia, V7Y 1B3. The common shares of DXI Energy are listed for trading on the Toronto Stock Exchange ("TSX") under the symbol "DXI" and the OTCQB ("OTCQB") under the symbol "DXIEF".

The following management's discussion and analysis ("MD&A") is dated March 22, 2017 and should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the years ended December 31, 2016 and 2015. Additional information relating to DXI Energy can be found on SEDAR at www.sedar.com.

FORWARD-LOOKING STATEMENTS

This document contains expectations, beliefs, plans, goals, objectives, assumptions, information, and statements about future events, conditions, results of operations or performance that constitute "forward-looking information" or "forward-looking statements" (collectively, "forward-looking statements") under applicable securities laws. Undue reliance should not be placed on forward-looking statements. Forward-looking statements are based on current expectations, estimates and projections that involve a number of risks and uncertainties, which could cause actual results to differ materially from those anticipated by the Company and described in the forward-looking statements. We caution that the foregoing list of risks and uncertainties is not exhaustive. Events or circumstances could cause actual dates to differ materially from those estimated or projected and expressed in, or implied by, these forward-looking statements. The forward-looking statements contained in this document are made as of the date hereof and the Company does not intend, and does not assume any obligation, to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise unless expressly required by applicable securities laws.

The information set out herein with respect to forecasted 2017 results is "financial outlook" within the meaning of applicable securities laws. The purpose of this financial outlook is to provide readers with disclosure regarding DXI Energy's reasonable expectations as to the anticipated results of its proposed business activities for 2017. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

NON-IFRS MEASURES

This document contains certain financial measures, as described below, which do not have standardized meanings prescribed by International Financial Reporting Standards ("IFRS"). As these measures are commonly used in the oil and gas industry, the Company believes that their inclusion is useful to investors. The reader is cautioned that these amounts may not be directly comparable to measures for other companies where similar terminology is used. "Operating Netback" is calculated by deducting royalties and operating and transportation expenses from gross oil and gas revenues. "Cash Flows from Operations" is calculated by adding back settlement of decommissioning liabilities and change in operating working capital to cash flows from operating activities. Operating netback and cash flows from operations are used by DXI Energy as key measures of performance and are not intended to represent operating profits nor should they be viewed as an alternative to income or loss or other measures of financial performance, cash flows from operating activities calculated in accordance with IFRS.

The following table reconciles cash flows from (used in) operating activities to cash flows from (used in) operations, a non-IFRS measure:

	Three months ended December 31		Year ended December 31	
(CA$ thousands)	2016	2015	2016	2015
	$	$	$	$
Cash flows from (used in) operating activities	(1,005)	371	(350)	1,064
Change in operating working capital	798	(207)	(667)	(204)
Cash flows from (used in) operations	(207)	164	(1,017)	860

OTHER MEASUREMENTS

All dollar amounts are referenced in Canadian dollars, except when noted otherwise. Some numbers in this MD&A have been rounded to the nearest thousand for discussion purposes. Where amounts are expressed on a barrel of oil equivalent ("BOE") basis, natural gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel. The term BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at a burner tip and does not represent a value equivalency at the wellhead. Natural gas liquids ("NGL's") in this discussion include condensate, propane, butane, and ethane.

CRITICAL ACCOUNTING ESTIMATES AND JUDGMENTS

The preparation of financial statements in accordance with IFRS requires management to make estimates and judgments that affect reported assets, liabilities, revenues, expenses, gains, and losses. These estimates and judgments are subject to change based on experience and new information. The financial statement areas that require significant estimates and judgments are as follows:

Decommissioning liability

The Company recognizes decommissioning liabilities for its exploration and evaluation assets and property and equipment. Measurement of the decommissioning liabilities involves estimates and judgements as to the cost and timing of incurrence of future decommissioning programs. It also involves assessment of appropriate discount rates, rates of inflation applicable to future costs and the rate used to measure the accretion charge for each reporting period. Measurement of the liability also reflects current engineering methodologies as well as current and expected future environmental legislation and standards. Actual decommissioning costs will ultimately depend on future market prices for the decommissioning costs which will reflect the market conditions at the time the decommissioning costs are actually incurred. The final cost of the currently recognized decommissioning provisions may be higher or lower than currently provided for.

Exploration and evaluation expenditures

The application of the Company's accounting policy for exploration and evaluation expenditures requires judgment in determining whether it is likely that future economic benefits will flow to the Company, which is based on assumptions about future events or circumstances. Estimates and assumptions made may change if new information becomes available. If, after the expenditure is capitalized, information becomes available suggesting that the recovery of the expenditure is unlikely, the amount capitalized is written off in profit or loss in the period in which the new information becomes available.

Share-based payment transactions

The Company measures the cost of equity-settled transactions with employees by reference to the fair value of the equity instruments at the date at which they are granted. Management uses judgment to determine the most appropriate valuation model to estimate the fair value for share-based payment transactions. The inputs to the valuation model, including the expected life of the share option, volatility and dividend yield, require judgment for determination.

Financial contract liability

The application of the Company's accounting policy for financial liabilities requires the Company to adjust the carrying amounts of the financial liabilities in the event it revises its payments or receipts to reflect actual and revised estimated cash flows. The Company's financial contract liability was originally recognized at fair value using the effective interest method which ensures that any interest expense over the period of repayment is at a constant rate on the balance of the liability carried in the balance sheet. Effective June 30, 2014, the Company's financial contract liability was reduced by the residual reserve value of its working interest in the wellbores at September 30, 2016.

At December 31, 2016, the financial contract liability was adjusted to reflect the present value of the amount outstanding at year-end, net of the present value of the residual reserves of its working interest in the wellbores.

Impairment

Management applies judgment in assessing the existence of impairment and impairment reversal indicators based on various internal and external factors.

The recoverable amounts of CGUs and individual assets have been determined based on the higher of fair value less costs to sell or value-in-use. The key estimates the Company applies in determining the recoverable amount normally include anticipated future commodity prices, expected production volumes, future operating and development costs, and discount rates. Changes to these assumptions will affect the recoverable amounts of CGUs and individual assets and may then require a material adjustment to their related carrying value. At December 31, 2016, the Company has one CGU in Canada (Drake/Woodrush) and one CGU in the United States (Kokopelli).

Financial instruments

When estimating the fair value of financial instruments, the Company uses valuation methodologies that utilize observable market data where available. In addition to market information, the Company incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk. See note 9 to the consolidated financial statements for the basis of valuation of loans from related parties and warrants issued in the year.

Reserves

The estimate of reserves is used in forecasting the recoverability and economic viability of the Company's oil and gas properties, and in the depletion and impairment calculations. The process of estimating reserves is complex and requires significant interpretation and judgment. It is affected by economic conditions, production, operating and development activities, and is performed using available geological, geophysical, engineering, and economic data. Reserves are evaluated at least annually by the Company's independent reserve evaluators and updates to those reserves, if any, are estimated internally. Future development costs are estimated using assumptions as to the number of wells required to produce the commercial reserves, the cost of such wells and associated production facilities and other capital costs.

FINANCIAL REPORTING UPDATE

Certain pronouncements were issued by “IASB” or “IFRIC” that are mandatory for accounting periods beginning after January 1, 2017 or later periods.

The following new accounting standards, amendments to accounting standards and interpretations, have not been early adopted in these consolidated financial statements. The Company is currently assessing the impact, if any, of this new guidance on the Company’s future results and financial position:

IFRS 9, “Financial Instruments”: In July 2014, the IASB completed the final phase of its project to replace IAS 39, the current standard on the recognition and measurement of financial instruments. IFRS 9 is now the new standard which sets out the recognition and measurement requirements for financial instruments and some contracts to buy or sell non-financial items. IFRS 9 provides a single model of classifying and measuring financial assets and liabilities and provides for only two classification categories: amortized cost and fair value. Hedge accounting requirements have also been updated in the new standard and are now more aligned with the risk management activities of an entity. IFRS 9 is effective for annual periods beginning on or after January 1, 2018. Early adoption is permitted; however, if an entity elects to apply this standard early, it must disclose that fact and apply all of the requirements in this standard at the same time. It is anticipated that the adoption of IFRS 9 does not have material impact on the Company’s consolidated financial statements.

IFRS 15 was issued in May 2014 “Revenue from Contracts with Customers.” IFRS 15 applies to contracts with customers, excluding, most notably, insurance and leasing contracts. IFRS 15 prescribes a framework in accounting for revenues from contracts within its scope, including (a) identifying the contract, (b) identify separate performance obligations in the contract, (c) determine the transaction price of the contract, (d) allocate the transaction price to the performance obligations and (e) recognize revenues when each performance obligation is satisfied. IFRS 15 also prescribes additional financial statement presentations and disclosures. The Company currently expects to adopt IFRS 15 as of January 1, 2018, under the modified retrospective method where the cumulative effect is recognized at the date of initial application. The Company’s evaluation of IFRS 15 is ongoing and not complete. The IASB has issued and may issue in the future, interpretative guidance, which may cause its evaluation to change. The Company does not currently believe IFRS 15 will have a material effect on its consolidated financial statements.

IFRS 16, “Leases”: In January 2016, the IASB issued the standard to replace IAS 17 “Leases”. For lessees applying IFRS 16, a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted. It is anticipated that the adoption of IFRS 16 will have impact on the Company’s consolidated balance sheet due to the operating lease commitments as disclosed in note 18 to the consolidated financial statements.

DISCLOSURE CONTROLS OVER FINANCIAL REPORTING

The Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures as defined in National Instrument 52-109 of the Canadian Securities Administrators, to provide reasonable assurance that: (i) material information relating to the Company is made known to the CEO and the CFO by others, particularly during the period in which the interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.

The CEO and the CFO have evaluated the effectiveness of DXI Energy's disclosure controls and procedures as at December 31, 2016 and have concluded that such disclosures and procedures are effective.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Company's CEO and the CFO are responsible for establishing and maintaining internal control over financial reporting ("ICFR") for the Company. They have, as at December 31, 2016, designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework the Company's officers used to design the Company's ICFR is the Internal Control - Integrated Framework (2013) ("COSO Framework") published by The Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

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

As at December 31, 2016, the CEO and CFO have concluded, based on their evaluation of the design and operating effectiveness of the Company's disclosure controls and procedures and ICFR that disclosure controls and procedures and ICFR are effective.

WHISTLEBLOWER POLICY

Effective December 28, 2007, the Company's Audit Committee adopted resolutions that authorized the establishment of procedures for complaints received regarding accounting, internal controls or auditing matters, and for a confidential, anonymous submission procedure for employees and consultants who have concerns regarding questionable accounting or auditing matters. The implementation of the whistleblower policy is in accordance with the new requirements pursuant to Multilateral Instrument 52-110 Audit Committees, national Policy 58-201 Corporate Governance Guidelines and National Instrument 58-101 Disclosure of Corporate Governance Practices.

GROWTH STRATEGY

The Company implements a full cycle exploration and development program and, at the same time, opportunistically seeks to acquire assets with exploitation potential. To complement this strategy, the Company has retained a team of experienced and qualified personnel to act quickly on new opportunities.

RESULTS OF OPERATIONS

FINANCIAL AND OPERATING HIGHLIGHTS

During the year ended December 31, 2016, the Company:

1. Retired the Company's bank loan and related credit facility with a Canadian bank;

2. Completed a $995,800 private placement;

3. Decreased G&A expenses for the year ended December 31, 2016 by $675,000 (30%) to $1.6 million in response to a 24% decrease in average realized prices per BOE from 2015 to 2016; and

4. Decreased the loss for the year ended December 31, 2016 to $5.5 million from $7.1 million for the comparative period ended December 31, 2015.

REVENUE

Fourth Quarter 2016 vs. Fourth Quarter 2015	Three Months Ended December 31		
(CA$ thousands, except as otherwise noted)	2016	2015	% change
Production Volumes:			
Oil and natural gas liquids (bbls/d)	106	515	-80%
Natural gas (mcf/d)	1,327	2,773	-52%
Total (BOE/d)	327	977	-67%
Average realized prices:			
Oil and natural gas liquids ($/bbl)	57.53	46.72	23%
Natural gas ($/mcf)	3.28	2.26	45%
Total ($/BOE)	31.90	31.03	3%
Revenue, before royalties:			
Oil and natural gas liquids	558	2,206	-75%
Natural gas	396	562	-30%
Total	954	2,768	-66%

For the three months ended December 31, 2016 ("Q4 2016"), total revenue, before royalties, decreased by $1.8 million or, 66%, due to a decline in oil and natural gas production for the quarter. This was slightly offset by a minimal increase in combined average realized prices.

During Q4 2016, oil production decreased to an average of 106 BOPD from 515 BOPD for the three months ended December 31, 2015. This 80% decrease reflects the natural decline in oil production and increase in water cut associated with Halfway formation waterfloods of the Woodrush type in northeastern British Columbia.

The reduction in natural gas production for Q4 2016 is mainly due to the natural decline in natural gas production at Kokopelli in Colorado.

Year-to-date 2016 vs. Year-to-date 2015	Year ended December 31		
(CA$ thousands, except as otherwise noted)	2016	2015	% change
Production Volumes:			
Oil and natural gas liquids (bbls/d)	209	369	-43%
Natural gas (mcf/d)	1,666	1,764	-6%
Total (BOE/d)	487	663	-27%
Average realized prices:			
Oil and natural gas liquids ($/bbl)	43.25	52.68	-18%
Natural gas ($/mcf)	2.47	2.33	6%
Total ($/BOE)	27.02	35.52	-24%
Revenue, before royalties:			
Oil and natural gas liquids	3,306	7,093	-53%
Natural gas	1,502	1,486	1%
Total	4,808	8,579	-44%

For the year ended December 31, 2016, total revenue, before royalties, decreased by $3.8 million or, 44%, due to a decline in combined average realized prices and a reduction in oil and natural gas production.

During the year ended December 31, 2016, oil production decreased to an average of 209 BOPD from 369 BOPD for the corresponding period of 2015. This 43% decrease reflects the natural decline in oil production and increase in water cut associated with Halfway formation waterfloods of the Woodrush type in northeastern British Columbia.

The reduction in natural gas production for the year ended December 31, 2016 is mainly due to the natural decline in natural gas production at Kokopelli in Colorado. In Canada, production restriction imposed by Spectra, the transporter of the Company's natural gas in northeastern British Columbia, further limited natural gas deliveries in Q4 2016.

OIL OPERATIONS

($/bbl)	Three months ended December 31 2016	2015	% change	Year ended December 31 2016	2015	% change
	$	$		$	$	
Oil and NGL's revenue, realized price	57.53	46.72	23%	43.25	52.68	-18%
Royalties	(8.46)	(9.31)	-9%	(7.49)	(10.25)	-27%
Operating and transportation expenses	(21.63)	(10.62)	104%	(18.31)	(13.39)	37%
Operating netback	27.44	26.79	2%	17.45	29.04	-40%

The average price received for oil sales increased by 23% for Q4 2016, relative to the corresponding period of 2015. The increase in DXI Energy's average realized oil price reflected the benchmark price recovery in Canada and the rest of the world. The average price received for oil sales decreased by 18% for the year ended December 31, 2016, relative to the corresponding period of 2015. The decline in DXI Energy's average realized oil price for the year reflected lower benchmark average prices in Canada and the rest of the world.

Average oil royalties for the three and twelve months ended December 31, 2016 were lower, relative to the corresponding periods of 2015, due to lower oil production in both periods.

Operating and transportation expenses for the three and twelve months ended December 31, 2016 were higher, relative to the corresponding periods of 2015, mainly due to the temporary closure of the contract processing terminal and the necessity to transport oil to an alternative facility further from the Woodrush oilfield. In addition, the increase resulted in higher per unit costs as fixed operating costs were allocated over a lower oil production volume.

NATURAL GAS OPERATIONS

($/mcf)	Three months ended December 31 2016	2015	% change	Year ended December 31 2016	2015	% change
	$	$		$	$	
Gas revenue, realized price	3.28	2.26	45%	2.47	2.33	6%
Royalties	(0.37)	(0.31)	20%	(0.27)	(0.16)	65%
Operating and transportation expenses	(3.21)	(3.27)	-2%	(2.59)	(3.19)	-19%
Operating netback (loss per unit)	(0.30)	(1.32)	-78%	(0.39)	(1.02)	-62%
Barrel of oil equivalent netback ($/BOE)	(1.77)	(7.91)	-78%	(2.32)	(6.09)	-62%

The average price received for gas sales increased by 45% for Q4 2016, relative to the corresponding period of 2015. The increase in DXI Energy's average realized gas price reflected the benchmark price recovery in northeastern British Columbia and northwestern Alberta, Canada and the United States.

Average gas royalties for the three and twelve months ended December 31, 2016 were higher compared to the corresponding periods of 2015. Initiation of gas production from the eight wells at Kokopelli in

September 2015 contributed to the increase in royalties in both periods as the effective rate in Colorado is higher than the lower royalty rates for marginal gas production in British Columbia.

Average operating and transportation expenses paid for the three and twelve months ended December 31, 2016 were lower compared to the corresponding periods of 2015. The decline in per unit operating and transportation expenses attributed to lower variable operating costs due to lower natural gas production at Kokopelli in Colorado.

FINANCING EXPENSES

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except per BOE)	2016	2015	% change	2016	2015	% change
	$	$		$	$	
Interest on bank credit facility	-	9	-100%	1	75	-99%
Interest on short-term loan from related parties	26	89	-71%	116	282	-59%
Interest on financial contract liability	-	138	-100%	296	525	-44%
Accretion of long-term loans from related parties	252	143	76%	1,117	143	681%
Other financing expenses	15	14	7%	49	92	-47%
	293	393	-25%	1,579	1,117	41%
Average debt outstanding	7,550	7,873	-4%	7,550	6,575	15%
Average interest rate on debt	8.2%	5.0%	65%	8.2%	6.9%	20%
Interest expense per BOE (1)	5.19	1.09	376%	1.75	1.47	19%

(1) Interest expense used in the calculation of ``Interest expense per BOE`` includes interest on bank credit facility and loans from related parties.

Interest expense on short-term loan from related parties for the three and twelve months ended December 31, 2016 was approximately 71% and 59% lower than the corresponding periods of 2015, due to lower average balances on the related party loan.

Accretion expense is the Financing Expense realized in the current period or year on the related party loan, which was issued with warrants. In accordance with IFRS, the related party debt is measured using a deemed fair value of a similar loan with no warrants attached. The loan is accreted using the “implicit” interest rate (as distinct from the related debt instrument’s coupon rate) on the related party loan.

Accretion expense for the three and twelve months ended December 31, 2016 was approximately 76% and 681% higher than the corresponding periods of 2015. This was because the warrants were originally issued in Q4 2015 thus burdening 2015 with three months of accretion expense while 2016 has a full year of accretion expense.

GENERAL AND ADMINISTRATIVE ("G&A") EXPENSES

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except per BOE)	2016	2015	% change	2016	2015	% change
	$	$		$	$	
Salary and benefits	104	104	0%	433	461	-6%
Other G&A expenses	206	591	-65%	1,281	2,056	-38%
Gross G&A expenses	310	695	-55%	1,714	2,517	-32%
Capitalized G&A expenses	-	(58)	-100%	(111)	(195)	-43%
Overhead recoveries	(9)	(21)	-57%	(32)	(76)	-58%
Total net G&A expenses	301	616	-51%	1,571	2,246	-30%
$ per BOE	10.01	6.85	46%	8.82	9.28	-5%

Other G&A expenses decreased by 65% and 38% for the three and twelve months ended December 31, 2016, relative to the corresponding periods of 2015. The decrease was due to the implementation of the Company's overall cost savings plan. This also contributed to the lower gross G&A expenses for both periods. Per BOE, G&A expenses increased by 46% to $10.01/BOE for Q4 2016 due to a 80% decline in quarterly oil production.

STOCK BASED COMPENSATION

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except per BOE)	2016	2015	% change	2016	2015	% change
	$	$		$	$	
Stock based compensation expense	4	24	-83%	188	771	-76%
$ per BOE	0.13	0.27	-50%	1.06	3.18	-67%

The variance in share based compensation ("SBC") expenses is mainly driven by the timing and valuation of new stock option grants. Due to a higher number of stock options vested in 2015, it resulted in higher SBC expenses for the three and twelve months ended December 31, 2015.

AMORTIZATION, DEPLETION AND IMPAIRMENT LOSSES

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except per BOE)	2016	2015	% change	2016	2015	% change
	$	$		$	$	
Amortization and depletion	309	740	-58%	1,633	2,655	-38%
Impairment losses	1,472	504	192%	2,860	1,534	86%
Total amortization, depletion and impairment losses	1,781	1,244	43%	4,493	4,189	7%
$ per BOE	59.25	13.84	328%	25.22	17.30	46%

The decrease in amortization and depletion for the three and twelve months ended December 31, 2016 was primarily due to lower depletion recorded for producing oil and gas wells at Drake/Woodrush as a result of lower production. This was offset by higher depletion for producing gas wells at Kokopelli due to higher production after the eight new wells commenced production in September 2015.

During the year ended December 31, 2016, the Company recorded an impairment of $940,000 on its oil and gas properties in British Columbia, Canada and $130,000 on one of the non-core natural gas properties in Alberta, Canada. The impairments were recognized based on the difference between the carrying value of the assets and their recoverable amounts. Additionally, the Company recorded an impairment loss of $1.8 million at its exploration and evaluation assets in the U.S. because the leases of certain assets were expired ($1.4 million) and the carrying value of some assets exceeded their recoverable amount ($390,000). During the year ended December 31, 2015, the Company recorded an impairment of $1.0 million on its oil and gas properties in British Columbia, Canada. The impairment was recognized based on the difference between the carrying value of the assets and its recoverable amounts. Additionally, an impairment loss of $534,000 was recognized due to some expired leases in the U.S.

LOSS FOR THE PERIOD

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except per share amounts and BOE)	2016	2015	% change	2016	2015	% change
	$	$		$	$	
Income (loss)	(2,366)	(3,827)	-38%	(5,486)	(7,108)	-23%
$ per common share, basic	(0.05)	(0.10)	-50%	(0.13)	(0.19)	-33%
$ per common share, fully diluted	(0.05)	(0.10)	-50%	(0.13)	(0.19)	-33%
$ per BOE	(78.71)	(42.57)	85%	(30.79)	(29.36)	5%

The 38% decrease in the loss for the current quarter was primarily due to lower operating and transportation expenses and G&A expenses and the recognition of $3.0 million loss on valuation of financial contract liability in Q4 2015. This was offset by lower net revenues for the quarter and the recognition of $2.0 million gain on valuation of derivative liability in Q4 2015.

The 23% decrease in the loss for the year ended December 31, 2016 was primarily due to lower operating and transportation expenses and G&A expenses and the recognition of $3.0 million loss on valuation of financial contract liability in Q4 2015. This was offset by lower net revenues.

CASH FLOWS FROM OPERATIONS

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except per share amounts and BOE)	2016	2015	% change	2016	2015	% change
	$	$		$	$	
Cash flow from (used in) operations	(207)	164	-226%	(1,017)	860	-218%
$ per common share, basic	(0.00)	0.00	0%	(0.02)	0.02	-203%
$ per common share, fully diluted	(0.00)	0.00	0%	(0.02)	0.02	-203%
$ per BOE	(6.89)	1.82	-477%	(5.71)	3.55	-261%

Cash flows from operations for the three and twelve months ended December 31, 2016 were reduced from the corresponding periods in 2015 as a result of lower revenues from price and production declines combined with higher financing expenses.

Cash flows from operations is impacted by production, prices received, royalties paid, operating and transportation expenses and general and administrative expenses.

CAPITAL EXPENDITURES

DXI Energy is committed to future growth through its strategy to implement a full-cycle exploration and development program, augmented by strategic acquisitions with exploitation upside.

Additions to property and equipment and exploration and evaluation assets:

	Year ended December 31, 2016		Year ended December 31, 2015		
(CA$ thousands)	$	% of total	$	% of total	% change
Land acquisition and retention	40	7.5%	76	1.3%	-47%
Drilling and completion	331	62.5%	3,825	66.7%	-91%
Facility and pipelines	-	0.0%	1,545	26.9%	-100%
Capitalized general and administrative	159	30.0%	292	5.1%	-46%
Total	530	100.0%	5,738	100.0%	-91%

LIQUIDITY AND CAPITAL RESOURCES

DXI Energy manages its capital structure to support current and future business plans and periodically adjusts the structure in response to changes in economic conditions and the risk characteristics of its underlying assets and operations. DXI Energy may adjust its capital structure by issuing shares, altering debt levels, modifying capital programs, acquiring or disposing of assets or participating in joint ventures.

	December 31, 2016	December 31, 2015	
(CA$ thousands)	$	$	% change
Adjusted working capital deficit(1)	5,361	4,867	10%
Bank credit facility	-	147	-100%
Loans from related parties	7,550	7,500	1%
Financial contract liability	3,198	3,055	5%
Net debt (2)	16,109	15,569	
Share capital	98,111	97,162	1%
Contributed surplus and accumulated other comprehensive income	14,071	14,556	-3%
Deficit	(110,636)	(105,150)	5%
Total Capital	17,655	22,137	

(1) Accounts payable and accrued liabilities and cash portion of financial contract liability less cash and cash equivalents, accounts receivable, and prepaids and deposits

(2) Excludes derivative liability and decommissioning liability

Adjusted Working Capital

As at December 31, 2016 *(CA$ thousands)*	$
Working capital deficit	(11,075)
Non-cash derivative liability	153
Adjusted working capital deficit	(10,922)
Add: current portion of loans from related parties	2,363
Add: non-cash portion of financial contract liability	3,198
Adjusted working capital deficit (excluding loans from related parties and financial contract liability)	(5,361)

The adjusted working capital deficit at December 31, 2016 includes $141,000 of cash and cash equivalents, $672,000 of accounts receivable, $19,000 of prepaids and deposits, $2.2 million of accounts payable and accrued liabilities, and $4.0 million of financial contract liability.

DXI Energy expects to fund operations and capital expenditures with cash flows from operations, existing cash and cash equivalents and by accessing the capital markets, as required.

Going Concern, Financial Contract Liability and Loans from Related Parties

The financial statements were prepared on a going concern basis. The going concern basis assumes that the Company will continue in operation for the foreseeable future and will be able to realize its assets and discharge its liabilities and commitments in the normal course of business.

The Company has a working capital deficiency of $11.1 million, which includes the loans from related parties of $2.4 million, and accumulated deficit of $110.6 million. Of this amount, $7.2 million is represented by a financial contract liability of Dejour USA, which was due on September 30, 2016. The maximum cash component due in full settlement of the financial contract liability is US$3.0 million. The details of the settlement progress are described in the section “Financial Contract Liability” below.

On March 12, 2015, as amended on May 6, 2015, June 22, 2015, September 28, 2015 and November 18, 2015, the Company issued a promissory note for $4.5 million to Hodgkinson Equities Corp. (“HEC”), a private company controlled by the CEO of the Company. The promissory note is secured by all assets of Dejour USA and a negative pledge by the Company not to further encumber its Canadian oil and gas properties without HEC’s prior approval. It bears interest at the Canadian prime rate plus 5% per annum. The principal and interest was repayable by the earlier of (i) within 10 business days of receipt of written demand from HEC for the repayment and (ii) June 10, 2015 or such later date to which the term of the promissory note may be extended. On May 6, 2015, the due date of the loan was extended to September 30, 2015. On September 28, 2015, the due date of the loan was further extended to December 31, 2015. On November 18, 2015, the Company extended the due date of the loan from December 31, 2015 to November 30, 2018. Additionally, a monthly principal repayment of $114,230.77 is due on the 1st day of each month commencing June 1, 2016. HEC agreed to waive the requirement of the Company to repay the total monthly principal repayments of $1,142,000 for a period of 10 months. In consideration for the extension, the Company issued HEC 9,000,000 Warrants. Each Warrant entitles the holder to acquire one common share at a price of C$0.45/US$0.35 per share any time prior to December 4, 2020. Shares acquired through the exercise of Warrants prior to April 5, 2016 are restricted from sale through the facilities of the stock exchanges. On February 19, 2016, the Company rescinded the negative pledge security agreement and issued a first mortgage in favour of HEC on its Canadian oil and gas properties. The first mortgage security so issued ranks "pari passu" with HVI's first mortgage security interest. Upon an event of default, all the indebtedness under the promissory note become due and payable and the interest rate is immediately increased to the Canadian prime rate plus 8.5% per annum.

On June 22, 2015, as amended on September 28, 2015 and November 18, 2015, the Company issued a promissory note for $2.0 million to Hodgkinson Ventures Inc. ("HVI"), a private company associated with the CEO of the Company, on a "pari passu" basis with the loan from HEC. The promissory note is secured by all assets of Dejour USA and a negative pledge by the Company not to further encumber its Canadian oil and gas properties without HVI's prior approval. It bears interest at the Canadian prime rate plus 5% per annum. The principal and interest was repayable on or before September 30, 2015. On September 28, 2015, the due date of the loan was extended to December 31, 2015. On November 18, 2015, the Company extended the due date of the loan from December 31, 2015 to November 30, 2018. Additionally, a monthly principal repayment of $50,769.23 is due on the 1st day of each month commencing June 1, 2016. HVI agreed to waive the requirement of the Company to repay the total monthly principal repayments of $508,000 for a period of 10 months. In consideration for the extension, the Company issued HVI 4,000,000 Warrants. Each Warrant entitles the holder to acquire one common share at a price of C$0.45/US$0.35 per share any time prior to December 4, 2020. Shares acquired through the exercise of Warrants prior to April 5, 2016 are restricted from sale through the facilities of the stock exchanges. On February 19, 2016, the Company rescinded the negative pledge security agreement and issued a first mortgage in favour of HVI on its Canadian oil and gas properties. The first mortgage security so issued ranks "pari passu" with HEC's first mortgage security interest. Upon an event of default, all the indebtedness under the promissory note become due and payable and the interest rate is immediately increased to the Canadian prime rate plus 8.5% per annum.

On September 15, 2015, as amended on January 11, 2016, March 31, 2016 and June 2, 2016, the Company issued a grid promissory note of up to $1.0 million to a director and officer of the Company and his spouse. The promissory note bears interest at 12% per annum. The principal and interest accrued on the loan were repayable on or before December 31, 2015. On January 11, 2016, the Company issued an additional grid promissory note of up to $200,000 to a director and officer of the Company and his spouse and the due date of the loan was extended to March 31, 2016. On March 31, 2016, the due date of the loan was further extended to September 30, 2016. On June 2, 2016, the Company increased the maximum amount of the non-revolving loan from $1.2 million to $1.5 million. The interest rate was also reduced from 12% to 10% per annum. Additionally, the Company issued a 2nd mortgage in favour of the Lenders on DEAL's oil and gas properties to a maximum of $1.5 million as partial security for the loan. On September 30, 2016, the due date of the loan was extended to December 31, 2016. On December 31, 2016, the due date of the loan was further extended to June 30, 2017. The maximum loan amount available at December 31, 2016 was $1.5 million (December 31, 2015 - $1.0 million). During the year ended December 31, 2016, $350,000 was borrowed (2015 - $1.0 million) and $300,000 was repaid (2015 - $Nil) leaving a balance outstanding of $1.1 million at December 31, 2016.

The Company's ability to continue as a going concern is dependent upon attaining profitable operations and the continued financial support of the non-arm's length lenders who have provided the Company with sufficient capital in 2015 to meet capital expenditure commitments and continue exploration and development activities. There is no assurance that these activities will be successful. These material uncertainties cast substantial doubt upon the Company's ability to continue as a going concern. These consolidated financial statements do not reflect the adjustments to the carrying values of assets and liabilities, the reported revenues and expenses, and the balance sheet classifications used that would be necessary if the going concern assumptions were not appropriate.

Financial Contract Liability

On December 31, 2012, Dejour USA entered into a financial contract with a U.S. oil and gas drilling fund ("Drilling Fund") to fund the drilling of up to three wells and the completion of up to four wells in the State of Colorado. The Drilling Fund contributed US$6.5 million cash to earn working interests in production from the wellbores ranging from 55.56% to 77.78% before payout and 44.44% to 58.33% after payout. This amount was subsequently increased by US$500,000 to US$7.0 million with the Company's consent.

The December 31, 2012 financial contract states the Drilling Fund has the right to require Dejour USA to purchase its working interests in the wellbores for cash in September 2016, 36-months after the final well in the 4-well program is placed on production. The repurchase price is based on a predetermined formula which ensures the Drilling Fund earns a minimum return, compounded annually and applied on a monthly basis, on 75% of its original US$7.0 million investment over the 36-month period. Accordingly, the Company considered the transaction to be a financial contract as the risks and rewards of ownership were not substantially transferred to the Drilling Fund and, on December 31, 2012, the Company recorded the transaction in its accounts by increasing property and equipment and financial contract liability by US$6.5 million on its balance sheet. This amount was subsequently increased to US$7.0 million.

On June 30, 2014, the financial contract was amended and the Drilling Fund agreed to retain its working interest in the wells as at September 30, 2016, should it exercise its right to require Dejour USA to pay the minimum return calculated in accordance with the provisions of the contract. In determining the minimum return to be paid, the Drilling Fund agreed to deduct the residual reserve value of its working interest in the 4 wellbores at September 30, 2016. The parties also agreed to have a third party engineering firm calculate the residual value of the reserves in accordance with industry-accepted valuation standards.

Finally, the parties agreed to limit the cash consideration to be paid by Dejour USA, should it be required to pay the minimum return provided for in the December 31, 2012 contract to US$3.0 million. Additional consideration, if any, may be paid by Dejour USA by an assignment of a working interest in certain proven assets at a jointly owned oil and gas property in Colorado applying an industry-standard valuation approach.

The June 30, 2014 amendment transferred the risks of ownership of the 4 wellbores back to the Drilling Fund and the financial contract liability was adjusted to reflect the present value of the amount owing to the Drilling Fund under the financial contract at December 31, 2016 ($7.8 million), net of the present value of the residual reserves ($617,000), or $7.2 million, as follows:

	$
Balance at January 1, 2015 (US$2,361)	2,739
Accretion expense (US$410)	525
Foreign exchange loss	595
Adjustment to financial contract liability (US$2,436)	3,348
Balance at December 31, 2015 (US$5,207)	7,207
Accretion expense (US$222)	296
Foreign exchange gain	(214)
Adjustment to financial contract liability (US$47)	(63)
Balance at December 31, 2016 (US$5,382)	7,226

On September 30, 2016, the Drilling Fund served notice to Dejour USA requiring Dejour USA to purchase the Drilling Fund's 77.71% working interest in the 4 wellbores in accordance with the provisions of the "put" option contract described above. However, prior to serving such notice, the Drilling Fund executed certain assignments transferring ownership of its working interests in the 4 wellbores to another entity and the assignee mortgaged its interest therein. The Company is assessing as to whether such assignment and subsequent mortgaging of working interests by the entity disentitled the Drilling Fund from exercising the "put" option which underlies the entire financial contract, and the related liability as set out in these consolidated financial statements, and whether, as a result thereof, the "put" contract option exercise was null and void as at September 30, 2016.

Capital Resources

The Company and its partners intend to continue to develop the Kokopelli project when natural gas and natural gas liquids prices paid to producers return to acceptable levels.

CONTRACTUAL OBLIGATIONS

As of December 31, 2016, the Company has obligations to make future payments, representing contracts and other commitments that are known and committed.

(CA$ thousands)	2017	2018	2019	2020	2021	Thereafter	Total
	$	$	$	$	$	$	$
Operating lease obligations	101	13	-	-	-	Nil	114
Debt repayments(1)	3,030	4,520	-	-	-	Nil	7,550
Interest payments(2)	53	-	-	-	-	-	53
Financial contract liability(3)	7,226	-	-	-	-	Nil	7,226
Total	10,410	4,533	-	-	-	Nil	14,943

(1) Short-term and long-term loans from related parties

(2) Fixed interest payments on loan from related parties of $1,050,000

(3) This represents the Company's obligations over the 36-month put option period until it expires. See Note 12 to the consolidated financial statements for details.

RELATED PARTY TRANSACTIONS

During the year ended December 31, 2016 and 2015, the Company entered into the following transactions with related parties:

(a) Compensation awarded to key management included a total of salaries and consulting fees of $470,000 (2015 - $473,000) and non-cash stock-based compensation of $80,000 (2015 - $464,000). Key management includes the Company's officers and directors. The salaries and consulting fees are included in general and administrative expenses. Included in accounts payable and accrued liabilities at December 31, 2016 is $262,000 (December 31, 2015 - $200,000) owing to the two officers of the Company.

(b) Interest expenses of $595,000 (2015 - $343,000) related to the loans from related parties were paid to the CEO of the Company and his spouse or the companies controlled by or associated with the CEO of the Company.

(c) In 2015, the Company entered into loan agreements with a director and officer of the Company and his spouse and the private companies associated with the director and officer of the Company. The terms and conditions of these agreements are described in the section "Going Concern, Financial Contract Liability and Loans from Related Parties" above.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has no material undisclosed off-balance sheet arrangements that have or are reasonably likely to have, a current or future effect on our results of operations or financial condition at December 31, 2016.

SELECTED ANNUAL INFORMATION

The following table summarizes key financial and operating information over the three most recently completed financial year.

(in thousands of dollars, except per unit amounts)	2016	2015	2014
Gross oil and gas revenues	4,808	8,579	9,049
Net income (loss)			
Per share - basic ($/common share)	(0.13)	(0.19)	(0.20)
Per share - diluted ($/common share)	(0.13)	(0.19)	(0.20)
Total assets	21,260	27,686	23,274
Production (BOE/d)	487	663	449
Average realized price ($/BOE)	27.02	35.52	55.14
Operating netback ($/BOE)	6.16	13.43	21.11
Netback as a percentage of sales	23%	38%	38%

SUMMARY OF QUARTERLY RESULTS

The following table summarizes key financial and operating information by quarter for the past eight quarters ending December 31, 2016:

(CA$ thousands, except per unit amounts)	2016 Q4	2016 Q3	2016 Q2	2016 Q1	2015 Q4	2015 Q3	2015 Q2	2015 Q1
Gross oil and gas revenues	954	1,009	1,182	1,663	2,768	2,189	2,152	1,470
Net income (loss)	(2,366)	(957)	(564)	(1,599)	(3,827)	(1,608)	(503)	(1,169)
Per share - basic ($/common share)	(0.05)	(0.02)	(0.02)	(0.04)	(0.10)	(0.04)	0.00	(0.03)
Per share - fully diluted ($/common share)	(0.05)	(0.02)	(0.02)	(0.04)	(0.10)	(0.04)	0.00	(0.03)
Total assets	21,260	22,770	24,584	25,066	27,686	26,741	27,505	24,264
Average production (BOE/d)	327	385	498	740	977	643	514	514
Average realized price ($/BOE)	31.90	28.38	26.16	24.70	31.03	37.01	46.02	31.74
Operating netback ($/BOE)	7.60	7.86	8.35	3.15	10.37	17.46	22.70	4.83
Netback as a percentage of sales	24%	28%	32%	13%	33%	47%	49%	15%

The fluctuations in DXI Energy's revenue and income (loss) from quarter to quarter are primarily caused by variations in production volumes, realized oil and natural gas prices and the related impact on royalties and operating and transportation expenses. Please refer to the Results of Operations section of this MD&A for detailed discussion of changes from the 4th quarter of 2016 to the 4th quarter of 2015, and to the Company's previously issued interim and annual MD&A for changes in prior quarters.

BUSINESS RISKS

DXI Energy's exploration and production activities are concentrated in the Northeastern B.C. portion of the competitive Western Canadian Sedimentary Basin and the Piceance Basin of Central United States, where activity is highly competitive and includes a variety of different sized companies ranging from smaller junior producers and intermediate and senior producers to the much larger integrated petroleum companies. DXI Energy is subject to a number of risks which are also common to other organizations involved in the oil and gas industry. Such risks include finding and developing oil and gas reserves at economic costs, estimating amounts of recoverable reserves, production of oil and gas in commercial quantities, marketability of oil and gas produced, fluctuations in commodity prices, financial and liquidity risks and environmental and safety risks.

In order to reduce exploration risk, DXI Energy employs highly qualified and motivated professional employees who have demonstrated the ability to generate quality proprietary geological and geophysical prospects. To maximize drilling success, DXI Energy explores in areas that afford multi-zone prospect potential, targeting a range of shallower low to moderate risk prospects with some exposure to select deeper high-risk prospects with high-reward opportunities.

DXI Energy has retained an independent engineering consulting firm that assists the Company in evaluating recoverable amounts of oil and gas reserves. Values of recoverable reserves are based on a number of variable factors and assumptions such as commodity prices, projected production, future production costs and government regulation. Such estimates may vary from actual results.

The Company mitigates its risk related to producing hydrocarbons through the utilization of the most advanced technology and information systems. In addition, DXI Energy strives to operate the majority of its prospects, thereby maintaining operational control. The Company does rely on its partners in jointly owned properties that DXI Energy does not operate.

DXI Energy is exposed to market risk to the extent that the demand for oil and gas produced by the Company exists within Canada and the United States. External factors beyond the Company's control may affect the marketability of oil and gas produced. These factors include commodity prices and variations in the Canada-United States currency exchange rate, which in turn respond to economic and political circumstances throughout the world. Oil prices are affected by worldwide supply and demand fundamentals while natural gas prices are affected by North American supply and demand fundamentals. DXI Energy may periodically use futures and options contracts to hedge its exposure against the potential adverse impact of commodity price volatility.

Exploration and production for oil and gas is very capital intensive. As a result, the Company relies on equity markets as a source of new capital. In addition, DXI Energy utilizes bank financing to support on-going capital investment. Funds from operations also provide DXI Energy with capital required to grow its business. Equity and debt capital is subject to market conditions and availability may increase or decrease from time to time. Funds from operations also fluctuate with changing commodity prices.

SAFETY AND ENVIRONMENT

Oil and gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. The Company conducts its operations with high standards in order to protect the environment and the general public. DXI Energy maintains current insurance coverage for comprehensive and general liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect current corporate requirements, as well as industry standards and government regulations.