(formerly operating as Dejour Energy Inc.)

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the Year Ended December 31, 2015

Date of Report: March 9, 2016

INTRODUCTION

The Company was incorporated under the law 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**"), on the New York Stock Exchange ("**NYSE**") under the symbol "DXI".

The following management's discussion and analysis ("MD&A") is dated March 9, 2016 and should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the years ended December 31, 2015 and 2014.

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 2016 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 2016. 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 operating activities to cash flows from operations, a non-IFRS measure:

	Three months ended December 31		Year ended December 31	
(CA$ thousands)	2015	2014	2015	2014
	$	$	$	$
Cash flows from (used in) operating activities	371	(126)	1,064	(581)
Change in operating working capital	(207)	(578)	(204)	481
Cash flows from (used in) operations	164	(704)	860	(100)

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 judgement 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 judgement 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, 2015, 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 judgement 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, 2015, the Company has two CGUs in Canada (Drake/Woodrush and Saddle Hills) 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 osts.

FINANCIAL REPORTING UPDATE

Future Accounting Policies Changes

Certain pronouncements were issued by the International Accounting Standards Board ("IASB") or the International Financial Reporting Interpretations Committee ("IFRIC") that are mandatory for accounting periods beginning after January 1, 2016 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.

IFRS 15, "Revenue from Contract with Customers". In May 2014, the IASB issued the standard to replace IAS 18 "Revenues", IAS 11 "Construction Contracts", and related interpretations. The standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2018, with earlier adoption permitted.

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.

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, 2015 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, 2015, 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 ("COSO Framework") published by The Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Under the supervision of the CEO and the CFO, the Company conducted an evaluation of the effectiveness of the Company's ICFR as at December 31, 2015 based on the COSO Framework. Based on this evaluation, the officers concluded that as of December 31, 2015, the Company maintained effective ICFR. It should be noted that while the Company's officers believe that the Company's controls provide a reasonable level of assurance with regard to their effectiveness, they do not expect that the ICFR will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control system are met.

There were no changes in the Company's ICFR during the year ended December 31, 2015 that materially affected, or are reasonably likely to materially affect, the Company's ICFR.

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.

SHARE CONSOLIDATION

On June 29, 2015, the Company's shareholders approved the consolidation of its issued and outstanding common shares on the basis of one (1) post-consolidation common share for every five (5) pre-consolidation common shares. The Company's common shares began trading on a post-consolidation basis on the NYSE and TSX on October 30, 2015. All share and per share information in this document gives effect to the share consolidation on a retroactive basis, unless otherwise indicated.

RESULTS OF OPERATIONS

FINANCIAL AND OPERATING HIGHLIGHTS

During the year ended December 31, 2015, the Company:

1. Successfully completed and tied into production two new wells at the Company's Woodrush property, north of Fort St. John, British Columbia;

2. Completed the drilling, casing and completion of eight natural gas wells in the Company's Kokopelli development project in Colorado. Production from the eight natural gas wells commenced in the 4th quarter of 2015. The Company has a 25% working interest in this project.

3. Secured $6.5 million in bridge financing from a company controlled by a Director and Officer ($4.5 million) and from a company associated with the Director and Officer ($2.0 million). Extended the maturity date of $6.5 million bridge financing from December 31, 2015 to November 30, 2018;

4. Increased oil and natural gas production by 48% to 663 BOE/d from 449 BOE/d for the comparative year ended December 31, 2014;

5. Reduced operating and transportation expenses for oil operations from $27.65/bbl for the year ended December 31, 2014 to $13.39/bbl for the year ended December 31, 2015; and

6. Reduced G&A expenses per BOE by 56% to $9.28 per BOE from $21.31 per BOE for the comparative year ended December 31, 2014.

REVENUE

Fourth Quarter 2015 vs. Fourth Quarter 2014	Three Months Ended December 31		
(CA$ thousands, except as otherwise noted)	2015	2014	% change
Production Volumes:			
Oil and natural gas liquids (bbls/d)	515	162	218%
Natural gas (mcf/d)	2,773	891	211%
Total (BOE/d)	977	310	215%
Average realized prices:			
Oil and natural gas liquids ($/bbl)	46.72	72.29	-35%
Natural gas ($/mcf)	2.26	3.87	-42%
Total ($/BOE)	31.03	48.78	-36%
Revenue, before royalties:			
Oil and natural gas liquids	2,206	1,079	104%
Natural gas	562	331	70%
Total	2,768	1,410	96%

For the three months ended December 31, 2015 ("Q4 2015"), total revenue, before royalties, increased by $1,358,000 or, 96%, due to an increase in oil and natural gas production for the quarter. This was offset by a decline in combined average realized prices.

The increase in oil production for Q4 2015 is related to the commencement of production from the new oil well at Woodrush in January 2015, combined with added production from enhancements to the waterflood operation.

The increase in natural gas production for Q4 2015 is related to the commencement of production from the new gas well at Woodrush in January 2015 and the eight new wells at Kokopelli in September 2015.

Year-to-date 2015 vs. Year-to-date 2014	Year ended December 31		
(CA$ thousands, except as otherwise noted)	2015	2014	% change
Production Volumes:			
Oil and natural gas liquids (bbls/d)	369	182	103%
Natural gas (mcf/d)	1,764	1,602	10%
Total (BOE/d)	663	449	48%
Average realized prices:			
Oil and natural gas liquids ($/bbl)	52.68	87.99	-40%
Natural gas ($/mcf)	2.33	5.45	-57%
Total ($/BOE)	35.52	55.14	-36%
Revenue, before royalties:			
Oil and natural gas liquids	7,093	5,854	21%
Natural gas	1,486	3,195	-53%
Total	8,579	9,049	-5%

For the year ended December 31, 2015, total revenue, before royalties, decreased by $470,000 or, 5%, due to a decline in combined average realized prices. This was offset by 48% increase in oil and natural gas production for the year on a BOE basis.

The increase in oil production for the year ended December 31, 2015 is related to the commencement of production from the new oil well at Woodrush in January 2015, combined with added production from enhancements to the waterflood operation.

The increase in natural gas production for the year ended December 31, 2015 is related to the commencement of production from the new gas well at Woodrush in January 2015 and the eight new wells at Kokopelli in September 2015. This was offset by the disposition of 65% of the Company's working interest in its core natural gas property in the eastern portion of Piceance Basin of Colorado on June 30, 2014 and the "turnaround" of the McMahon gas plant near Ft. St. John, British Columbia in June 2015 for approximately 40 days.

OIL OPERATIONS

	Three months ended December 31			Year ended December 31		
($/bbl)	2015	2014	% change	2015	2014	% change
	$	$		$	$	
Oil and NGL's revenue, realized price	46.72	72.28	-35%	52.68	87.99	-40%
Royalties	(9.31)	(11.34)	-18%	(10.25)	(14.77)	-31%
Operating and transportation expenses	(10.62)	(32.01)	-67%	(13.39)	(27.65)	-52%
Operating netback	26.79	28.93	-7%	29.04	45.57	-36%

The average price received for oil sales decreased by 35% and 40% for the three and twelve months ended December 31, 2015, relative to the corresponding periods of the prior year. The decrease in DXI Energy's average realized oil price reflected lower benchmark prices in Canada and the rest of the world.

Average oil royalties for the three and twelve months ended December 31, 2015 were lower, relative to the corresponding periods of 2014, due to lower average oil prices received in both periods.

Operating and transportation expenses for the three and twelve months ended December 31, 2015 were lower compared to the corresponding periods of 2014. The decline in per unit operating and transportation expenses resulted from the allocation of fixed operating costs over a higher oil production volume.

NATURAL GAS OPERATIONS

	Three months ended December 31			Year ended December 31		
($/mcf)	2015	2014	% change	2015	2014	% change
	$	$		$	$	
Gas revenue, realized price	2.26	3.87	-42%	2.33	5.45	-57%
Royalties	(0.31)	(0.29)	7%	(0.16)	(0.86)	-81%
Operating and transportation expenses	(3.27)	(4.37)	-25%	(3.19)	(3.86)	-17%
Operating netback	(1.32)	(0.79)	67%	(1.02)	0.73	-239%
Barrel of oil equivalent netback ($/BOE)	(7.91)	(4.76)	66%	(6.09)	4.39	-239%

The average price received for gas sales decreased by 42% and 57% for the three and twelve months ended December 31, 2015, relative to the corresponding periods of the prior year. The decrease in DXI Energy's average realized gas prices reflected lower benchmark prices in northeastern British Columbia and northwestern Alberta, Canada, due, in part, to National Energy Board ("NEB") imposed repairs to four key TransCanada Pipeline Ltd. ("TCPL") pipelines in the region. On December 19, 2014, the NEB ordered TCPL to repair the pipelines resulting in a 400 Mmcf/d reduction in pipeline capacity for producers in the region, including the Company. This situation prevailed through December 31, 2015. The temporary closures have resulted in a temporary excess of gas supply in the immediate region with resultant lower prices paid to producers.

Average gas royalties for the year ended December 31, 2015 were significantly lower compared to the prior year. This was due to lower average gas prices received in the year ended December 31, 2015.

Average operating and transportation expenses paid for the three and twelve months ended December 31, 2015 were lower compared to the corresponding periods of the prior year. The decrease in per unit operating and transportation expenses resulted from lower water disposal costs at Kokopelli in Colorado in 2015 compared with 2014. This decrease was partially offset by the increased costs associated with the reactivation of one of the gas wells at Drake/Woodrush in February 2015 and higher contractual pipeline transportation costs associated with a new contract signed on November 1, 2014.

FINANCING EXPENSES

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except per BOE)	2015	2014	% change	2015	2014	% change
	$	$		$	$	
Interest on bank credit facility	9	31	-71%	75	138	-46%
Interest on loans from related parties	89	-	100%	282	-	100%
Interest on financial contract liability	138	108	28%	525	428	23%
Accretion of loans from related parties	143	-	100%	143	-	100%
Accretion of loan facility	-	-	0%	-	521	-100%
Other financing expenses	14	16	-13%	92	81	14%
	393	155	154%	1,117	1,168	-4%
Average debt outstanding	7,873	2,027	288%	6,575	2,496	163%
Average interest rate on debt	5.0%	6.1%	-19%	6.9%	5.5%	24%
Interest expense per BOE (1)	1.09	1.09	0%	1.47	0.84	75%

(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 related to the Company's bank credit facility for the three and twelve months ended December 31, 2015 was lower compared to the corresponding periods of the prior year. The decrease was due to lower average bank debt outstanding.

GENERAL AND ADMINISTRATIVE ("G&A") EXPENSES

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except per BOE)	2015	2014	% change	2015	2014	% change
	$	$		$	$	
Salary and benefits	104	318	-67%	461	1,034	-55%
Other G&A expenses	591	894	-34%	2,056	2,954	-30%
Gross G&A expenses	695	1,212	-43%	2,517	3,988	-37%
Capitalized G&A expenses	(58)	(67)	-13%	(195)	(393)	-50%
Overhead recoveries	(21)	(27)	-22%	(76)	(102)	-25%
Total net G&A expenses	616	1,118	-45%	2,246	3,493	-36%
$ per BOE	6.85	39.19	-83%	9.28	21.31	-56%

Salary and benefits decreased by 67% and 55% for the three and twelve months ended December 31, 2015, relative to the corresponding periods of the prior year. The decrease was due to a termination of all salaried employees at the Company's office in Denver, Colorado as part of the June 30, 2014 sale of a controlling working interest in the Kokopelli project to the Company's Kokopelli partner and new "Operator" of the project. This also contributed to the lower gross G&A expenses for the three and twelve months ended December 31, 2015.

STOCK BASED COMPENSATION

(CA$ thousands, except per BOE)	Three months ended December 31 2015	2014	% change	Year ended December 31 2015	2014	% change
	$	$		$	$	
Stock based compensation expense	24	345	-93%	771	1,270	-39%
$ per BOE	0.27	12.09	-98%	3.18	7.75	-59%

The variance in share based compensation ("SBC") expenses is mainly driven by the timing and valuation of new stock option grants. Lower share prices in the year ended December 31, 2015 contributed to the decrease in SBC expenses for the three and twelve months ended December 31, 2015.

AMORTIZATION, DEPLETION AND IMPAIRMENT LOSSES

(CA$ thousands, except per BOE)	Three months ended December 31 2015	2014	% change	Year ended December 31 2015	2014	% change
	$	$		$	$	
Amortization and depletion	740	691	7%	2,655	2,867	-7%
Impairment losses	504	3,560	-86%	1,534	3,648	-58%
Total amortization, depletion and impairment losses	1,244	4,251	-71%	4,189	6,515	-36%
$ per BOE	13.84	149.01	-91%	17.30	39.75	-56%

During the year ended December 31, 2015, the Company recorded an impairment loss of $1.0 million at Woodrush oilfield because the carrying value exceeded its recoverable amount. The write-down reflects a decline in oil prices during 2015. Additionally, an impairment loss of $0.5 million was recognized due to some expired in the United States.

During the year ended December 31, 2014, the Company recorded an impairment loss of $3.6 million because the carrying value of the Woodrush oilfield at December 31, 2014 exceeded its recoverable amount.

LOSS FOR THE PERIOD

(CA$ thousands, except per share amounts and BOE)	Three months ended December 31 2015	2014	% change	Year ended December 31 2015	2014	% change
	$	$		$	$	
Income (loss)	(3,827)	(3,331)	15%	(7,108)	(7,203)	-1%
$ per common share, basic	(0.10)	(0.09)	15%	(0.19)	(0.20)	-4%
$ per common share, fully diluted	(0.10)	(0.09)	15%	(0.19)	(0.20)	-4%
$ per BOE	(42.57)	(116.76)	-64%	(29.36)	(43.94)	-33%

The 15% increase in the loss for the three months ended December 31, 2015 was primarily due to higher operating and transportation expenses and the recognition of $1.4 million loss on debt extinguishment. This was offset by higher net revenues and lower G&A expenses.

CASH FLOWS FROM OPERATIONS

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except per share amounts and BOE)	2015	2014	% change	2015	2014	% change
	$	$		$	$	
Cash flow from (used in) operations	164	(704)	123%	860	(100)	960%
$ per common share, basic	0.00	(0.02)	0%	0.02	(0.00)	0%
$ per common share, fully diluted	0.00	(0.02)	0%	0.02	(0.00)	0%
$ per BOE	1.82	(24.68)	107%	3.55	(0.61)	682%

Cash flows from operations for the current quarter increased substantially, compared to the same quarter of 2014 as a result of higher net revenues and lower G&A expenses for the quarter.

Cash flows from operations for the year ended December 31, 2015 increased, compared to the year ended December 31, 2014 as a result of higher production, lower operating and transportation expenses and lower G&A expenses for the year.

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.

During the year ended December 31, 2015, the Company successfully completed and tied into production the two new wells that were recently drilled at its Woodrush property, north of Fort St. John, British Columbia. Further, the Company successfully drilled, cased and completed eight natural gas wells in its Kokopelli development project in Colorado. Production from the eight natural gas wells was commenced in the 4th quarter of 2015. The Company has a 25% working interest in this project.

Additions to property and equipment and exploration and evaluation assets:

	Year ended December 31, 2015		Year ended December 31, 2014		
(CA$ thousands)	$	% of total	$	% of total	% change
Land acquisition and retention	76	1.3%	102	2.7%	-25%
Drilling and completion [(1)]	3,825	66.7%	554	14.4%	590%
Facility and pipelines	1,545	26.9%	2,755	71.9%	-44%
Capitalized general and administrative	291	5.1%	410	10.7%	-29%
Other assets	1	0.0%	13	0.3%	-92%
Total	5,738	100.0%	3,834	100.0%	50%

(1) excludes non-cash capital expenditures of $1,520,000 related to the acquisition of certain property and equipment in March 2014

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.

(CA$ thousands)	December 31, 2015 $	December 31, 2014 $	% change
Adjusted working capital deficit[1]	715	1,554	-54%
Bank credit facility	147	1,955	-92%
Loans from related parties	7,500	0	100%
Financial contract liability	7,207	2,739	163%
Net debt [2]	15,569	6,248	
Share capital	97,162	97,132	0%
Contributed surplus and accumulated other comprehensive income	14,556	11,295	29%
Deficit	(105,150)	(98,042)	7%
Total Capital	22,137	16,633	

(1) Accounts payable and accrued liabilities less cash and cash equivalents, accounts receivable, and prepaids and deposits

(2) Excludes warrant liability, derivative liability and decommissioning liability

Adjusted Working Capital

As at December 31, 2015 *(CA$ thousands)*	$
Working capital deficit	(10,295)
Non-cash derivative liability	1,226
Adjusted working capital deficit	(9,069)
Add: Bank credit facility	147
Add: Current portion of loans from related parties	1,000
Add: Financial contract liability	7,207
Adjusted working capital deficit (excluding bank credit facility, loans from related parties and financial contract liability)	(715)

The adjusted working capital deficit at December 31, 2015 includes $38,000 of cash and cash equivalents, $2,202,000 of accounts receivable, $31,000 of prepaids and deposits, and $2,985,000 of accounts payable and accrued liabilities. The 54% decrease in adjusted working capital deficit from December 31, 2014 to December 31, 2015 is primarily due to the repayment of bank credit facility during the year ended December 31, 2015.

DXI Energy expects to fund operations and capital expenditures with cash flows from operations, drawings on its bank credit facilities, drawings on its loans from related parties, 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 $10.3 million, which includes the loans from related parties of $1.0 million, and accumulated deficit of $105.2 million. Excluding the non-cash derivative liability of $1.2 million, the adjusted working capital deficiency was $9.1 million. Of this amount, $7.2 million is represented by a financial contract liability of Dejour USA, which is due on September 30, 2016. The maximum cash component due in full settlement of the financial contract liability is US$3.0 million.

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 up to $4,500,000 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. 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. 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. As at December 31, 2015, the maximum $4.5 million had been advanced to the Company. 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.

On June 22, 2015, as amended on September 28, 2015 and November 18, 2015, the Company issued a promissory note for up to $2,000,000 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. 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. 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. As at December 31, 2015, the maximum $2.0 million had been advanced to the Company. 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.

On September 15, 2015, as amended on January 11, 2016, the Company issued a grid promissory note of up to $1,000,000 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 are 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. As at December 31, 2015, $1,000,000 had been advanced to the Company.

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$7,000,000 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$7,000,000 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$6,500,000 on its balance sheet. This amount was subsequently increased to US$7,000,000.

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$3,000,000. 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 September 30, 2016 ($7,843,000), net of the present value of the residual reserves ($636,000), or $7,207,000, as follows:

	$
Balance at January 1, 2014 (US$5,755)	6,121
Loan advance during the year (US$181)	210
Accretion expense (US$388)	450
Foreign exchange loss	351
	7,132
Less:	
(a) Net operating income (US$846)	(982)
(b) Adjustment to financial contract liability (US$3,117)	(3,411)
Balance at December 31, 2014 (US$2,361)	2,739
Accretion expense (US$410)	525
Foreign exchange loss	595
	3,859
Add: Adjustment to financial contract liability (US$2,436)	3,348
Balance at December 31, 2015 (US$5,207)	7,207

The increase in the financial contract liability was due to (1) the significant decline in the value of residual reserves and (2) the upward movement of foreign exchange rate at the year-end.

Capital Resources

During the year ended December 31, 2015, the Company incurred $1.0 million to complete and tie into production the 2 infill wells that were drilled in December 2014, in Northeastern, British Columbia. In the U.S., the Company paid $4.5 million for the ongoing Kokopelli development program in Colorado and it is related to the drilling, casing and completion of eight natural gas wells. These wells were tied into production in the fourth quarter of 2015.

CONTRACTUAL OBLIGATIONS

As of December 31, 2015, the Company has obligations to make future payments, representing contracts and other commitments that are known and committed.

(CA$ thousands)	2016	2017	2018	2019	2020	Thereafter	Total
	$	$	$	$	$	$	$
Operating lease obligations	99	51	13	-	-	Nil	163
Bank credit facility	147	-	-	-	-	Nil	147
Loans from related parties	2,155	1,980	3,365	-	-	Nil	7,500
Financial contract liability[1]	7,207	-	-	-	-	Nil	7,207
Total	9,608	2,031	3,378	-	-	Nil	15,017

(1) This represents the Company's obligations over the 36-month put option period until it expires. See Note 13 to the consolidated financial statements for details.

RELATED PARTY TRANSACTIONS

During the years ended December 31, 2015 and 2014, 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 $473,000 (2014 - $1,092,000) and non-cash stock-based compensation expense of $464,000 (2014 - $823,000). 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, 2015 is $200,000 (December 31, 2014 - $200,000) owing to the two officers of the Company.

(b) Included in interest and other income is $Nil (2014 - $15,000) received from the companies controlled by officers of the Company for rental income.

(c) Interest expenses of $343,000 (2014 - $Nil) 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.

(d) 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, 2015.

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)	2015	2014	2013
Gross oil and gas revenues	8,579	9,049	9,317
Net income (loss)			
Per share - basic ($/common share)[1]	(0.19)	(0.20)	(0.09)
Per share - diluted ($/common share)[1]	(0.19)	(0.20)	(0.09)
Total assets	27,686	23,274	25,499
Production (BOE/d)	663	449	504
Average realized price ($/BOE)	35.52	55.14	50.79
Operating netback ($/BOE)	13.43	21.11	22.75
Netback as a percentage of sales	38%	38%	45%

(1) Net income (loss) per share amounts for the periods presented have been adjusted on a retroactive basis to reflect the October 30, 2015 one-for-five share consolidation.

SUMMARY OF QUARTERLY RESULTS

The following table summarizes key financial and operating information by quarter for the past eight quarters ending December 31, 2015:

(CA$ thousands, except per unit amounts)	2015 Q4	2015 Q3	2015 Q2	2015 Q1	2014 Q4	2014 Q3	2014 Q2	2014 Q1
Gross oil and gas revenues	2,768	2,189	2,152	1,470	1,410	2,257	2,597	2,785
Net income (loss)	(3,827)	(1,608)	(503)	(1,169)	(3,331)	(1,620)	730	(2,982)
Per share - basic ($/common share)[1]	(0.10)	(0.04)	0.00	(0.05)	(0.10)	(0.05)	0.00	(0.10)
Per share - fully diluted ($/common share)[1]	(0.10)	(0.04)	0.00	(0.05)	(0.10)	(0.05)	0.00	(0.10)
Total assets	27,686	26,741	27,505	24,264	23,274	25,349	22,661	28,485
Average production (BOE/d)	977	643	514	514	310	382	561	546
Average realized price ($/BOE)	31.03	37.01	46.02	31.74	48.78	64.30	50.91	56.65
Operating netback ($/BOE)	10.37	17.46	22.70	4.83	12.79	29.71	14.75	26.39
Netback as a percentage of sales	33%	47%	49%	15%	26%	46%	29%	47%

(1) Net income (loss) per share amounts for the periods presented have been adjusted on a retroactive basis to reflect the October 30, 2015 one-for-five share consolidation.

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 2015 to the 4th quarter of 2014, 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.