MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2016

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The following is management's discussion and analysis (MD&A) of BNK Petroleum Inc.'s ("BNK" or the "Company") operating and financial results for the year ended December 31, 2016, compared to the prior year, as well as information and expectations concerning the Company's outlook based on currently available information. The MD&A should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2016 and 2015. Unless otherwise noted, all financial data has been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board. The reporting and measurement currency is the United States dollar. Additional information relating to BNK including its Annual Information Form is filed on SEDAR at www.sedar.com on the Company's website at www.bnkpetroleum.com.

This report is prepared as of March 23, 2017. Please read carefully the important cautionary notes regarding technical information, forward-looking statements and other matters set out in this report.

Currency

The Company's reporting currency for financial reporting purposes is U.S. dollars. All dollar amounts set forth in this report are expressed in United States dollars, except where otherwise indicated. The following table sets forth, for each of the years indicated, the high and low exchange rates, the average noon exchange rate and the year-end exchange rate of one United States dollar in exchange for Canadian dollars as reported by the Bank of Canada.

	Year ended December 31		
	2016	2015	2014
High	CDN$1.2544	CDN$1.1727	CDN$1.0613
Low	1.4590	1.3990	1.1643
Average	1.3248	1.2768	1.1045
Year End	1.3426	1.3841	1.1601

Description of Business

BNK Petroleum Inc. is an international energy company focused on finding and exploiting large, predominately unconventional oil and gas resource plays. The Company's focus is on maximizing the value of its existing assets in the United States, while targeting growth in production and reserves through the acquisition of exploration and production rights that it considers to be prospective for hydrocarbons by applying new and proven technologies by its experienced technical team. The common shares of the Company trade on the Toronto Stock Exchange ("TSX") under the symbol "BKX".

Operating Summary

The Company's results of operations are dependent on production volumes of natural gas, crude oil and natural gas liquids and the prices received for the production. Prices for these commodities have shown significant volatility during recent years and are determined by supply and demand factors, including weather and general economic conditions.

OVERVIEW

Results at a Glance

Year Ended December 31,	2016	2015	2014
Financial (US $000 except per share)			
Oil and gas gross revenues	**11,085**	17,811	27,694
Net operating income[(1)]	**6,410**	11,099	19,875
Net loss	**(11,148)**	(6,569)	(57,478)
Basic and diluted net loss per share	**(0.06)**	(0.04)	(0.36)
Cash flow from operations	**5,180**	5,581	12,750
Additions to property, plant and equipment	**2,497**	9,133	46,839
Operating			
Average production (Boepd)	**1,045**	1,415	1,053
Average price ($/BOE)	**28.98**	34.09	72.05
Royalties ($/BOE)	**6.55**	7.94	13.51
Netback ($/BOE)[(2)]	**16.76**	21.10	51.71
Netback including commodity contracts ($/BOE)[(2)]	**27.70**	29.43	53.45
Balance Sheet			
Cash and cash equivalents	**11,101**	1,666	12,035
Total assets	**147,004**	149,806	163,429
Adjusted working capital [(3)]	**10,640**	7,298	663
Total non-current liabilities	**22,431**	24,749	1,355

(1) Net operating income is considered a non-GAAP measure. Refer to the section entitled “Non-GAAP Measures” at the end of this MD&A.

(2) Netback and netback including commodity contracts are considered non-GAAP measures. Refer to the section entitled “Non-GAAP Measures” at the end of this MD&A.

(3) Adjusted working capital excludes the current portion of long-term debt in 2014. Adjusted working capital is considered a non-GAAP measure. Refer to the section entitled “Non-GAAP Measures” at the end of this MD&A.

Highlights

In October 2016, the Company completed an equity offering issuing 70,000,000 shares at a price of C$0.20 per share for gross proceeds of C$14,000,000. The Company intends to use the net proceeds from this offering for exploration and development of its Tishomingo Field, located in Oklahoma, including funding a drilling program and for general working capital. The net cash proceeds of the equity offering totalled $9.7 million.

The average production for 2016 was 1,045 BOEPD, a decrease of 26% compared to 2015 production of 1,415 BOEPD. The decrease was primarily due to the normal production decline as the Company did not drill or complete any new wells in 2016 and the last wells completed were in the second quarter of 2015. The decline was also due to three wells that were shut-in during part of the fourth quarter, due to offset fracture stimulation operations on 19 wells by another operator in the Woodford formation beneath the Caney.

Gross revenues for 2016 decreased by 37% compared to 2015. Cash flow from continuing operations was $6.3 million for 2016 compared to $9.3 million in 2015. The decrease in revenue and cash flow from continuing operations for 2016 compared to 2015 was due to the 26% decrease in production combined with a 15% decrease in average price.

Due to the Company's continuing cost cutting efforts, general & administrative expenses decreased 21% for 2016 compared to 2015.

Netbacks(1) decreased from $21.10 in 2015 to $16.76 in 2016, a decrease of 21%. The decrease in 2016 was due to the decrease in average prices compared to the prior year.

Almost 80% of 2016 oil production was hedged which resulted in substantially higher netbacks when the impact of the commodity hedges are included. Netbacks including commodity contracts(1) was $27.70 in 2016 compared to $29.43 in 2015, a decrease of only 6%.

Net loss for 2016 was $11.1 million compared to $6.6 million for the same period in 2015. The Company had an unrealized loss on financial commodity contracts of $8.0 million in 2016, compared to an unrealized gain of $4.0 million in 2015.

During 2016, the Company made paydowns totaling $3.9 million on its credit facility to reduce the outstanding balance on the credit facility to $20.5 million at December 31, 2016. The Company has $3.9 million available to borrow on the credit facility as the existing lenders reaffirmed the available borrowing capacity at $24.4 million at the end of 2016.

(1) Netback and netback including commodity contracts are considered non-GAAP measures. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.

OPERATIONS UPDATE

Tishomingo Field, Ardmore Basin, Oklahoma

In December 2016, the Company began its 2017 drilling program with the commencement of drilling of the Chandler 8-6H well, in which the Company has a 99.9% working interest. The Company finished drilling the Chandler 8-6H well in January 2017 and completed the fracture stimulation in February 2017. The 30-day initial production rate of the well is 230 barrels of oil per day and 265 BOE per day. The well is producing in line with the Company's proved undeveloped (PUD) case type curve for oil that is used to estimate the reserves attributed to the Company's Tishomingo field.

In January 2017, the Company began drilling the Hartgraves 1-6H well, the second well in its 2017 drilling program, in which it holds a 100% working interest. The drilling was completed in early March and the Company expects to begin fracture stimulation of the well in the second quarter of 2017.
The Company began drilling its third well of its 2017 drilling program, the Brock 9-2H well, in March 2017. The Company expects to finish drilling the Brock 9-2H well, in which it has a 100% working interest, in the second quarter of 2017.

The average production for 2016 was 1,045 BOEPD, a decrease of 26% compared to 2015 production of 1,415 BOEPD. The decreases were primarily due to the normal production decline as the Company did not drill or complete any new wells in 2016 and the last wells completed were in the second quarter of 2015. The decline was also due to three wells that were shut-in during part of the fourth quarter, due to offset fracture stimulation operations on 19 wells by another operator in the Woodford formation beneath the Caney. The operator completed the fracture stimulations in the first quarter of 2017 and all of these wells have been brought back on to production. The Company does not expect this to impact the long-term production of the wells going forward. [The current production from two of the wells is comparable to their pre-shut-in levels and production from the third continues to increase. The Company participated in four of the Woodford wells that were fracture stimulated by the other operator with its share of production currently totaling approximately 70 BOEPD.]

Europe

In November 2016, the Company relinquished the Sedano concession to the Spanish government. The five year term of the Urraca concession expired in September 2016. In November, the Company filed the paperwork with the government to relinquish this concession and is awaiting their response. The Company plans to either liquidate or sell all of its remaining European assets and has reclassified all of its European operations as discontinued operations.

DISCUSSION OF OPERATING RESULTS

Production and Revenue

	FY2016	FY2015	%
Average oil production (Bopd)	**622**	879	(29)
Average natural gas production (mcf/d)	**1,116**	1,568	(29)
Average NGL production (Boepd)	**237**	275	(14)
Average production (Boepd)	**1,045**	1,415	(26)
Average oil price ($/bbl)	**39.59**	46.20	(14)
Average natural gas price ($/mcf)	**2.03**	2.44	(17)
Average NGL price ($/bbl)	**14.36**	13.79	4
Average price ($/BOE)	**28.98**	34.09	(15)
Oil revenue ($000)	**9,008**	14,823	(39)
Natural gas revenue ($000)	**829**	1,398	(41)
NGL revenue ($000)	**1,247**	1,385	(10)

Oil production for 2016 was 622 bopd compared to 879 bopd for 2015, a decrease of 29%. The production decrease is due to the normal production decline, in addition to the 3 shut-in wells discussed above. Oil revenue decreased by 39% in 2016 versus 2015 due to a decrease in oil prices of 14% combined with the production decrease.

For 2016, average natural gas production was 1,116 mcfpd compared to 1,568 mcfpd in 2015, a decrease of 29%. The production decrease is due to the normal production decline, in addition to the 3 shut-in wells discussed above. Natural gas revenue decreased by 41% in 2016 versus 2015 due to a decrease in natural gas prices of 17% combined with the production decrease and higher shrinkage factor.

Natural gas liquids (NGL) production 2016 decreased to 237 boepd from 275 boepd in 2015, a decrease of 14%. The production decrease is due to the normal production decline, in addition to the 3 shut-in wells discussed above. NGL revenue decreased by 10% in 2016 compared to 2015 due to the decrease in production, partially offset by a 4% increase in price.

Production on a per boe basis was 1,045 boepd in 2016 compared to 1,415 boepd in 2015, a decrease of 26%. The decrease is due to the factors discussed above. Gross revenue for 2016 decreased by 37% compared to 2015 due to a 26% production decrease combined with the 15% decrease in average prices.

Royalties, Operating Expenses and Netbacks

($/BOE)	**FY2016**	FY2015	%
Average price	**28.98**	34.09	(15)
Royalties	**6.55**	7.94	(18)
Operating expenses	**5.67**	5.05	12
Netback (1)	**16.76**	21.10	(21)

(1) Netback is considered a non-GAAP measure. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.

For 2016, oil was 59% of the production mix compared to 62% in 2015. The decreased percentage of oil in the production mix in 2016 is primarily due to the Nickel Hill 36-3H well and the T-zone wells which have a higher gas to oil ratio than the East Side Caney zone wells.

Royalties on Tishomingo production averaged approximately 22.6% for 2016 versus 23.3% in 2015 due to different royalty burdens on the leases drilled by the Company.

Major operating expenses are related to the gathering and processing of natural gas and NGLs as well as periodic well repairs and maintenance. Operating expenses were $2,168,000 for 2016 compared to $2,614,000 for 2015. The operating expense decreases are due to a decrease in production volumes. Operating expenses per barrel increased by 12% in 2016 compared to 2015. This increase is primarily due to average production being lower by 26% in 2016, as certain costs are fixed.

Realized and Unrealized Gains and Losses from Risk Management Contracts

The Company has entered into financial commodity contracts which are summarized in the table below. Total Volume Hedged in the table is the annual volumes and Price is the fixed price specified in the financial commodity contracts.

At December 31, 2016 the following financial commodity contracts were outstanding and recorded at estimated fair value:

Commodity	Period	Total Volume Hedged (BBLS/MMBTU)	Price ($/BBL or $/MMBTU)
Oil – WTI	January 1, 2017 to June 30, 2017	14,500	$87.65
Oil - WTI	January 1, 2017 to December 31, 2017	117,951	$60.13
Oil - WTI	January 1, 2018 to January 31, 2018	8,818	$60.13
Oil - WTI	January 1, 2018 to December 31, 2018	89,892	$54.70
Oil – WTI	January 1, 2017 to December 31, 2017	11,870	$48.40
Oil - WTI	January 1, 2018 to December 31, 2018	25,460	$48.40
Oil - WTI	January 1, 2019 to December 31, 2019	102,010	$48.40
Oil - WTI	January 1, 2020 to April 30, 2020	30,920	$48.40
Oil – WTI	January 1, 2017 to December 31, 2017	5,502	$51.55
Oil – WTI	January 1, 2018 to December 31, 2018	4,218	$51.55
Oil – WTI	January 1, 2019 to October 31, 2019	3,307	$51.55
Gas - Henry Hub	January 1, 2017 to December 31, 2017	119,993	$3.06
Gas - Henry Hub	January 1, 2017 to November 30, 2017	42,922	$2.80
Gas - Henry Hub	December 1, 2017 to December 31, 2017	9,731	$2.90
Gas - Henry Hub	January 1, 2018 to January 31, 2018	7,983	$3.06
Gas - Henry Hub	January 1, 2018 to November 30, 2018	107,041	$2.90
Gas - Henry Hub	January 1, 2017 to December 31, 2017	26,045	$2.93
Gas - Henry Hub	January 1, 2018 to December 31, 2018	50,629	$2.93
Gas - Henry Hub	January 1, 2019 to December 31, 2019	138,883	$2.93
Gas - Henry Hub	January 1, 2020 to March 31, 2020	31,571	$2.93
Gas - Henry Hub	January 1, 2017 to December 31, 2017	12,866	$2.91
Gas - Henry Hub	January 1, 2018 to December 31, 2018	10,945	$2.91
Gas - Henry Hub	January 1, 2019 to September 30, 2019	7,911	$2.91

The estimated fair value of $(767,000) as at December 31, 2016 for the financial oil and gas contracts which has been determined based on the prospective amounts that the Company would receive or pay to terminate the contracts.

If the realized gains from these commodity contracts were included in the average price computation, the Company's netbacks[1] would be as follows:

Netbacks including Commodity Contracts (1)

($/BOE)	**FY2016**	FY2015	%
Average price	**39.92**	42.42	(6)
Royalties	**6.55**	7.94	(18)
Operating expenses	**5.67**	5.05	12
Netbacks[1] including commodity contracts	**27.70**	29.43	(6)

(1) Netbacks including Commodity Contracts is considered a non-GAAP measure. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.

Exploration and Evaluation Expenses

Exploration and evaluation expenses were $835,000 in 2016 due to a writedown related to exploration and evaluation leases.

General and Administrative Expenses

General and administrative expenses (G&A) for 2016 were $3,760,000 compared to $4,789,000 for 2015, a decrease of 21%. This decrease in G&A compared to 2015 relates primarily to management's efforts to reduce costs throughout the Company. This resulted in reductions in salary and benefits, legal and professional fees and travel costs.

Depletion and Depreciation

Depletion and depreciation expense for 2016 were $5,249,000 compared to $7,975,000 in 2015. The decrease is due to decreased production. Depletion and depreciation expense on a per barrel basis was $13.72 for 2016 compared to $15.43 in 2015.

Stock based compensation

Stock based compensation increased from $602,000 in 2015 to $611,000 in 2016. The increase was due to the timing of stock awards grants to directors and employees and cancellations of stock options in 2016.

Interest on loans and borrowings

Interest on loans and borrowings increased from $1,933,000 for 2015 to $1,946,000 for 2016. The increase is due to the Company's additional borrowings of $8.5 million in February 2015 on the credit facility partially offset by the $3.9 million of paydowns during 2016.

Net loss for the period and cash used in operating activities

The Company incurred a net loss of $11,148,000 ($0.06 per share) for 2016 compared to a net loss of $6,570,000 ($0.04 per share) for the same period of 2015. The 2016 net loss compared to the same period in 2015 is due to a combined loss in risk management contracts for 2016 of $3,843,000 versus a combined gain of $8,276,000 for 2015, a decrease in net revenue of $5,135,000 and exploration and evaluation expenses of $835,000 in 2016, partially offset by a decrease in net loss from discontinued operations of $9,195,000, a decrease in depletion and depreciation expense of $2,726,000, a decrease in general and administrative costs of $1,029,000, a decrease in operating expenses of $446,000 and a foreign exchange loss of $105,000 in 2016 versus a foreign exchange loss of $288,000 in 2015.

Cash provided by operating activities for 2016 was $5,180,000 compared to $5,581,000 in 2015.

DISCONTINUED OPERATIONS

In Poland, the Company has relinquished its last remaining concession and decided to shut down all operations. In Spain, the Company relinquished its Sedano concession and the Urraca concession expired in September 2016. Since the Company plans to either liquidate or sell all of its European assets, the Company has reclassified all of its European operations as discontinued operations.

Net loss from discontinued operations is as follows:

		2016		2015
Other income	$	**375**	$	550
General & administrative expense		**(1,609)**		(3,146)
Exploration & evaluation expense		**-**		(7,544)
Depreciation		**(51)**		(102)
Gain on sale of assets		**43**		-
Foreign currency gain (loss)		**72**		(122)
	$	**(1,170)**	$	(10,364)

The decrease in general and administrative expenses in 2016, compared to 2015, is due to headcount reductions in Europe which reduced salary and benefit expense. Exploration and evaluation expense in 2015 includes a $7.5 million impairment related to the exploration and evaluation assets of the Sedano and Urraca concessions in Spain.

CAPITAL EXPENDITURES

($000, except as noted)

		2016		2015
Additions to oil and gas properties	**$**	**2,497**	$	9,133
Additions to exploration and evaluation		**-**		393
	$	**2,497**	$	9,526

For 2016, the Company spent approximately $2.5 million in the U.S. all of which was incurred on drilling and completion costs.

LIQUIDITY AND CAPITAL RESOURCES

	At December 31,	
	2016	**2015**
Working Capital (US$)	$ **10,640,000**	$ **7,298,000**
Loans and Borrowings (US$)	$ **20,500,000**	$ **24,400,000**
Shares Outstanding, end of period	**232,689,292**	**162,689,292**
Market Price per share, end of period (in Canadian $)	**$ 0.32**	**$ 0.21**
Market Value of Shares (in Canadian $)	**$ 74,461,000**	**$ 34,165,000**

In October 2016, the Company completed an equity offering issuing 70,000,000 shares at a price of C$0.20 per share for gross proceeds of C$14,000,000. The Company intends to use the net proceeds from this offering for exploration and development of its Tishomingo Field, located in Oklahoma, including funding a drilling program and for general working capital. The net cash proceeds of the equity offering totalled $9.7 million.

In July 2014, the Company's US subsidiary obtained a new $100 million credit facility from Morgan Stanley Capital Group Inc. ("Morgan Stanley"), which is secured by the US subsidiary's interests in the Tishomingo Field. The credit facility has an initial commitment amount of $15.9 million and is intended to fund the drilling of Caney wells in the Tishomingo Field. The facility bears interest at a per annum rate equal to then three month LIBOR plus an applicable margin ranging from 2% to 7% based on a number of factors including the ratio of outstanding borrowings to a calculated borrowing base level and individual well value concentration. The facility provides for interest only payments until the July 2018 maturity date. Additional commitment amounts will be subject to new reserve evaluations. The Credit Facility is subject to a semi-annual review and redetermination of the borrowing base. Any redetermination of the borrowing base is effective immediately and if the borrowing base is reduced, the Company has four months to repay any shortfall.

In February 2015, the US subsidiary borrowed an additional $8.5 million on the credit facility. During 2016, the Company has made paydowns totaling $3.9 million on the credit facility to reduce the outstanding balance on the credit facility to $20.5 million. Primary debt covenants of the facility require the US subsidiary to maintain a positive working capital balance, to ensure the ratio of outstanding debt to an adjusted EBITDA amount be no greater than 4 to 1 at any quarter end and to ensure the ratio of adjusted EBITDA to interest expense be no less than 2.5 at any quarter end.

At December 31 2016, the US subsidiary was in compliance with all of these covenants. At December 31, 2016, loans and borrowings of $20.5 million (December 31, 2015: $24.4 million) are presented net of loan acquisition costs of $0.3 million (December 31, 2015: $0.5 million).

At December 31, 2016 the Company had working capital of $10.6 million versus $7.3 million at December 31, 2015. The Company closely monitors its working capital and borrowing capacity to insure adequate funds are available to finance its administrative and operating requirements.

The Company has entered into financial commodity contracts as part of its risk management strategy to manage its cash flow for future activity and to offset commodity price fluctuations. The Company believes that the combination of cash on hand, proceeds from the equity financing discussed above, cash flow from operations, borrowings from its credit facility and/or other equity or debt financings will be sufficient to finance the

Company's cash requirements through 2017. Other potential sources of cash flow include proceeds from additional debt or equity offerings.

CONTRACTUAL OBLIGATIONS

The following are the contractual maturities of financial liabilities, excluding estimated interest payments at December 31, 2016:

	Total	2017	2018
Loans and borrowings *	(20,500)	-	(20,500)
Trade and other payables	(2,888)	(2,888)	-
	(23,388)	(2,888)	(20,500)

* See "Liquidity and Capital Resources" and "Principal Business Risks" for discussion of events that would require early repayment of the credit facility.

COMMITMENTS

The Urraca concession application in Spain outlined the annual work programs in each year of the five year concession term, including the drilling of a total of nine wells on the concession. However, the concession application stipulated that failure to drill the required wells in the time indicated in the concession application would not constitute a default of the concession requirements if required permits are not approved by the government in a timely fashion. A failure to meet work commitments without obtaining an extension, suspension, or another arrangement may result in the loss of the applicable concession. The Company understands that there may be circumstances in which a failure to meet work commitments could result in liability in regard to the unperformed current year work commitments. The five year term of the Urraca concession expired in September 2016. In November, the Company filed the paperwork with the government to relinquish this concession and is awaiting their response.

QUARTERLY SUMMARY

Below is a summary of the Company's performance over the last eight quarters:

	2016			
($000, except as noted)	**Q4**	**Q3**	**Q2**	**Q1**
Daily Production				
Oil (bpd)	445	628	672	744
Natural gas (mcfpd)	588	1,001	1,181	1,702
NGL's (bpd)	118	229	280	324
Average production (boepd)	661	1,024	1,149	1,352

	2015			
($000, except as noted)	**Q4**	**Q3**	**Q2**	**Q1**
Daily Production				
Oil (bpd)	832	904	914	867
Natural gas (mcfpd)	1,436	1,799	1,637	1,397
NGL's (bpd)	296	350	303	149
Average production (boepd)	1,367	1,554	1,490	1,249

($000, except as noted)	2016 Q4	Q3	Q2	Q1
Average Price				
Oil ($/bbl)	46.63	42.55	42.41	30.24
Natural gas ($/mcf)	2.50	2.43	1.59	1.93
NGL ($/bbl)	19.61	15.07	15.45	10.96
Average price ($/bbl)	37.13	31.84	30.19	21.69

($000, except as noted)	2015 Q4	Q3	Q2	Q1
Average Price				
Oil ($/bbl)	39.36	44.41	54.35	46.13
Natural gas ($/mcf)	1.89	2.54	2.38	2.97
NGL ($/bbl)	13.54	12.78	16.72	10.68
Average price ($/bbl)	28.86	31.65	39.35	36.62

($000, except as noted)	2016 Q4	Q3	Q2	Q1
Netback(1)				
Average price ($/boe)	37.13	31.84	30.19	21.69
Royalties	8.35	7.21	6.83	4.91
Operating expenses	7.81	6.05	5.46	4.49
Netback ($/boe)	20.97	18.58	17.90	12.29

($000, except as noted)	2015 Q4	Q3	Q2	Q1
Netback(1)				
Average price ($/boe)	28.86	31.65	39.35	36.62
Royalties	6.57	7.39	9.51	8.24
Operating expenses	5.19	5.02	4.96	5.05
Netback ($/boe)	17.10	19.24	24.88	23.33

($000, except as noted)	2016 Q4	Q3	Q2	Q1

Net operating income(2)				
Oil and gas revenue	2,259	3,001	3,157	2,669
Royalties	509	680	714	604
Operating expenses	475	570	571	552
	1,275	1,751	1,872	1,513

	2015			
($000, except as noted)	**Q4**	**Q3**	**Q2**	**Q1**
Net operating income(2)				
Oil and gas revenue	3,834	4,525	5,335	4,117
Royalties	826	1,056	1,290	926
Operating expenses	653	717	672	568
	2,355	2,752	3,373	2,623

	2016			
($000, except as noted)	**Q4**	**Q3**	**Q2**	**Q1**
Net earnings (loss)	(3,745)	(843)	(5,310)	(1,250)
Basic and Fully Diluted Earnings (loss) per share	(0.02)	0.01	(0.03)	(0.01)
Funds from operations(3)	511	1,442	1,801	1,172
Bank debt	20,500	20,500	22,600	24,400
Total assets	147,004	139,447	142,067	148,533

	2015			
($000, except as noted)	**Q4**	**Q3**	**Q2**	**Q1**
Net earnings (loss)	(6,350)	4,199	(3,660)	(760)
Basic and Fully Diluted Earnings (loss) per share	(0.04)	0.03	(0.02)	0.00
Funds from operations(3)	1,993	2,608	2,963	1,017
Bank debt	24,400	24,400	24,400	24,400
Total assets	149,806	158,514	157,456	161,377

(1) Netback is considered a non-GAAP measure. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.
(2) Net operating income is considered a non-GAAP measure. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.
(3) Funds from operations is considered a non-GAAP measure. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.

Quarterly Variability

Fluctuations in quarterly results are due to a number of factors, some of which are not within the Company's control such as:

- Oil, gas and NGL price changes due to market conditions.
- Changes in production resulting from fluctuations in drilling and completions and shut-in of wells.
- Fluctuations in the U.S. dollar against Canadian dollar and Euro result in higher or lower general and administrative expenses in United States dollar terms. The fluctuations also affect the net proceeds in United States dollar terms from equity issuances.
- The changes in G&A from quarter to quarter reflect changes in operations, changes in personnel, and non-recurring charges related to specific transactions or events.

USE OF PROCEEDS

The net proceeds received by the Company from the offering were estimated to be approximately C$13,160,000, after deducting the fees of C$840,000 paid by the Company to the Agents that facilitated the offering. The actual use of proceeds at December 31, 2016, compared to the proposed use of proceeds included in the Company's prospectus dated October 21, 2016 is as follows:

(all amounts in Canadian $)	**Proposed Use of Proceeds**	**Actual Use of Proceeds**	**Remaining to be Spent**
Capital Expenditures for exploration and development of Tishomingo Field, Oklahoma, U.S.	$ 11,260,000	$ 300,000	$ 11,060,000*
Estimated costs of the offering	400,000	300,000	-
General Working Capital	1,500,000	150,000	1,350,000
	$ 13,160,000	$ 750,000	$ 12,410,000

* This figure includes the C$100,000 difference between the estimated and actual costs of the offering.

FOURTH QUARTER 2016

During the fourth quarter of 2016, oil production decreased 47% to 445 boepd from 832 boepd for the same quarter of 2015. The Company's natural gas production decreased 59% to 588 mcfpd from 1,436 mcfpd in the same quarter of 2015. NGL production decreased during the quarter by 60% to 118 boepd from 296 boepd in the same quarter of 2015.

Overall production during the fourth quarter of 2015 was 661 boepd as compared to 1,367 boepd in the fourth quarter of 2015, a decrease of 52%. The decrease in production was due to the three wells that were shut-in during the 2016 fourth quarter as well as the normal production decline as no new wells were brought into production in 2016.

Oil, gas and NGL prices increased during the quarter compared to the same quarter of 2015 as shown in the following table:

	Q4-2016	Q4-2015	% Change
Natural gas ($/mcf)	2.50	1.89	32
NGL ($/bbls)	19.61	13.54	45
Oil ($/bbls)	46.63	39.36	18
Total Average price ($/boe)	37.13	28.86	29

The Company's netbacks[(1)] increased as follows:

	Q4-2016	Q4-2015	% Change
Average price ($/boe)	37.13	28.86	29
Less: Royalties	8.35	6.57	27
Less: Operating expenses	7.81	5.19	50
Netback	20.97	17.10	23

(1) Netbacks is considered a non-GAAP measure. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.

If the realized gains from the Company's outstanding commodity contracts described above in "Realized and Unrealized Gains and Losses from Risk Management Contracts" were included in the average price computation, the Company's netbacks[(1)] would be as follows:

	Q4-2016	Q4-2015	% Change
Average price ($/boe) including commodity contracts	47.56	40.24	18
Less: Royalties	8.35	6.57	27
Less: Operating expenses	7.81	5.19	50
Netbacks including commodity contracts [(1)]	31.40	28.48	10

(1) Netbacks including commodity contracts is considered a non-GAAP measure. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.

Oil and gas revenue during the fourth quarter of 2016 was $2,258,000 compared to $3,834,000 for the same quarter in 2015 and net operating income[(2)] was lower at $1,275,000 during the fourth quarter of 2016 as compared to $2,355,000 in the fourth quarter of 2015.

The Company had a net loss of $3,745,000 during the fourth quarter of 2016 compared to a $6,350,000 loss for the fourth quarter of 2015 primarily due to discontinued operations loss of $8.2 million in the fourth quarter of 2015 compared to the 2016 discontinued operations loss of $0.3 million. The Company generated cash from operating activities of $454,000 in the fourth quarter 2016 compared to $1,039,000 from the prior year fourth quarter.

Capital expenditures during the fourth quarter 2016 totaled $1,751,000 all of which was incurred in the U.S.

(2) Net operating income is considered a non-GAAP measure. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities, the disclosures of contingencies at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the year. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change in the financial statements. Accordingly, actual results may differ from the estimated amounts. Significant estimates and judgments made by management in the preparation of these consolidated financial statements are as follows:

Oil and gas assets

Development and production assets are assessed for recoverability at a cash generating unit ("CGU") level. The determination of CGUs is subject to management judgments. Recoverability is assessed by comparing the carrying value of the asset to its recoverable amount, which is based on the higher of fair value of the assets less the cost to sell ("FVLCS") or value in use ("VIU"). The key estimates used in the determination of the recoverable amount include the following:

- Reserves – Assumptions that are valid at the time of reserve estimation may change significantly when additional information becomes available. Changes in forward price estimates, production costs or recovery rates may change the economic status of reserves and may ultimately result in a restatement of reserves.

- Oil and gas prices – Forward price estimates are used in the cash flow model. Commodity prices can fluctuate for a variety of reasons including supply and demand fundamentals, inventory levels, exchange rates, weather and economic and political factors.

- Discount rate – The discount rate used to calculate the net present value of cash flows is based on estimates of an industry peer group weighted average cost of capital. Changes in the economic environment could result in significant changes to this estimate.

Depletion of oil and gas assets

Depletion of oil and gas assets is determined based on total proved and probable reserve values and includes future development costs as estimated by the Company's external reserve evaluator. Amounts recorded for depletion and depreciation are based on estimates of petroleum and natural gas reserves. By their nature, the estimates of reserves, including the estimates of future prices, costs, discount rates and the related future cash flows, are subject to measurement uncertainty. Accordingly, the impact to the consolidated financial statements in future periods could be material.

Asset retirement obligations

The provisions for site restoration and abandonment is based on current legal requirements, technology, price levels and expected plans and are based on significant assumptions such as inflation rate and discount rate. Actual costs and cash outflows can differ from estimates because of changes in laws or regulations, market conditions and changes in technology.

Derivative instruments

The estimated fair value of derivative financial instruments resulting in financial assets and liabilities, by their very nature is subject to estimation, due to the use of future oil and natural gas prices and the volatility in these prices.

Compensation costs

Compensation costs recognized for share based compensation plans are subject to the estimation of what the ultimate payout will be using pricing models such as Black-Scholes model which is based on assumptions such as volatility, forfeiture rate, interest rate and expected term.

Income taxes

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company operates are subject to change. As such income taxes are subject to measurement uncertainty. Deferred income tax assets are assessed by management at the end of the reporting period to determine the likelihood that they will be realized from future taxable earnings.

OUTSTANDING SHARE DATA

There were 232,689,292, 232,689,292 and 162,689,292 common shares outstanding as at March 23, 2017, December 31, 2016 and December 31, 2015 respectively. The Company had 10,365,833, 10,745,833 and 8,893,666 stock options outstanding as of March 23, 2017, December 31, 2016 and December 31, 2015, respectively.

PRINCIPAL BUSINESS RISKS

BNK's business and results of operations are subject to a number of risks and uncertainties, including but not limited to the following:

- the uncertainty of finding oil and gas in commercial quantities
- securing markets for existing and future production
- commodity price fluctuations due to market forces
- financial risk due to foreign exchange rates and interest rate exposure
- changes to government regulations in the United States, including regulations relating to prices, taxes, royalties and environmental protection
- changing government policies and regulations, social instability and other political, economic or diplomatic developments in the countries in which the Company operates
- availability of equity or debt financing is affected by many factors many of which are beyond the control of the Company
- uncertainties inherent in estimating quantities of oil and natural gas reserves and cash flows to be derived therefrom
- the oil and gas industry is intensely competitive and the Company competes with a large number of companies with greater resources
- risks related to the Company's credit facility, including the risk that the Company could be required under the terms of the credit facility to prepay the outstanding principal amount and other amounts owing under the facility in certain circumstances, some of which are out of the Company's control, including in the event that Mr. Wolf Regener ceases to be the President of BNK Petroleum (US) Inc. and certain changes to the board of directors of the Company. A failure by the Company to perform its obligations under the credit facility could result in, among other adverse effects, the loss of the Company's Tishomingo Field assets. A copy of the Amended and Restated Credit Agreement was filed on SEDAR on August 11, 2014.
- the other risks identified in the Company's most recent Annual Information Form under the "Risk Factors" section and the Company's other public disclosure, available under the Company's profile on SEDAR at www.sedar.com.

The Company seeks to mitigate these risks by:

- maintaining product mix to manage exposure to commodity price risk
- monitoring production trends to maximize the potential of its capital spending program
- from time to time, entering into financial commodity contracts to hedge against commodity price risk
- ensuring strong third-party operators for non-operated properties
- transacting with creditworthy counterparties
- monitoring commodity prices and capital programs to manage cash flow
- reviewing proposed changes in applicable government regulations and laws to assess the impact on the Company's operations

DISCLOSURE CONTROLS AND PROCEDURES

The Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P") and internal controls over financial reporting ("ICOFR") as defined in National Instrument 52-109 Certification of Disclosure in Issuer's Annual and Interim Filings in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements in accordance with IFRS.

The DC&P have been designed to provide reasonable assurance that material information relating to BNK is made known to the CEO and CFO by others and that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by BNK under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation. The Company's CEO and CFO have concluded, based on their evaluation that the Company's disclosure controls and procedures and ICOFR are effective to provide reasonable assurance that material information related to the issuer, is made known to them by others within the Company.

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

It should be noted a control system, including the Company's DC&P and ICOFR, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system will be met and it should not be expected that DC&P and ICOFR will prevent all errors or fraud.

OUTLOOK

In the United States, the Company intends to drill and complete additional wells in the Caney/Sycamore formations on its Oklahoma lands under which it has an estimated 158 potential economic drilling locations in the Tishomingo field. The Company continues to work on identifying additional basins that it believes are prospective for shale oil and gas as well.

NON-GAAP MEASURES

Netback per barrel, net operating income and funds from operations (collectively, the "Company's Non-GAAP Measures") are not measures recognized under Canadian generally accepted accounting principles ("GAAP") and do not have any standardized meanings prescribed by GAAP. Management of the Company believes that such measures are relevant for evaluating returns on each of the Company's projects as well as the performance of the enterprise as a whole. The Company's Non-GAAP Measures may differ from similar computations as reported by other similar organizations and, accordingly, may not be comparable to similar non-GAAP measures as reported by such organizations. The Company's Non-GAAP Measures should not be construed as alternatives to net income, cash flows related to operating activities, working capital or other financial measures determined in accordance with GAAP, as an indicator of the Company's performance.

Netback per barrel and its components are calculated by dividing revenue, less royalties and operating expenses by the Company's sales volume during the period. Netbacks including commodity contracts and its components are calculated by dividing revenue and realized gains from commodity contracts, less royalties and operating expenses by the Company's sales volume during the period. Netback per barrel is a non-GAAP measure but it is commonly used by oil and gas companies to illustrate the unit contribution of each barrel produced. However, non-GAAP measures do not have any standardized meaning prescribed by GAAP and therefore, may not be comparable to similar measures used by other companies and should not be used to make comparisons.

Net operating income is similarly a non-GAAP measure that represents revenue net of royalties and operating expenses. The Company believes that net operating income is a useful supplemental measure to analyze operating performance and provides an indication of the results generated by the Company's principal business activities prior to the consideration of other income and expenses. The following is the reconciliation of the non-GAAP measure net operating income:

	2016	2015
Oil and gas revenue, net of royalties	**8,578**	13,713
Operating expenses	**2,168**	2,614
Net operating income	**6,410**	11,099

Funds from operations is calculated as cash from operating activities before change in non-cash operating working capital. The Company considers this a key measure as it demonstrates its ability to generate the funds necessary for future growth after taking into account the short-term fluctuations in the collection of accounts receivable and the payment of accounts payable. The following is the reconciliation of the non-GAAP measure funds from operations:

	2016	2015
Cash flow from continuing operations	**6,272**	9,346
Change in non-cash working capital	**1,346**	765
Funds from operations	**4,926**	8,581

NEW ACCOUNTING STANDARDS

The IASB issued IFRS 9, "Financial Instruments", which is the first phase of the IASB's project to replace IAS 39, "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial asset and liabilities with a single model that has only two classification categories: amortized cost and fair value. The standard is effective for the Company for annual periods beginning on January 1, 2018, with required retrospective application and early adoption permitted. The Company is currently evaluating the impact of adopting this new standard.

In May 2014, the IASB published IFRS 15 "Revenue from Contracts with Customers," to replace IAS 18 "Revenue," which establishes principles for reporting useful information to users of financial statements about the nature, amount, timing and uncertainty of revenue and cash flows arising from an entity's contracts with customers. The standard is effective for the Company for annual periods beginning on January 1, 2018, with required retrospective application and early adoption permitted. The Company is currently evaluating the impact of adopting this new standard.

In January 2016, the IASB issued the complete IFRS 16 Leases ("IFRS 16") which replaces IAS 17, Leases. The effective date of IFRS 16 is for annual periods beginning on or after January 1, 2019 and early adoption is permitted. Under IFRS 16, a single recognition and measurement model will apply for lessees which will require recognition of assets and liabilities for most leases. The extent of the impact of adoption of the standard has not yet been determined.

CAUTIONARY STATEMENTS

(a) The Company's natural gas production is reported in thousands of cubic feet ("Mcfs"). The Company also uses references to barrels ("Bbls") and barrels of oil equivalent ("Boes") to reflect natural gas liquids and oil production and sales. Boes may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

(b) Discounted and undiscounted net present value of future net revenues attributable to reserves do not represent fair market value.

(c) Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

(d) This MD&A and the Company's other public disclosure contains peak and 30-day initial production rates and other short-term production rates. Readers are cautioned that initial production rates are preliminary in nature and are not necessarily indicative of long-term performance or of ultimate recovery.

CAUTION REGARDING FORWARD-LOOKING INFORMATION

This MD&A contains forward-looking information including information regarding the use of proceeds from the equity offering completed in October 2016, availability of funds from the Company's reserve-based loan facility, proposed timing and expected results of exploratory and development work in the Company's Tishomingo Field, expected productivity from current and future wells, planned capital expenditure programs and cost estimates, the effect of design and performance improvements on future productivity, the Company's European projects, planned use and sufficiency of proceeds from the Company's debt and equity financings, cash on hand and cash flow from operations and the Company's strategy and objectives. The use of any of the words "target", "plans", "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward-looking statements.

Such forward-looking information is based on management's expectations and assumptions, including that the Company's geologic and reservoir models and analysis will be validated, that indications of early results are reasonably accurate predictors of the prospectiveness of the shale intervals, that previous exploration results are indicative of future results and success, that expected production from future wells can be achieved as modeled, declines will match the modeling, future well production rates will be improved over existing wells, that rates of return as modeled can be achieved, that recoveries are consistent with management's expectations, that additional wells are actually drilled and completed, that design and performance improvements will reduce development time and expense and improve productivity, that discoveries will prove to be economic, that well shut-ins will not materially reduce production or adversely affect future productivity, that anticipated results and estimated costs will be consistent with managements' expectations, that all required permits and approvals and the necessary labor and equipment will be obtained, provided or available, as applicable, on terms that are acceptable to the Company, when required, that no unforeseen delays, unexpected geological or other effects, equipment failures, permitting delays or labor or contract disputes are encountered, that the development plans of the Company and its co-venturers will not change, that the demand for oil and gas will be sustained, that the Company will continue to be able to access sufficient capital through financings, credit facilities, farm-ins or other participation arrangements to maintain its projects, that the Company will continue in compliance with the covenants under its reserve-based loan facility and that the borrowing base will not be reduced, that the Company will not be adversely affected by changing government policies and regulations, social instability or other political, economic or diplomatic developments in the countries in which it operates and that global economic conditions will not deteriorate in a manner that has an adverse impact on the Company's business and its ability to advance its business strategy.

Forward looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated. These risks include, but are not limited to: any of the assumptions on which such forward looking information is based vary or prove to be invalid, including that the Company's geologic and reservoir models or analysis are not validated, anticipated results and estimated costs will not be consistent with managements' expectations, that the Company will not achieve a comparable level of hedging going forward in respect of its existing production, that the Company will not achieve the results anticipated by management from the Company's cost reduction measures, the risks associated with the oil and gas industry (e.g. operational risks in development, exploration and production; delays or changes in plans with respect to exploration and development projects or capital expenditures; the uncertainty of reserve and resource estimates and projections relating to production, costs and expenses, and health, safety and environmental risks, including flooding and extended interruptions due to inclement or hazardous weather conditions), well shut-ins and the potential for damage to the affected wells, the risk of commodity price and foreign exchange rate fluctuations, risks and uncertainties associated with securing the necessary regulatory approvals and financing to proceed with continued development of the Tishomingo Field, the Company or its subsidiaries is not able for any reason to obtain and provide the information necessary to secure required approvals or that required regulatory approvals are otherwise not available when required, that unexpected geological results are encountered, that completion techniques require further optimization, that production rates do not match the Company's assumptions, that very low or no production rates are achieved, that the Company will cease to be in compliance with the covenants under its reserve-based loan facility and be required to repay outstanding amounts or that the borrowing base will be reduced pursuant to a borrowing base redetermination, that the Company is unable to access required capital, that occurrences such as those that are assumed will not occur, do in fact occur, and those conditions that are assumed will continue or improve, do not continue or improve and the other risks identified in the Company's most recent Annual Information Form under the "Risk Factors" section and the Company's other public disclosure, available under the Company's profile on SEDAR at www.sedar.com.

Although the Company has attempted to take into account important factors that could cause actual costs or results to differ materially, there may be other factors that cause actual results not to be as anticipated, estimated or intended. There can be no assurance that such statements will prove to be accurate as actual results and future events could differ materially from those anticipated in such statements. The forward-looking information included in this MD&A is expressly qualified in its entirety by this cautionary statement. Accordingly, readers should not place undue reliance on forward-looking information. The Company undertakes no obligation to update these forward-looking statements, other than as required by applicable law.

CORPORATE INFORMATION

DIRECTORS AND OFFICERS

Ford Nicholson [2,3,5]
Director, Chairman of the Board

Gregory M. Cameron [1,3]
Director

Victor Redekop [1,2,4,5]
Director

Eric Brown [1,2,3]
Director

General Wesley K. Clark [4]
Director

Leslie O'Connor [5]
Director

David Neuhauser
Director

Wolf Regener [4]
Director, President and Chief Executive Officer

Gary Johnson
Chief Financial Officer and Vice President

1 Member of the Audit Committee
2 Member of the Corporate Governance Committee
3 Member of the Compensation Committee
4 Member of the HS&E Committee
5 Member of the Reserves Committee

STOCK EXCHANGE LISTING
The Toronto Stock Exchange
Trading Symbol: BKX

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Vancouver, BC

AUDITORS
KPMG, LLP
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BANKERS
Amegy Bank National Association
Denver, CO, USA

HSBC Bank Canada
Calgary, AB

Morgan Stanley
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