



MANAGEMENT'S DISCUSSION AND ANALYSIS

SEPTEMBER 30, 2016



MANAGEMENT'S DISCUSSION AND ANALYSIS

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 three and nine months ended September 30, 2016, compared to the preceding quarter and the corresponding periods in 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 unaudited interim condensed financial statements for the three and nine months ended September 30, 2016 and the audited consolidated financial statements and MD&A for the year ended December 31, 2015. The interim consolidated financial statements have been prepared in accordance with International Accounting Standard 34 "Interim Financial Reporting" following the same accounting policies and methods of computation as the annual consolidated financial statements of the Company for the year ended December 31, 2015. 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 and on the Company's website at www.bnkpetroleum.com.

This report is prepared as of November 8, 2016. Please read carefully the important cautionary notes regarding technical information, forward-looking statements and other matters set out in this report.

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

	Three Months ended		Nine Months ended	
	September 30,		September 30,	
	2016	2015	2016	2015
Financial (US \$000 except as noted)				
Oil and gas gross revenue	3,001	4,526	8,826	13,977
Net operating income ⁽¹⁾	1,751	2,753	5,135	8,744
Net income (loss)	(843)	4,197	(7,403)	(221)
Basic and diluted net loss per share	(0.01)	0.03	(0.05)	(0.00)
Cash flow from continuing operations	2,016	2,561	5,560	6,616
Additions to property, plant and equipment	208	684	746	9,081
Operating				
Average production (Boepd)	1,024	1,554	1,174	1,432
Average price (\$/BOE)	31.84	31.65	27.44	35.75
Netback (\$/BOE) ⁽²⁾	18.58	19.24	15.97	22.37
Netback including commodity contracts (\$/BOE) ⁽²⁾	28.24	28.50	27.00	29.71
	16-Sep	16-Jun	16-Mar	15-Dec
Balance Sheet				
Cash and cash equivalents	1,677	2,442	2,885	1,666
Total assets	139,447	142,067	148,533	149,806
Working capital	3,748	5,278	7,950	7,298
Total non-current liabilities	21,528	23,446	24,726	24,749

(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.

Highlights

In October 2016, the Company completed an equity offering under which it issued 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 of this offering for exploration and development of its Tishomingo Field, located in Oklahoma, including funding a drilling program and for general working capital.

The average production for the third quarter of 2016 was 1,024 BOEPD, a decrease of 34% compared to third quarter 2015 production of 1,554 BOEPD. The average production for the nine months ended September 30, 2016 was 1,174 BOEPD, a decrease of 18% compared to the nine months ended September 30, 2015 production

of 1,432 BOEPD. The decreases were primarily due to the initial production volumes from completion of the fracture stimulation operations on the Nickel Hill 36-3H well and the Emery 17-1H well in mid-2015.

Gross revenues for the third quarter 2016 decreased by 33% compared to the third quarter of 2015. Gross revenues for the nine months ended September 30, 2016 decreased by 37% compared to the same period of 2015. Cash flow from continuing operations was \$2.0 million for the third quarter of 2016 compared to \$2.6 million in the third quarter of 2015. Cash flow from continuing operations was \$5.6 million for the nine months ended September 30, 2016 compared to \$6.6 million in the same period of 2015. The decrease in revenues and cash flow from continuing operations in the third quarter of 2016 compared to the same quarter in 2015 was due to the 34% decrease in average production. The decrease in revenue and cash flow from continuing operations for the nine months ended September 30, 2016 compared to the same period in 2015 was due to the 18% decrease in production combined with a 23% decrease in average price.

Due to the Company's continuing cost cutting efforts, general & administrative expenses decreased 6% for the third quarter of 2016 and 20% for the first nine months of 2016 compared to the prior year comparable periods.

Netbacks⁽¹⁾ decreased from \$19.24 in the third quarter 2015 to \$18.58 in the third quarter of 2016, a decrease of 3%. Netbacks⁽¹⁾ decreased from \$22.37 in the first nine months of 2015 to \$15.97 for the same period of 2016, a decrease of 29%. The decrease in the first nine months of 2016 was due to the decrease in average prices compared to the prior year period.

Over 75% 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⁾ for the third quarter decreased from \$28.50 in 2015 to \$28.24 in 2016, a decrease of 1%. Netbacks including commodity contracts⁽¹⁾ for the first nine months decreased from \$29.71 in 2015 to \$27.00 in 2016, a decrease of 9%.

Net loss for the third quarter 2016 was \$0.8 million compared to net income of \$4.2 million in the third quarter of 2015. Net loss for the first nine months of 2016 was \$7.4 million compared to \$0.2 million for the same period in 2015. The third quarter 2016 included an unrealized loss on financial commodity contracts of \$0.4 million compared to an unrealized gain of \$4.3 million for the same period in 2015. The first nine months of 2016 included an unrealized loss on financial commodity contracts of \$6.0 million compared to an unrealized gain of \$2.4 million for the same period in 2015.

During 2016, the Company has made paydowns totaling \$3.9 million on its credit facility to reduce the outstanding balance on the credit facility to \$20.5 million at September 30, 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 subsequent to the end of the third quarter.

(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

The average production for the third quarter of 2016 was 1,024 BOEPD, a decrease of 34% compared to the third quarter 2015 production of 1,554 BOEPD. The average production for the nine months ended September 30, 2016 was 1,174 BOEPD, a decrease of 18% compared to the nine months ended September 30, 2015 production of 1,432 BOEPD. The decreases were primarily due to the completion of the fracture stimulation operations on the Nickel Hill 36-3H well and the Emery 17-1H well in the second quarter of 2015. In October 2016, four wells were temporarily shut-in for about four weeks, due to offset fracture stimulations being performed on a number of Woodford shale wells by another operator, including 4 wells where the Company has a 5% working interest. The

Company does not expect this to impact the long-term production of the wells going forward. The wells have been put back on production and the current production from the wells is comparable to their pre-shut-in levels.

Europe

In May 2016, the Company submitted documents with the Spanish government to relinquish the Sedano concession and is awaiting a response. In September 2016, the Urraca concession expired and the Company has started the process with the Spanish government to relinquish this concession. 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

	Three months ended September 30			Nine months ended September 30		
	2016	2015	%	2016	2015	%
Average oil production (Bopd)	628	904	(31)	681	895	(24)
Average natural gas production (mcf/d)	1,001	1,799	(44)	1,293	1,613	(20)
Average NGL production (Boepd)	229	350	(35)	277	268	3
Average production (Boepd)	1,024	1,554	(34)	1,174	1,432	(18)
Average oil price (\$/bbl)	42.55	44.41	(4)	38.04	48.35	(21)
Average natural gas price (\$/mcf)	2.43	2.54	(4)	1.96	2.61	(25)
Average NGL price (\$/bbl)	15.07	12.78	18	13.60	13.88	(2)
Average price (\$/BOE)	31.84	31.65	1	27.44	35.75	(23)
Oil revenue (\$000)	2,459	3,693	(33)	7,098	11,812	(40)
Natural gas revenue (\$000)	224	420	(47)	694	1,149	(40)
NGL revenue (\$000)	317	412	(23)	1,034	1,016	2

Oil production for the third quarter 2016 was 628 bopd compared to 904 bopd for the same period in 2015, a decrease of 31%. Oil production for the first nine months of 2016 was 681 bopd compared to 895 bopd for the first nine months of 2015, a decrease of 24%. The production decreases are due to the initial production volumes from the fracture stimulation operations of the 2 wells in the second quarter of 2015. Oil revenue decreased by 33% in the third quarter of 2016 and 40% for the first nine months of 2016 versus the comparable periods in 2015 due to decreases in oil prices of 4% and 21% for the respective periods combined with the production decreases.

For the third quarter of 2016, average natural gas production was 1,001 mcfpd compared to 1,799 mcfpd in the same quarter in 2015, a decrease of 44%. Average natural gas production for the first nine months of 2016 was 1,293 mcfpd compared to 1,613 mcfpd in the same period in 2015, a decrease of 20%. The production decreases are due to the initial production volumes from the fracture stimulation operations of the 2 wells in the second quarter of 2015. Natural gas revenue decreased by 47% in the third quarter 2016 and 40% for the first nine months of 2016 versus the comparable periods in 2015 due to decreases in natural gas prices of 4% and 25% for the respective periods combined with the production decreases.

Natural gas liquids (NGL) production in the third quarter of 2016 decreased to 229 boepd from 350 boepd in 2015, a decrease of 35%. The production decrease is due to the initial production volumes from the fracture stimulation operations of the 2 wells in the second quarter of 2015. NGL production for the first nine months of 2016 was 277 boepd compared to 268 boepd in the same period in 2015, an increase of 3%. The production increase is due to a higher percentage of NGLs being extracted from gas production during processing, partially offset by the initial production volumes from the fracture stimulation operations of the 2 wells in the second

quarter of 2015. NGL revenue decreased by 23% in the third quarter 2016 compared to the third quarter of 2015 due to the decrease in production, partially offset by a 18% increase in price. NGL revenue increased by 2% for the first nine months of 2016 due to the increase in production partially offset by the 2% decrease in NGL prices.

Production on a per boe basis was 1,024 boepd in the third quarter of 2016 compared to 1,554 boepd in the third quarter of 2015, a decrease of 34%. For the first nine months of 2016, production was 1,174 boepd compared to 1,432 boepd for the first nine months of 2015, a decrease of 18%. The decreases are due to the factors discussed above. Gross revenue in the third quarter of 2016 decreased by 33% compared to the third quarter of 2015 due to a 34% production decrease. Gross revenue for the first nine months of 2016 decreased by 37% compared to the same period of 2015 due to a 18% production decrease combined with the 23% decrease in average prices.

Royalties, Operating Expenses and Netbacks⁽¹⁾

	Three months ended September 30			Nine months ended September 30		
	2016	2015	%	2016	2015	%
(\$/BOE)						
Average price	31.84	31.65	1	27.44	35.75	(23)
Royalties	7.21	7.39	(2)	6.21	8.37	(26)
Operating expenses	6.05	5.02	21	5.26	5.01	5
Netbacks ⁽¹⁾	18.58	19.24	(3)	15.97	22.37	(29)

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

For the third quarter of 2016, oil was 61% of the production mix compared to 58% in the third quarter of 2015. Oil made up 58% of the production mix in the first nine months of 2016 compared to 63% of oil in the production mix for first nine months of 2015. The decrease of oil in the production mix in the first nine months of 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 Caney zone wells.

Royalties on Tishomingo production averaged approximately 22.6% for 2016 versus 23.4% 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 \$570,000 for the third quarter of 2016 compared to \$717,000 for the same period of 2015. Operating expenses were \$1,693,000 for the first nine months of 2016 compared to \$1,961,000 for the same period of 2015. The operating expense decreases are due to a decrease in production volumes. Operating expenses per barrel increased by 21% in third quarter of 2016 and 5% in the first nine months of 2016 compared to the same periods in 2015. These increases are primarily due to lower average production of 34% in the third quarter of 2016 and 18% in the first nine months of 2016.

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 September 30, 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	October 1, 2016 to December 31, 2016	8,100	\$89.90
Oil - WTI	October 1, 2016 to December 31, 2016	30,801	\$60.13
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, 2019	8,818	\$60.13
Oil - WTI	January 1, 2018 to December 31, 2018	89,892	\$54.70
Oil – WTI	October 1, 2016 to December 31, 2016	3,410	\$48.40
Oil – WTI	January 1, 2017 to December 31, 2017	11,870	\$48.40
Oil - WTI	January 1, 2017 to December 31, 2017	25,460	\$48.40
Oil - WTI	January 1, 2018 to December 31, 2018	102,010	\$48.40
Oil - WTI	January 1, 2019 to April 30, 2019	30,920	\$48.40
Gas - Henry Hub	October 1, 2016 to December 31, 2016	35,259	\$3.06
Gas - Henry Hub	October 1, 2016 to November 30, 2016	11,196	\$2.48
Gas - Henry Hub	December 1, 2016 to December 31, 2016	3,902	\$2.80
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 December 31, 2018	107,041	\$2.90
Gas - Henry Hub	October 1, 2016 to December 31, 2016	6,302	\$2.93
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

The estimated fair value of \$1.3 million as at September 30, 2016 for the financial oil and gas contracts has been determined based on the prospective amounts that the Company would receive or pay to terminate the contracts.

In October 2016, subsequent to the end of the third quarter, the Company entered into additional financial commodity contracts which are summarized in the table below.

Commodity	Period	Total Volume Hedged (BBLs/MMBTU)	Price (\$/BBL or \$/MMBTU)
Oil – WTI	December 1, 2016 to December 31, 2016	458	\$51.55
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	December 1, 2016 to December 31, 2016	1,328	\$2.91
Gas - Henry Hub	January 1, 2017 to December 31, 2017	14,172	\$2.91
Gas - Henry Hub	January 1, 2018 to December 31, 2018	9,997	\$2.91
Gas - Henry Hub	January 1, 2019 to October 31, 2019	8,859	\$2.91

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

Netbacks including Commodity Contracts (1)

(\$/BOE)	Three months ended September 30			Nine months ended September 30		
	2016	2015	%	2016	2015	%
Average price	41.50	40.91	(1)	38.47	43.09	(11)
Royalties	7.21	7.39	(2)	6.21	8.37	(26)
Operating expenses	6.05	5.02	21	5.26	5.01	5
Netbacks ⁽¹⁾ including commodity contracts	28.24	28.50	(1)	27.00	29.71	(9)

(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.

General and Administrative Expenses

General and administrative expenses (G&A) for the third quarter of 2016 were \$872,000 compared to \$925,000 for the same period of 2015, a decrease of 6%. G&A for the first nine months of 2016 were \$2.9 million compared to \$3.6 million for the same period of 2015, a decrease of 20%. These decreases in G&A compared to 2015 relate primarily to management's efforts to reduce costs throughout the Company. This resulted in reductions in salary and benefits, professional fees and travel costs.

Depletion and Depreciation

Depletion and depreciation expense for the third quarter of 2016 was \$1,286,000 compared to \$2,284,000 in the same period of 2015. Depletion and depreciation expense for the first nine months of 2016 was \$4,381,000 compared to \$6,262,000 in the same period of 2015. The decrease for both periods is due to decreased production. Depletion and depreciation expense on a per barrel basis was \$13.65 for the third quarter of 2016 compared to \$15.97 in the third quarter of 2015. Depletion and depreciation expense on a per barrel basis was \$13.61 for the first nine months of 2016 compared to \$16.01 in the first nine months of 2015.

Stock based compensation

Stock based compensation increased from \$127,000 for the third quarter of 2015 to \$144,000 in the third quarter of 2016. For the first nine months of 2016, stock based compensation increased from \$455,000 in 2015 to \$506,000 in 2016. These increases were 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 decreased from \$499,000 for the third quarter of 2015 to \$430,000 for the third quarter of 2016. The decrease is due to the \$3.9 million paydown of the credit facility during 2016 which reduced the outstanding balance on the credit facility to \$20.5 million at September 30, 2016. For the first nine months, interest increased from \$1,448,000 in 2015 to \$1,456,000 in 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 paydown discussed above.

Net income (loss) for the period and cash used in operating activities

The Company incurred a net loss of \$843,000 (\$0.01 per share) for the third quarter of 2016 compared to net income of \$4,197,000 (\$0.03 per share) for the same period of 2015. The 2016 net loss compared to the net income for the same period in 2015 is due to a combined gain in risk management contracts for the third quarter of 2016 of \$464,000 versus a combined gain of \$5,610,000 for the third quarter of 2015, a decrease in net revenue of \$1,149,000, partially offset by a decrease in depletion and depreciation expense of \$998,000 and a decrease in operating expenses of \$147,000.

The Company incurred a net loss of \$7,403,000 (\$0.05 per share) for the first nine months of 2016 compared to a net loss of \$221,000 (\$0.00 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 \$2,415,000 versus a combined gain of \$5,242,000 for 2015, a decrease in net revenue of \$3,877,000, partially offset by a decrease in depletion and depreciation expense of \$1,881,000, a decrease in net loss from discontinued operations of \$1,312,000, a decrease in general and administrative costs of \$711,000, a decrease in operating expenses of \$268,000 and a foreign exchange gain of \$8,000 in 2016 versus a foreign exchange loss of \$256,000 in 2015.

Cash provided by operating activities for the first nine months of 2016 was \$4,725,000 compared to \$4,542,000 for the same period in 2015.

CAPITAL EXPENDITURES

(\$000, except as noted)

	Nine months ended September 30	
	2016	2015
Additions to oil and gas properties	\$ 746	\$ 9,081
Additions to exploration and evaluation	-	28
	<u>\$ 746</u>	<u>\$ 9,109</u>

For the first nine months of 2016, the Company spent approximately \$0.7 million in the U.S.

LIQUIDITY AND CAPITAL RESOURCES

	At September 30,	
	2016	2015
Working Capital (US\$)	\$ <u>3,748,000</u>	\$ <u>5,403,000</u>
Loans and Borrowings (US\$)	\$ <u>20,500,000</u>	\$ <u>24,400,000</u>
Shares Outstanding, end of period	162,689,292	162,689,292
Market Price per share, end of period (in Canadian \$)	\$ 0.215	\$ 0.38
Market Value of Shares (in Canadian \$)	\$ <u>34,978,000</u>	\$ <u>61,822,000</u>

In October 2016, the Company completed an equity offering under which it issued 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 of this offering to fund a drilling program for the further development of its Tishomingo Field, located in Oklahoma.

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 Corporation 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 September 30, 2016, the Company was in compliance with all of these covenants. At September 30, 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: \$0.4 million).

At September 30, 2016 the Company had working capital of \$3.7 million versus \$5.3 million at September 30, 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 2016. 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 September 30, 2016:

	Total	2016	2017	2018
Loans and borrowings *	(20,500)	-	-	(20,500)
Trade and other payables	(2,301)	(2,301)	-	-
	<u>(22,801)</u>	<u>(2,301)</u>	<u>0</u>	<u>(20,500)</u>

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

COMMITMENTS

The Sedano and Urraca concession applications in Spain outlined the annual work programs in each year of the four and five year concession terms, respectively, including the drilling of a total of nine wells on each concession. However, the concession applications stipulated that failure to drill the required wells in the time indicated in the concession applications 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.

As a result of permitting delays, BNK’s subsidiary submitted applications to suspend the Sedano and Urraca concession work programs. Approval of the application for Sedano was received during the third quarter of 2015. Approval of the Urraca application was never received. In May 2016, the Corporation submitted documents with the government to relinquish the Sedano concession and is awaiting a response. In September 2016, the Urraca concession expired and the Company has started the process with the government to relinquish this concession.

QUARTERLY SUMMARY

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

(\$000, except as noted)	2016		2015	
	Q3	Q2	Q1	Q4
Daily Production				
Oil (bpd)	628	672	744	832
Natural gas (mcfpd)	1,001	1,181	1,702	1,436
NGL's (bpd)	229	280	324	296
Average production (boepd)	1,024	1,149	1,352	1,367

(\$000, except as noted)	2015		2014	
	Q3	Q2	Q1	Q4
Daily Production				
Oil (bpd)	904	914	867	910
Natural gas (mcfpd)	1,799	1,637	1,397	1,182
NGL's (bpd)	350	303	149	173
Average production (boepd)	1,554	1,490	1,249	1,280

(\$000, except as noted)	2016		2015	
	Q3	Q2	Q1	Q4
Average Price				
Oil (\$/bbl)	42.55	42.41	30.24	39.36
Natural gas (\$/mcf)	2.43	1.59	1.93	1.89
NGL (\$/bbl)	15.07	15.45	10.96	13.54
Average price (\$/bbl)	31.84	30.19	21.69	28.86

(\$000, except as noted)	2015		2014	
	Q3	Q2	Q1	Q4
Average Price				
Oil (\$/bbl)	44.41	54.35	46.13	72.11
Natural gas (\$/mcf)	2.54	2.38	2.97	3.53
NGL (\$/bbl)	12.78	16.72	10.68	24.55
Average price (\$/bbl)	31.65	39.35	36.62	57.82

(\$000, except as noted)	2016		2015	
	Q3	Q2	Q1	Q4
Netback⁽¹⁾				
Average price (\$/boe)	31.84	30.19	21.69	28.86
Royalties	7.21	6.83	4.91	6.57
Operating expenses	6.05	5.46	4.49	5.19
Netback (\$/boe)	18.58	17.90	12.29	17.10

(\$000, except as noted)	2015		2014	
	Q3	Q2	Q1	Q4
Netback⁽¹⁾				
Average price (\$/boe)	31.65	39.35	36.62	57.82
Royalties	7.39	9.51	8.24	10.84
Operating expenses	5.02	4.96	5.05	5.38
Netback (\$/boe)	19.24	24.88	23.33	41.60

(\$000, except as noted)	2016		2015	
	Q3	Q2	Q1	Q4
Net operating income⁽²⁾				
Oil and gas revenue	3,001	3,157	2,669	3,834
Royalties	680	714	604	826
Operating expenses	570	571	552	653
	1,751	1,872	1,513	2,355

(\$000, except as noted)	2015		2014	
	Q3	Q2	Q1	Q4
Net operating income⁽²⁾				
Oil and gas revenue	4,525	5,335	4,117	6,809
Royalties	1,056	1,290	926	1,277
Operating expenses	717	672	568	634
	2,752	3,373	2,623	4,898

(\$000, except as noted)	2016			2015
	Q3	Q2	Q1	Q4
<i>Net earnings (loss)</i>	(843)	(5,310)	(1,250)	(6,350)
<i>Basic and Fully Diluted Earnings (loss) per share</i>	0.01	(0.03)	(0.01)	(0.04)
<i>Funds from operations</i> ⁽³⁾	1,441	1,801	1,172	2,117
<i>Bank debt</i>	20,500	22,600	24,400	24,400
<i>Total assets</i>	139,447	142,067	148,533	149,806

(\$000, except as noted)	2015			2014
	Q3	Q2	Q1	Q4
<i>Net earnings (loss)</i>	4,197	(3,660)	(103)	(57,628)
<i>Basic and Fully Diluted Earnings (loss) per share</i>	0.03	(0.02)	0.00	(0.36)
<i>Funds from operations</i> ⁽³⁾	2,573	2,963	1,017	3,651
<i>Bank debt</i>	24,400	24,400	24,400	15,401
<i>Total assets</i>	158,514	157,456	161,377	163,429

(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.

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, 162,689,292 and 162,689,292 common shares outstanding as at November 8, 2016, September 30, 2016 and September 30, 2015 respectively. The Company had 10,860,833, 10,580,833 and 9,208,667 stock options outstanding as of November 8, 2016, September 30, 2016 and September 30, 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. 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:

	Three months ended September 30		Nine months ended September 30	
	2016	2015	2016	2015
Oil and gas revenue, net of royalties	2,321	3,470	6,828	10,705
Operating expenses	570	717	1,693	1,961
Net operating income	1,751	2,753	5,135	8,744

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:

	Three months ended September 30		Nine months ended September 30	
	2016	2015	2016	2015
Cash flow from continuing operations	2,016	2,561	5,559	6,616
Change in non-cash working capital	575	(12)	1,145	688
Funds from operations	1,441	2,573	4,414	5,928

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 ("Mcf"). 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: BKK

LEGAL COUNSEL

DuMoulin Black LLP
Vancouver, BC

AUDITORS

KPMG, LLP
Calgary, AB

BANKERS

Amegy Bank National Association
Denver, CO, USA

HSBC Bank Canada
Calgary, AB

Morgan Stanley
New York, NY

CONSULTING ENGINEERS

Netherland, Sewell & Associates, Inc.
Houston, TX, USA

TRANSFER AGENT AND REGISTRAR

Computershare Trust Company
Calgary, AB

HEAD OFFICE

Suite 350, 760 Paseo Camarillo
Camarillo, CA, USA 93010
Telephone: (805) 484-3613
Fax: (805) 484-9649

CANADIAN OFFICE

10th Floor, 595 Howe Street
Vancouver, BC, Canada V6C 2T5
Telephone (604) 687-1224
Fax: (604) 687-3635