Management's Discussion and Analysis
For the year ended December 31, 2017
Dated March 20, 2018

BUSINESS DESCRIPTION AND READER GUIDANCE

Condor Petroleum Inc. ("Condor" or the "Company") is an international oil and gas company incorporated on October 20, 2006 with activities in the Republic of Kazakhstan ("Kazakhstan") and the Republic of Turkey ("Turkey"). Additional information relating to the Company, including the Annual Information Form, is available on SEDAR at www.sedar.com.

The following Management's Discussion and Analysis ("MD&A") of Condor should be read in conjunction with the Company's audited consolidated financial statements for the years ended December 31, 2017 and 2016 (the "Financial Statements"). The Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board. This MD&A is dated March 20, 2018, the date the Condor Board of Directors approved the financial statements.

All financial amounts are in Canadian dollars, unless otherwise stated.

NON-GAAP FINANCIAL MEASURES

The Company refers to "operating netback" in this MD&A, a term with no standardized meaning as prescribed by GAAP and which may not be comparable with similar measures presented by other issuers. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with GAAP. Operating netback is calculated as revenue less production costs, royalty expense and transportation and selling expense on a dollar basis and divided by the sales volume for the period on a per barrel of oil equivalent basis. The reconciliation of this non-GAAP measure is presented in the "Sales and operating netback" section of this MD&A. This non-GAAP measure is commonly used in the oil and gas industry to assist in measuring operating performance against prior periods on a comparable basis and has been presented in order to provide an additional measure to analyze the Company's crude oil and natural gas sales on a per barrel of oil equivalent basis and ability to generate funds.

OVERALL PERFORMANCE

Highlights

- Poyraz Ridge natural gas production commenced in mid-December 2017 and 360.9 MMscf of gas has been produced during start-up and commissioning activities through February 2018 which generated approximately $2.5 million in revenue and $1.8 million in operating netback[1] at an average sales price of $7.15 per Mscf.
- The Company's average overall production rate of 1,506 boepd for the past thirty days includes 402 bopd from Kazakhstan oil and 1,104 boepd from Turkey gas and is approximately four times the Company's 2017 average rate of 423 boepd.
- Crude oil sales in the fourth quarter of 2017 yielded an operating netback of $22.40 per barrel and representing an increase of 16% from the fourth quarter of 2016.
- The after tax NPV_{10} value of the Company's Proved reserves increased 9% to USD 30.1 million as of December 31, 2017 from USD 27.7 million as of December 31, 2016 and the after tax NPV_{10} value of the Company's Proved plus Probable reserves increased 8% to USD 68.1 million as of December 31, 2017 from USD 63.0 million as of December 31, 2016.
- The Yakamoz 1 exploration well in Turkey was drilled to a total depth of 2,250 meters encountering numerous gas shows while drilling. Though the well was abandoned without testing, post-well remapping of the Yakamoz prospect indicates the well was drilled off-structure and side-tracking alternatives are being developed. Deeper potential reservoirs are also being matured.
- The court proceedings related to the Company's Zharkamys exploration contract ("Zharkamys Contract") with the Ministry of Energy of the Government of Kazakhstan ("Ministry") continue. On March 1, 2018 the Kazakhstan Civil Court ("Civil Court") released its ruling which confirmed that a force majeure event had occurred. The Ministry has the right to appeal the ruling within 30 calendar days. If the Ministry does not appeal the Civil Court ruling will enter into legal force and would allow the Company to submit an addendum to the Zharkamys Contract to the Ministry which, after ratification, would extend the exploration period by 630 days.
- During the first quarter of 2017, the Company established and received funds from a USD 10.0 million secured non-revolving credit facility which bears interest at 14% and matures on January 31, 2020 and issued to the lender a warrant certificate exercisable into one million common shares of Condor at $2.35 per share on or before January 31, 2020.
- The Company recorded a net loss of $66.7 million for the year ended December 31, 2017 (2016: $11.9 million) which includes $56.6 million of exploration and evaluation expense pertaining to the derecognition of the Zharkamys contract in the first quarter of 2017.

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1 Operating netback is a non-GAAP measure and is a term with no standardized meaning as prescribed by GAAP and may not be comparable with similar measures presented by other issuers. See non-GAAP financial measures. The calculation of operating netback is aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook.

- On January 1, 2018 the reference natural gas sales price in Turkey set by the state owned pipeline transportation company BOTAŞ was increased by approximately 14% to 800 TL per thousand cubic meter, or approximately $7.63 per Mscf at the current exchange rate of 2.97 TL/CAD.

Operations

The Company produces crude oil in Kazakhstan and natural gas in Turkey and overall production increased 186% to 154,429 barrels of oil equivalent or an average of 423 boepd in 2017 from 53,954 barrels of oil equivalent or an average of 148 bopd in 2016. Production increased mainly due to realizing a full year of crude oil production in 2017 while in 2016 production commenced in September at Shoba and in October at Taskuduk following the signing of the respective production contracts. In addition, the Company commenced natural gas production in Turkey in mid-December of 2017. Gas production rates were initially restricted to allow for optimization of the facility equipment settings and de-bottlenecking activities during start-up operations. The facility transitioned into routine operations mode in February 2018.

Capital expenditures in 2017 amounted to $19.3 million (2016: $16.7 million) and relate mainly to development activities in Turkey including construction of the Poyraz Ridge gas plant, construction of a 16 km sales gas pipeline and development well drilling, completions and tie-ins. Poyraz Ridge natural gas production commenced in mid-December 2017 and has since transitioned the Company into positive cash flow. During start-up and commissioning activities from mid-December 2017 through February 2018 the Company produced 360.9 MMscf of gas which generated $2.5 million in revenue, taking advantage of Turkey's strong gas prices and favourable fiscal regime. Gas production has averaged 1,104 boepd during the past thirty days. Up to two additional development wells could be drilled in 2018 to offset natural decline rates.

A four well Poyraz Ridge drilling program was completed in January 2017, which consisted of three appraisal and development wells (P3, P5, and PW2) and one exploration well (PW5) targeting the footwall compartment lying to the north of the field. PW5 did not flow at commercial rates and is undergoing additional evaluation based on newly reprocessed 3D seismic inversion data and an updated geologic model. A fifth well (PW4) was drilled in May 2017 and the fluids used during completion operations are currently being recovered so that PW4 gas production can begin. Three legacy wells (P1, P2, and PW1) which were drilled from 2011 to 2014 were also tied into the gathering system and connected to the gas plant.

The Yakamoz 1 exploration well in Turkey was drilled to a total depth of 2,250 meters in July 2017 to test a "new" sub thrust-fold play type located 2 km from the Poyraz Ridge gas field. The well confirmed that an active petroleum system extends to the north and west of Poyraz Ridge and, as predicted, numerous gas shows proved an extensive fracture system prevails along the Miocene-Eocene sub-thrust trend. Though Yakamoz 1 was abandoned without testing, the well provided critical structural and stratigraphic information. Based on the new velocity-depth information, re-mapping of the Yakamoz prospect concluded the well was drilled off-structure. This data coupled with recent reprocessing of the original 2D seismic data has been integrated into a revised geological model with a view to side-tracking the Yakamoz 1 well, targeting both the proven primary Miocene & Upper Eocene reservoirs and the deeper (2500+ meters) untested secondary Middle–Lower Eocene reservoirs. The reprocessed seismic data has significantly improved both data quality and imaging of both structure and stratigraphy and has identified two potential up-dip locations to the southwest and northwest of the Yakamoz 1 well, each with an additional 200 meters of vertical section.

The net loss for the year ended December 31, 2017 of $66.7 million (2016: $11.9 million) includes $56.6 million of exploration and evaluation expense pertaining to the derecognition of the Zharkamys Contract in the first quarter of 2017 and $1.6 million of exploration and evaluation expense related to the Yakamoz 1 well. Cash used in operating activities amounted to $8.2 million for the year ended December 31, 2017 compared to $9.2 million in 2016.

Zharkamys Contract

The Zharkamys Contract was due to expire on December 14, 2016. Prior to this date, the Kazakhstan Chamber of International Commerce and subsequently the Civil Court confirmed that a force majeure event had occurred which, under Kazakhstan subsurface use law, can be the basis for the Zharkamys Contract validity period to be extended for a period of 630 days.

In May 2017, the Kazakhstan Court of Appeal ("Court of Appeal"), pursuant to an appeal filed by the Ministry, released its ruling that the force majeure event was not recognized and reversed the decision of the Civil Court. As a result of the Court of Appeal ruling there was uncertainty regarding the Company's legal rights to extend the Zharkamys Contract and the related exploration and evaluation assets in the amount of $56.6 million were derecognized as at March 31, 2017.

The Company referred the case to the Kazakhstan Supreme Court ("Supreme Court") and in November 2017 the Supreme Court released its ruling which overturned both the Civil Court and the Court of Appeal rulings and referred the case back to the Civil Court for further review by a new panel of judges.

On March 1, 2018 the Civil Court released its ruling which confirmed that the force majeure event had occurred. The Ministry has the right to appeal the Civil Court ruling within 30 calendar days following the issuance of the ruling. If the Ministry does not appeal within the mandated period, the Civil Court ruling will enter into legal force and would allow the Company to submit an addendum to the Zharkamys Contract to the Ministry which, after ratification, would extend the exploration period by 630 days.

The on-going court proceedings do not affect the Company's production rights for the Shoba and Taskuduk oilfields which are each governed by separate production contracts.

Credit Facility

During the first quarter of 2017 the Company established and received funds from a USD 10.0 million secured non-revolving credit facility which bears interest at 14% and matures on January 31, 2020 ("Credit Facility"). Interest for the first year of the Credit Facility is due on January 31, 2018 followed by eight payments of USD 1.25 million of principal plus interest due quarterly in arrears commencing March 31, 2018. Condor also issued to the lender a warrant certificate exercisable into one million common shares of Condor at $2.35 per share on or before January 31, 2020. The loan proceeds are available to fund capital expenditures related to drilling, infrastructure and workovers at Poyraz Ridge and for general corporate purposes.

Reserves

The Company's 2017 and 2016 reserves were prepared by independent reserves evaluator McDaniel & Associates Consultants Ltd. (see Reserves Advisory) and the gross Company reserves are summarized by volume and net present value discounted at 10% ("NPV_{10}") as follows:

Gross Company reserves volumes as of December 31, 2017	Kazakhstan	Turkey		Total
	Oil Mbbl	Gas MMscf	Gas Mboe	Oil &Gas Mboe
Proved	1,399	8,228	1,371	2,770
Probable	1,188	10,034	1,672	2,860
Proved plus Probable	2,587	18,262	3,044	5,631
Possible	1,048	7,166	1,194	2,242
Proved plus Probable plus Possible	3,635	25,427	4,238	7,873

Gross Company reserves NPV_{10} (After Tax, in USD 000's)	Kazakhstan	Turkey	Total
Proved	9,238	20,874	30,112
Probable	12,857	25,172	38,028
Proved plus Probable	22,095	46,046	68,141
Possible	15,924	12,806	28,729
Proved plus Probable plus Possible	38,020	58,852	96,872

The Company's gross Proved reserves decreased 24% to 2,770 Mboe as of December 31, 2017 from 3,658 Mboe as of December 31, 2016 and Proved plus Probable reserves decreased 18% to 5,631 Mboe as of December 31, 2017 compared to 6,865 Mboe as of December 31, 2016 due primarily to reductions in the mapped areas at Poyraz Ridge based on well results and reprocessed 3D seismic inversion data and the presence of paraffin which impacted some of the producing interval reserves.

Despite the reserve volume decreases the overall reserve values (NPV_{10} after tax) increased to USD 30.1 million as of December 31, 2017 from 27.7 million as of December 31, 2016 for the Proved reserves and to USD 68.1 million in 2017 from 63.0 million for the Proved plus Probable reserves. The reserve value increases are due mainly to higher forecasted Turkish gas prices which range from USD 5.69/Mscf to 7.07/Mscf as of December 31, 2017 versus USD 5.09/Mscf to 6.46/Mscf as of December 31, 2016 and lower estimated future development costs and transportation costs.

SELECTED FINANCIAL INFORMATION

For the year ended December 31 ($000's except per share amounts)	2017	2016
Revenue	5,652	1,532
Net loss	(66,668)	(11,892)
Net loss per share (basic and diluted)	(1.54)	(0.29)
Capital expenditures	19,272	16,682

RESULTS OF OPERATIONS

Sales and operating netback[1]

For the year ended December 31		2017			2016	
	Oil ($000's)	Gas ($000's)	Total ($000's)	Oil ($000's)	Gas ($000's)	Total ($000's)
Crude oil and natural gas sales	5,312	340	5,652	1,532	-	1,532
Production costs	(1,660)	(40)	(1,700)	(502)	-	(502)
Royalty expense	(124)	(44)	(168)	(39)	-	(39)
Transportation and selling expense	(579)	(14)	(593)	-	-	-
Operating netback[1]	2,949	242	3,191	991	-	991
	Oil ($/bbl)	Gas ($/Mscf)	Total ($/boe)	Oil ($/bbl)	Gas ($/Mscf)	Total ($/boe)
Crude oil and natural gas sales	34.74	6.52	34.98	26.39	-	26.39
Production costs	(10.86)	(0.77)	(10.52)	(8.65)	-	(8.65)
Royalty expense	(0.81)	(0.84)	(1.04)	(0.67)	-	(0.67)
Transportation and selling expense	(3.79)	(0.27)	(3.67)	-	-	-
Operating netback[1]	19.29	4.64	19.75	17.07	-	17.07
Sales volume	152,895 bbl	52,174 Mscf	161,591 boe	58,048 bbl	-	58,048 boe

1 Operating netback is a non-GAAP measure and is a term with no standardized meaning as prescribed by GAAP and may not be comparable with similar measures presented by other issuers. See non-GAAP financial measures. The calculation of operating netback is aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook.

Revenues from crude oil and natural gas sales increased to $1.6 million on 40,437 barrels of oil equivalent or $39.54 per barrel of oil equivalent for the three months ended December 31, 2017 compared to $1.2 million on 41,755 barrels of oil equivalent or $19.23 per barrel of oil equivalent for the same period in 2016. For the year ended December 31, 2017, revenues increased to $5.7 million on 161,591 barrels of oil equivalent or $34.98 per barrel of oil equivalent versus $1.5 million on 58,048 barrels of oil equivalent or $26.39 per barrel of oil equivalent for 2016. Operating netback averaged $23.57 per barrel of oil equivalent in the fourth quarter of 2017 (2016: $19.23) and $19.75 per barrel of oil equivalent for 2017 (2016: $17.07).

Total revenue increased in 2017 due to increased crude oil production and sales volumes as there was no production in 2016 until production resumed at Shoba in September and Taskuduk in October following the signing of the respective production contracts and the commencement of natural gas production in Turkey in mid-December 2017. Revenue also increased due to higher operating netbacks per barrel of oil as domestic crude oil prices in Kazakhstan have strengthened in 2017. In addition, the delivery point for crude oil sales was previously at the Company's facilities in the Shoba and Taskuduk oilfields but commencing in May 2017, the Company began delivering crude oil by truck to nearby refineries and recognized a higher sales price and the related transportation and selling expense. For the year ended December 31, 2017, the transportation and selling expense amounted to $0.6 million or $3.67 per barrel (2016: nil).

Marketing

All crude oil sales in Kazakhstan to date have been in the domestic market at prevailing local prices. The Government of Kazakhstan does not set a domestic price for crude oil and there is no industry accepted reference price. The domestic price is influenced by market factors and industry conditions and while it usually trends similar to world oil prices (e.g. Brent or Urals Med), there is no set differential. The domestic prices are denominated and settled in Tenge, the local currency. The Shoba and Taskuduk production contracts each contain a domestic sales obligation to deliver up to thirty five percent of production to the domestic market and provide the Government of Kazakhstan the right to purchase up to seventy percent of the production of each property at prevailing market prices.

All natural gas sales in Turkey are expected to be domestic sales at prices which are denominated and settled in Turkish Lira. Turkish gas prices are set and published monthly by the state owned pipeline transportation company BOTAŞ. The benchmark for the Company's gas sales are BOTAŞ Level 2 wholesale tariff less a marketing differential. There are no domestic obligations per the Company's operating licenses in Turkey, but the Turkish Petroleum Law requires that sixty five percent of production from onshore producers be sold to domestic markets.

Production

For the year ended December 31	2017	2016	Change	Change %
Crude oil (bbl)	145,459	53,954	91,505	170%
Natural gas (Mscf)	53,817	-	53,817	-
Natural gas (boe)	8,970	-	8,970	-
Total production volume (boe)	154,429	53,954	100,475	186%
Crude oil (bopd)	399	148	251	170%
Natural gas (Mscfpd)	147	-	147	-
Natural gas (boepd)	24	-	24	-
Average daily production (boepd)	423	148	275	186%

The Company produces crude oil in Kazakhstan and natural gas in Turkey and overall production increased 186% to 154,429 barrels of oil equivalent or an average of 423 boepd in 2017 from 53,954 barrels of oil equivalent or an average of 148 bopd in 2016. Production increased mainly due to realizing a full year of crude oil production in 2017 while in 2016 production commenced in September at Shoba and in October at Taskuduk following the signing of the respective production contracts. In addition, the Company commenced natural gas production in Turkey in mid-December of 2017. Gas production rates were initially restricted to allow for optimization of the facility equipment settings and de-bottlenecking activities during start-up operations. The facility transitioned into routine operations mode in February 2018.

Production costs

Production costs are comprised mainly of personnel, fuel, heavy equipment, safety, maintenance, property tax and social infrastructure costs. Total production costs increased to $1.7 million for the year ended December 31, 2017 from $0.5 million for the year ended December 31, 2016 which equates to $10.52 per barrel of oil equivalent for the year ended December 31, 2017 from $8.65 per barrel for the year ended December 31, 2016. The increase is due to higher Shoba and Taskuduk production and sales volumes and associated road improvements, facility winterization enhancements and social infrastructure costs.

Substantially all of the production costs in 2017 relate to crude oil production in Kazakhstan as natural gas production commenced in Turkey in mid-December 2017.

Royalty expense

Royalty expense increased to $0.2 million for the year ended December 31, 2017 from $0.04 million for the same period in 2016 due to the increase in oil and gas production and sales. The Company is subject to progressive royalty rates in Kazakhstan amounting to 2.5% in 2017 (2016: 2.5%) and a flat royalty rate in Turkey of 12.5%.

General and administrative expenses

General and administrative expenses are comprised mainly of personnel, professional services, office, and travel costs and decreased to $8.0 million for the year ended December 31, 2017 from $9.1 million for the same period in 2016 due to mainly lower personnel and office costs. The Company continues to utilize existing staff and resources to minimize cost increases related to the acquisition of the Turkish properties in March of 2016.

Depletion and depreciation

For the year ended December 31, 2017, depletion and depreciation expense increased to $2.8 million from $1.0 million for the same period in 2016 due mainly to the increased volume of crude oil sales in Kazakhstan and the commencement of natural gas production in mid-December in Turkey.

Stock based compensation

Stock based compensation expense decreased to $0.1 million for the year ended December 31, 2017 from $0.8 million for the same period in 2016. The expense is recognized on a graded basis and fluctuates based on the timing of the grants and vesting periods.

Finance income, expense and accretion expense

For the year ended December 31, 2017, finance income, which includes interest income and accretion of Kazakhstan value added tax ("VAT") receivables, amounted to $0.8 million compared to $0.4 million in the previous period.

Finance expense increased to $3.5 million for the year ended December 31, 2017 from $0.8 million for the same period in 2016 mainly due to the interest on the Credit Facility secured in the first quarter of 2017. Finance expense includes interest on long term borrowings, amortization of loan issuance costs, amortization of the warrants, the impact of initial VAT receivables discounting and accretion expense on historical cost obligations and decommissioning provisions.

Foreign exchange loss amounted to $1.3 million in the year ended December 31, 2017 compared to $1.8 million for the same period in 2016 due to the foreign exchange movements of USD denominated current assets, mainly cash and cash equivalents as well short-term and long term portions of the USD denominated borrowings and inter-company loans.

Deferred income tax recovery

Deferred income tax recovery increased to $3.4 million for year ended December 31, 2017 compared to a recovery of $1.8 million in the same period of 2016 due to the recognition of a deferred tax asset of $3.4 million related to deductible temporary differences on Kazakhstan oil and gas properties and tax losses carried forward.

LIQUIDITY AND CAPITAL RESOURCES

In Turkey, the Poyraz Ridge gas processing facilities and pipeline were substantially completed and commissioned in December 2017 and no significant capital expenditures are expected on the facilities in 2018. Depending on the timing and amount of available capital including funds from operating activities, the Company is planning to drill up to two wells at Poyraz Ridge in 2018. There are no work commitments related to the Poyraz Ridge or Destan operating licenses in Turkey.

In Kazakhstan, the Company has work commitments of $5.5 million. Depending on the timing and amount of available capital including funds from operating activities, the Company is planning to drill up to two wells at Shoba in 2018. Any work program shortfalls in Kazakhstan are not subject to penalties, and punitive actions including the suspension or revocation of the respective contract only apply in cases where financial work commitment fulfilment is less than thirty percent for two consecutive years.

As at December 31, 2017 the Company has $(1.7) million of working capital and expects positive cash flow from crude oil sales in Kazakhstan and positive cash flow from natural gas sales in Turkey. The Company believes it has sufficient capital to fund the planned capital and operating activities for at least the next twelve months. Any potential shortfalls may be required to be funded through various debt and equity instruments, asset portfolio management and other available corporate and financial opportunities.

COMMITMENTS AND CONTINGENT LIABILITIES

The Company's contractual work commitments as at December 31, 2017 are as follows:

($000's)	< 1 year	1-3 years	4-5 years	> 5 years	Total
Shoba	4,519	5,398	1,040	2,111	13,068
Taskuduk	948	67	55	119	1,189

The Company has contractual work commitments pursuant to the Shoba and Taskuduk production contracts in Kazakhstan. These work commitments may be amended from time to time in accordance with planned development activities proposed by the Company and approved by the Government of Kazakhstan and additional amounts could be significant. During 2017, the capital expenditure portion of the Shoba work commitments were reduced from $16.9 million to $8.8 million and the remaining expenditures and development activities previously scheduled for 2017 were shifted into 2018 and 2019. Non-fulfilment of work commitments for Shoba or Taskuduk could result in punitive actions including the suspension or revocation of the respective contract in case financial work commitment fulfilment is less than thirty percent for two consecutive years. Financial work commitment shortfalls for development activities at Shoba and Taskuduk are not subject to penalties while shortfalls on the training, social development and scientific research components may be subject to penalties of 1% of the shortfall.

There are no work commitments related to the Poyraz Ridge or Destan operating licenses in Turkey.

OUTSTANDING SHARE DATA

Common shares

As at December 31, 2017 and the date of this MD&A there were 43,265,100 common shares outstanding.

Convertible securities

As at December 31, 2017 and the date of this MD&A, outstanding convertible securities are comprised of 3,029,000 stock options with a weighted average exercise price of $2.31 and a warrant certificate exercisable into one million common shares of Condor at $2.35 per share on or before January 31, 2020.

OFF-BALANCE SHEET ARRANGEMENTS

The Company did not have any off-balance sheet arrangements as at December 31, 2017.

QUARTERLY INFORMATION

The following table sets forth selected financial information of the Company for the eight most recently completed quarters to December 31, 2017:

For the quarter ended ($000's except per share amounts)	**Q4 2017**[3]	**Q3 2017**	**Q2 2017**	**Q1 2017**	**Q4 2016**	**Q3 2016**	**Q2 2016**	**Q1 2016**
Revenue [1]	1,599	1,701	1,405	947	1,203	72	257	-
Net income (loss)[2]	(125)	(2,531)	(4,105)	(59,907)	(3,183)	(1,650)	(2,994)	(4,065)
Net income (loss) per share (basic and diluted)	(0.003)	(0.06)	(0.10)	(1.38)	(0.07)	(0.04)	(0.06)	(0.12)

1 Prior to Q4 2016, revenues were inconsistent due to certain production and sales constraints related to exploration period and trial production limitations, low domestic crude oil prices in Kazakhstan during 2016 and delays in executing the Shoba and Taskuduk production contracts. Thereafter, revenues are impacted by the level of production and sales volumes in each period and by crude oil sales prices, which increased each quarter during 2017.

2 Net income (loss) in all periods has been impacted by, among other things, production, sales and revenue issues discussed in (3) above, general and administrative costs, stock based compensation expense and foreign exchange gains and losses in the respective periods. The Q1 2017 net loss includes $56.6 million of exploration and evaluation expense related to the Zharkamys Contract derecognition.

3 Natural gas production and sales in Turkey commenced in mid-December 2017 at the Company's Poyraz Ridge gas field.

CRITICAL ACCOUNTING ESTIMATES

The timely preparation of financial statements requires management to make use of judgments, estimates and assumptions when transactions affecting the current accounting period cannot be finalized until future periods. These estimates will affect assets, liabilities and the disclosure of assets and liabilities at the date of the financial statements, as well as revenues and expenses during the reporting periods. Such estimates are based on informed judgments made by management. Actual results could differ from those estimates as future confirming events occur. Significant assumptions and estimates about the future and other sources of estimation uncertainty that management has made at the financial position reporting date that could result in a material adjustment to the carrying amount of assets and liabilities, in the event that actual results differ from assumptions made, are outlined below.

- Business combinations: the Company uses the acquisition method to account for business combinations. Assets acquired and liabilities assumed in a business combination are recorded at fair value at the time of acquisition. The determination of fair value requires the Company to make estimates, assumptions and judgments that are subject to measurement uncertainty. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of property, plant and equipment, other long term assets and provisions. Consequently, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings, due to the impact on future depreciation and depletion expense as well as impairment tests;
- Impairment testing: estimates include volumes of recoverable reserves and resources, future commodity prices, future operating and capital costs, production profiles, discount rates, and consequently fair values of properties. A downward revision in the reserve or resource estimates or future forecast prices or an upward revision to future capital costs could result in an asset impairment which would reduce future earnings and the associated net book value of assets;
- Other long term assets and liabilities: estimates include the timing and amounts of future receipts and payments, discount rates and related cash flows. A change in the timing of cash flows or discount rates may impact earnings as a result of changes in finance income and expense;
- Depletion: estimates include the amount of reserve volumes and future development capital. A downward revision in the reserve estimates or an upward revision to future capital may result in increased depletion and a reduction in net book value of assets if such a revision results in an accounting impairment. Depletion is charged on a unit-of-production basis over the Proved plus Probable reserves for each cash generating unit and a revision in the productive capacity of the assets may result in increased depletion and a reduced net book value of assets;
- Decommissioning provisions: estimates include the amount and expected timing of asset retirements, discount and inflation rates and future cash flows. As a result of the long term nature of the Company's operations, these estimates may change over time which may result in a change in the decommissioning provision and corresponding asset value, and impact future earnings as a result of changes in accretion and depletion expense;
- Stock based compensation: estimates include determining appropriate share price volatility, expected lives, forfeiture rates and risk free rates;
- Deferred income tax: determining likelihood of income tax assets being realized requires estimates of future taxable income. Changes in the estimate of future taxable income and the recovery of deductible temporary differences may result in the recognition of a deferred tax asset on the statement of financial position and an increase in earnings at the time when the tax recovery is charged.

NEW ACCOUNTING PRONOUNCEMENTS

- On January 13, 2016, the IASB issued IFRS 16, "Leases" ("IFRS 16"), which requires entities to recognize lease assets and lease obligations on the balance sheet. For lessees, IFRS 16 removes the classification of leases as either operating leases or finance leases, effectively treating all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements, and may continue to be treated as operating leases. Lessors will

continue with a dual lease classification model. Classification will determine how and when a lessor will recognize lease revenue, and what assets would be recorded. IFRS 16 is effective for years beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 "Revenue From Contracts With Customers" has been adopted. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of the new standard on the financial statements.

- On July 24, 2014, the IASB issued IFRS 9, "Financial Instruments" ("IFRS 9") to replace International Accounting Standard 39, "Financial Instruments: Recognition and Measurement." IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the IAS 39 requirements; however, where the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in OCI rather than net earnings, unless this creates an accounting mismatch. In addition, a new expected credit loss model for calculating impairment on financial assets replaces the incurred loss impairment model used in IAS 39. The new model will result in more timely recognition of expected credit losses. IFRS 9 is effective for years beginning on or after January 1, 2018. The Company will apply the new standard retrospectively and elect to use the practical expedients permitted under the standard. Comparative periods will not be restated.
- On May 28, 2014, the IASB published IFRS 15, "Revenue From Contracts With Customers" ("IFRS 15") replacing IAS 11, "Construction Contracts", IAS 18, "Revenue" and several revenue-related interpretations. IFRS 15 establishes a single revenue recognition framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded. The new standard is effective for annual periods beginning on or after January 1, 2018. The standard may be applied retrospectively or using a modified retrospective approach. The Company will apply the standard using the modified retrospective approach recognizing the cumulative impact of adoption in retained earnings as of January 1, 2018. Comparative periods will not be restated.

These new standards are not expected to have any material impact on the financial statements when adopted.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Company's President and Chief Executive Officer ("CEO") and Vice President, Finance and 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 ("ICFR") 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 for external purposes in accordance with IFRS.

The DC&P have been designed to provide reasonable assurance that material information relating to Condor 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 Condor under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.

The CEO and CFO are required to cause the Company to disclose any change in the Company's ICFR that occurred during the most recent interim period that has materially affected, or is reasonably likely to materially affect, the Company's ICFR. No changes in ICFR were identified during such period that have materially affected or are reasonably likely to materially affect, the Company's ICFR. It should be noted that a control system, including the Company's DC&P and ICFR, 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 ICFR will prevent all errors or fraud.

The CEO and CFO have evaluated the Company's DC&P and ICFR as at December 31, 2017 based on the framework in "Internal Control Over Financial Reporting – Guidance for Smaller Public Companies" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the evaluation, the CEO and CFO concluded, that the Company's design and operation of DC&P and ICFR were effective as of December 31, 2017.

During the year ended December 31, 2017, there were no changes to the Company's ICFR that materially affected, or are reasonably likely to materially affect the Company's ICFR. Control systems, no matter how well conceived or operated, can provide only reasonable, not absolute assurance that the objectives of the control systems are met.

FINANCIAL RISK MANAGEMENT

Credit risk

Credit risk arises from the possibility that a counterparty to which the Company provides goods or services is unable or unwilling to fulfill their obligations. The maximum exposure to credit risk at year end is as follows:

Carrying amounts as at December 31 (000's)	**2017**	**2016**
Cash and cash equivalents	3,910	21,531
Trade and other receivables	976	1,061
Other current financial assets	4,609	1,207
Other long term assets	6,257	9,637
	15,752	33,436

The Company limits its exposure to credit risk on cash and cash equivalents and bank deposits by depositing and investing in banks with investment grade credit ratings. As at December 31, 2017 $3.6 million of cash and cash equivalents are invested with Canadian chartered banks, $0.1 million is held in the Netherlands, $0.1 million is held in Kazakhstan and $0.1 million is held in Turkey.

Credit risk on trade receivables is mainly related to crude oil and natural gas marketers and the risk of financial loss if a customer, partner or counterparty to a financial instrument fails to meet its contractual obligations. Sales of crude oil and related receivables in Kazakhstan are with one customer and sales of natural gas and related receivables in Turkey are with one customer, and are therefore subject to concentration risk. This risk is mitigated by management's policies and practices related to credit risk. In Turkey, the Company holds a bank guarantee provided by the buyer of its natural gas amounting to two month's estimated gas sales as security on gas sales receivables. The Company has examined its accounts receivable and concluded that an allowance for doubtful accounts is not necessary and that the amount shown as accounts receivable is valid and collectible.

Other long term assets include Kazakhstan VAT receivables which may be offset against VAT collected on future domestic sales or refunded on future export sales. The Company has not made any provision and considers the amounts to be fully recoverable.

Liquidity risk and capital management

Liquidity risk is the risk the Company will encounter difficulty in meeting obligations and commitments and repaying liabilities as they fall due. The Company requires liquidity mainly to satisfy financial obligations and operating requirements related to activities in Kazakhstan and Turkey.

At December 31, 2017 the Company had a working capital deficit of $1.7 million (December 31, 2016 – surplus of $19.4 million). The Company commenced gas production and sales in December 2017 and accordingly anticipates cash from operating activities to increase in 2018 and provide the necessary capital for oil and gas development activities and repayment of the loan principal and interest. Also, the Company has the ability to adjust its capital structure by issuing new equity or debt, disposing of assets and making adjustments to its capital expenditure program to the extent the capital expenditures are not committed.

The Company does not have any externally imposed restrictions on its capital, except on the bank deposits for decommissioning obligations in Kazakhstan and Turkey.

To manage capital and operating spending, budgets are prepared, monitored regularly and updated as required. The Company also utilizes authorizations for expenditures to manage capital spending.

The cash flows presented in the tables below differ from the amounts included in the statement of financial position because the amounts disclosed in the tables are the contractual undiscounted cash flows.

The Company's contractual obligations as at December 31, 2017 are as follows:

(000's)	< 1 year	1-3 years	4-5 years	> 5 years	Total
Accounts payable and accrued liabilities	2,608	-	-	-	2,608
Borrowings	9,403	6,819	-	-	16,222
Non-cancellable operating leases	460	442	-	-	902
Other long term liabilities (undiscounted)	481	962	962	1,802	4,207

The Company's contractual obligations as at December 31, 2016 are as follows:

(000's)	< 1 year	1-3 years	4-5 years	> 5 years	Total
Accounts payable and accrued liabilities	4,526	-	-	-	4,526
Non-cancellable operating leases	245	298	305	127	975
Other long term liabilities (undiscounted)	504	1,007	1,007	2,517	5,035

Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk is comprised of three types of market price changes: foreign currency exchange rates, interest rates and commodity prices.

Foreign currency exchange risk

The Company is exposed to significant foreign currency risk as a substantial portion of the Company's foreign activities are transacted in or referenced to foreign currencies including USD, KZT and TRY, and a significant portion of the Company's cash and cash equivalents and borrowings are held in USD. The Company had no forward exchange rate contracts in place at or during the years ended December 31, 2017 and 2016.

During the year ended December 31, 2017, the CAD appreciated from 1.34 per 1.00 USD to 1.25, which led to a foreign exchange loss of $1.1 million (2016: loss of $1.8 million) related mainly to USD denominated cash and cash equivalents and inter-company loans.

During the year ended December 31, 2017, the KZT depreciated from 247 per 1.00 CAD to 265 and TRY depreciated from 2.62 per 1.00 CAD to 3.02 resulting in a $4.8 million translation loss adjustment through equity (2016: loss of $2.5 million) and a $0.2 million foreign exchange loss related mainly to USD denominated inter-company loans.

A $0.01 change in the Canadian dollar to U.S. dollar exchange rate at December 31, 2017 would have changed profit or loss by $0.1 million (2016: $0.2 million). This analysis assumes that all other variables, in particular interest rates, remain constant.

Interest rate risk

Interest rate risk is the risk of change in the borrowing rates of the Company. The interest rate on borrowings is fixed. Therefore, the Company has no current exposure to changes in interest rates, except for interest rates on cash and cash equivalents.

Commodity price risk

The Company is exposed to changes in commodity prices inherent in the oil and natural gas industry. Commodity prices for petroleum and natural gas are impacted by economic events and factors which are beyond the Company's control. Fluctuations in petroleum and natural gas prices may have a significant effect on the Company's results of operations and cash flows from operating activities and, subsequently, may also affect the value of the oil and gas properties and the level of spending for exploration and development. The majority of the Company's production is sold under short-term contracts, which exposes the Company to the risk of price movements. The Company had no forward price contracts or derivatives in place at or during the years ended December 31, 2017 or 2016.

Fair value of financial instruments

Loans and receivables include cash and cash equivalents, trade and other receivables, other current assets and other long term assets. Other financial liabilities include accounts payable and accrued liabilities, current and long term borrowings, and other long term liabilities. The fair value of cash and cash equivalents, accounts receivable, other current assets and accounts payable and accrued liabilities approximate their carrying values due to the short-term nature of these instruments. The carrying value of other long term assets and other long term liabilities approximate their fair value as they are either discounted at, or carry interest incurred at certain market rates.

OTHER BUSINESS RISKS

In the normal course of business, the Company is exposed to a variety of risks and uncertainties. In addition to the risks associated with liquidity and capital resources, critical accounting estimates, financial instruments, credit risk and market risk described in this MD&A, the Company is exposed to various operational, technical, financial and regulatory risks and uncertainties, many of which are beyond its control and may significantly affect future results. Operations may be unsuccessful or delayed as a result of competition for services, supplies and equipment, mechanical and technical difficulties, the ability to attract and retain employees and contractors on a cost-effective basis, commodity and marketing risk and seasonality. The Company is exposed to considerable risks and uncertainties including, but not limited to:

- finding oil and natural gas reserves on an economical basis;
- uncertainties related to estimating the Company's reserves;
- financial risks including access to debt or equity markets which the Company is likely dependent upon in order to fully develop the current properties;
- technical problems which could lead to unsuccessful wells, well blowouts and environmental damage;
- obtaining timely regulatory approvals;
- third party related operational risks including the ability to obtain access to wells, access to third party gathering and processing facilities, access to pipeline, railway and other transportation infrastructure;
- fluctuations in commodity prices, interest rates and foreign currency exchange rates;
- adverse factors including climate, geographical and weather conditions and labour disputes;
- timing of future debt and other obligations;
- relinquishment of land territory during and upon the completion of the exploration period;
- regulatory legislation and policies, including the fulfillment of contractual minimum work programs, the compliance with which may require significant expenditures and non-compliance with which may result in fines, penalties, production restrictions, suspensions or revocations of contracts;
- changes to taxation policies, laws and interpretations thereof;
- political risks inherent with international activities and doing business in foreign jurisdictions;
- obtaining comprehensive and appropriate insurance coverage at reasonable rates; and
- obtaining approval for extensions to exploration periods, and, upon commercial discovery, negotiating and signing development contracts.

Please see the Company's Annual Information Form, filed on SEDAR (www.sedar.com) for further discussion on these risks.

RESERVES ADVISORY

This MD&A includes information pertaining to the Evaluation of Crude Oil and Natural Gas Reserves Kazakhstan and Turkey as of December 31, 2017 prepared by independent reserves evaluator McDaniel & Associates Consultants Ltd. ("McDaniel"). The report was prepared by qualified reserves evaluator in accordance with definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook and National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and is based on respective McDaniel pricing effective December 31, 2017 and McDaniel pricing effective December 31, 2016. Additional reserve information as required under NI 51-101 is included in the Company's Annual Information Form filed on SEDAR.

Statements relating to reserves are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated. The reserve estimates described herein are estimates only. The actual reserves may be greater or less than those calculated. Estimates with respect to reserves that may be developed and produced in the future are often based upon volumetric calculations, probabilistic methods and analogy to

similar types of reserves, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves.

References herein to barrels of oil equivalent ("boe") are derived by converting gas to oil in the ratio of six thousand standard cubic feet ("Mscf") of gas to one barrel of oil based on an energy conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given 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 Mscf to 1 barrel, utilizing a conversion ratio at 6 Mscf to 1 barrel may be misleading as an indication of value, particularly if used in isolation.

"Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved reserves.

"Probable" reserves are those additional reserves that are less certain to be recovered than Proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable reserves.

"Possible" reserves are those additional reserves that are less certain to be recovered than Probable reserves. There is a 10 percent probability that the quantities actually recovered will equal or exceed the sum of Proved plus Probable plus Possible reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated Proved plus Probable plus Possible reserves.

FORWARD-LOOKING STATEMENTS

Certain statements in this MD&A constitute forward-looking statements under applicable securities legislation. Such statements are generally identifiable by the terminology used, such as "anticipate", "appear", "believe", "intend", "expect", "plan", "estimate", "budget", "outlook", "scheduled", "may", "will", "should", "could", "would", "in the process of" or other similar wording. Forward-looking information in this MD&A includes, but is not limited to, information concerning: the ability of the drilled wells to become producing wells; projections and timing with respect to crude oil and natural gas production; expected markets and prices for future oil and gas sales; the timing and ability to obtain various approvals for the Company's exploration and development activities; the timing and ability to access oil and gas pipelines and oil and gas domestic and export sales markets; anticipated capital expenditures and cash flows; sources and availability of financing for potential budgeting shortfalls; the timing and ability to obtain future funding on favorable terms; general business strategies and objectives; possible outcomes regarding the Zharkamys Contract including the possibility that the term may be extended or, conversely, that it may revert back to the Ministry; the timing and ability to obtain exploration contract, production contract and operating license extensions; the potential for additional contractual work commitments; the ability to meet and fund the contractual work commitments; the satisfaction of the work commitments; the results of non-fulfillment of work commitments; the expectations related to future general and administrative and other expenses; projections relating to the adequacy of the Company's provision for taxes; the timing and ability to collect VAT; expected rates of return; and treatment under governmental regulatory regimes and tax laws.

By its very nature, such forward-looking information requires Condor to make assumptions that may not materialize or that may not be accurate. Forward-looking information is subject to known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such information. Such risks and uncertainties include, but are not limited to: regulatory changes; the timing of regulatory approvals; the risk that actual minimum work programs will exceed the initially estimated amounts; the results of exploration and development drilling and related activities; imprecision of reserves estimates and ultimate recovery of reserves; historical production and testing rates may not be indicative of future production rates, capabilities or ultimate recovery; the historical composition and quality of oil and gas may not be indicative of future composition and quality; general economic, market and business conditions; industry capacity; uncertainty related to marketing and transportation; competitive action by other companies; fluctuations in oil and natural gas prices; the effects of weather and climate conditions; fluctuation in interest rates and foreign currency exchange rates; the ability of suppliers to meet commitments; actions by governmental authorities, including increases in taxes; decisions or approvals of administrative tribunals and the possibility that government policies or laws may change or government approvals may be delayed or withheld; changes in environmental and other regulations; risks associated with oil and gas operations, both domestic and international; international political events; and other factors, many of which are beyond the control of Condor. Capital expenditures may be affected by cost pressures associated with new capital projects, including labor and material supply, project management, drilling rig rates and availability, and seismic costs.

These risk factors are discussed in greater detail in filings made by Condor with Canadian securities regulatory authorities including the Company's Annual Information Form, which may be accessed through the SEDAR website (www.sedar.com).

Readers are cautioned that the foregoing list of important factors affecting forward-looking information is not exhaustive. The forward-looking information contained in this MD&A are made as of the date of this MD&A and, except as required by applicable law, Condor does not undertake any obligation to update publicly or to revise any of the included forward-looking information, whether as a result of new information, future events or otherwise. The forward-looking information contained in this MD&A is expressly qualified by this cautionary statement.

ABBREVIATIONS

The following is a summary of abbreviations used in this MD&A:

bbl	Barrels of oil
bopd	Barrels of oil per day
boe	Barrels of oil equivalent
boepd	Barrels of oil equivalent per day
scf	Standard cubic feet
scfpd	Standard cubic feet per day
M	Thousand
MM	Million
NPV	Net present value
CAD	Canadian dollars
TL	Turkish Lira
USD	United States dollars
%	Percent
/	Per