MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three months and years ended December 31, 2017 and 2016

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

The following Management's Discussion and Analysis ("MD&A") as provided by the management of Valeura Energy Inc. ("Valeura" or the "Company") is dated as of March 20, 2018 and should be read in conjunction with Valeura's audited consolidated financial statements and related notes for the years ended December 31, 2017 and 2016. Additional information relating to Valeura is available under Valeura's profile on www.sedar.com, including Valeura's Annual Information Form for the year ended December 31, 2017 ("2017 AIF"). The reporting currency is the Canadian Dollar (see the sections titled "Foreign Exchange" and "Currency Translation Adjustment" for discussion on Valeura's functional currencies).

Basis of Presentation

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") as at and for the years ended December 31, 2017 and 2016, and have been prepared in accordance with the accounting policies and methods of computation as set forth in note 3 of the consolidated financial statements.

The discussion and analysis of oil and natural gas production is presented on a working-interest, before royalty basis. For the purpose of calculating unit of production information, natural gas is converted to a barrel of oil equivalent ("boe") using six thousand cubic feet of natural gas equal to one barrel of oil. This conversion ratio of 6:1 is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Readers are cautioned that boe as a unit of measure may be misleading, particularly if used in isolation.

The Company makes estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the revenues and expenses during the reporting period. Management reviews these estimates, including those related to accruals, reserves, environmental and decommissioning obligations and income taxes at each financial reporting period. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates. Readers should be aware that historical results are not necessarily indicative of future performance.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

Highlights and Selected Financial Information

	Three months ended		Years ended	
	December 31, 2017	December 31, 2016	**December 31, 2017**	December 31, 2016
Financial				
Petroleum and natural gas sales	**$ 3,824**	$ 3,508	**$ 14,646**	$ 16,155
Net loss	**(946)**	(3,189)	**(8,384)**	(6,086)
Per share, basic and diluted	**(0.01)**	(0.06)	**(0.12)**	(0.10)
Adjusted funds flow[1]	**(446)**	915	**(1,205)**	6,048
Per share, basic and diluted	**$ (0.01)**	$ 0.02	**$ (0.02)**	$ 0.10
Production volumes				
Natural gas (Mcf/d)	**6,176**	4,699	**5,662**	4,742
Crude oil (bbl/d)	**9**	12	**8**	9
Total (boe/d)	**1,038**	795	**952**	799
Sales prices				
Natural gas (per Mcf)	**$ 6.61**	$ 7.96	**$ 6.98**	$ 9.20
Crude oil (per bbl)	**82.78**	63.67	**71.84**	55.88
Total (per boe)	**40.03**	47.97	**42.16**	55.22
Exploration and development capital	**$ 1,856**	$ 536	**$ 12,791**	$ 9,535
Acquisitions	**-**	-	**21,450**	-
Dispositions	**-**	-	**(26,288)**	-
Working capital[2]			**3,421**	3,786
Cash			**11,108**	1,987
Weighted average shares outstanding				
Basic and diluted (thousands)[3]	**73,148**	58,254	**70,944**	58,254

Outstanding Share Data

	December 31, 2017
Common shares	73,148,321
Stock options	6,370,500
Fully Diluted	79,518,821

On February 24, 2017 the Company completed the acquisition of one of its joint venture partners, Thrace Basin Natural Gas (Turkiye) Corporation ("TBNG") for US$20.8 million (CAD$27.1 million) in cash effective March 31, 2016 (the "TBNG Acquisition"). In connection with that transaction, 14,629,000 common shares were issued pursuant to a financing arrangement entered into in 2016 (the "2016 Offering"). As a result of the 2016 Offering, gross proceeds of approximately $11 million were released from escrow. Valeura used the net proceeds to partially fund the TBNG Acquisition and for shallow gas drilling in 2017.

1 Non-GAAP measure – see note regarding non-GAAP measures on page 26.

2 Working capital is current assets less current liabilities. Assets held for sale have been excluded from this calculation.

3 The weighted average number of common shares outstanding is not increased for outstanding stock options when the effect is anti-dilutive.

The Company

Valeura is a Canada-based public company currently engaged in the exploration, development and production of oil and natural gas in the Thrace Basin of northwest Turkey. Valeura's shares are traded on the Toronto Stock Exchange ("TSX") under the trading symbol "VLE".

Valeura was established in 2010 to grow internationally through opportunistic acquisitions of producing assets with exploitation and exploration upside in selected countries in regions of interest, which included the Mediterranean Basin. The Company completed its first international transaction in Turkey during 2010 and since that time has executed a number of other transactions and won several new exploration licence awards in the country.

The asset and financing deals completed by the company between Q4 2016 and Q1 2018 have transformed the Company by increasing the size of the asset base, giving Valeura operatorship of all key assets, and providing the financial capacity to fully explore and appraise the unconventional basin-centered gas accumulation "BCGA" play. Additionally, the Company has secured Statoil as a large, well-respected partner which provides further technical and financial capacity to explore and appraise the deep, unconventional potential of the lands.

As at December 31, 2017, the Company held an interest in 21 exploration licences and production leases in the Thrace Basin of Turkey comprising approximately 0.53 million gross acres (0.43 million net acres of shallow rights and 0.3 million net acres of deep rights). The Thrace Basin assets include an 81.5% working interest in the shallow rights and deep rights of 11 production leases referred to as the ("**South Thrace Lands**"), and an 81.5% (shallow rights) working interest, 31.5% (deep rights) working interest in 3 production leases and 2 exploration licenses, referred to as the ("**West Thrace Lands**") (together the TBNG JV), and a 100% (shallow rights) and a 50% (deep rights) working interest in the two Banarli exploration licenses (the "**Banarli Licences**").

The Thrace Basin lands have shallow gas production and further development and exploration potential from both conventional reservoir and tight gas reservoirs. All or some of the Banarli Licenses, West Thrace Lands and South Thrace Lands are also believed to have potential for an unconventional BCGA play in over-pressured formations below approximately 2,500 metres. Valeura has recently drilled, completed and flow-tested the Yamalik-1 gas-condensate discovery on the Banarli Licenses. This well successfully proved the BCGA thesis concept at this location.

The Company is focussed on growing its established business in Turkey, particularly its natural gas operations in the Thrace Basin which yields very high natural gas prices relative to North America. As a result of the success of the Yamalik-1 gas-condensate discovery, the primary focus of Valeura's business has transitioned to the delineation and commercial demonstration of the massive BCGA play. However, the Company still continues to optimize the established conventional shallow gas assets in the Thrace Basin.

Operations

Production Operations

The Company generates cash flow from sales of petroleum and natural gas production from its assets in the Thrace Basin of Turkey. Natural gas is currently produced from approximately 91 wells (gross), with approximately 70 percent of the production coming from conventional shallow gas from sandstone reservoirs in the Danismen and Osmancik formations at a depth of 500 to 1,500 metres. The gas, which is composed primarily of methane, is gathered, dehydrated and compressed in Company-operated facilities and distributed on a Company-operated sales line network directly to 55 light industry customers.

Asset Transactions

West Thrace Deep Rights Sale

On January 6, 2017, the Company's wholly-owned affiliate, Corporate Resources B.V. ("CRBV") completed a sale and purchase agreement (the "West Thrace Deep Rights Sale") with Statoil Banarli Turkey B.V. ("Statoil"), a wholly-owned affiliate of Statoil ASA, to sell Valeura's 40 percent participating interest in the deep formations below approximately 2,500 metres depth on the West Thrace Lands, including two exploration licenses and the three production leases as described above, for cash consideration of US$12 million which was received in early January 2017.

Banarli Farm-in

On January 6, 2017, Valeura closed a farm-in agreement for the exploration of the deeper formations below approximately 2,500 metres on the Banarli Licenses in accordance with the farm-in agreement between the CRBV and Statoil (the "Banarli Farm-in"). Under the Banarli Farm-in, Statoil was given the option to earn a 50% interest in the deep formations on the Banarli Licenses by investing at least US$36 million in a three-phase work program, which includes a cost carry of CRBV on two deep wells and new 3D seismic. Valeura also received US$6.0 million in up-front payments as a contribution to back costs.

TBNG Acquisition

On February 24, 2017, the Company's wholly-owned affiliate, Valeura Energy (Netherlands) B.V. completed the acquisition of 100 percent of the shares of its joint venture partner in the TBNG JV, TBNG, for US$20.7 million (CAD$27.1 million). The Company's participating interest in the shallow rights on the South Thrace Lands and West Thrace Lands, previously held by both parties (the "TBNG JV lands") thereby increased from 40 percent to 81.5 percent and Valeura became the operator.

Subsequent West Thrace Deep Rights Sale

Following the closing of the West Thrace Deep Rights Sale and the TBNG Acquisition, TBNG entered into a sale and purchase agreement with Statoil to sell an additional 10 percent participating interest in the deeper formations on the West Thrace lands, for cash consideration of US$3.0 million (the "Subsequent West Thrace Deep Rights Sale") which closed June 22, 2017. As a result of the West Thrace Deep Rights Sale, TBNG Acquisition and Subsequent West Thrace Deep Rights Sale, Valeura has a 31.5% interest is the Deep Rights on the West Thrace Lands.

Valeura is operator of the deep exploration program in both Banarli and West Thrace Lands during the earning phase of the Banarli Farm-in. Once Statoil has fully earned its 50% interest in Banarli, they have the option to request operatorship of the deep program.

Work Program

In 2017, in the TBNG JV Lands, Valeura completed 35 workovers on existing production wells and also performed re-entry fracing on two wells. The Company also drilled six new shallow gas wells on the TBNG JV lands and the Banarli Licences. Three of the wells are currently producing, one well was plugged and abandoned as a dry hole and two others are suspended and awaiting appraisal. In addition, a total of new 500 square kilometres of 3D seismic was acquired over the Banarli Licences and TBNG JV lands that will contribute conventional shallow gas, tight gas and basin centred gas accumulation play opportunities.

To progress the exploration of the unconventional BCGA play with its partner Statoil, in 2017 Valeura completed the drilling and testing of the Yamalik-1 exploration well and the acquisition of the Karaca 3D seismic program. Both of these operations were fully funded by Statoil under their Banarli Farm-in. The Karaca 3D seismic program recording stage was carried out between June 18 and September 20, 2017, acquiring approximately 500 square kilometres of 3D seismic. Processing of these data is currently ongoing with delivery of the final data expected around the end of Q1 2018.

Yamalik-1 was spudded on May 13, 2017 and was rig released on July 22, 2017. The well was operated by Valeura and drilled to a total depth of 4,196 metres. The well encountered highly overpressed and gas saturated Teslimkoy and Kesan reservoir formations from approximately 2,900 metres down to the total depth of 4,196 metres. The overpressure at the total depth was greater than 0.8 psi/ft based on testing results. There were no sections that were interpreted as water-bearing, or where the pressures dropped. The average net sand in the objective section was 44%.

In November and December 2017, Valeura completed four production tests on the Yamalik-1 well. Two slick-water fracs were performed in each of four different indicated gas pay zones. The testing program was designed to demonstrate that fracing would allow gas to flow to surface from these deep, tight reservoirs, and without the production of formation water. Both of these factors are key components to demonstrate the presence of a BCGA. The 24-hour aggregate production test rate from the four production tests in the Kesan formation was 2.9 MMcf/d. Additionally, the gas flowed with a significant amount of condensate (with a test data range of 20 to 70 barrels per MMcf).

Valeura is now proceeding with engineering and design work to enable Yamalik-1 to be tied into Valeura's gas gathering and sales network. Valeura is targeting to recommence operations in Q2 2018. The project is expected be funded jointly by Valeura and Statoil.

Political and Regulatory Environment

Turkey has gone through a period in 2016 and 2017 of political change and uncertainty. During this period, the Company's ability to conduct drilling and production operations in the Thrace Basin has not been adversely affected by political or regulatory events. No unusual delays or security issues have been experienced and the Company continues to maintain a professional working relationship with local authorities and regulators. The main impact on Valeura during this period has been the continued devaluation on the Turkish Lira.

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Management acknowledges that its ability to make reliable estimates can be complicated by political, economic and security situation events as and when they occur. Management has based its estimates with respect to the Company's operations on information available up to the date of this MD&A.

Outlook

Valeura believes that the deep, unconventional BCGA play in the Thrace Basin provides the most significant upside potential for the Company. Valeura's primary focus for 2018 and 2019 will be the appraisal and de-risking of the BCGA play discovered by the Yamalik-1 and evaluated by D&M. The objective of the work program is to delineate the pervasiveness of the play across the Thrace Basin lands where Valeura holds an interest, and to demonstrate that commercial flow rates can be achieved. Success will allow Valeura to convert prospective resources to contingent resources and reserves, test for upside beyond the scope of the D&M Resources Report, and reduce the overall risk of the play.

The key work program activities that support this strategy are:

- complete the Yamalik-1 well and tie-in to production facilities for long-term testing and gas sales;
- drill and test BCGA Delineation Well #1 in Banarli Licenses (100% funded by Statoil);
- drill and test BCGA Delineation Well #2 in the West Thrace Lands (Valeura 31.5%);
- drill and test BCGA Delineation Well #3 in the Banarli Licenses (Valeura 50%); and
- tie-in successful wells for long-term production testing and gas sales.

Further testing and the tie-in of Yamalik-1 is planned to commence in early Q3 2018. Suitable production testing equipment is now planned to be exported from North America to Turkey to support the operation. The Yamalik-1 production testing in Q4 2017 was complicated by the inability of available test equipment to manage the flowback of sand used in the fracing. This type of post-frac flow back is standard in North American drilling and completion operations. Once this test equipment is in country, it will then be available for testing all of the wells in the delineation drilling campaign.

The delineation drilling campaign is also expected to commence in late Q3 2018 and the three wells will be drilled back-to-back. The wells have been designed to drill to 5,000 m to attempt to find the maximum depth of the BCGA play. Yamalik-1 reached 4,196 m depth and was still in an overpressured hydrocarbon column that flowed gas and condensate after fracing and testing. Each well is expected to take about three months to drill which will then be followed by a fracing and testing program.

Additionally, Valeura and its partners are evaluating the re-completion potential of Hayrabolu-10 which was drilled in 2013 in the West Thrace Lands to a depth of 4,054 m. After standard perforation, gas flowed to surface but no fracture stimulation was performed. If it is concluded that the well design still permits re-entry fracture stimulation, the well is expected to be completed, tied-in and tested in Q4 2018.

The Company continues to progress activity on its shallow production from the TBNG JV and Banarli Licenses. Current activity is focused on workovers of producing wells with one new well to be drilled on the West Thrace Lands in Q2 2018. The Company expects to interpret the new 500 square km Karaca 3D seismic when final processing is completed in April 2018 and review the new portfolio of opportunities prior to making further drilling decisions.

In all its activities, the Company remains committed to continuing its safe operations and ensuring that operational and administrative functions are conducted in the most cost-efficient way.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

Results of Operations

	Three months ended		Years ended	
	December 31, 2017	December 31, 2016	**December 31, 2017**	December 31, 2016
Petroleum and natural gas sales	**$ 3,824**	$ 3,508	**$ 14,646**	$ 16,155
Royalties	**(515)**	(444)	**(1,971)**	(2,102)
Production costs	**(1,174)**	(620)	**(4,423)**	(2,232)
Operating netback[4]	**2,135**	2,444	**8,252**	11,821
Other income	**314**	184	**1,363**	846
General and administrative expenses	**(701)**	(1,308)	**(4,606)**	(5,376)
Transaction costs	**-**	(356)	**(1,160)**	(794)
Realized foreign exchange loss	**(569)**	(49)	**(2,683)**	(449)
Current tax expense	**(1,625)**	-	**(2,371)**	-
Adjusted funds flow[5]	**(446)**	915	**(1,205)**	6,048
Non-cash expenses				
Share-based compensation	**(140)**	(107)	**(470)**	(386)
Accretion on decommissioning liabilities	**(487)**	(196)	**(1,779)**	(876)
Transactions costs	**-**	-	**-**	(65)
Unrealized foreign exchange gain (loss)	**254**	(1,586)	**12**	(2,583)
Depletion and depreciation	**(2,510)**	(1,860)	**(9,025)**	(7,436)
Impairment	**-**	(1,048)	**-**	(1,048)
Exploration and evaluation expense	**(43)**	-	**(707)**	-
Deferred tax recovery	**2,444**	693	**4,790**	260
Net loss	**$ (928)**	$ (3,189)	**$ (8,384)**	$ (6,086)

Sales Volumes

	Three months ended		Years ended	
	December 31, 2017	December 31, 2016	**December 31, 2017**	December 31, 2016
Natural gas (Mcf/d)	**6,176**	4,699	**5,662**	4,742
Crude oil (bbl/d)	**9**	12	**8**	9
Total (boe/d)	**1,038**	795	**952**	799

Sales volumes for Q4 2017 and the year ended December 31, 2017 increased to 1,038 boe/d and 952 boe/d, respectively, compared to 795 boe/d and 799 boe/day for the same periods in 2016 due to additions from the TBNG Acquisition, workovers and recompletions and three new drills partially offset by natural declines on both the TBNG JV and Banarli Licences.

[4] Non-GAAP measure – see note regarding non-GAAP measures on page 26.
[5] Non-GAAP measure– see note regarding non-GAAP measures on page 26.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

Pricing Information

	Three months ended		Years ended	
Average reference prices	**December 31, 2017**	December 31, 2016	**December 31, 2017**	December 31, 2016
Natural gas – BOTAS (per Mcf)[6]	**TL 19.84**	TL 19.84	**TL 19.84**	TL 21.41
Natural gas – BOTAS (per Mcf)	**$ 6.65**	$ 8.09	**$ 7.07**	$ 9.41
Average exchange rate (TL/CAD)	**2.984**	2.453	**2.805**	2.276

	Three months ended		Years ended	
Average realized prices	**December 31, 2017**	December 31, 2016	**December 31, 2017**	December 31, 2016
Natural gas (per Mcf)	**$ 6.61**	$ 7.96	**$ 6.98**	$ 9.20
Crude oil (per bbl)	**$ 82.78**	$ 63.67	**$ 71.84**	$ 55.88

Natural gas prices under sales contracts for all production in the Thrace Basin are linked to the BOTAS benchmark price in TL. Tracking of the BOTAS price, converted to US$, suggests that the price trends similar to the EU natural gas price. This is not unexpected, as the gas sources as similar for both BOTAS and the EU. Natural gas prices remain relatively strong in Turkey compared to North America, despite the recent volatility and overall decrease in the value of the TL.

Natural gas sales from the TBNG JV lands are under direct sales contracts to industrial buyers in the area and each contract is at a negotiated discount to the BOTAS benchmark price. Natural gas from Banarli is being sold to the TBNG JV, net of a transportation and marketing fee. Valeura receives the majority of the benefits from this fee arrangement and the associated proceeds by virtue of its current 81.5 percent working interest in the TBNG JV facilities.

Between October 1, 2014 and September 30, 2016 the BOTAS benchmark price remained unchanged but effective October 1, 2016 the price was reduced by 10 percent. The Company's Q4 2017 average realized natural gas price in Turkey decreased by 17 percent to $6.61 per Mcf from $7.96 per Mcf in Q4 2016 due primarily to the decrease in the BOTAS benchmark price effective October 1, 2016 and the devaluation of the TL against the Canadian Dollar. The average realized natural gas price in Turkey for Q4 2017 of $6.61 per Mcf represents a 1.0 percent discount to the BOTAS benchmark price.

As of January 1, 2018 the BOTAS reference price was increased by 14 percent. Applying this increase to the Q4 2017 BOTAS reference price would result in an average natural gas reference price of approximately $7.50 per Mcf for the quarter.

Petroleum and Natural Gas Sales Revenues

	Three months ended		Years ended	
	December 31, 2017	December 31, 2016	**December 31, 2017**	December 31, 2016
Natural gas	**$ 3,754**	$ 3,440	**$ 14,431**	$ 15,971
Crude oil	**70**	68	**215**	184
Total revenues	**$ 3,824**	$ 3,508	**$ 14,646**	$ 16,155

[6] BOTAS owns and operates the national crude oil and natural gas pipeline grids in Turkey and purchases the majority of Turkey's natural gas imports. BOTAS regularly posts prices and its Level-2 Wholesale Tariff benchmark is shown herein as a reference price. See the 2017 AIF for further discussion.

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The composition of petroleum and natural gas sales revenues for Q4 2017 and the year ended December 31, 2017 was approximately 98 percent natural gas and two percent crude oil. Revenues for Q4 2017 increased in comparison to the same period in 2016 due primarily to increased production partially offset by lower realized natural gas prices. Revenues for the years ended December 31, 2017 decreased in comparison to the same period in 2016 due primarily to lower realized natural gas prices in Turkey as a result of the devaluation of the Turkish Lira against the Canadian Dollar partially offset by increased production.

Royalties

	Three months ended		Years ended	
	December 31, 2017	December 31, 2016	**December 31, 2017**	December 31, 2016
Royalties	**$ 515**	$ 444	**$ 1,971**	$ 2,102
Percentage of revenue	**13.5%**	12.7%	**13.5%**	13.0%

Royalties for Q4 2017 increased in comparison to the same period in 2016 as a result of higher petroleum and natural gas revenue. Royalties for the year ended December 31, 2017 decreased in comparison to the same period in 2016 as a result of lower petroleum and natural gas sales revenues. Revenues are subject to a 12.5 percent government royalty and an overriding royalty on the TBNG JV Lands, only, of one percent.

Production Costs

	Three months ended		Years ended	
	December 31, 2017	December 31, 2016	**December 31, 2017**	December 31, 2016
Production costs	**$ 1,174**	$ 620	**$ 4,423**	$ 2,232
$ per boe	**12.29**	8.47	**12.73**	7.63

Production costs for Q4 2017 and the year ended December 31, 2017 increased in comparison to the same periods in 2016 due primarily to Valeura increasing its ownership of the TBNG JV from 40% to 81.5%. Additionally there were non-recurring costs associated with integrating the TBNG Acquisition and the related expansion of the operations. The increased costs were due to higher labour costs and a backlog of repairs and maintenance to wells and facilities. Costs were reduced marginally in Q4 2017 as compared to Q3 2017, due to reduced repairs and maintenance.

Operating Netbacks (per boe)

	Three months ended		Years ended	
	December 31, 2017	December 31, 2016	**December 31, 2017**	December 31, 2016
Petroleum and natural gas sales	**$ 40.03**	$ 47.97	**$ 42.16**	$ 55.22
Royalties	**(5.39)**	(6.07)	**(5.67)**	(7.18)
Production costs	**(12.29)**	(8.47)	**(12.73)**	(7.63)
Operating netback	**$ 22.35**	$ 33.43	**$ 23.76**	$ 40.41

Operating netbacks for Q4 2017 and the year ended December 31, 2017 are significantly lower in comparison to the same periods in 2016 due primarily to lower prices. The lower realized prices, as described in the Pricing Information section, are the result of the reference price decrease in October 2016 and further devaluation of the Turkish Lira. In addition, the increased production costs due to extensive maintenance and repairs have further reduced the netbacks. The netbacks in 2017 are well below the forecasted average netback of $35.00 per boe for the same reasons described above. The forecasted $35.00 operating netback includes petroleum and natural gas sales of $49.00 per boe, an average royalty rate of 13 percent or $6.40 per boe and operating costs of $7.60 per boe.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

General and Administrative Expenses

	Three months ended		Years ended	
	December 31, 2017	December 31, 2016	**December 31, 2017**	December 31, 2016
General and administrative expenses	**$ 1,505**	$ 1,400	**$ 6,861**	$ 5,953
Business development	**1**	21	**32**	142
Total	**1,506**	1,421	**6,893**	6,095
Recoveries	**(805)**	(113)	**(2,287)**	(719)
Total general and administrative expenses	**$ 701**	$ 1,308	**$ 4,606**	$ 5,376

Total general and administrative expenses net of recoveries for Q4 2017 and the year ended December 31, 2017 decreased in comparison to the same periods in 2016 as a result of increased overhead recoveries from joint venture partners. Increased gross general and administrative expenses corresponds to increased personnel related to the expansion of the business. The expansion is two-fold including operatorship of the TBNG JV Lands and Banarli Farm-in (drilling and seismic) in the earning phase. These operator roles require significantly increased responsibilities and, at the same time, enabled increased overhead recoveries shown above.

Transaction Costs

In 2017, the Company recorded transaction costs of $1.2 million compared to $0.9 million for the same period in 2016. Transaction costs in 2017 are related to expenses associated with the Banarli Farm-in, West Thrace Deep Rights Sale, TBNG Acquisition and Subsequent West Thrace Deep Rights Sale. Transaction costs include primarily legal fees, advisory fees and other costs related to due diligence reviews.

Foreign Exchange

During Q4 2017 and the year ended December 31, 2017, the Company recorded a foreign exchange loss (realized and unrealized) of $0.3 million and $2.7 million, respectively, compared to a foreign exchange loss of $1.6 million and $3.0 million for the same periods in 2016. The foreign exchange losses are due to the volatility of the Turkish Lira against the Canadian Dollar.

The functional currency for the Company's Turkish operations is the Turkish Lira. Foreign exchange gains and losses are the result of translation of accounts denominated in currencies other than the functional currencies of Valeura and its subsidiaries, and settling transactions denominated in currencies other than the functional currency of the entity.

The Company's petroleum and natural gas sales are conducted in Turkey and are denominated in Turkish Lira. As such, the Company is exposed to any fluctuations in the Turkish Lira (TL) to Canadian Dollar (CAD) and United States Dollar (USD) exchange rates. A decrease in the value of the Turkish Lira against the Canadian or United States Dollars will result in a decrease in revenues, royalty expense and operating costs. Correspondingly, an increase in the value of the Turkish Lira against the Canadian and United States Dollars will result in an increase in revenues, royalty expense and operating costs. Changes in the value of the Turkish Lira against the Canadian and United States Dollars could also impact reserve values.

The recent negative volatility in the value of the Turkish Lira may impair the ability of the Company to effectively manage foreign exchange exposure. Continued devaluation of the Turkish Lira, without a corresponding increase in the natural gas reference price, will have a negative impact on adjusted funds flow and could affect the ability of the Company to fund its capital program in the future.

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Changes to the TL/CAD exchange rate would have had the following impact on revenues, royalties and production costs for the three months and year ended December 31, 2017:

+/- 1 percent change in realized TL/CAD exchange rate	Petroleum and natural gas revenues	Royalties	Production costs
Three months ended December 31, 2017	$ 40	$ 5	$ 11
Year ended December 31, 2017	$ 155	$ 20	$ 43

The Company's drilling and seismic operations and related contracts in Turkey are predominantly based in US Dollars. Material changes in the value of the US Dollar against the Turkish Lira or Canadian Dollar will impact the Company's capital costs.

Changes to the TL/USD exchange rate, which are impacted by the TL/CAD exchange rate upon conversion to the Company's Canadian Dollar presentation currency, would have had the following impact on capital expenditures for the three months and year ended December 31, 2017:

+/- 1 percent change in realized TL/USD exchange rate, upon conversion to presentation currency	Capital expenditures
Three months ended December 31, 2017	$ 10
Year ended December 31, 2017	$ 55

To the extent that the Company engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Company may contract. Valeura continues to assess its exposure to all foreign currencies, including its exposure to the Turkish Lira and any cost effective ways to mitigate such exposure.

Other Income

During Q4 2017 and the year ended December 31, 2017, the Company recorded other income of $0.3 million and $1.4 million, respectively, compared to $0.2 million and $0.8 million for the same periods in 2016. Other income is comprised of third party processing and marketing income and interest income related to cash on hand. The increase during Q4 2017 and the year ended December 31, 2017 is attributed to higher third party volumes processed, and higher working interest participation in processing revenues due to the TBNG Acquisition.

Adjusted Funds Flow

Adjusted funds flow for Q4 2017 and the year ended December 31, 2017 was an outflow of $0.4 million and $1.2 million, respectively, compared to an inflow of $0.9 million and $6.0 million for the same periods in 2016. Adjusted funds flow in 2017 was negatively impacted by expenses related to the TBNG Acquisition and Banarli Farm-in including transactions costs, income taxes and realized foreign exchange losses that are not considered ongoing expenses. Adjusted funds flow for 2017, representing an outflow of funds, is not an accurate reflection of anticipated adjusted funds flow for 2018, expected to be a net inflow of funds.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

The following table reconciles Valeura's cash provided by operating activities to adjusted funds flow:

	Three months ended		Years ended	
	December 31, 2017	December 31, 2016	**December 31, 2017**	December 31, 2016
Cash provided by (used in) operating activities	**$ 7,484**	$ 657	**$ 3,854**	$ 6,294
Decommissioning costs incurred	**256**	-	**270**	-
Change in non-cash working capital	**(8,186)**	258	**(5,329)**	(246)
Adjusted funds flow	**$ (446)**	$ 915	**$ (1,205)**	$ 6,048

Non-cash Expenses:

Share-based Compensation

Share-based compensation is a non-cash expense associated with the stock options issued to directors, officers, employees and certain other service providers of the Company.

Share-based compensation expense for Q4 2017 and the year ended December 31, 2017 was $0.1 million and $0.5 million, respectively, compared to $0.1 million and $0.4 million for the same periods in 2016. During 2017, the Company granted 1,750,000 options at a weighted average exercise price of $0.74 per option.

Accretion on Decommissioning Liabilities

Accretion on decommissioning obligations for Q4 2017 and the year ended December 31, 2017 was $0.5 million and $1.8 million, respectively, compared to $0.2 million and $0.9 million for the same periods in 2016. The increase is due to the TBNG Acquisition and an increased percentage ownership in the TBNG JV wells and facilities and the associated impact on decommissioning obligations.

Exploration and Evaluation Expense

Exploration and evaluation ("E&E") expense consists of exploration projects that are deemed to have a lower fair value when compared to book value. E&E expense for the year ended December 31, 2017 was $0.7 million (2016 – nil) and was comprised of one shallow gas dry hole.

Depletion and Depreciation

Depletion and depreciation for Q4 2017 and the year ended December 31, 2017 was $2.5 million and $9.0 million, respectively, compared to $1.9 million and $7.4 million for the same periods in 2016. Depletion is calculated on a unit-of-production basis utilizing proved plus probable reserves.

On a per unit basis, depletion and depreciation for Q4 2017 and the year ended December 31, 2017 was $26.28/boe and $25.97/boe, respectively, compared to $25.43/boe and $25.43/boe for the same periods in 2016.

Current Tax

Current tax for Q4 2017 and the year ended December 31, 2017 was an expense of $1.6 million and $2.4 million respectively compared to $nil for the same periods in 2016. The current tax expense for 2017 is primarily due to income taxes incurred for the proceeds on the sale of the West Thrace lands and other farm-in payments. The Company had expected capital expenditures for the year to provide enough recoveries to offset the tax incurred on the sale proceeds, however reduced level of other capital expenditures due to the focus on the Statoil funded deep exploration play led to the increase in expense.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

Deferred Tax

Deferred tax for Q4 2017 and the year ended December 31, 2017 was a recovery of $2.4 million and $4.8 million, respectively, compared to a recovery of $0.7 million and $0.3 million for the same periods in 2016. Deferred tax relates to changes in the temporary difference between the net book value and the tax basis of the assets and liabilities in the Company's Turkish operations that commenced in 2011.

Currency Translation Adjustments

Translation of all assets and liabilities from their respective functional currencies to the reporting currency are performed using the rates prevailing at the statement of financial position date. The differences arising upon translation from the functional currency to the reporting currency are recorded as currency translation adjustments in accumulated other comprehensive income or loss ("AOCI") and are held within AOCI until a disposal or partial disposal of a subsidiary occurs. A disposal or partial disposal will then give rise to a realized foreign exchange gain or loss which is recorded in net earnings.

The currency translation adjustment for Q4 2017 and the year ended December 31, 2017 was a loss of $2.3 million and $6.0 million, respectively, compared to a loss of $6.6 million and $11.5 million for the same periods in 2016 reflecting the fluctuation in the value of the Turkish Lira compared to the Canadian dollar in the respective periods.

Business Combination

The acquisition of TBNG has been accounted for as a business combination under IFRS 3. The purchase price equation (in Canadian Dollars), is as follows:

Consideration

Cash	$ 27,078

Purchase Price Equation

Cash	$ 5,628
Restricted Cash	3,395
Accounts receivable	3,582
Inventory	833
Prepaids and deposits	287
Exploration and evaluation assets	6,248
Property, plant and equipment	28,002
Accounts payable and accrued liabilities	(9,773)
Deferred tax liability	(2,919)
Decommissioning obligations	(8,205)
	$ 27,078

Net cash consideration is $21.5 million, representing the cash price paid ($27.1 million) less cash received ($5.6 million). TBNG's identifiable assets and liabilities have been measured at their individual fair values on the date of acquisition. Determinations of fair value often require management to make assumptions and estimates about future events. Valeura has determined the fair value of assets acquired and liabilities assumed as at the date of acquisition. Valeura has determined that book value equals fair value for the following captions: Cash, Restricted Cash, Accounts Receivable, Prepaid Expenses and Deposits, Accounts Payable and Accrued Liabilities. The fair value of Property, plant and equipment and Exploration and Evaluation assets (together "Capital Assets) was determined based on internal reserve evaluation. Deferred taxes was determined by applying the statutory tax rate to the Capital Asset fair value less available tax pools. The fair value of decommissioning obligations was determined based on Valeura's IFRS accounting policies for measuring decommissioning obligations. The purchase price equation was finalized in Q3 2017. Revenue and net income is included in the Consolidated Statements of Loss and Comprehensive Loss from the February 24, 2017 to December 31, 2017. Had the acquisition closed on January 1, 2017, for the year ended December 31, 2017, the Company estimates that its pro forma revenue and net loss would have been approximately $15,170 and $(8,816) respectively.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

Capital Expenditures

The following summarizes the Company's capital spending:

	Three months ended		Years ended	
	December 31, 2017	December 31, 2016	**December 31, 2017**	December 31, 2016
Geological and geophysical	**$ 142**	$ 134	**$ 932**	$ 1,094
Drilling & completions	**785**	370	**8,830**	7,116
Workovers & recompletions	**894**	21	**2,287**	93
Equipping, facilities & other	**35**	11	**742**	1,232
Total exploration and development capital program	**1,856**	536	**12,791**	9,535
Acquisitions	**-**	-	**21,450**	-
Dispositions	**-**	-	**(26,288)**	-
Total net capital	**$ 1,856**	$ 536	**$ 7,953**	$ 9,535

The Company's capital spending for 2017 was $12.8 million, including $0.9 million for geological and geophysical operations, $8.8 million for drilling and completions, $2.3 million for workovers and recompletions and $0.7 million for equipping, facilities and other. The Company spent $21.5 million on the TBNG Acquisition and received a combined $26.3 million on the West Thrace Deep Rights Sale and the Banarli Farm-in proceeds for a total net capital spent during 2017 of $7.9 million.

During 2017 in the TBNG JV, the Company spudded five new wells (Valeura 81.5% working interest). Of the five wells spudded, three wells have been completed and put on production, one well is undergoing evaluation and one well has been plugged and abandoned. The Company also completed workovers on 35 gross wells and two re-entry fracs were successfully completed in Kayi-14 and Baglik-1. Both wells are currently on-stream and contributing to the Company's gas sales. The Company also completed workovers on 4 gross wells.

In the Banarli Licenses, the Company spudded Aydinkoy-1 which was drilled to a measured depth of 2,821 metres, cased and completed. The well discovered gas, but of much lower volumes than predicted and is currently being further evaluated to determine if a tie-in can be justified. The Company also completed four workovers on the Banarli Licences.

Share Capital

Common shares	Number of Shares	Amount
Balance, December 31, 2016	58,519,321	$ 136,586
Offering	14,629,000	10,108
Balance, December 31, 2017	**73,148,321**	**$ 146,694**

As at December 31, 2017, Valeura had 73,148,321 common shares outstanding and 6,370,500 outstanding options, for a total number of shares outstanding of 79,518,821, assuming exercise of all options. On March 1, 2018, the Company closed a bought deal financing issuing 10,527,000 common shares at a price of $5.70 per common share for net proceeds (after share issue costs) of approximately $55.7 million. The total number of shares outstanding at March 20, 2018 is 90,045,821 assuming exercise of all outstanding stock options and adding 10,527,000 common shares from the offering.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

Liquidity, Financing and Capital Resources

	Three months ended		Years ended	
	December 31, 2017	December 31, 2016	**December 31, 2017**	December 31, 2016
Opening cash position	**$ 2,968**	$ 4,611	**$ 1,987**	$ 6,973
Inflow of funds				
Share issuance – net of share issuance costs	**-**	-	**10,108**	-
West Thrace Deep Rights sales	**-**	-	**18,841**	-
Statoil Farm-in proceeds	**-**	-	**7,447**	-
Adjusted funds flow[7]	**-**	915	**-**	6,048
Restricted cash	**223**	-	**-**	-
Proceeds from stock option exercises	**-**	-	**-**	437
Changes in working capital and foreign exchange on cash[8]	**10,475**	-	**11,614**	-
	10,698	915	**48,010**	6,485
Outflow of funds				
Capital expenditures[9]	**(1,856)**	(536)	**(12,791)**	(9,535)
Decommissioning costs incurred	**(256)**	-	**(270)**	-
TBNG Acquisition[10]	**-**	-	**(21,450)**	-
Restricted cash	**-**	-	**(3,173)**	-
Changes in working capital and foreign exchange on cash[11]	**-**	(728)	**-**	(1,936)
Adjusted funds flow	**(446)**	-	**(1,205)**	-
	(2,558)	(1,264)	**(38,889)**	(11,471)
Closing cash position	**$ 11,108**	$ 1,987	**$ 11,108**	$ 1,987

Capital Funding and Resources

As at December 31, 2017, Valeura's working capital[12] balance was $3.2 million including cash of $11.1 million. Valeura's 2017 opening cash position was $2.0 million. In 2017, the Company utilized this opening cash balance plus $10.1 million from the 2016 Offering (net of share issuance costs), $14.9 million from the West Thrace Deep Rights Sale, $7.4 million from the Banarli Farm-in and $3.9 million from the Subsequent West Thrace Deep Rights

[7] Non-GAAP measure – see note regarding non-GAAP measures on page 26.

[8] Includes the following captions from the consolidated statements of cash flows: changes in non-cash working capital from operating activities, changes in non-cash working capital from investing activities and foreign exchange gain (loss) on cash held in foreign currencies.

[9] Includes the following captions from the consolidated statements of cash flows: exploration and evaluation expenditures and property and equipment expenditures.

[10] See Business Combination section.

[11] Includes the following captions from the consolidated statements of cash flows: changes in non-cash working capital from operating activities, changes in non-cash working capital from investing activities and foreign exchange gain (loss) on cash held in foreign currencies.

[12] Working capital is current assets less current liabilities. Assets held for sale have been excluded from this calculation.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

sale to fund the TBNG Acquisition ($27.1 million less $5.6 million of cash in TBNG) and an exploration and development capital program of $12.8 million. The cash position at December 31, 2017 of $11.1 million is significantly higher than the cash position for the end of year 2016 and the end of Q3 2017 due to receipt of joint venture partner fund proceeds received close to year end. The related capital expenditures are reflected in the working capital balance.

Financial Capacity

2018 Financing

As at December 31, 2017 the Company's working capital[12] surplus was $3.2 million. The working capital position and adjusted funds flow for 2018 are expected to be sufficient to fund the planned minimum shallow gas drilling/workover capital program for 2018 of $2.0 to $3.0 million. The Company completed all drilling commitments for 2017 and has one commitment well to be drilled in the first half of 2018.

On March 1, 2018 the Company closed a financing, issuing common shares for net proceeds of approximately $55.7 million, after share issue costs (the "2018 Offering"). Valeura intends to use the net proceeds from the 2018 Offering to fund its 2018 and 2019 capital program and for general corporate purposes.

2018/2019 Planned Capital Program

Valeura's 2018 and 2019 capital program will be almost entirely focused on the drilling and testing of wells to delineate and demonstrate commerciality of the unconventional BCGA play discovered by Yamalik-1 in 2017. Funds are also allocated for the tie-in of these wells to allow for production and sales of any discovered gas. The work program for the unconventional play is being finalized as at the date of this MD&A. It is expected that the net proceeds of the 2018 Offering will be used as follows:

Activity or Nature of Expenditure	Approximate use of Net Proceeds	Anticipated Timing
2018		
Yamalik-1 Completion and Tie-in to Production Facilities	$3,100,000	Q2 2018
Hayrabolu-10 Workover	$2,100,000	Q4 2018
Drill and Test West Thrace #1 Deep Well	$9,500,000	Q4 2018
Facilities Capital and Tie-in for 3 Wells	$5,250,000	Q4 2018
G&G and studies on Banarli and West Thrace	$2,000,000	2018
Total 2018:	**$21,950,000**	
2019		
Drill and Test Banarli #3 Deep Well	$15,000,000	Q1 2019
Pilot Production Well	$10,800,000	2019
Facilities Capital and Tie-in for Banarli #3	$1,750,000	Q1 2019
3D Seismic Program, G&G and studies on Banarli and West Thrace	$5,500,000	2019
Total 2019:	**$33,050,000**	
Total:	**$55,000,000**	

The capital program planned for 2018 for the deep and shallow drilling is anticipated to be in the range of $19.0 and $22.0 million.

The Company maintains considerable flexibility in managing its capital budget for 2018 and 2019. As a result of the TBNG Acquisition, the Company is now the operator of the TBNG JV, which provides a greater level of control of capital spending. The drilling and workover capital spending on the TBNG JV lands is focused on fulfilling drilling commitments and offsetting natural production declines. The Company will continue to utilize current working capital and adjusted funds flow to fund any capital spending on the TBNG JV lands. In addition to the TBNG JV lands, Valeura expects to maintain operatorship of the deep rights on the Banarli Lands and West Thrace Lands for 2018 and will tightly manage all capital requirements and commitments.

Capital Management

The Company's objective is to maintain a flexible capital structure which allows it to execute its growth strategy through expenditures on exploration and development activities while maintaining a strong financial position. The Company's capital structure includes working capital and shareholders' equity. Currently, total capital resources available include working capital and adjusted funds flow.

The successful future operations of the Company are dependent on the ability of the Company to secure sufficient funds through operations, bank financing, equity offerings or other sources and there are no assurances that such funding will be available when needed. Failure to obtain such funding on a timely basis could cause the Company to reduce capital spending and could lead to the loss of exploration licences due to failure to meet drilling deadlines and lower production volumes and associated revenues.

The Company's capital expenditures include expenditures in oil and gas activities which may or may not be successful. The Company makes adjustments to the capital structure in light of changes in economic conditions and the risk characteristics of the underlying petroleum and natural gas assets. In order to maintain or adjust the capital structure, the Company may, from time to time, issue shares, adjust its capital spending or issue debt instruments. The Company is not subject to any externally imposed capital requirements while it maintains operatorship over all the lands in the Thrace Basin. An exception to this statement could occur in 2019 if Statoil elects to complete Phase 3 under the Banarli Farm-in and thereby earns a 50 percent working interest in the deep rights at Banarli. At that point, Statoil may exercise its option under the Banarli Farm-in to take operatorship of the deep rights and propose a more significant drilling program. The Company has received net proceeds of $55.7 million in an equity offering as described in the Financial Capacity section above in order to meet commitments for an expended capital program. However, such a program could result in an even more significant capital commitment for which the Company will be required to further assess alternatives including the availability of equity and debt capital to fund the program.

Credit Facilities

The Company has a general credit facility in the amount of US$0.3 million with a Turkish bank for the purpose of obtaining letters of credit required by the Turkish government. As at December 31, 2017, the Company has issued letters of credit totaling US$0.04 million (December 31, 2016 – US$0.3 million). The general credit facility is not secured by any of the Company's assets and interest rate terms have not been set as the purpose of this facility is for issuance of letters of credit only. The Company is currently in discussions to expand the letter of credit facility to an amount in excess of US$2.0 million.

Related Party Transactions

Valeura paid $50,000 to an entity controlled by one of the members of Valeura's board of directors, for financing arrangement fees related to a potential bridge loan to complete the financing of the TBNG Acquisition in the event of delayed Turkish government approvals. This financing proved unnecessary and the TBNG Acquisition closed on February 24, 2017. This fee is included in transaction costs for the year ended December 31, 2017.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

Selected Quarterly Information

	Three months ended			
	December 31, 2017	September 30, 2017	June 30, 2017	March 31, 2017
Total daily production (boe/d)	1,038	1,024	934	807
Average wellhead price ($/boe)	$ 40.03	$ 42.14	$ 44.28	$ 42.49
Petroleum and natural gas sales	3,824	3,970	3,764	3,088
Adjusted funds flow	(446)	1,165	959	(2,883)
Per share, basic and diluted	(0.01)	0.02	0.01	(0.04)
Net loss	(946)	(4,911)	(526)	(2,001)
Per share, basic and diluted	$ (0.01)	$ (0.07)	$ (0.01)	$ (0.03)
	Three months ended			
	December 31, 2016	September 30, 2016	June 30, 2016	March 31, 2016
Total daily production (boe/d)	795	680	933	792
Average wellhead price ($/boe)	$ 47.97	$ 56.10	$ 56.62	$ 60.09
Petroleum and natural gas sales	3,508	3,510	4,809	4,328
Adjusted funds flow	915	1,066	2,098	1,969
Per share, basic and diluted	0.02	0.02	0.04	0.03
Net loss	(3,189)	(1,263)	(642)	(992)
Per share, basic and diluted	$ (0.06)	$ (0.02)	$ (0.01)	$ (0.02)

Significant factors that have impacted the Company's results during the above periods include:

- Revenue is directly impacted by the Company's ability to offset natural production declines with production additions from an on-going capital expenditure program and acquisitions.
- Valeura has benefited from relatively high natural gas prices and netbacks in Turkey compared to North America, although the weakening of the TL since 2015 and a reduction of the BOTAS benchmark price on October 1, 2016 have reduced wellhead price realizations compared to 2015 and 2016.
- With its revenues in TL, capital expenditures primarily in United States Dollars and reporting currency in Canadian Dollars, Valeura has a high level of foreign exchange and currency translation exposure.

Fourth Quarter Review

During Q4 2017, petroleum and natural gas sales were up one percent from Q3 2017 reflecting additions from four well workovers, offset by natural declines. Petroleum and natural gas sales were up 30 percent from Q4 2016 due to additions from the TBNG Acquisition, workovers and recompletions and three new drills partially offset by natural declines on both the TBNG JV and Banarli Licences. Adjusted funds flows in Q4 2017 was negatively impacted by current taxes and realized FX losses. The Company spent $1.9 million on exploration and development capital which was funded by adjusted funds flow and the existing cash position. Net loss of $1.0 million was recorded in Q4 2017, which reflects recognition of $2.5 million of depletion and depreciation, $0.1 million of share-based compensation, $0.5 million of accretion on decommissioning liabilities, $0.3 million of foreign exchange losses and $2.4 million deferred tax recovery.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

Selected Annual Information

			Years Ended
	December 31, 2017	December 31, 2016	December 31, 2015
Petroleum and natural gas sales	$ 14,646	$ 16,155	$ 21,543
Cash provided by operations	3,854	6,294	11,693
Adjusted funds flow	(1,205)	6,048	10,185
Per share, basic and diluted	(0.02)	0.10	0.18
Net loss	(8,384)	(6,086)	(562)
Per share, basic and diluted ($/share)	(0.12)	(0.10)	(0.01)
Daily production (boe/d)	952	799	966
Sales price ($/boe)	42.16	55.22	61.10
Cash	11,108	1,987	6,973
Total assets	89,872	75,890	101,212
Total long term liabilities	21,676	13,017	19,945
Net working capital[13]	$ 3,170	$ 3,786	$ 7,253

Valeura's petroleum and natural gas sales, cash provided by operations, adjusted funds flow and net loss are all impacted by production levels and commodity pricing. Daily production in 2017 increased 19 percent from 2016 due to additions from the TBNG Acquisition offset by natural declines on both the TBNG JV and Banarli Licences. Natural gas prices were strong in Turkey over the three year period but have been negatively impacted by the devaluation of the TL to the Canadian dollar and a 10 percent decrease in the BOTAS benchmark price effective October 1, 2016. Total assets in 2017 increased as a result of the TBNG Acquisition but were negatively impacted by the devaluation of the TL against the Canadian Dollar.

Commitments and Contractual Obligations

On August 1, 2016 the Company renegotiated its existing office sublease that was originally signed on June 15, 2015. The term of this sublease runs through January 30, 2019. The remaining amount committed under this renegotiated sublease is approximately $0.3 million including an estimate for operating costs. At December 31, 2017 the remaining commitment of $0.3 million will be discharged in the following years: 2018 – $0.28 million and 2019 – $nominal.

New Accounting Pronouncements and Critical Accounting Policies

Use of estimates and judgments

The preparation of consolidated financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Critical judgments in applying accounting policies:

The following are the critical judgments that management has made in the process of applying the Company's accounting policies and that have the most significant effect on the amounts recognized in the consolidated financial statements:

[13] Working capital is current assets less current liabilities. Assets held for sale have been excluded from this calculation.

- Valeura's assets are aggregated into cash-generating units for the purpose of calculating impairment. Cash generating units ("CGU" or "CGUs") are based on an assessment of the unit's ability to generate independent cash inflows. The determination of these CGUs was based on management's judgment in regards to shared infrastructure, geographical proximity, petroleum type and similar exposure to market risk and materiality.
- Judgments are required to assess when impairment indicators exist and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future oil and natural gas prices, future costs, discount rates, market value of land and other relevant assumptions.
- The application of the Company's accounting policy for exploration and evaluation assets requires management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found.
- Judgments are made by management to determine the likelihood of whether deferred income tax assets at the end of the reporting period will be realized from future taxable earnings.

Key sources of estimation uncertainty:

The following are key estimates and their assumptions made by management affecting the measurement of balances and transactions in the consolidated financial statements:

- Business combinations are accounted for using the acquisition method of accounting when the assets acquired meet the definition of a business in accordance with IFRS. The determination of fair value assigned to assets acquired and liabilities assumed often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of oil and gas properties and E&E assets acquired include estimates of reserves acquired, forecast benchmark commodity prices and discount rates used to present value future cash flows. Changes in any of the assumptions or estimates used in determining the fair value of assets acquired and liabilities assumed could impact the amounts assigned to assets and liabilities.
- Estimation of recoverable quantities of proved and probable reserves include estimates and assumptions regarding future commodity prices, exchange rates, discount rates and production and transportation costs for future cash flows as well as the interpretation of complex geological and geophysical models and data. Changes in reported reserves can affect the impairment of assets, the decommissioning obligations, the economic feasibility of exploration and evaluation assets and the amounts reported for depletion, depreciation and amortization of property, plant and equipment. These reserve estimates are verified by third party professional engineers, who work with information provided by the Company to establish reserve determinations in accordance with National Instrument 51-101 and the COGE Handbook.
- The Company estimates the decommissioning obligations for oil and natural gas wells and their associated production facilities and pipelines. In most instances, removal of assets and remediation occurs many years into the future. Amounts recorded for the decommissioning obligations and related accretion expense require assumptions regarding removal date, future environmental legislation, the extent of reclamation activities required, the engineering methodology for estimating cost, inflation estimates, future removal technologies in determining the removal cost, and the estimate of the liability specific discount rates to determine the present value of these cash flows.
- The Company's estimate of share-based compensation is dependent upon estimates of historic volatility and forfeiture rates.
- The deferred tax liability is based on estimates as to the timing of the reversal of temporary differences, substantively enacted tax rates and the likelihood of assets being realized.

Adoption of Accounting Standards

In April 2016, the IASB issued its final amendment to IFRS 15 Revenue from Contracts with Customers, which replaces IAS 18 Revenue, IAS 11 Construction Contracts, and related interpretations. The new standard contains a single model that applies to contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is to be recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and timing of the revenue recognized. The new standard applies to contracts with customers and does not apply to insurance contracts, financial instruments or lease contracts. Valeura is substantially completed the analysis of the new standard and has concluded that it will not have a material impact on net earnings of the Company.

Valeura anticipates applying the new standard on a retrospective basis on January 1, 2018. The standard requires enhanced disclosure of revenue from contracts with customers in categories that how depict the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors. Several examples of these categories are included such as geography, contract duration, market or type of customer, type of contract, sales channels, timing of transfer of good or service, type of good or service.

In July 2014, the IASB completed the final elements of IFRS 9 Financial Instruments. The standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 Financial Instruments: Recognition and Measurement. IFRS 9, as amended, includes a principle-based approach for classification and measurement of financial assets, a single 'expected loss' impairment model and a substantially reformed approach to hedge accounting. The standard will come into effect for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 9 will be applied on a retrospective basis by Valeura on January 1, 2018 and the Company is currently evaluating the impact of the standard on its financial statements. Valeura does not currently have financial instrument contracts to which it applies hedge accounting.

The International Accounting Standards Board ("IASB") released the following new standards:

In January 2016, the IASB issued IFRS 16 Leases, which replaces IAS 17 Leases. For lessees applying IFRS 16, a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted. IFRS 16 will be applied by Valeura on January 1, 2019 and the Company is currently evaluating the impact of the standard on its financial statements.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

The Company's President and Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P") for Valeura. DC&P, as defined in National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian securities law and include controls and procedures designed to ensure that information required to be so disclosed is accumulated and communicated to management, including the CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure. The CEO and CFO of Valeura evaluated the effectiveness of the design and operation of the Company's DC&P. Based on that evaluation, the officers concluded that Valeura's DC&P were effective as at December 31, 2017.

Internal control over financial reporting ("ICFR"), as defined in National Instrument 52-109, includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of the Company; (ii) are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of the Company are being made in accordance with authorizations of management and Directors of the Company; and (iii) are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that could have a material effect on the consolidated financial statements.

The CEO and CFO are responsible for establishing and maintaining ICFR for Valeura. They have, as at the financial year ended December 31, 2017, designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Under the supervision of the CEO and CFO, Valeura conducted an evaluation of the effectiveness of the Company's ICFR as at December 31, 2017 and concluded that as of December 31, 2017, Valeura maintained effective ICFR. The Company uses the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") – Integrated Framework ("2013 Framework"). Valeura has designed its internal controls over financial reporting based on the 2013 framework. It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

There were no changes to Valeura's ICFR during the year ended December 31, 2017 that materially affected, or are reasonably likely to materially affect, the Company's ICFR.

Off Balance Sheet Arrangements

The Company had no off balance sheet arrangements outstanding as at December 31, 2017 other than those previously disclosed under the Commitments and Contractual Obligations section.

Financial Instruments

Financial instruments of the Company include cash, accounts receivable, accounts payable and accrued liabilities. The carrying values of the financial instruments approximate their fair values due to their relatively short periods to maturity.

Business Risks and Uncertainties

There are a number of risk factors that the Company faces as participants in the international oil and gas industries, which are inherently risky.

The reader is referred to Valeura's 2017 AIF for a more complete description of business risks and uncertainties.

Political Risks

As discussed previously, the political environment in Turkey has been impacted by recent events. The Company will continue to monitor conditions including the safety of personnel and operations, the security situation generally, impact on the Turkish Lira and banking facilities, the functioning of the GDPA, impact on our joint venture partners and any changes in offtakes by our natural gas customers.

Variations in Foreign Exchange Rates and Interest Rates

The Company's functional currency in its subsidiary operations in Turkey is the Turkish Lira. The revenue stream in Turkey is based on Turkish Lira revenue for natural gas sales and US dollar based revenue for crude oil translated into Turkish Lira. Decreases in the value of the Turkish Lira could therefore result in decreases in revenue. The Company's drilling operations in Turkey and related contracts are based primarily in US dollars. Operating costs in Turkey are based primarily in Turkish Lira. Material increases in the value of the US dollar compared to the Canadian dollar will negatively impact the Company's costs of seismic and drilling and completions activity.

Increases in the value of the Turkish Lira could result in increases in operating costs. Future Canadian/US dollar and US dollar/Turkish Lira exchange rates could also impact the future value of the Company's reserves as determined by independent evaluators.

The recent volatility and weakness in the value of the Turkish Lira may impair the ability of the Company to manage this exposure. Continued devaluation of the Turkish Lira without a corresponding increase in the natural gas reference price will have a negative impact on adjusted funds flow and could affect the ability of the Company to fund its' capital program in the future.

To the extent that the Company engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Company may contract. Valeura continues to assess its exposure to all foreign currencies. The Company is in the process of specifically assessing its exposure to the Turkish Lira and any possibilities that may exist to mitigate such exposure.

Foreign Operations

The Company pursues operations outside of Canada. As such, the Company's operations will be subject to a number of risks over which it has no control. These risks may include risks related to economic, social or political instability or change, terrorism, hyperinflation, currency non-convertibility or instability and changes of laws affecting foreign ownership, interpretation or renegotiation of existing contracts, government participation, taxation, working conditions, rates of exchange, exchange control, exploration licensing, petroleum and export licensing and export duties as well as government control over domestic oil and gas pricing. Problems may also arise due to the quality or failure of locally obtained equipment or technical support, which could result in failure to achieve expected target dates for exploration operations or result in a requirement for greater expenditure.

The Company will operate in such a manner as to minimize and mitigate its exposure to these risks. However, there can be no assurance that the Company will be successful in protecting itself from the impact of all of these risks.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Company in Turkey will be affected by numerous factors beyond its control. The Company's ability to market its natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Company may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities, and related to operational problems with such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business. The Company's revenues, profitability, future growth and the carrying value of its oil and gas properties, provided such properties yield production, are substantially dependent on prevailing prices of oil and gas.

The Company's ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Company. These factors include economic conditions in the United States and Canada, the actions of the Organization of Petroleum Exporting Countries ("OPEC"), governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Company's carrying value of its proved reserves, borrowing capacity, revenues, profitability and cash flows from operations. The Canadian/US dollar and Canadian/Turkish Lira exchange rates also affect the profitability of the Company.

The BOTAS price is a reference price fixed by the Turkish government. The natural gas reference price is correlated to contract prices for natural gas imports into Turkey. Any reduction to the price of imported gas would allow the Turkish government to reduce natural gas subsidies and pay down debt and may not result in a pass-through reduction in the reference price. Weakening of the TL/USD exchange rate has the potential to cause the government gas subsidy to increase. Considering the high natural gas prices in the surrounding region, and the devaluation of the Turkish Lira against the United States Dollar throughout 2017, the current level of natural gas pricing in Turkey is not expected to decline any further in the near term. There is potential for some of the larger regional natural gas producers such as Iran and Russia to renegotiate more favorable USD priced contracts with the Turkish government. As a result of natural gas infrastructure restrictions and the lack of gas-on-gas competition in Turkey, Valeura does not have the same susceptibility that other producers have to fluctuations in global commodity prices.

Volatility of Commodity Prices

Prices for oil and natural gas fluctuate in response to changes in the supply of and demand for petroleum and natural gas, market uncertainty and a variety of additional factors that are largely beyond the Company's control. Oil prices are determined by international supply and demand. Factors which affect oil prices include the actions of OPEC, non-OPEC supply growth, world economic conditions, government regulation, political stability throughout the world, the availability of alternative fuel sources and weather conditions. World oil prices are quoted in United States dollars and the price received by the Company is affected by the Canadian/US dollar exchange rate, which will fluctuate over time. Natural gas prices internationally are affected by supply and demand, weather conditions and by prices of alternative sources of energy. Turkish natural gas prices are quoted in Turkish Lira and the price received by the Company is affected by the Canadian dollar/Turkish Lira exchange rate, which fluctuates over time. Material increases in the value of the Canadian dollar may negatively impact production revenues. Such increases may also negatively impact the future value of reserves as determined by independent evaluators.

The impact on the oil and gas industry, in general, from commodity price volatility is significant. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. Purchasing land and properties similarly increases in cost during these periods. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers also decline. This volatility causes significant variation in net production revenue for the Company from period to period. In an environment of low prices, certain wells or other projects may become uneconomic and the Company may elect not to produce from certain wells, leading to a reduction in development opportunities and the volume and value of reserves.

Volatile oil and gas prices make it difficult to estimate the acquisition value of producing properties and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value.

Capital Requirements

The impact on capital markets caused by investor uncertainty in the global economy has a significant impact on the Company's business model. The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. There can be no assurance that debt or equity financing will be available or that cash generated by operations will be sufficient to make these expenditures. If debt or equity financing is available, it may not be on terms acceptable to the Company. Failure to obtain such financing on a timely basis could cause the Company to reduce capital spending which would result in reduced production and the potential loss of exploration licences due to a failure to meet drilling deadlines.

Third Party Credit Risk

The Company must successfully market its oil and natural gas to prospective buyers. The Company may be exposed to third party credit risk through its contractual arrangements with its current or future marketers of its oil and natural gas production. In the event such entities fail to meet their contractual obligations to the Company, such failures may have a material impact on the Company's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program unless sole risk provisions are available under the joint venture agreements.

Exploration, Development and Production

The long-term commercial success of the Company will depend on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that the Company will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisition or participations are identified, the Company may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

In addition, operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, the invasion of water into producing formations, blow-outs, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

The Company attempts to control operating risks by maintaining a disciplined approach to implementation of its exploration and development programs. Exploration risks are managed by hiring experienced technical professionals and by concentrating the exploration activity on specific core regions that have multi-zone potential where the Company has experience and expertise. The Company is not always able to control these risks when it is a non-operator.

Uncertainty of Reserve Estimates

The process of estimating oil and gas reserves is complex and involves a significant number of assumptions in evaluating available geological, geophysical, engineering and economic data; therefore, reserves estimates are inherently uncertain. To estimate the economically recoverable oil and natural gas reserves and related future net cash flows, many factors and assumptions are incorporated such as expected reservoir characteristics based on geological, geophysical and engineering assessments, future production rates based on historical performance and expected future operating and investment activities, future oil and gas prices and quality differentials, future development and operating costs and assumed effects of regulation by government agencies.

Properties will, over a period of time, actually deliver oil and natural gas in quantities different than originally estimated due to changes in reservoir performance. The timing of future capital expenditures is subject to uncertainty. Projected future commodity prices and the operating and capital cost structure are subject to significant management judgment and currently, highly volatile. Actions by foreign governments to alter their respective royalty and tax regimes may have a significant and unpredictable impact.

Environment, Health and Safety

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. In international jurisdictions, environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material.

Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge. There are potential risks to the environment inherent in the business activities of the Company.

Management of Growth

The Company may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Company to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The potential inability of the Company to deal with this growth could have a material adverse impact on its business, operations and prospects.

Insurance

The Company's involvement in the exploration for and development of oil and natural gas properties may result in the Company becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Company maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Company may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that the Company is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Special Note Regarding Non-GAAP Measures

This MD&A includes references to financial measures commonly used in the oil and gas industry. The terms "operating netback" (petroleum and natural gas sales less royalties, production expenses and transportation costs), and "adjusted funds flow" (cash provided by operating activities before decommissioning costs incurred and changes in non-cash working capital) are non-GAAP measures and do not have standardized meanings prescribed by GAAP and are therefore unlikely to be comparable to similar measures used by other issuers. The Company uses these supplemental non-GAAP measures to assist readers in evaluating operating performance. The Company considers adjusted funds flow a key measure as it demonstrates the ability of the Company's continuing operations to generate the cash flow necessary to fund future growth through capital investments and considers operating netback an important measure as it demonstrates its profitability level relative to current commodity prices.

Forward-looking Statements

Certain information included in this MD&A constitutes forward-looking information under applicable securities legislation. Such forward-looking information is for the purpose of explaining management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes, such as making investment decisions. Forward-looking information typically contains statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", "project", "target" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information in this MD&A includes, but is not limited to: the 2018 work program and budget; the timeliness and costs for the deep drilling program in 2018 and 2019; the design, elements and final cost of the Yamalik-1 Testing Program and the expected timeline; the potential to tie-in and conduct a long term production test and achieve natural gas sales from the Yamalik-1 well; the final cost and timeline to complete the processing of the Karaca 3D seismic; the potential of a basin-centered gas play in the Thrace Basin; management's belief regarding the potential of the Company's deep basin-centred gas play and shallow gas business in the Thrace Basin; the Company's commitment to safety and optimizing operational and administrative functions; the Company's business strategy and outlook, operational plans, expected capital expenditures and target exit sales rate; and the availability of operating cash flow and the ability to finance development from existing cash and operating cash flow.

Forward-looking information is based on management's current expectations and assumptions regarding, among other things: political stability of the areas in which the Company is operating and completing transactions, and in particular the aftermath of the July 2016 failed coup attempt and April 2017 constitutional referendum in Turkey; continued safety of operations and ability to proceed in a timely manner; continued operations of and approvals forthcoming from the Turkish government in a manner consistent with past conduct; future seismic and drilling activity on the expected timelines; the prospectivity of the TBNG JV lands and Banarli Licences, including the deep potential; the continued favourable pricing and operating netbacks in Turkey; future production rates and associated operating netbacks and cash flow; decline rates; future sources of funding; future economic conditions; future currency exchange rates; the ability to meet drilling deadlines and other requirements under licences and leases; and the Company's continued ability to obtain and retain qualified staff and equipment in a timely and cost efficient manner. In addition, the Company's work programs and budgets are in part based upon expected agreement among joint venture partners and associated exploration, development and marketing plans and anticipated costs and sales prices, which are subject to change based on, among other things, the actual results of drilling and related activity, availability of drilling, fracing and other specialized oilfield equipment and service providers, changes in partners' plans and unexpected delays and changes in market conditions. Although the Company believes the expectations and assumptions reflected in such forward-looking information are reasonable, they may prove to be incorrect.

Forward-looking information involves significant known and unknown risks and uncertainties. Exploration, appraisal, and development of oil and natural gas reserves are speculative activities and involve a significant degree of risk. A number of factors could cause actual results to differ materially from those anticipated by the Company including, but not limited to: the risks of currency fluctuations; changes in gas prices and netbacks in Turkey; uncertainty regarding the contemplated timelines for the Yamalik-1 tie-in program; completion of the Banarli Farm-in program and the basin-centered gas delineation drilling program; the risks of disruption to operations and access to worksites, threats to security and safety of personnel and potential property damage related to political issues, terrorist attacks, insurgencies or civil unrest in Turkey; political stability in Turkey, including potential changes in Turkey's constitution, political leaders or parties or a resurgence of a coup or other political turmoil; the uncertainty regarding government and other approvals; counterparty risk; potential changes in laws and regulations; risks associated with weather delays and natural disasters; the risk associated with international activity; and, the uncertainty regarding the ability to fulfill the drilling commitments on the West Thrace lands. See Valeura's 2017 AIF filed on SEDAR at www.sedar.com for a detailed discussion of the risk factors.

The forward-looking information contained in this MD&A is made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, unless required by applicable securities laws. The forward looking information contained in this MD&A is expressly qualified by this cautionary statement.