valeura energy inc.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three and nine months ended September 30, 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 November 14, 2017 and should be read in conjunction with Valeura's unaudited condensed interim consolidated financial statements and related notes for the three and nine month periods ended September 30, 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, 2016 ("2016 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 unaudited condensed interim consolidated financial statements have been prepared in accordance with IAS 34 – Interim Financial Reporting of the International Financial Reporting Standards ("IFRS"). The unaudited condensed interim consolidated financial statements have been prepared in accordance with IFRS accounting policies and methods of computation as set forth in Valeura's 2016 audited consolidated financial statements, with the exception of certain disclosures that are normally required to be included in annual consolidated financial statements, which have been condensed or omitted in the interim statements. The unaudited condensed interim consolidated financial statements should be read in conjunction with Valeura's audited consolidated financial statements and MD&A for the year ended December 31, 2016.

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		Nine months ended	
	September 30, 2017	September 30, 2016	**September 30, 2017**	September 30, 2016
Financial				
Petroleum and natural gas sales	**$ 3,970**	$ 3,510	**$ 10,822**	$ 12,647
Net loss	**(4,911)**	(1,263)	**(7,438)**	(2,897)
Per share, basic and diluted	**(0.07)**	(0.02)	**(0.11)**	(0.05)
Funds flow from (used in) operations[1]	**1,165**	1,066	**(759)**	5,133
Per share, basic and diluted	**$ 0.02**	$ 0.02	**$ (0.01)**	$ 0.09
Production volumes				
Natural gas (Mcf/d)	**6,077**	4,020	**5,489**	4,756
Crude oil (bbl/d)	**11**	10	**8**	8
Total (boe/d)	**1,024**	680	**923**	801
Sales prices				
Natural gas (per Mcf)	**$ 6.98**	$ 9.35	**$ 7.13**	$ 9.61
Crude oil (per bbl)	**65.16**	56.24	**67.49**	52.15
Total (per boe)	**42.14**	56.10	**42.96**	57.63
Exploration and development capital	**$ 4,992**	$ 3,080	**$ 10,935**	$ 8,999
Acquisitions	**-**	-	**21,450**	-
Dispositions	**-**	-	**(26,288)**	-
Working capital[2]			**5,458**	3,697
Cash			**2,968**	2,336
Weighted average shares outstanding Basic and diluted (thousands)[3]	**73,148**	58,506	**70,201**	58,164

Outstanding Share Data

	September 30, 2017
Common shares	73,148,321
Stock options	6,370,500
Fully Diluted	79,518,821

On October 14, 2016, the Company entered into an agreement with a syndicate of underwriters pursuant to which the Company agreed to sell and the underwriters agreed to purchase, on an underwritten private placement basis 14,629,000 subscription receipts of the Company (the "Subscription Receipts") at a price of $0.75 per Subscription Receipt for total gross proceeds of approximately $11 million (the "Offering"). The Offering closed November 3, 2016 and the ultimate completion of the Offering was subject to certain conditions, including, without limitation, the closing of the acquisition of the Company's joint venture partner, Thrace Basin Natural Gas (Turkiye) Corporation ("TBNG") for US$20.7 million (CAD$27.1 million) in cash effective March 31, 2016 (the "TBNG Acquisition"). On February 24, 2017 the TBNG Acquisition closed, 14,629,000 common shares were issued pursuant to the 14,629,000 subscription receipts and gross proceeds of approximately $11 million from the

[1] Non-GAAP measure – see note regarding non-GAAP measures on page 18.
[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.

Offering were released from escrow. Valeura used the net proceeds to partially fund the TBNG Acquisition and to a ramp-up shallow gas drilling on the TBNG JV lands and Banarli Licenses in 2017.

The Company

Valeura and its subsidiaries are currently engaged in the exploration, development and production of petroleum and natural gas in 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. As at September 30, 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) (TBNG JV – 0.35 million gross acres, Banarli Licences – 0.13 million gross acres and other – 0.05 million gross acres).

The Thrace Basin assets include a 100 percent working interest in two exploration licences in an early exploration and production stage (the "Banarli Licences"), a 81.5 percent working interest in 16 production leases and exploration licences under a joint venture, which Valeura operates, with an established natural gas production and marketing business (the "TBNG JV") and a 35 percent working interest in three other production leases that currently do not have active operations. The Thrace Basin lands have both conventional shallow gas exploration and development potential and unconventional tight gas potential. The tight gas play is in early-stage development after more than four years of activity aimed at de-risking the play. Some of these lands are also believed to have potential for a basin-centered gas play in over-pressured formations below approximately 2,500 metres. Valeura has recently drilled the Yamalik-1 well on the Banarli Licences with Statoil to test this basin-centered gas play concept and has commenced the completion, multi-stage fracing and flow testing program ("Yamalik-1 Testing Program") of the well.

Turkish Operations

TBNG JV

The TBNG JV lands in the Thrace Basin provide cash flow to the Company from sales of petroleum and natural gas production, interests in 344,781 gross acres of land as at September 30, 2017, and exposure to a significant unconventional tight gas opportunity. The lands encompass 14 production leases and two exploration licences. In February 2017, the TBNG JV was awarded the two production leases that were under application at year-end 2016.

Natural gas is currently produced from approximately 86 wells (gross) on the TBNG JV lands. Approximately 70 percent of the natural gas produced from the TBNG JV lands in Q3 2017 was 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 owned facilities and distributed on an owned sales line network directly to 55 light industry customers.

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 TBNG JV lands thereby increased from 40 percent to 81.5 percent and Valeura became the operator. Operatorship has facilitated Valeura's ability to work with its remaining partner Pinnacle Turkey Inc. ("PTI") to accelerate the ramp-up of exploration and development activities on the TBNG JV lands in 2017.

West Thrace Deep Rights Sale

On January 6, 2017, the Company's wholly-owned affiliate, Corporate Resources B.V. ("CRBV") completed the 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 certain TBNG JV lands, including two exploration licenses and the three production leases (the "West Thrace lands"), for cash consideration of US$12 million which was received in early January 2017.

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 deep formations below approximately 2,500 metres depth 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 Subsequent West Thrace Deep Rights Sale, Valeura retains a 31.5 percent participating interest and Statoil acquired a 50 percent participating interest in the deep formations on the West Thrace lands. Valeura retains an 81.5 percent participating interest in the shallow formations on the West Thrace lands and an 81.5 percent participating interest in all formations on the other TBNG JV Lands.

Banarli Licences

On April 8, 2013, the Company announced that it had been awarded the Banarli Licence 5104 on a 100 percent basis. This licence originally covered an area of 118,598 gross acres near the centre and deepest part of the Thrace Basin and had a four-year initial term. The Company shot 93 kilometres of new 2D seismic in June 2013 to complement more than 300 kilometres of vintage 2D seismic on this licence. During Q2 2015, the GDPA approved the Company's application to convert the Banarli Licence under the new petroleum law to two new contiguous exploration licences encompassing an area of 133,840 gross acres. The clock on the initial term of the licences re-started and the term was extended to five years ending on June 27, 2020. During the initial five-year term, the Company will be required to complete, in aggregate on the two licences, 152 square kilometres of 3D seismic and drill three wells, including a 2,000 metre well in each of year one and year two and a 3,800 metre well in year four. As of the date hereof, the Company has completed the 3D seismic and drilling commitments.

Following the successful conversion of the Banarli Licences in 2015 and the late 2014 drilling success just south of the Banarli Licences on the TBNG JV lands at Gurgen-1, Valeura shifted its corporate strategy to focus on exploration for both shallow conventional gas and deeper unconventional tight gas at Banarli. As an initial step, Valeura acquired 152 square kilometres of 3D seismic on the Banarli Licences in the second quarter of 2015 and merged this with the 3D seismic on the TBNG JV Lands at Osmanli and Tekirdag providing an interpreted data set covering more than 580 square kilometres. Valeura subsequently drilled two vertical exploration wells at Banarli in November and December 2015. A third exploration well was drilled in June 2016.

Banarli Farm-in

On January 6, 2017, the Company closed the farm-in agreement for the exploration of the deeper formations below approximately 2,500 metres on the Company's Banarli Licences in accordance with the farm-in agreement between CRBV and Statoil (the "Banarli Farm-in"). Under the Banarli Farm-in, Statoil will have the option to earn a 50 percent interest in the deep formations on the Banarli Licences by investing in an exploration program that includes payments and carried costs of at least US$36 million. The actual amount invested by Statoil to earn its 50 percent interest may be higher based on the actual agreed costs of the three-phase work program, which includes two deep wells and new 3D seismic. Valeura is operator of the deep exploration program during the earning phase of the Banarli Farm-in and retains a 100 percent interest in the shallow formations in the Banarli exploration licences. Valeura has received US$6.0 million for up-front payments as a contribution to back costs incurred on the Banarli Licences. On July 24, 2017 Valeura completed drilling on the first deep well, Yamalik-1, and commenced the Yamalik-1 Testing Program in early November, which is expected to take 60 days to complete. On June 18, 2017 recording began on the Karaca 3D seismic program on the Banarli Licences and adjacent to the West Thrace Lands and was completed September 20, 2017. Refer to the Capital Expenditures section for further details on the drilling and seismic programs.

Turkish Political Events

On July 15, 2016, an attempted coup by elements of the Turkish military was put down by the government. This event and the aftermath have not affected the Company's ability to conduct drilling and production operations in the Thrace Basin and no unusual delays or security issues have been experienced. The impact so far has been a further devaluation in the Turkish Lira ("TL"), sovereign debt ratings downgrades and a state of emergency declaration, which remains in place as at the date hereof. On April 16, 2017 Turkey held a referendum on a proposed new constitution which was endorsed by a narrow margin. The result served to stabilize the Turkish Lira value against the Canadian Dollar. Further developments in Q3 2017, including the detention of a US embassy worker, have again destabilized the value of the Turkish Lira. 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, impact on our joint venture partners and any changes in offtakes by our natural gas customers.

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. The ability to make reliable estimates is further complicated when the political, economic and security situation is uncertain. Management has based its estimates with respect to the Company's operations in Turkey based on information available up to the date of this MD&A. The situation in Turkey remains uncertain and significant changes could occur which could materially impact the assumptions and estimates made in this MD&A. Changes in assumptions are recognized in the financial statements prospectively.

Outlook

The Company continues to believe that the deep basin-centered gas play in the Thrace Basin provides the most significant upside potential in its asset portfolio in Turkey. Results from the Yamalik-1 Testing Program will be important in shedding additional light on this potential. The Company holds participating interests of 31.5% (West Thrace lands) to 50% (Banarli Licences post Statoil earning) in the deep rights in almost 0.2 million gross acres of land that are prospective for a basin-centered gas play.

The Company has commissioned DeGolyer and MacNaughton ("D&M") of Dallas, Texas to provide a resource assessment (the "D&M Resource Assessment") under the Canadian Oil and Gas Evaluation Handbook and in accordance with National Instrument 51-101, Standards of Disclosure For Oil and Gas Activities for the potential basin-centered gas play underlying Valeura's significant acreage position in the Thrace Basin. The D&M Resource Assessment will be timed to incorporate the results from the Yamalik-1 Testing Program. The D&M Resource Assessment will provide the first measure of the basin-centered gas play potential and help frame the upside for shareholders.

Preliminary plans to further delineate the basin-centered gas play in 2018 are being developed. Under the Banarli Farm-in, Statoil must drill, complete and test one additional deep well to earn its 50% interest in the deep rights on the Banarli Licences.

The Company also believes there is a meaningful shallow gas business in the Thrace Basin and remains focused on developing a viable exploitation plan that incorporates well workovers and re-completions, drilling and selective fracing programs. Valeura operates and holds interests in 0.5 million gross acres of land. Following the closing of the TBNG Acquisition in Q1 2017, Valeura holds participating interests of 81.5% (TBNG JV lands) to 100% (Banarli Licences) in the shallow rights on these lands. The 2018 shallow gas drilling program will be determined once the new Karaca 3D seismic is integrated with the lessons learned from the shallow gas drilling and tight gas fracing programs over the past six years.

The Company's outlook for 2017 exit rate net sales remains unchanged from earlier guidance, with a target range of 1,000 to 1,100 boe/d on the basis of a 7% reduction in the 2017 capital program to $12 to $13 million (net). In Q4 2017, the Company is planning to carry out re-entry fracs in two wells on the TBNG JV lands targeting normally pressured tight gas formations. This frac program builds on the extensive tight gas frac program carried out by the TBNG JV in the 2011 to 2015 period.

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

The Corporation will remain committed to safe operations and ensuring that operational and administrative functions are conducted in the most cost efficient way, with target cost reductions in the 2018 budget.

The Company does not expect to provide guidance on its 2018 work program and budget until Q1 2018, pending the results of the Yamalik-1 Testing Program and its impact on further deep drilling under the Banarli Farm-in, the reset of the shallow gas drilling inventory and further discussion with partners.

Results of Operations

	Three months ended		Nine months ended	
	September 30, 2017	September 30, 2016	**September 30, 2017**	September 30, 2016
Petroleum and natural gas sales	**$ 3,970**	$ 3,510	**$ 10,822**	$ 12,647
Royalties	**(530)**	(453)	**(1,456)**	(1,658)
Production costs	**(1,306)**	(636)	**(3,249)**	(1,612)
Operating netback[4]	**2,134**	2,421	**6,117**	9,377
Other income	**338**	206	**1,049**	662
General and administrative expenses	**(909)**	(969)	**(3,905)**	(4,068)
Transaction costs	**(194)**	(438)	**(1,160)**	(438)
Realized foreign exchange loss	**(323)**	(154)	**(2,114)**	(400)
Current tax recovery (expense)	**119**	-	**(746)**	-
Funds flow from (used in) operations[5]	**1,165**	1,066	**(759)**	5,133
Non-cash expenses				
Share-based compensation	**(138)**	(110)	**(330)**	(279)
Accretion on decommissioning liabilities	**(487)**	(231)	**(1,292)**	(680)
Transactions costs	**-**	(65)	**-**	(65)
Unrealized foreign exchange loss	**(813)**	(315)	**(242)**	(997)
Depletion and depreciation	**(2,352)**	(1,632)	**(6,515)**	(5,576)
Exploration and evaluation expense	**(664)**	-	**(664)**	-
Deferred tax recovery (expense)	**(1,622)**	24	**2,364**	(433)
Net loss	**$ (4,911)**	$ (1,263)	**$ (7,438)**	$ (2,897)

Sales Volumes

	Three months ended		Nine months ended	
	September 30, 2017	September 30, 2016	**September 30, 2017**	September 30, 2016
Natural gas (Mcf/d)	**6,077**	4,020	**5,489**	4,756
Crude oil (bbl/d)	**11**	10	**8**	8
Total (boe/d)	**1,024**	680	**923**	801

[4] Non-GAAP measure – see note regarding non-GAAP measures on page 18.
[5] Non-GAAP measure– see note regarding non-GAAP measures on page 18.

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

Sales volumes for the three and nine months ended September 30, 2017 increased to 1,024 boe/d and 923 boe/d, respectively, compared to 680 boe/d and 801 boe/day for the same periods in 2016 due to additions from the TBNG Acquisition, workovers and recompletions and three new drills (one in each quarter of 2017) partially offset by natural declines on both the TBNG JV and Banarli Licences.

Pricing Information

	Three months ended		Nine months ended	
Average reference prices	**September 30, 2017**	September 30, 2016	**September 30, 2017**	September 30, 2016
Natural gas – BOTAS (per Mcf)[6]	**TL 19.84**	TL 21.93	**TL 19.84**	TL 21.93
Natural gas – BOTAS (per Mcf)	**$ 7.10**	$ 9.67	**$ 7.23**	$ 9.90
Average exchange rate (TL/CAD)	**2.794**	2.267	**2.745**	2.216

	Three months ended		Nine months ended	
Average realized prices	**September 30, 2017**	September 30, 2016	**September 30, 2017**	September 30, 2016
Natural gas (per Mcf)	**$ 6.98**	$ 9.35	**$ 7.13**	$ 9.61
Crude oil (per bbl)	**$ 65.16**	$ 56.24	**$ 67.49**	$ 52.15

Natural gas prices remain relatively strong in Turkey compared to North America, despite the recent volatility of the TL and a reduction in the benchmark price for domestic sales implemented on October 1, 2016. Natural gas prices under sales contracts for all production in the Thrace Basin are linked to the BOTAS benchmark price in TL. 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 effective Canadian Dollar converted average BOTAS benchmark price was $7.10 per thousand cubic feet ("Mcf") for Q3 2017. Natural gas sales from the TBNG JV lands are under direct sales contracts to industrial buyers in the area. All natural gas sales contracts for the TBNG JV lands reflect 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, and is being distributed to existing TBNG JV customers located north of Banarli. 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.

The Company's Q3 2017 average realized natural gas price in Turkey decreased by 25 percent to $6.98 per Mcf from $9.35 per Mcf in Q3 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 Q3 2017 of $6.98 per Mcf represents a 2.0 percent discount to the BOTAS benchmark price.

Petroleum and Natural Gas Sales Revenues

	Three months ended		Nine months ended	
	September 30, 2017	September 30, 2016	**September 30, 2017**	September 30, 2016
Natural gas	**$ 3,902**	$ 3,459	**$ 10,677**	$ 12,531
Crude oil	**68**	51	**145**	116
Total revenues	**$ 3,970**	$ 3,510	**$ 10,822**	$ 12,647

[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 2016 AIF for further discussion.

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

The composition of petroleum and natural gas sales revenues for the three and nine months ended September 30, 2017 was approximately 99 percent natural gas and one percent crude oil. Revenues for Q3 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 nine months ended September 30, 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		Nine months ended	
	September 30, 2017	September 30, 2016	**September 30, 2017**	September 30, 2016
Royalties	**$ 530**	$ 453	**$ 1,456**	$ 1,658
Percentage of revenue	**13.3%**	12.9%	**13.5%**	13.1%

Royalties for Q3 2017 increased in comparison to the same period in 2016 as a result of higher petroleum and natural gas revenue. Royalties for the nine months ended September 30, 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		Nine months ended	
	September 30, 2017	September 30, 2016	**September 30, 2017**	September 30, 2016
Production costs	**$ 1,306**	$ 636	**$ 3,249**	$ 1,612
$ per boe	**13.86**	10.17	**12.90**	7.35

Production costs for the three and nine months ended September 30, 2017 increased in comparison to the same periods in 2016 due primarily to costs associated with integrating the TBNG Acquisition and related expansion of the operations. The expansion of the operations labour staff with the TBNG Acquisition was planned in conjunction with the increased drilling program for 2017. 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 Q3 2017 as compared to Q2 2017, but due to continuing repair and maintenance costs anticipated reductions in production costs were not realized in Q3 2017. Production costs for the remainder of 2017 are expected to be similar to Q3 2017.

Operating Netbacks (per boe)

	Three months ended		Nine months ended	
	September 30, 2017	September 30, 2016	**September 30, 2017**	September 30, 2016
Petroleum and natural gas sales	**$ 42.14**	$ 56.10	**$ 42.96**	$ 57.63
Royalties	**(5.62)**	(7.24)	**(5.78)**	(7.56)
Production costs	**(13.86)**	(10.17)	**(12.90)**	(7.35)
Operating netback	**$ 22.66**	$ 38.69	**$ 24.28**	$ 42.72

Operating netbacks for the three and nine months ended September 30, 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 in Q2 and Q3 2017, 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 an average royalty rate of 13% 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		Nine months ended	
	September 30, 2017	September 30, 2016	**September 30, 2017**	September 30, 2016
General and administrative expenses	**$ 1,721**	$ 1,293	**$ 5,356**	$ 4,553
Business development	**8**	(192)	**31**	121
Total	**1,729**	1,101	**5,387**	4,674
Recoveries	**(820)**	(132)	**(1,482)**	(606)
Total general and administrative expenses	**$ 909**	$ 969	**$ 3,905**	$ 4,068

Total general and administrative expenses net of recoveries for the three and nine months ended September 30, 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 have enabled increased overhead recoveries shown above.

Transaction Costs

To date in 2017, the Company recorded transaction costs of $1.2 million compared to $0.5 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 the three and nine months ended September 30, 2017, the Company recorded a foreign exchange loss (realized and unrealized) of $1.1 million and $2.4 million, respectively, compared to a foreign exchange loss of $0.5 million and $1.4 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 funds flow from operations and could affect the ability of the Company to fund its capital program in the future.

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

Changes to the TL/CAD exchange rate would have had the following impact on revenues, royalties and production costs for the three and nine months ended September 30, 2017:

+/- 1 percent change in realized TL/CAD exchange rate	Petroleum and natural gas revenues	Royalties	Production costs
Three months ended September 30, 2017	$ 42	$ 5	$ 12
Nine months ended September 30, 2017	$ 115	$ 14	$ 32

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 and nine months ended September 30, 2017:

+/- 1 percent change in realized TL/USD exchange rate, upon conversion to presentation currency	Capital expenditures
Three months ended September 30, 2017	$ 33
Nine months ended September 30, 2017	$ 46

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 the three and nine months ended September 30, 2017, the Company recorded other income of $0.3 million and $1.0 million, respectively, compared to $0.2 million and $0.7 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 the three and nine months ended September 30, 2017 is attributed to higher third party volumes processed, and higher working interest participation in processing revenues due to the TBNG Acquisition.

Funds flow from Operations

Funds flow from operations for the three and nine months ended September 30, 2017 was an inflow of $1.2 million and an outflow of $0.8 million, respectively, compared to an inflow of $1.1 million and $4.1 million for the same periods in 2016. The increase in funds flow from operations in Q3 2017 was due to higher volumes and lower transaction costs, partially offset by lower natural gas price realization, higher production costs and higher foreign exchange losses. Funds flow from operations for the nine months ended September 30, 2017 was negatively impacted by TBNG Acquisition related expenses that are not considered ongoing expenses.

(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 funds flow from operations:

	Three months ended		Nine months ended	
	September 30, 2017	September 30, 2016	**September 30, 2017**	September 30, 2016
Cash provided by (used in) operating activities	**$ (2,943)**	$ 1,516	**$ (3,630)**	$ 5,637
Decommissioning costs incurred	**-**	-	**14**	-
Change in non-cash working capital	**4,108**	(450)	**2,857**	(504)
Funds flow from (used in) operations	**$ 1,165**	$ 1,066	**$ (759)**	$ 5,133

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 the three and nine months ended September 30, 2017 was $0.1 million and $0.3 million, respectively, compared to $0.1 million and $0.3 million for the same periods in 2016. During the nine months ended September 30, 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 the three and nine months ended September 30, 2017 was $0.5 million and $1.3 million, respectively, compared to $0.2 million and $0.7 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.

Depletion and Depreciation

Depletion and depreciation for the three and nine months ended September 30, 2017 was $2.4 million and $6.5 million, respectively, compared to $1.6 million and $5.6 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 the three and nine months ended September 30, 2017 was $24.97/boe and $25.86/boe, respectively, compared to $26.13/boe and $25.41/boe for the same periods in 2016.

Current Tax

Current tax for the three and nine months ended September 30, 2017 was a recovery of $0.1 million and an expense of $0.7 million respectively compared to $nil for the same periods in 2016. The current tax in the first nine months of 2017 represents a preliminary estimate of taxes incurred primarily for the proceeds on the sale of the West Thrace lands. Capital expenditures in Q3 2017 have provided a reduction to current tax and future capital expenditures in the remainder of 2017 are anticipated to provide further recoveries to current tax.

Deferred Tax

Deferred tax for the three and nine months ended September 30, 2017 was an expense of $1.6 million and recovery of $2.3 million, respectively, compared to a recovery of $0.02 million and an expense of $0.4 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.

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

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 the three and nine months ended September 30, 2017 was a loss of $2.9 million and a loss of $3.7 million, respectively, compared to a loss of $1.5 million and $4.9 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), based on the best information available regarding TBNG working capital on February 24, 2017, 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, Other Assets, 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.

(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		Nine months ended	
	September 30, 2017	September 30, 2016	**September 30, 2017**	September 30, 2016
Geological and geophysical	**$ 111**	$ 151	**$ 790**	$ 960
Drilling & completions	**4,220**	2,571	**8,045**	6,746
Workovers & recompletions	**133**	6	**1,393**	72
Equipping, facilities & other	**528**	352	**707**	1,221
Total exploration and development capital program	**4,992**	3,080	**10,935**	8,999
Acquisitions	**-**	-	**21,450**	-
Dispositions	**-**	-	**(26,288)**	-
Total net capital	**$ 4,992**	$ 3,080	**$ 6,097**	$ 8,999

The Company's capital spending for Q3 2017 was $5.0 million, including $0.1 million for geological and geophysical operations, $4.2 million for drilling and completions, $0.1 million for workovers and recompletions and $0.5 million for equipping, facilities and other.

TBNG JV

During Q3 2017, the Company spudded two wells, Koseilyas-2 and Karaevli-6, on the TBNG JV lands (Valeura 81.5% working interest). Koseilyas-2 was drilled to a measured depth of 1,107 metres and is currently on production. Karaevli-6 was drilled to a measured depth of 1,261 metres and has been plugged and abandoned. The Company also completed workovers on 7 gross wells.

Banarli Licence

During Q3 2017 the Company spudded Aydinkoy-1 (Valeura 100% participating interest). The well was drilled to a measured depth of 2,821, cased and completed and is currently being evaluated. The Company also completed one workover on the Banarli Licence at Bati Gurgen.

Banarli Farm-in

On May 13, 2017 the Company spudded the first deep exploration well, Yamalik-1 under Phase 1 of the Banarli Farm-in with its partner Statoil. The well was drilled to a total depth of 4,196 metres with positive evaluation results. Interpretation of the extensive drilling results provided further positive indicators of the potential for a basin-centered gas play in the Thrace Basin of Turkey. The Yamalik-1 Testing Program commenced at the beginning of November and is expected to take 60 days. The drilling and testing program for Yamalik-1 is being funded 100% by Statoil up to a cap of 110% of the budget. The Yamalik-1 drilling program was completed within the budget of US$12.85 million. The budget for the Yamalik-1 Testing Program is US$10.3 million.

As part of the Banarli Farm-in, Statoil is required to fully fund up to US$10.0 million on new 3D seismic acquisition and processing. The recording stage of the seismic program commenced on June 18, 2017 and was completed on September 20, 2017 and approximately 500 square kilometres of 3D seismic has been acquired over much of the Banarli Licences and a large portion of the West Thrace lands. Processing of the new 3D seismic is underway and should be completed late in Q1 2018. A fast-track processing step has been agreed with Statoil and is expected to provide early preliminary data before year end 2017. The new 3D seismic will be used to support planning for the 2018 deep program and to build on the shallow gas prospect portfolio.

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

The Company's net capital expenditure program for 2017 is anticipated to be $12 to $13 million funded out of the existing working capital and funds flow from operations. The focus will be on the Yamalik-1 Testing Program (funded by Statoil) and two re-entry fracs in Q4 2017 on the TBNG JV Lands.

Liquidity, Financing and Capital Resources

	Three months ended		Nine months ended	
	September 30, 2017	September 30, 2016	**September 30, 2017**	September 30, 2016
Opening cash position	**$ 9,903**	$ 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**	-
Funds flow from operations[7]	**1,165**	1,066	**-**	5,133
Restricted cash	**204**	-	**-**	-
Proceeds from stock option exercises	**-**	-	**-**	437
Changes in working capital and foreign exchange on cash[8]	**-**	-	**1,139**	-
	1,369	1,066	**37,535**	5,570
Outflow of funds				
Capital expenditures[9]	**(4,992)**	(3,080)	**(10,935)**	(8,999)
Decommissioning costs incurred	**-**	-	**(14)**	-
TBNG Acquisition[10]	**-**	-	**(21,450)**	-
Restricted cash	**-**	-	**(3,396)**	-
Changes in working capital and foreign exchange on cash[11]	**(3,312)**	(261)	**-**	(1,208)
Funds flow used in operations	**-**	-	**(759)**	-
	(8,304)	(3,341)	**(36,554)**	(10,207)
Closing cash position	**$ 2,968**	$ 2,336	**$ 2,968**	$ 2,336

7 Non-GAAP measure – see note regarding non-GAAP measures on page 18.

8 Includes the following captions from the condensed interim 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 condensed interim 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 condensed interim 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.

Capital Funding and Resources

As at September 30, 2017, Valeura's working capital[12] balance was $5.5 million including cash of $3.0 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 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 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 $10.9 million.

Financial Capacity

As at September 30, 2017 the Company's working capital[12] surplus was $5.5 million. The working capital position is expected to be sufficient to fund the planned minimum capital program of $1 to $2 million (net) in Q4 2017. The Company completed the drilling of two commitment wells in the first half of 2017 and no further commitment wells are required in 2017.

For 2018, Valeura will continue to manage the capital program within working capital and funds flow from operations. There is only one commitment well for 2018 which can be satisfied with a shallow well. The deep well follow up to Yamalik-1 will likely be spud mid-year 2018 and will be fully funded by Statoil. Upon completion of the farm-in obligation Statoil will earn a 50% working interest in the deep rights at Banarli and may elect to take over operatorship. Valeura will be obligated to pay its 50% share of capital obligations after such elections, which could occur late 2018.

The Company maintains considerable flexibility in managing its capital budget for 2017 and 2018. 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, offsetting natural declines and growing production. The Company will continue to utilize current working capital and funds flow from operations to complete its workover and re-entry fracing program on the TBNG JV lands in Q4 2017 and does not expect to provide guidance on its 2018 work program and budget until Q1 2018, pending results of the Yamalik-1 Testing Program. In addition, Valeura continues to evaluate debt/loan facility alternatives to expand financial capacity in 2017. However, consistent production and funds flow growth will be required to form the foundation to build a loan facility.

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 funds flow from operations.

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

[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)

operatorship over all the lands in the Thrace Basin. An exception to this statement could occur in 2018 if Statoil elects to complete Phases 2 and 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 including a pilot project, which would require the Company to contribute its 50 percent participating interest share of these costs. Such a program could result in a significant capital commitment for which the Company will be required to 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 September 30, 2017, the Company has issued letters of credit totaling US$0.04 million (September 30, 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.

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 nine months ending September 30, 2017.

Selected Quarterly Information

	Three months ended			
	September 30, 2017	June 30, 2017	March 31, 2017	December 31, 2016
Total daily production (boe/d)	1,024	934	807	795
Average wellhead price ($/boe)	$ 42.14	$ 44.28	$ 42.49	$ 47.97
Petroleum and natural gas sales	3,970	3,764	3,088	3,508
Funds flow from (used in) operations	1,165	959	(2,883)	915
Per share, basic and diluted	0.02	0.01	(0.04)	0.02
Net income (loss)	(4,911)	(526)	(2,001)	(3,189)
Per share, basic and diluted	$ (0.07)	$ (0.01)	$ (0.03)	$ (0.06)
	Three months ended			
	September 30, 2016	**June 30, 2016**	**March 31, 2016**	**December 31, 2015**
Total daily production (boe/d)	680	933	792	809
Average wellhead price ($/boe)	$ 56.10	$ 56.62	$ 60.09	$ 59.45
Petroleum and natural gas sales	3,510	4,809	4,328	4,425
Funds flow from operations	1,066	2,098	1,969	1,600
Per share, basic and diluted	0.02	0.04	0.03	0.03
Net income (loss)	(1,263)	(642)	(992)	287
Per share, basic and diluted	$ (0.02)	$ (0.01)	$ (0.02)	$ 0.01

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.

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 Company has the option to terminate the sublease agreement after 18 months. The remaining amount committed under this renegotiated sublease is approximately $0.43 million including an estimate for operating costs. At September 30, 2017 the remaining commitment of $0.36 million will be discharged in the following years: 2017 – $0.08 million, 2018 – $0.28 million, 2019 – $nominal.

Critical Accounting Policies

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. The reader is referred to Valeura's December 31, 2016 audited consolidated financial statements and MD&A for a description of estimates and judgments.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

The Company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on January 1, 2017 and ending on September 30, 2017 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

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.

Off Balance Sheet Arrangements

The Company had no off balance sheet arrangements outstanding as at September 30, 2017 other than those previously disclosed under the Commitments and Contractual Obligations section.

Financial Instruments

Financial instruments of the Company include cash, accounts receivable, inventory, 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 a participant in the international oil and gas industry which are inherently risky.

All risk factors have not materially changed from December 31, 2016. The reader is referred to Valeura's December 31, 2016 audited consolidated financial statements, MD&A and 2016 AIF for a description of these risks.

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 "funds flow from operations" (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 funds flow from operations 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 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 and early fast-track processing step to facilitate planning; the preparation of the D&M Resource Assessment and the timing thereof; 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 determination of the Company's 2018 shallow gas and deep drilling programs; the Company's business strategy and outlook, 2017 work program, operational plans, expected capital expenditures and target exit sales rate; the timing for the preparation of the 2018 work program and budget; 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 Testing Program and the Karaca 3D seismic 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 2016 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.