This document comprises a prospectus relating to Valeura Energy Inc. prepared in accordance with the Prospectus Rules. This document has been approved by the Financial Conduct Authority in accordance with Part VI of the Financial Services and Markets Act 2000 and has been filed with the FCA and made available to the public in accordance with Rule 3.2 of the Prospectus Rules.

Applications have been made to the UK Listing Authority and the London Stock Exchange for all of the Common Shares to be admitted to the standard segment of the Official List and to trading on the London Stock Exchange's Main Market for listed securities, respectively. Admission to trading on the Main Market constitutes admission to trading on a UK regulated market. It is expected that Admission will become effective and that unconditional dealings in the Common Shares will commence on 25 April 2019. Dealings on the London Stock Exchange before Admission will only be settled if Admission takes place. **All dealings before the commencement of unconditional dealings will be of no effect if Admission does not take place and such dealings will be at the sole risk of the parties concerned.**

The Company has established arrangements to enable investors to settle interests in the Common Shares through the CREST system. Securities issued by non-UK companies, such as the Company, cannot be held or transferred electronically in the CREST system. However, depositary interests allow such securities to be dematerialised and settled electronically through CREST. The Depositary Interests will be independent securities constituted under English law, which may be held and transferred through the CREST system. Investors should note that it is the Depositary Interest, which will be settled through CREST and not the Common Shares.

The Common Shares are currently listed on the Toronto Stock Exchange, where they will continue to be listed. The Company is seeking a secondary listing for the Common Shares on the standard segment of the Official List and to trading on the London Stock Exchange.

The Company and each of the Directors, whose names appear on page 38 of this document, accept responsibility for the information contained in this document. To the best of the knowledge of the Company and the Directors (who have taken all reasonable care to ensure that such is the case), the information contained in this document is in accordance with the facts and does not omit anything likely to affect the import of such information.

Prospective investors should read this document in its entirety. In particular, your attention is drawn to Part 2 of this document, "*Risk Factors*" for a discussion of the risks that might affect the value of your shareholding in the Company. Prospective investors should be aware that an investment in the Company involves a degree of risk and that, if certain of the risks described in this document occur, investors may find their investment materially adversely affected. Accordingly, an investment in the Common Shares is only suitable for investors who are particularly knowledgeable in investment matters and who are able to bear the loss of the whole or part of their investment.

Valeura Energy Inc.

(*incorporated in Alberta, Canada with Corporate Access Number 208838144*)

Admission to the Official List (by way of a Standard Listing under Chapter 14 of the Listing Rules) and to trading on the London Stock Exchange's Main Market for listed securities of 86,584,989 Common Shares

Financial Adviser

The Common Shares have not been, and will not be, registered under the United States Securities Act of 1933 (as amended), or under the securities laws or with any securities regulatory authority of any state or other jurisdiction of the United States or of any province or territory of Australia or Japan. Securities may not be offered or sold in the United States absent: (i) registration under the US Securities Act; or (ii) an available exemption from registration under the US Securities Act. The Common Shares have not been and will not be offered or sold in the United States, Australia or Japan or to or for the account or benefit of any person resident in the United States, Australia or Japan and this document does not constitute an offer to sell or a solicitation of an offer to purchase or subscribe for Common Shares in such jurisdictions or in any jurisdiction in which such offer or solicitation is unlawful or would impose any unfulfilled registration, publication or approval requirements on the Company.

FirstEnergy Capital LLP (trading as GMP FirstEnergy ("**GMP FirstEnergy**")) is authorised and regulated in the UK by the FCA. GMP FirstEnergy is acting exclusively for the Company as financial adviser (and not as sponsor) and for no other person in connection with Admission and will not regard any other person (whether or not a recipient of this document) as its client in relation to Admission and will not be responsible to anyone other than the Company for providing the protections afforded to its clients or for providing advice in relation to Admission. GMP FirstEnergy has not been engaged by the Company as sponsor in connection with Admission and will not be responsible to anyone (including the Company) for providing the protections afforded to its clients for providing advice as sponsor in relation to Admission or any other transaction or arrangement referred to in this document.

GMP FirstEnergy and/or any of its respective affiliates may have engaged in transactions with, and provided various investment banking, financial advisory and other services for the Company, for which they would have received customary fees. GMP FirstEnergy and/or any of its respective affiliates may provide such services to the Company and any of its respective affiliates in the future.

Apart from the responsibilities and liabilities, if any, which may be imposed on GMP FirstEnergy by FSMA, or the regulatory regime established thereunder, or under the regulatory regime of any other jurisdiction where exclusion of liability under the relevant regulatory regime would be illegal, void or unenforceable, GMP FirstEnergy accepts no responsibility whatsoever, and makes no representation or warranty, express or implied, for the contents of this document, including its accuracy or completeness, or for any other statement made or purported to be made by it, or on behalf of it, the Company or any other person in connection with the Company or the Common Shares and nothing contained in this document is or shall be relied upon as a promise or representation in this respect, whether as to the past or future. GMP FirstEnergy accordingly disclaims all and any responsibility or liability whether arising in tort,

contract or otherwise (save as referred to above) which it may otherwise have in respect of this document or any such statement. GMP FirstEnergy has given and not withdrawn its consent to the issue of this document with the inclusion of the references to its name in the form and context to which it is included.

The application for Admission has been made in compliance with Listing Rule 3.

The distribution of this document and the offer, sale and/or issue of Common Shares in certain jurisdictions may be restricted by law. No action has been or will be taken by the Company, the Directors or GMP FirstEnergy to permit a public offer or sale of Common Shares or possession or distribution of this document (or any other offering or publicity material or application form relating to the Common Shares) in any jurisdiction. Persons into whose possession this document comes are required by the Company, the Directors and GMP FirstEnergy to inform themselves about and to observe any such restrictions. This document does not constitute or form part of an offer to sell, or the solicitation of an offer to buy, Common Shares to any person in any jurisdiction to whom or in which such offer or solicitation is unlawful.

Application has been made for the Common Shares to be admitted to the standard segment of the Official List. A Standard Listing affords investors in the Company a lower level of regulatory protection than that afforded to investors in companies whose securities are admitted to the premium segment of the Official List, which are subject to additional obligations under the Listing Rules.

Without prejudice to any obligation of the Company to publish a supplementary prospectus pursuant to section 87G of FSMA or Rule 3.4 of the Prospectus Rules, the publication of this document does not create any implication that there has been no change in the affairs of the Group since, or that the information contained herein is correct at any time subsequent to, the date of this document.

Forward Looking and Cautionary Statements

Certain statements contained in this document constitute forward-looking statements. These statements, including the explanatory wording in the document in relation to the Group's working capital, relate to future events or the future performance of the Group but do not seek in any way to qualify the working capital statement given by the Company. These statements relate to future events or the future performance of the Group. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", "expect" or similar expressions. These statements involve numerous assumptions, known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those expressed, anticipated or implied in such forward-looking statements. The Company believes that the expectations reflected in forward-looking statements contained herein are reasonable but no assurance can be given that such expectations will prove to be correct or accurate and accordingly, such forward-looking statements included in, or incorporated by reference into, this document should not be unduly relied upon. These statements speak only as of the date of this document. Actual operational and financial results or events may differ materially from the Company's expectations contained in the forward-looking statements as a result of various factors, many of which are beyond the control of the Company.

Statements related to "reserves" or "resources" are deemed to be forward-looking information as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources can be profitably produced in the future. The forward-looking statements contained in this Prospectus are expressly qualified by this cautionary statement. The Company does not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities laws.

Forward-looking statements involve 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. Forward-looking statements are based on a number of factors and assumptions which have been used to develop such statements but which may prove to be incorrect. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on forward-looking statements because the Company can give no assurance that such expectations will prove to be correct.

Investors are cautioned that forward-looking statements are not guarantees of future performance. The Company makes no representation, warranty or prediction that the results predicted by such forward-looking statements will be achieved and these forward-looking statements represent, in each case, only one of many possible scenarios and should not be viewed as the most likely or standard scenario. Forward-looking statements may, and often do, differ materially from actual results. Any forward-looking statements in this document speak only as at the date of this document, reflect the Group's current view with respect to future events and are subject to risks relating to future events and other risks, uncertainties and assumptions relating to the Group's operations, results of operations, growth strategy and the availability of new credit. Investors should specifically consider the factors identified in this document that could cause actual results to differ. All of the forward-looking statements made in this document are qualified by these cautionary statements.

Subject to the requirements of the Prospectus Rules, the DGTRs and the Listing Rules, or applicable law, the Company explicitly disclaims any intention or obligation or undertaking publicly to release the result of any revisions to any forward-looking statements in this document that may occur due to any change in the Group's expectations or to reflect events or circumstances after the date of it.

Company's website

Information contained on the Company's website or the contents of any website accessible from hyperlinks on the Company's website are not incorporated into and do not form any part of this document.

INTERPRETATION

Certain terms used in this Prospectus are defined in Part 16 of this document, "*Definitions*".

References to the singular in this document shall include the plural and vice versa, where the context so requires. References to sections or Parts are to sections or Parts of this document. All references to time in this document are to London time unless otherwise stated.

Preferred Currency

Unless specifically expressed otherwise, all dollar ($) references herein are in Canadian ("C") dollars.

Use of Unrisked Estimates

The unrisked estimates of prospective resources referred to in this Prospectus have not been risked for either the chance of discovery or the chance of development. If a discovery is made, there is no certainty that it will be developed or, if it is developed, there is no certainty as to the timing of such development or that it will be commercially viable to produce any portion of the prospective resources.

BOEs

A BOE is determined by converting a volume of natural gas to barrels using the ratio of 6 Mcf to one barrel. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Further, a conversion ratio of 6 Mcf:1 BOE assumes that the gas is very dry without significant natural gas liquids. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilising a conversion on a 6:1 basis may be misleading as an indication of value.

Short Production Test Rates

The short production test rates disclosed in this Prospectus are preliminary in nature and may not be indicative of stabilised on-stream production rates. Initial on-stream production rates are typically disclosed with reference to the number of days in which production has been measured. Initial on-stream production rates are not necessarily indicative of long-term performance or ultimate recovery. To date, Valeura's shallow gas conventional wells and fracked unconventional tight gas wells have exhibited relatively high decline rates at more than 50 per cent. and 75 per cent., respectively, in their first year of production.

There is currently no long-term flow information for the deep, unconventional BCGA. While the same geological formations that are producing gas in the shallow are being targeted in the deep, unconventional play, they are in a different depth and pressure environment and the type curves are not expected to be indicative of deep, unconventional well production rates. A pressure transient analysis or well-test interpretation has not been carried out in respect of the production tests on the Yamalik-1 well. All natural gas rates and volumes are presented net of any load fluids.

Dated 17 April 2019

CONTENTS

PART 1 – SUMMARY

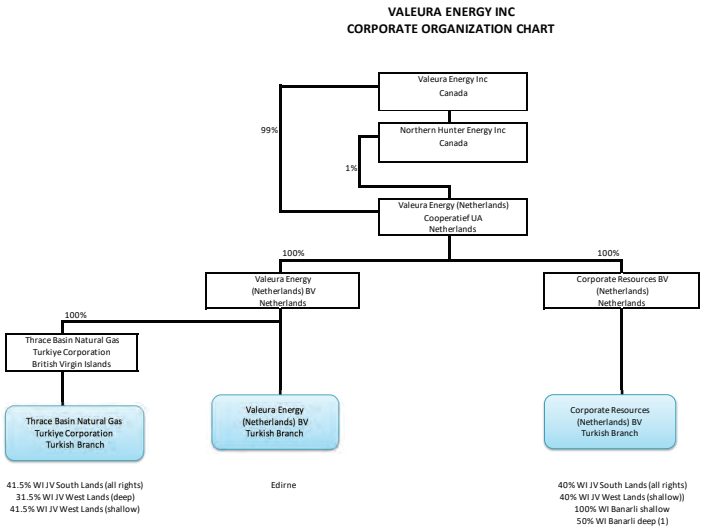
Summaries are made up of disclosure requirements known as "Elements". These elements are numbered in Sections A – E (A.1 – E.7).

This summary contains all the Elements required to be included in a summary for this type of security and issuer. Because some Elements are not required to be addressed, there may be gaps in the numbering sequence of the Elements.

Even though an Element may be required to be inserted in the summary because of the type of security and issuer, it is possible that no relevant information can be given regarding the Element. In this case, a short description of the Element is included in the summary with the mention of "not applicable".

Section A – Introduction and warnings		
A.1	**Introduction**	This summary must be read as an introduction to the Prospectus. Any decision to invest in Common Shares should be based on consideration of the Prospectus as a whole by the investor. Where a claim relating to the information contained in the Prospectus is brought before a court, the plaintiff investor might, under the national legislation of the Member States, have to bear the costs of translating the Prospectus before the legal proceedings are initiated. Civil liability attaches only to those persons who have tabled the summary, including any translation thereof, but only if the summary is misleading, inaccurate or inconsistent when read together with other parts of the Prospectus or it does not provide, when read together with the other parts of the Prospectus, key information in order to aid investors when considering whether to invest in such securities.
A.2	**Consent for intermediaries**	Not applicable. The Company has not given its consent to the use of this document for the resale or final placement of Common Shares by financial intermediaries.

Section B – Issuer		
B.1	**Legal and commercial name**	Valeura Energy Inc.
B.2	**Domicile/ legal form/ legislation/ country of incorporation**	The Company was incorporated and registered under the name Sasha Corp. in Alberta, Canada on 12 June 2000, and is a company subject to the provision of the ABCA. The Company's corporate access number is 208838144. The Company changed its name to International Sasha Corp. on 3 November 2000, to PanWestern Energy Inc. on 22 June 2004, and to Valeura Energy Inc. on 29 June 2010. The head office of Valeura is located at Suite 1200, 202 – 6th Avenue SW, Calgary, Alberta, T2P 2R9 and its registered and records office is located at 4600, 525 – 8th Avenue SW, Calgary, Alberta, T2P 1G1.
B.3	**Current operations/ principal activities and markets**	The Company is the holding company of the Group, which is engaged in the exploration, development and production of hydrocarbons, principally natural gas, in Turkey. Valeura's operations are focused on the Thrace Basin in the northwest of Turkey. Valeura currently holds working interests in 20 production leases and exploration licences covering approximately 0.53 million gross acres (0.43 million net acres of shallow rights and 0.28 million net acres of deep rights).
B.4	**Significant recent trends**	The most significant trends affecting the Company and the oil and gas industry in Turkey include: ● Historically, the BOTAS Reference Price has behaved in a similar manner to the regional price for natural gas when translated to US$,

		though price changes have tended to lag the more market-driven natural gas prices in the region. ● In 2018 BOTAS introduced regular updates to the natural gas price and since mid-2018 the price has been adjusted numerous times. Analysis suggests that these price adjustments are taking into account variations in the regional price of natural gas, and changes in the TL exchange rate. While indications are that the BOTAS pricing continues to move toward a more market-driven price for natural gas, there is no guarantee that the government will continue this policy in the future. ● Turkey has had an active oil and gas industry for almost a century, but it has generally been small relative to other mature oil and gas jurisdictions. Major oil and gas companies have come into the country during the exploration phase of activity when there is potential for new plays that could yield significant oil and gas volumes, for example, deep water plays in the Black Sea or the Mediterranean. ● Currently the industry is dominated by the Turkish state oil and gas company, "TPAO" and small to mid-cap oil and gas companies but activity has been steady in line with global oil and gas activity trends.
B.5	**Group structure**	The Company is the parent company of the Group. It holds (directly and via its 100 per cent. holding of Northern Hunter Energy Inc.) 100 per cent. of the issued share capital of Valeura Energy (Netherlands) Cooperatief UA ("**VENC**"). VENC has two wholly owned subsidiaries, Valeura Energy (Netherlands) BV ("**VENBV**") and Corporate Resources BV (Netherlands) ("**CRBV**"). Thrace Basin Natural Gas Turkiye Corporation ("**TBNG**") is a wholly owned subsidiary of VENBV. VENBV, CRBV and TBNG carry out the Group's Thrace Basin Natural Gas operations. The Thrace Basin assets include an 81.5 per cent. working interest in the shallow rights and deep rights of 11 production leases in the South Thrace Lands; an 81.5 per cent. (shallow rights) working interest and 31.5 per cent. (deep rights) working interest in three production leases and one exploration licence in the West Thrace Lands; and a 100 per cent. (shallow rights) and a 50 per cent. (deep rights) working interest in the Banarli Exploration Licences. In addition, Valeura holds a 35 per cent. working interest in three other production leases (Edirne, Turkey) that currently do not have active operations. The Group structure as at the date of this document is as follows: 

B.6 **Major Shareholders**

As at the Last Practicable Date, the Company is aware of the following Shareholders that, directly or indirectly, hold interests in 5 per cent. or more of the Company's capital or voting rights:

Shareholder	*Number of Common Shares*	*Percentage of the share capital*
Baillie Gifford & Co	15,285,400	17.7%

There are no differences between the voting rights enjoyed by the Shareholder described above and those enjoyed by the other holders of Common Shares.

B.7 **Selected historical key financial information**

The tables below summarise certain key financial information relating to the Group for the periods indicated and should be read together with the whole of this Prospectus. The selected key historical financial information set out below has been extracted without material adjustment from the Company's consolidated financial statements as at and for the years ended 31 December 2018, 2017 and 2016.

Summary Consolidated Statements of Operations

	Year ended 31-Dec 2018 C$'000	*Year ended 31-Dec 2017 C$'000*	*Year ended 31-Dec 2016 C$'000*
Revenue			
Petroleum and natural gas sales	11,969	14,646	16,155
Royalties	(1,611)	(1,971)	(2,102)
Other Income	2,245	1,363	846
	12,603	**14,038**	**14,899**
Expenses			
Production	3,606	4,423	2,232
General and administrative	3,750	4,606	5,376
Exploration and Evaluation	–	707	–
Depletion and depreciation	7,306	9,025	7,436
Corporate and other	4,143	6,080	6,201
	18,805	**24,841**	**21,245**
Loss before tax	(6,202)	(10,803)	(6,346)
Tax expense/(benefit)	918	(2,419)	(260)
Net loss	**(7,120)**	**(8,384)**	**(6,086)**
Other comprehensive loss	(10,378)	(6,019)	(11,511)
Comprehensive loss	**(17,498)**	**(14,403)**	**(17,597)**

Summary Consolidated Statements of Financial Position

	As at 31-Dec 2018 C$'000	*As at 31-Dec 2017 C$'000*	*As at 31-Dec 2016 C$'000*
Assets			
Current Assets	73,907	16,792	24,688
Non-Current Assets	54,416	73,080	51,202
Total Assets	128,323	89,872	75,890

	As at 31-Dec 2018 C$'000	As at 31-Dec 2017 C$'000	As at 31-Dec 2016 C$'000
Liabilities and Shareholders' Equity			
Current Liabilities	14,387	13,371	4,267
Non-Current Liabilities	17,717	21,676	13,017
Total Liabilities	32,104	35,047	17,284
Share Capital	205,320	146,694	136,586
Contributed surplus	20,123	19,857	19,343
Accumulated Losses	(42,561)	(32,183)	(26,164)
Deficit	(86,726)	(79,543)	(71,159)
Total Equity	**96,219**	**54,825**	**58,606**
Total Liabilities and Shareholders' Equity	**128,323**	**89,872**	**75,890**

Summary Consolidated Statements of Cash flows

	Year ended 31-Dec 2018 C$'000	Year ended 31-Dec 2017 C$'000	Year ended 31-Dec 2016 C$'000
Cash was provided by (used in):			
Operating activities	584	3,854	6,294
Financing activities			
Share issuance (net of costs)	55,408	10,108	–
Proceeds from stock option exercises	1,912	–	437
Cash provided by financing activities	**57,320**	**10,108**	**437**
Investing activities			
TBNG Acquisition	–	(21,450)	–
West Thrace Deep Rights Sale	–	18,841	–
Equinor Farm-In proceeds	–	7,447	–
Property and equipment expenditures	74	(5,873)	(84)
Exploration & Evaluation expenditures	(8,097)	(6,918)	(9,451)
Change in restricted cash	2,899	(3,173)	–
Change in non-cash working capital	(2,715)	5,754	(1,677)
Cash used in Investing activities	(7,839)	(5,372)	(11,212)
Foreign exchange gain/ (loss) on cash held in foreign currencies	2,375	531	(505)
Net change in cash	51,272	9,121	(4,986)
Cash, beginning of year	11,108	1,987	6,973
Cash, end of year	62,380	11,108	1,987

There were no significant changes to the Group's financial condition and operating results during the years ended 31 December 2018, 2017 and 2016 except for the following:

(1) 2016 Subscription Receipts Offering: On 14 October 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 at a price of $0.75 per subscription receipt for total gross proceeds of approximately $11 million, subject to certain conditions, including, without limitation, the closing of the TBNG Acquisition described below. On 24 February 2017 the TBNG Acquisition closed, resultantly 14,629,000 common shares were issued pursuant to 14,629,000 subscription receipts and gross proceeds of approximately $11 million were released from escrow. (2) 2017 TBNG Acquisition: In February 2017, Valeura closed the acquisition of 100 per cent. of the shares of TBNG from TransAtlantic for US$20.7 million. Net cash consideration was $21.5 million, representing the cash price paid ($27.1 million) less cash received ($5.6 million). Following closing of the TBNG Acquisition, TBNG entered into a sale and purchase agreement with Statoil Turkey on 10 March 2017 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 $3.9 million. (3) 2017 Banarli Farm-In: In the first half of 2017, Valeura closed several farm-in and sales agreements with Statoil Turkey to give Statoil Turkey, now Equinor Turkey, rights to 50 per cent. interest in the deep rights in the Banarli and West Thrace lands by paying US$21 million in cash and fully funding the drilling and testing of two deep exploration wells and completion of a 3D seismic program, with each respective funding obligation having a minimum expenditure of $10 million. (4) 2018 Equity offering: The increase in the working capital/cash position in 2018 was mainly due to the net proceeds of $55.4 million from the equity financing (net of share issuance costs) completed in Q1 2018 (the "2018 Offering"). On 1 March 2018, the Company closed an agreement with a syndicate of underwriters agreed to purchase on a bought deal basis 10,527,000 common shares at a price of $5.70 per share, for total gross proceeds of approximately $60.0 million (net $55.4 million after fees and expenses related to the offering). (5) Natural gas pricing: Between 1 October 2014 and 30 September 2016 the BOTAS reference natural gas price remained unchanged but effective 1 October 2016 the price was reduced by 10 per cent. The Company's average gas price for 2017 decreased to $6.98 per Mcf from $9.20 per Mcf in 2016 due to the price decrease and the weakening of the TL against the Canadian dollar. The average discount to the BOTAS Reference Price decreased from about 2 per cent. in 2016 to 1 per cent. in 2017. In 2018, the government began a program to increase the BOTAS Reference Price to reflect the increase in regional natural gas prices and the decline in the value of the TL. Effective 1 January 2018, 1 April 2018, 1 August 2018, 1 September 2018 and 1 October 2018 the BOTAS Reference Price was increased by 14 per cent., 10 per cent., 14 per cent., 14 per cent. and 18.5 per cent. respectively. The Company's average realized natural gas price for 2018 was $7.54 per Mcf, an increase over the 2017 realized price of $6.98. The increase is due to the previously described reference price increases, partially offset by the weakening of the TL against the Canadian dollar. The realized price for 2018 represents a 1.0 per cent. discount to the BOTAS Reference Price, which is similar to the discount realized for 2017. (6) Production and sales: Production increased from 799 boe/day in 2016 to 952 boe/day in 2017 due to additions from the acquisition of TBNG, workovers, recompletions and new drills, partially offset

		by natural declines on both the TBNG Lands and Banarli Exploration Licences. Sales volumes for the year ended 31 December 2018 were 717 boe/d compared to 952 boe/d for the same period in 2017. Sales volumes decreased due to natural declines causing lower gross production. (7) Funds flow: Adjusted funds flow for the year ended 31 December 2017 was an outflow of $1.2 million compared to an inflow of $6.0 million for the same period 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 were not considered ongoing expenses. Adjusted funds flow for the year ended 31 December 2018 was $3.7 million compared to an outflow of $1.2 million for the same period in 2017. The increase in adjusted funds flow for 2018 was due to increased realized prices and absence of expenses related to the TBNG Acquisition and Banarli Farm-In which negatively impacted 2017 results. The increase was partially offset by current tax payments. There has been no significant changes to the Group's financial condition and operating results since 31 December 2018, being the latest date to which the Company's historical financial information in this Prospectus was prepared.
B.8	**Selected key pro forma financial information**	Not applicable; this document does not contain pro forma financial information.
B.9	**Profit forecast**	Not applicable; this document does not contain profit forecasts or estimates.
B.10	**Description of the nature of any qualifications in the audit report on the Historical Financial Information**	There are no qualifications included in the auditor's reports on the historical financial information included in this Prospectus.
B.11	**Working capital explanation**	The Company is of the opinion that the working capital available to the Group is sufficient for the Group's present requirements, that is, for at least the next 12 months following the date of this Prospectus.

Section C – Securities		
C.1	**Type and class of the securities admitted to trading**	The securities being admitted to trading are the Common Shares of the Company. The ISIN of the Common Shares is CA9191444020. On Admission, holders of Common Shares will be able to hold and transfer interests in the Common Shares within CREST pursuant to a depositary interest arrangement established by the Company. The Common Shares will not themselves be admitted to CREST, rather, the Depositary will issue the Depositary Interests in respect of underlying Common Shares. The Depositary Interests are independent securities constituted under English law which are held and transferred directly through the CREST system. Depositary Interests have the same ISIN as the underlying Common Shares and do not require a separate admission to trading on the London Stock Exchange. The Depositary Interests were created and issued pursuant to a Deed Poll issued and executed by the Depositary.

C.2	**Currency of the securities issue**	Following Admission, the price of the Common Shares will be quoted on the London Stock Exchange in GBP.
C.3	**Issued share capital**	On Admission, the Company will have an issued share capital of 86,584,989 fully paid Common Shares with no par value.
C.4	**Rights attaching to the securities**	The Common Shares rank equally for voting purposes. On a show of hands, each Shareholder present has one vote and on a poll each Shareholder has one vote per Common Share held. The Common Shares rank equally for dividends declared and for any distributions on a winding-up. The Common Shares rank equally in the right to receive a relative proportion of the Company's assets upon dissolution.
C.5	**Restrictions on free transferability of the securities**	The Company has no restrictions on share transfers in the Constitution and the Common Shares are freely transferable.
C.6	**Admission to trading**	Application has been made to the UKLA and the LSE for all of the Common Shares to be admitted to the standard segment of the Official List and to trading on the London Stock Exchange's Main Market for listed securities. It is expected that Admission will become effective and that dealings will commence at 8.00 a.m. on 25 April 2019.
C.7	**Dividend policy**	The Company has not declared or paid any dividends on the Common Shares since incorporation. It is currently not expected that dividends will be paid in respect of the Common Shares during the current phase of development of the Company's business and operations. The payment of dividends in the future will be at the discretion of the Board and will be dependent on the future earnings and financial condition of the Company and such other factors as the Board considers appropriate.

Section D – Risks		
D.1	**Key risks specific to the Company or its industry**	● The Thrace Basin Assets are anticipated to be the Group's sole source of near-term revenue earnings. A significant portion of the Group's reserves is undeveloped gas in low porosity and low permeability (i.e. "tight") formations. There is uncertainty regarding the sustainability of initial production rates and decline rates thereafter. The Directors believe that shallow gas wells and high-pressure stimulated tight gas wells will exhibit relatively high decline rates of 50 per cent. and 75 per cent., or more, respectively, in their first year of production. There are also risks and uncertainty regarding the Company's ability to address technical drilling challenges and the management of water production, as required. Losses resulting from the occurrence of any of these risks could have a material adverse effect on future operations, liquidity and financial condition of the Company. ● A significant portion of the Group's current value and potential future value is estimated to be associated with the natural gas prospective resource associated with the deep, unconventional basin-centered, gas/condensate play discovered with the Yamalik-1 exploration well. This play is still in the early phase of exploration and appraisal with large uncertainties and risk. There are large uncertainties laterally across Valeura's land interests, and vertically in the target Kesan Formation, as to the presence of gas, the pressure of any

		gas, the amount of condensate in the gas, and the ability to commercially produce any such gas. ● To the extent that Valeura is not the operator of its oil and gas properties, Valeura will be dependent on such operators for the timing of activities related to such properties, subject to any influence Valeura can bring to bear. The ability of Valeura management to influence other operators, as necessary, to protect its interests will be an important determinant of success. Once Equinor Turkey has fully earned its 50 per cent. interest under the Banarli Farm-In, Equinor Turkey has the option to request operatorship. Equinor Turkey could propose a more significant drilling program than currently envisaged, and if the Company does not have the resources to fund its share of the program its working interest could be diluted. ● The Company currently owns and operates production infrastructure from its wells to its gas consumers. However, in future the Company may require increased use of common carrier Turkish infrastructure. If such common carrier infrastructure was not available to the Company on commercially acceptable terms then this would limit the Company's ability to commercially exploit its assets. Disruption in or increased costs of transportation services could make oil and natural gas a less competitive source of energy or could make Valeura's oil and natural gas less competitive than other sources. ● The success of Valeura will depend in large measure on certain key personnel and management. The Company also relies on certain key personnel in-country with the ability to work in the Turkish language and report to management in Canada. The loss of the services of such key personnel could have a material adverse effect on Valeura. Valeura does not have key person insurance in effect for members of management. The competition for qualified personnel in the international oil and gas industry in which Valeura operates can be intense and there can be no assurance that Valeura will be able to attract and retain all personnel necessary for the development and operation of its business. The loss of one or more of its key personnel could have an adverse impact on the business of the Group. ● Failure to manage relationships with local communities, government and non-government organizations could adversely impact Valeura's business in Turkey. Negative community reaction to operations could have an adverse impact on profitability, the ability to finance or even the viability of Valeura in Turkey. This reaction could lead to disputes that may damage the Company's reputation and could lead to potential disruption of projects or operations. ● Prices and markets for oil and natural gas are unpredictable and tend to fluctuate significantly, which could reduce the Group's profitability, growth, and value. Future decreases in the prices of oil and gas or sustained low prices may have a material adverse effect on the Group's financial condition, its future results or operations (including rendering existing projects unprofitable), financing available to the Group, and quantities of reserves recoverable on an economic basis, as well as the market price for the Company's securities. ● Valeura's properties are in the form of Production Leases, Exploration Licences and other leases, licences and permits, and working interests in such leases, licences and permits. If Valeura or the holder of any lease, licence or permit in which it is interested fails to meet any specific requirements, the lease, licence or permit may be revoked or may terminate or expire, which may have a material adverse effect on Valeura's results of operations and business.

		● The Group's planned oil and gas operations are subject to a number of operational risks and hazards, some of which are beyond its control. These risks and hazards include unexpected maintenance or technical problems, natural disasters, industrial accidents, power or fuel supply interruptions, water supply interruptions and shortages, machinery and equipment failure, malfunction and breakdowns of information management systems, fires, and unusual or unexpected variations in mineralisation, geological or mining conditions, hazards associated with oil and gas exploration and development. ● The Company's activities are affected in varying degrees by government regulations relating to the oil and gas industry and foreign investment. Operations may be affected in varying degrees by government regulations with respect to price controls, export controls, income taxes, value-added taxes, expropriation of property, production restrictions, and environmental legislation. ● The Group's operations and proposed operations include the utilization of high-pressure hydraulic stimulation ("fracking"). Currently there are no restrictions on high pressure hydraulic stimulation of wells in Turkey, and Valeura is not aware that any such restrictions are being contemplated or proposed in Turkey. However a number of jurisdictions in Europe have temporarily or permanently banned hydraulic fracturing of wells, and there is a risk that these restrictions may spread to other jurisdictions in the region, including Turkey. High pressure hydraulic stimulation is critical to achieving commercial production from tight gas formations. Any future restrictions on hydraulic stimulation could have a material adverse effect on the result of Valeura's operations and overall business. ● The level of activity in the oil and gas industry is influenced by seasonal weather patterns. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and declines in demand for oil and gas. In Turkey, the wet weather in the winter months of the year can require delays in operations.
D.3	**Key risks specific to the securities**	● The market price of the Common Shares could be negatively affected by sales or an additional offering of substantial numbers of Common Shares in the public market, or the perception or any announcement that such sales or an additional offering could occur. ● The market price for the Common Shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond the Group's control. Financial markets have experienced significant price and volume fluctuations in the past several years that have particularly affected the market price of equity securities of companies and that have, in many cases, been unrelated to the operating performance, underlying asset values or prospects of such companies. ● Any decision to pay dividends on the Common Shares will be made by the Board on the basis of the Group's earnings, financial requirements and other conditions existing at such future time and will be subject to the ability of the Company's subsidiaries to pay dividends/make distributions to the Company. Accordingly, the Company cannot guarantee its ability to pay dividends in the future. ● The Common Shares will be admitted to the Standard List and so Shareholders will not be afforded the protections applicable to a Premium Listing, in particular the provisions of Chapter 6 to 13 of the Listing Rules.

		● The Common Shares will be listed on both the Toronto Stock Exchange and the Main Market of the London Stock Exchange. Both TSX, and the LSE and the FCA therefore have the right to suspend trading in the Common Shares in certain circumstances. If trading is suspended, Shareholders may not be able to dispose of their Common Shares on the LSE or TSX as the case may be.

Section E – Offer		
E.1	**Net proceeds/ estimate of expenses**	Not applicable.
E.2a	**Reasons for the offer/use of proceeds/net amount of proceeds**	Not applicable.
E.3	**Terms and conditions of the offer**	Not applicable.
E.4	**Interests material to the issue/conflicting interests**	Not applicable.
E.5	**Name of the offeror/lock-up agreements**	Not applicable.
E.6	**Dilution**	Not applicable.
E.7	**Estimated expenses charged to the investor**	Not applicable.

PART 2 – RISK FACTORS

The Group's business, financial condition or results of operations could be materially and adversely affected by the risks described below. In such cases, the market price of the Common Shares may decline due to any of these risks and investors may lose all or part of their investment. The Company considers the following risks to be the material risks for potential investors in the Company, but the risks listed do not necessarily comprise all those associated with an investment in the Company.

Any investment in the Common Shares may not be suitable for all recipients of this document and is subject to a high degree of risk. Prior to investing in the Common Shares, prospective investors should carefully consider the risks and uncertainties associated with any investment in the Common Shares, the Group's business and the industry in which it operates, together with all other information contained in this document, including, in particular, the risk factors described below. Any of the risks described below, as well as other risks and uncertainties discussed in this document, could have a material adverse effect on the Group's business and could therefore have a negative effect on the trading price of the Common Shares. Prospective investors should note that the risks relating to the Group, its industry and the Common Shares summarised in Part 1 of this document ('S*ummary'*), are the risks that the Company believes to be the most essential to an assessment by a prospective investor of whether to consider an investment in the Common Shares. However, as the risks which the Group faces relate to events and depend on circumstances that may or may not occur in the future, prospective investors should consider not only the information on the key risks summarised in Part 1 of this document (*'Summary'*), but also, among other things, the risks and uncertainties described below.

The following factors are not exhaustive, or an explanation of all of the risk factors involved in investing in the Common Shares, and should be used as guidance only. The factors listed under a single heading may not provide a comprehensive view of all risks relevant to the subject to which the heading relates. Additional risks and uncertainties that are not currently known to the Group, or that, the Group currently deems immaterial, may individually or cumulatively also have an adverse effect on the Group's business, results of operations, financial condition and prospects. In particular, the Group's performance might be affected by changes in market and/or economic conditions and in legal, regulatory and tax requirements. If such changes were to occur the price of the Common Shares may decline and investors could lose all or part of their investment. Prospective investors should also consider carefully whether an investment in the Common Shares is suitable for them in light of the information in this document and their personal circumstances.

The information contained in this document is based upon current legislation and tax practice and any changes in the legislation or in the levels and bases of, and reliefs from, taxation may affect the value of an investment in the Common Shares.

RISKS RELATING TO THE GROUP'S BUSINESS

The Group is largely reliant on the success of the Thrace Basin Assets and other exploration assets in Turkey

The Thrace Basin Assets are anticipated to be the Group's sole source of near-term revenue earnings. A significant portion of the Group's reserves is undeveloped gas in tight formations. Whilst the Group has drilled and stimulated tight formations a number of times, there is uncertainty regarding the sustainability of initial production rates and decline rates thereafter. The Directors believe that shallow gas wells and high-pressure stimulated tight gas wells will exhibit relatively high decline rates of 50 per cent. and 75 per cent., or more, respectively, in their first year of production. There are also risks and uncertainty regarding the Company's ability to address technical drilling challenges and the management of water production, as required. Losses resulting from the occurrence of any of these risks could have a material adverse effect on future operations, liquidity and financial condition of the Company.

A significant portion of the Group's current value and potential future value is estimated to be associated with the natural gas prospective resource associated with the deep, unconventional basin-centered, gas/condensate play discovered with the Yamalik-1 exploration well. This play is still in the early phase of exploration and appraisal with large uncertainties and risk. Whilst there are eight historic wells around the basin that all are interpreted to have encountered high-pressure gas at depth, the current well density in the

basin and this play is still very low. There are large uncertainties laterally across Valeura's land interests, and vertically in the target Kesan formation, as to the presence of gas, the pressure of any gas, the amount of condensate in the gas, and the ability to commercially produce any such gas. Regional drilling data and 3D seismic interpretation indicate that the target Kesan formation reservoir should be more than 2,000 metres thick with a high net sand but these interpretations need to be proven with drilling across the basin. Further, the porosity and permeability of the rock is very low and decreases with depth. The location of any sweet spots with high porosity and hence more gas is also still to be demonstrated both vertically and laterally. The above factors primarily affect the gas initially in place (GIIP). The ability to flow and recover gas commercially is still to be demonstrated. Most of the historic wells were drilled prior to high-pressure stimulation being a commonly accepted technique and none achieved a commercial flow rate using the perforation and testing techniques available at the time. The Yamalik-1 well was subjected to high-pressure stimulation for a limited number of intervals and is still being tested and at this point it has not demonstrated a commercial flow rate. High-pressure stimulation and testing is planned for Inanli-1, but this will not be commenced until Q2 2019.

In the longer term the Group will be dependent on the development of its deep interests in the Thrace Basin Assets. It is not uncommon for new gas developments to experience unexpected problems and delays during construction, commissioning and production start-up, or indeed for such projects to fail. Any adverse event affecting the development of the Thrace Basin Assets, either during their development or following the commencement of production, would have a material adverse effect on the Group's business, results of operations, financial condition and the price of the Common Shares, as the Group has no other near-term source of revenue earnings.

Dependence on other operators of assets

To the extent that Valeura is not the operator of its oil and gas properties, Valeura will be dependent on such operators for the timing of activities related to such properties, subject to any influence Valeura can bring to bear in operating committee and technical committee meetings under joint venture agreements or other regular communications, and will largely be unable to direct or control the activities of the operators. The ability of Valeura management to influence other operators, as necessary, to protect its interests will be an important determinant of success. By virtue of the TBNG Acquisition in early 2017, Valeura has taken over the operatorship of the TBNG JV which has significantly increased the Company's level of control of its business in Turkey.

Under the Banarli Farm-In, Equinor Turkey has a 50 per cent. interest in the deep formations on the Banarli Exploration Licences. Valeura, through its subsidiaries is currently the operator of the deep exploration program during Equinor Turkey's earning phase of the Banarli Farm-In, but once Equinor Turkey has fully earned its 50 per cent. interest, Equinor Turkey has the option to request operatorship of the deep program. At that point, Equinor Turkey could propose a more significant operations program than currently envisaged. If such a program resulted in a more significant capital commitment than anticipated, the Company may not have the resources to fund its share of the program and would be required to assess the availability of equity and debt capital to provide such funding or, if it failed to do so, its working interest in the deep formations under the Banarli Exploration Licences may be diluted.

Valeura may also be exposed to counter-party risk through its contractual arrangements with current or future joint venture partners, farm-in partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations, such failures could have a material adverse effect on Valeura and its cash flow from operations.

Joint Ownership of Exploration Licences and Production Leases

Valeura does not own 100 per cent. of the working interests in many of its respective Exploration Licences and Production Leases. Joint owners with Valeura will be independently evaluating their plans for the assets and their development and may seek to increase, decrease or dispose of their working interests in the Exploration Licences and Production Leases. Decisions of these joint owners are outside of Valeura's control and could have a material impact on the value of Valeura's working interests and the pace of development of such Exploration Licences and Production Leases.

Reliance on Turkish infrastructure

For its current production, the Company owns and operates production infrastructure from its wells to its gas consumers. However, in future the Company may require increased use of common Turkish infrastructure. If such common infrastructure was not available to the Company on commercially acceptable terms then this would limit the Company's ability to commercially exploit its assets.

Valeura's ability to market its natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. Valeura may also be affected by deliverability uncertainties related to the proximity of its resources 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.

Disruption in or increased costs of transportation services could make oil and natural gas a less competitive source of energy or could make Valeura's oil and natural gas less competitive than other sources. The industry depends on pipeline facilities and other methods of transportation to deliver shipments, and transportation costs are a significant component of the total cost of supplying oil and natural gas. Disruptions of these transportation services because of weather related problems, strikes, lockouts, terrorist activities, delays or other events could temporarily impair the ability to supply oil and natural gas to customers and may result in lost sales. In addition, increases in transportation costs, or changes in transportation costs for oil and natural gas produced by competitors, could adversely affect profitability. To the extent such increases are sustained, Valeura could experience losses and may decide to discontinue certain operations forcing Valeura to incur closure and/or care and maintenance costs, as the case may be. Additionally, lack of access to transportation may hinder the expansion of production at some of Valeura's properties and Valeura may be required to use more expensive transportation alternatives.

The Group is dependent on its directors, senior management team and employees with relevant experience

The Group is reliant on a number of key personnel. International exploration and development activities such as those the Company is engaged in require specialized skills and knowledge in the areas of petroleum engineering, geology, geophysics and drilling. In addition, specific knowledge and expertise relating to local laws (including regulations relating to land tenure, exploration, development, production, marketing, transportation, the environment, royalties and taxation) and market conditions is required to compete with other international oil and gas entities.

The success of Valeura will depend in large measure on certain key personnel and management. The Company also relies on certain key personnel in-country with the ability to work in the Turkish language and report to management in Canada. The loss of the services of such key personnel could have a material adverse effect on Valeura. Valeura does not have key person insurance in effect for members of management. The competition for qualified personnel in the oil and natural gas industry, particularly the international oil and gas industry in which Valeura operates, can be intense and there can be no assurance that Valeura will be able to attract and retain all personnel necessary for the development and operation of its business.

The loss of one or more of its key personnel could have an adverse impact on the business of the Group. Furthermore, it may be particularly difficult for the Group to attract and retain suitably qualified and experienced people, given the competition from other industry participants and the relative size of the Group.

There is no assurance that the Group will successfully continue to retain existing specialised personnel and senior management or attract additional experienced and qualified senior management and/or oil and gas personnel required to successfully execute and implement the Group's business plan, which will be particularly important as the Group expands. Competition for such personnel can be intense. The loss of such personnel and the failure to successfully recruit replacements in a timely manner, or at all, would have a material adverse effect on its business, prospects, financial condition and results of operations.

Management of Key Relationships in Turkey

Failure to manage relationships with local communities, government and non-government organizations could adversely impact Valeura's business in Turkey. Negative community reaction to operations could have an adverse impact on profitability, the ability to finance or even the viability of Valeura in Turkey. This reaction could lead to disputes that may damage the Company's reputation and could lead to potential disruption of projects or operations.

The Resources data cited in this document are estimates based on a number of assumptions that may prove inaccurate

The resources estimates presented by D&M have been classified as prospective resources. The resources estimates from D&M are estimates only. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources. Investors are cautioned that the quantities presented are estimates only and should not be construed as being exact quantities.

Negative factors with respect to the estimate of prospective resources include:

- The basin-centered gas accumulation play ("**BCGA play**") is in the early exploration and delineation cycle with sparse well control and very limited fracture stimulation and testing data.
- There is as yet no long-term well production performance from the BCGA play to establish that gas can be produced from any of the zones economically. There is insufficient testing and production data to generate a production type curve specific for the prospect, thereby requiring use of analogue information at this time to establish development plans and evaluate the chance of commerciality.
- The target reservoir is very deep and is of relatively low quality (ie. low porosity and permeability).
- The limited amount of deep drilling carried out in the Thrace Basin provides poor visibility on future costs to drill, frack and complete deep development wells to exploit the BCGA play and the associated impact on the chance of commerciality.
- Although oil and gas activity has been underway for many decades in the Thrace Basin area, as activity levels increase, timelines may increase to achieve government and local landowner approvals.

The Reserves data cited in this document are estimates based on a number of assumptions that may prove inaccurate

There are numerous uncertainties inherent in estimating quantities of proved, probable and possible reserves and future net revenue to be derived therefrom, including many factors beyond the control of Valeura. The reserves and future net revenue information set forth herein represents estimates only.

The reserves and estimated future net revenue from Valeura's properties have been independently evaluated by D&M. D&M include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of crude oil, natural gas liquids and natural gas, operating costs, abandonment and salvage values, royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on the respective price forecasts in use at the effective date of the Competent Person's Reports and many of these assumptions are subject to change and are beyond the control of Valeura. Actual production and future net revenue derived therefrom will vary from these evaluations, and such variations could be material. The present value of estimated future net revenue referred to herein should not be construed as the current market value of estimated crude oil, natural gas liquids and natural gas reserves attributable to Valeura's properties. The estimated discounted future net revenue from reserves are based upon price and cost estimates which may vary from actual prices and costs and such variance could be material. Actual future net revenue will also be affected by factors such as the amount and timing of actual production, supply and demand for crude oil and natural gas, curtailments or increases in consumption by purchasers and changes in governmental regulations or taxation.

Use of Unrisked Estimates

The unrisked estimates of prospective resources referred to in this Prospectus have not been risked for either the chance of discovery or the chance of development. If a discovery is made, there is no certainty that it will be developed or, if it is developed, there is no certainty as to the timing of such development or that it will be commercially viable to produce any portion of the prospective resources.

BOEs

A BOE is determined by converting a volume of natural gas to barrels using the ratio of 6 Mcf to one barrel. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Further, a conversion ratio of 6 Mcf:1 BOE assumes that the gas is very dry without significant natural gas liquids. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilising a conversion on a 6:1 basis may be misleading as an indication of value.

Short Production Test Rates

The short production test rates disclosed in this Prospectus are preliminary in nature and may not be indicative of stabilised on-stream production rates. Initial on-stream production rates are typically disclosed with reference to the number of days in which production has been measured. Initial on-stream production rates are not necessarily indicative of long-term performance or ultimate recovery. To date, Valeura's shallow gas conventional wells and fracked unconventional tight gas wells have exhibited relatively high decline rates at more than 50 per cent. and 75 per cent., respectively, in their first year of production.

There is currently no long-term flow information for the deep, unconventional BCGA. While the same geological formations that are producing gas in the shallow are being targeted in the deep, unconventional play, they are in a different depth and pressure environment and the type curves are not expected to be indicative of deep, unconventional well production rates. A pressure transient analysis or well-test interpretation has not been carried out in respect of the production tests on the Yamalik-1 well. All natural gas rates and volumes are presented net of any load fluids.

Seasonality

The level of activity in the oil and gas industry is influenced by seasonal weather patterns. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in demand for oil and gas. In Turkey, the wet weather in the winter months of the year can require delays in operations.

Substantial Capital Requirements

While Valeura is of the opinion that the working capital available to the Group is sufficient for the Group's requirements for at least the 12 months following the date of this Prospectus (the "Working Capital Period"), there can be no certainty that Valeura will not require additional debt or equity financing after the expiry of the Working Capital Period or the terms on which such funding may be obtained.

Valeura anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas resources and reserves in the future. Valeura's cash flow from its reserves, once developed, may not be sufficient to fund its ongoing activities at all times following the Working Capital Period. If Valeura's revenues from its reserves, once developed, decrease as a result of lower oil and natural gas prices or otherwise, it will affect Valeura's ability to expend the necessary capital to replace its reserves or to maintain its production, and it may have limited ability to acquire or expend the capital necessary to undertake or complete future drilling programs. Valeura may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities beyond the Working Capital Period. Failure to obtain such financing on a timely basis could cause Valeura to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If cash flow from operations is not sufficient for Valeura to satisfy its capital expenditure requirements beyond the Working Capital Period, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on terms acceptable to Valeura. There can be no assurance that debt or

equity financing or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to Valeura. The potential inability of Valeura to access sufficient capital for its operations beyond the Working Capital Period could have a material adverse effect on Valeura's financial condition, results of operations or prospects.

Management of Growth

Valeura may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of Valeura to manage growth effectively, including the increasingly complex operations with Equinor, and other acquired assets or companies, 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 Valeura to deal with this growth could have a material adverse impact on its business, operations and prospects.

Reliance on third party contractors

The Group will operate through a series of contractual relationships with operators and sub-contractors. All contracts will carry risks associated with the performance by the parties thereto of their obligations as to time and quality of work performed. Any disruption to services or supply may have an adverse effect on the financial performance of the Company's operations.

Whilst the Group is not aware of any specific matters, the Group's business and development plans may be adversely affected by any failure or delay by third parties in supplying these services, by any change to the terms on which these services are made available or by the failure of such third party contractors to provide services that meet its quality or volume requirements. It is not uncommon for oil and gas companies to have disputes with third party contractors, and for these disputes to have a material and adverse effect on the companies' operations.

If the Group is obliged to change a provider of such services, it may experience additional costs, interruptions to development or production or other adverse effects on its business. There is a risk that the Group may not be able to find adequate replacement services on commercially acceptable terms, on a timely basis, or at all.

Should the Group be unable to acquire or retain providers of key services on favourable terms, or should there be interruptions to, or inadequacies with, any services provided, this could have a material adverse effect on its business, results of its operations and its financial condition and the price of the Common Shares.

Variations in Foreign Exchange Rates and Interest Rates, and Hedging

The Company's drilling operations in Turkey and related contracts are based in U.S. Dollars. Material increases in the value of the U.S. Dollar will negatively impact the Company's costs of drilling and completions activity. Future Canadian Dollar/U.S. Dollar and Canadian Dollar/TL exchange rates could impact the future value of the Company's reserves as determined by independent evaluators. The Company's functional currency in its subsidiary operations in Turkey is TL. The revenue stream in Turkey is based on TL revenue for natural gas and U.S. Dollar based revenue for crude oil and condensate translated into TL. The majority of costs will be incurred in U.S. Dollars for capital expenditures and TL for operating expenditures. Decreases in the value of the TL could result in decreases in revenue. Increases in the value of the TL and U.S. Dollar could result in increases in the cost of operations. 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. Recent volatility and weakness in the value of the TL may impair the ability of the Company to manage this exposure. Further devaluation of the TL without a corresponding increase in the BOTAS Reference Price will result in continued decreases in funds flow from operations and will affect the ability of the Company to meet its financial obligations.

From time to time Valeura may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices

increase beyond the levels set in such agreements, Valeura will not benefit from such increases and may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Given that Valeura's natural gas sales and revenues in Turkey are priced in TL, Valeura from time to time may enter into agreements to fix the exchange rate of Canadian or United States Dollars to the TL in order to offset the risk of revenue losses. Valeura may similarly seek to fix the exchange rate between the TL and the Canadian or U.S. Dollar to offset the risk of a relative strengthening of the U.S. Dollar, which is the currency basis for large portion of the capital expenditures in Turkey.

Acquisitions, dilution and availability of debt

From time to time Valeura may enter into transactions to acquire assets or the shares of other entities. Valeura may make future acquisitions or enter into financings or other transactions involving the issuance of securities of Valeura which may be dilutive.

Valeura may have difficulty accessing debt needed to acquire and develop international oil and gas properties. This may result in the inability of Valeura to complete certain acquisitions or drilling activities. Future acquisitions may be financed partially or wholly with debt, which may increase debt levels above industry standards. Depending on future exploration and development plans, Valeura may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither Valeura's articles nor its by-laws limit the amount of indebtedness that it may incur. The level of Valeura's indebtedness from time to time could impair its ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise.

Internal Controls Over Financial Reporting

Valeura has established internal controls over financial reporting ("**ICFR**") which include policies and procedures that pertain to the maintenance of financial records, the preparation of accurate financial statements, controls over bank accounts and the prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets or funds. Valeura has delegation of authority policies approved by the respective boards of directors of the parent company and each subsidiary, which policies delineate how various corporate and financial matters must be approved and the authority levels of management and employees (including in-country managers in Turkey). Valeura has the right and periodically conducts audits of the records and expenditures of its operating partners. While the Directors have determined that Valeura maintains effective ICFR, Valeura cannot be certain errors or failures will not occur related to financial processes and reporting. Failure to properly implement existing controls, or difficulties encountered in their implementation, could impact the Company's results of operations or cause it to fail to meet its reporting obligations. If the Company or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Company's financial statements and reduce the trading price of the Common Shares.

At the operational level in Turkey, the Company relies upon certain local managers and employees and its operating partners. A large portion of the business and contracts in Turkey are in the Turkish language and the Company must rely on certain key personnel in-country who work in the Turkish language and report to management. A major disruption in the flow of information, or obtaining inaccurate information from these local employees and partners, could adversely impact the accuracy of financial reporting and management information.

The use of foreign subsidiaries by the Group may affect the Company's ability to pay dividends or make distributions

The Group conducts its operations at the Thrace Basin through its wholly owned subsidiaries, CRBV and VENBV and VENBV's wholly owned subsidiary, TBNG. The Company's ability to pay dividends on the Common Shares is reliant on the ability of these entities to generate cash flow and pay dividends or make other distributions to the Company. The ability of these entities to make payments to the Company may be constrained by, among other things: (i) the level of taxation, particularly corporate profits and withholding taxes, in Turkey; (ii) the introduction of exchange controls; and (iii) local law requirements in relation to the payments of dividends and distributions.

RISKS RELATING TO GROUP'S INDUSTRY

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Valeura will depend on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves Valeura may have at any particular time, and the production therefrom, will naturally decline over time as such existing reserves are produced and depleted. A future increase in Valeura's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also 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 connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. No assurance can be given that Valeura will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, Valeura may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by Valeura.

While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, natural declines as reserves are depleted and production or sales delays cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees. Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, Valeura will not be fully insured against all of these risks, nor are all such risks insurable. Although Valeura will maintain liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event Valeura could incur significant costs that could have a material adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations.

The Group's activities are subject to operational risks, hazards and unexpected disruptions, including damage to property or injury to persons, some of which are beyond its control

The Group's planned oil and gas operations are subject to a number of operational risks and hazards, some of which are beyond its control. These risks and hazards include unexpected maintenance or technical problems, natural disasters, industrial accidents, power or fuel supply interruptions, water supply interruptions and shortages, machinery and equipment failure, malfunction and breakdowns of information management systems, fires, and unusual or unexpected variations in mineralisation, geological conditions, hazards associated with oil and gas exploration and development.

The operations of the Group may be disrupted by a variety of risks and hazards which are beyond the control of the Company, including environmental hazards, industrial accidents, technical failures, labour disputes, unusual or unexpected rock formations, earthquakes, flooding and extended interruptions due to inclement or hazardous weather conditions, fire, explosions, and other incidents beyond the control of the Company. Other factors affecting the production and sale of oil and natural gas that could result in decreases in profitability include: (i) expiration or termination of permits, licences or leases, or sales price redeterminations or suspension of deliveries; (ii) future litigation; (iii) the timing and amount of insurance recoveries; (iv) work stoppages or other labour difficulties, including labour lawsuits which are common in Turkey; (v) worker vacation schedules and related maintenance activities; and (vi) changes in the market and general economic conditions. Weather conditions, equipment replacement or repair, fires, amounts of rock and other natural materials and other geological conditions can have a significant impact on operating results.

These risks and hazards could also result in damage to, or destruction of, production facilities, personal injury, environmental damage, business interruption, monetary losses and possible legal liability. While the Company currently intends to maintain insurance within ranges of coverage consistent with industry practice, no assurance can be given that the Company will be able to obtain such insurance coverage at reasonable rates (or at all), or that any coverage it obtains will be adequate and available to cover any such claims.

The Company is committed to providing a healthy and safe environment for its personnel, contractors and visitors. Exploration and production activities have inherent risks and hazards. The Company provides appropriate instructions, equipment, preventative measures, first aid information, and training to all employees and contractors through its occupational, health and safety management systems.

The Group's insurance and indemnities may not adequately cover all risks or expenses

Valeura's involvement in the exploration for and development of oil and natural gas properties may result in it becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although Valeura carries insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not in all circumstances be insurable or, in certain circumstances, Valeura 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 such uninsured liabilities would reduce the funds available to Valeura. The occurrence of a significant event that Valeura is not fully insured against, including terrorist activities, or the insolvency of the insurer of such event, could have a material adverse effect on Valeura's financial position, results of operations or prospects.

Availability of Drilling, Hydraulic Stimulation and Other Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling, hydraulic stimulation and other related equipment in the particular areas where such activities will be conducted. Whilst such equipment is available in Turkey it is not as available as in more developed oil & gas producing countries. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Valeura and may delay exploration and development activities.

The Group's operations may be harmful to the environment and may be subject to compliance, clean-up and other costs

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 regulations in Turkey. 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. In addition, many areas within the Thrace Basin are designated as prime agricultural land and therefore require land use approvals from both the Agricultural and Energy Ministries. Applicable legislation also requires that wells and facility sites be licenced, operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach 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 Valeura to incur costs to remedy such discharge. Although Valeura believes it is in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws or agricultural land use requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Valeura's financial condition, results of operations or prospects.

The Company's projects are subject to various Turkish environmental laws. The Company intends to conduct its activities in an environmentally responsible manner at the highest possible standards and in accordance with all applicable laws.

High Pressure Hydraulic Stimulation Considerations

The Group's operations and proposed operations include the utilization of high-pressure hydraulic stimulation ("**fracking**"). Currently, there are no restrictions on high-pressure hydraulic stimulation of wells in Turkey, and Valeura is not aware that any such restrictions are being contemplated or proposed in Turkey. However a number of jurisdictions in Europe have temporarily or permanently banned hydraulic fracturing as a form of high pressure stimulation of wells. There is a risk that these restrictions may spread to other jurisdictions in the region, including Turkey. High pressure hydraulic stimulation is critical to achieving commercial production from tight gas formations. Any future restrictions on hydraulic stimulation could have a material adverse effect on the result of Valeura's operations and overall business.

Compliance with environmental laws and regulations may prevent the Company from commercially developing its operations

The cost and complexity of complying with the applicable environmental laws and regulations may prevent the Company from being able to develop potentially economically viable oil and gas operations. Valeura's operations, production and marketing are subject to various environmental approvals, licences and permits. If Valeura fails, or its predecessors failed, to secure all applicable environmental approvals, licences and permits, Valeura may be subject to administrative punishments and orders that includes fines, or revocation or termination of approvals, licences and permits.

Although the Company believes that it is in compliance in all material respects with all applicable environmental laws and regulations, there are certain risks inherent to its activities, such as accidental spillages, leakages or other unforeseen circumstances, which could subject the Company to extensive costs and liability.

A violation of health and safety and/or environmental laws relating to oil and gas exploration, at a processing plant or in the course of transportation of hazardous substances, or a failure to comply with the instructions of the relevant authorities, could lead to, among other things, a temporary shutdown of all or a portion of the Group's exploration, processing or logistics operations, a loss of the Group's right to develop, exploit, operate a processing plant or transport products, or the imposition of costly compliance measures, criminal sanctions and/or monetary penalties. The Group will establish various committees, will implement safety and environmental compliance plans and contract officers and staff to oversee inspections and identify necessary corrective action. However, there can be no assurance that the Group's programmes will be effective, will comply with applicable laws or that costs of implementation will not increase significantly. If health and safety and/or environmental authorities were to require the Group to shut down all or a portion of its exploration, processing or logistics operations, or the more stringent enforcement of existing laws and regulations, such measures could have a material adverse effect on the Group's business, results of operation, financial condition and the price of the Common Shares.

There can be no assurances that new environmental laws, regulations or stricter enforcement policies, once implemented, will not oblige the Company to incur significant expenses and undertake significant investments in such respect, which could have a material adverse effect on the Company's business, financial condition and results of operations

Revocation or expiration of Exploration Licences, Production Leases and other licences, leases and permits

Valeura's properties are held in the form of Exploration Licences and Production Leases and its operations, production and marketing may be held and subject to other licences, leases and permits (together "**Licences**"). If Valeura, its predecessors or any other holder of a Licence in which Valeura has an interest, fails or has failed to secure all applicable Licences, Valeura may be subject to administrative punishments and orders that include fines, revocation or termination. If Valeura, or any other holder of a Licence in which Valeura has an interest, fails to meet the specific requirement of a Licence, the Licence may be revoked or may terminate or expire. Whilst Valeura monitors the status and expiry of all of its current Licences, all of which are in Turkey, there can be no assurance that any of the obligations required to maintain such Licences will be met. The revocation, termination or expiration of any of its Licences or the working interests relating to a Licence may have a material adverse effect on Valeura's results of operations and business. To the extent such Licences are subsequently suspended or revoked, Valeura may be curtailed or prohibited from proceeding with planned exploration, development or operation of its projects. Failure to comply with

permitting and legal requirements may result in enforcement actions, including orders issued by regulatory or judicial authorities causing operations to cease or be curtailed and may include corrective measures requiring capital expenditures, installation of additional equipment or remedial actions which could have an adverse effect on Valeura's business, financial condition or operations.

Title to Assets

Title to oil and natural gas interests is often not capable of conclusive determination without incurring substantial expense. While it is the practice of Valeura, in acquiring significant oil and gas leases or interest in oil and gas leases to fully examine the title to the interest under the lease, this should not be construed as a guarantee of title. There may be title defects that affect lands comprising a portion of Valeura's properties. To the extent title defects do exist, it is possible that Valeura may lose all or a portion of its right, title, estate and interest in and to the properties to which the title relates.

The oil and gas industry is subject to a number of laws and governmental regulations, compliance with which may be burdensome

The oil and natural gas industry in Turkey is subject to controls and regulations governing its operations imposed by legislation enacted by the Turkish government and with respect to pricing and taxation of oil and natural gas by agreements, all of which should be carefully considered by investors in the oil and gas industry. The Company's activities are affected in varying degrees by government regulations relating to the oil and gas industry and foreign investment. Operations may be affected in varying degrees by government regulations with respect to price controls, export controls, foreign exchange controls, income taxes, value-added taxes, expropriation of property, production restrictions and environmental legislation. It is not expected that any of these controls or regulations will affect the Company's operations in a manner materially different than they would affect other oil and gas companies of similar size operating in Turkey.

Price Volatility, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by Valeura will be affected by numerous factors beyond its control. Valeura'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. Valeura'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 Valeura. These factors include economic conditions in the United States, Canada, and Turkey, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, and political instability 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. In Turkey, natural gas prices for domestic sales are effectively set by the government, which are indirectly affected by these market forces. Any substantial and extended decline in the price of oil and gas would have an adverse effect on Valeura's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations. The exchange rate between the Canadian Dollar, U.S. Dollar and TL also affects the profitability of Valeura. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value.

Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects. Currently, the Company has no debt facilities in place. However, any bank borrowings available to Valeura in the future will in part be determined by Valeura's borrowing base. A sustained material decline in prices from historical average prices could reduce Valeura's borrowing base, therefore reducing the bank credit available to the Company and require that a portion, or all, of Valeura's bank debt, if any, be repaid.

Competition

Oil and gas exploration is intensely competitive in all its phases and involves a high degree of uncertainty with respect to the impact of such competition. Valeura will compete with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural

gas. Competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of Valeura, including Turkey's state-owned oil company. Valeura's ability to increase reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire suitable producing properties or acquire new exploration licences. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Valeura may also be subject to competition from the alternative fuel industry or fuel substitution by its customers.

RISKS RELATING TO TURKEY

Foreign Operations

Valeura currently has all of its operations in Turkey and expects to have all of its operations outside of Canada. Exploration, development and operating activities in Turkey are subject to the risks normally associated with the conduct of business in countries with less developed or emerging economies. As such, the Company's operations, financial condition and operating results could be significantly affected by 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 policies, including royalty and tax increases and retroactive tax claims, and investment restrictions, working conditions, rates of exchange, exchange control, exploration licensing, production leasing, petroleum and export licensing and export duties, government control over domestic oil and gas pricing, currency fluctuations, devaluation or other activities that limit or disrupt markets and restrict payments or the movement of funds, the possibility of being subject to exclusive jurisdiction of foreign courts in connection with legal disputes relating to licences to operate and concession rights in countries where Valeura currently operates, and difficulties in enforcing Valeura's rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations. Problems may also arise due to the quality or failure of equipment or technical support, which could result in failure to achieve expected target dates for exploration and development operations or result in a requirement for greater expenditure. Valeura will operate in such a manner as to minimize and mitigate its exposure to these risks. However, there can be no assurance that Valeura will be successful in protecting itself from the impact of all of these risks and the related financial consequences.

Government Rules and Regulations

Valeura's operations are subject to various levels of government controls and regulations in the countries where it operates. Oil and gas exploration and production is a sensitive political issue and as a result there is a relatively higher risk of direct government intervention in respect of laws and regulations that can affect the property rights and title to Valeura's assets in Turkey. Such intervention can extend, in certain jurisdictions, to nationalization, expropriation or other actions that effectively deprive companies of their assets.

Existing laws and regulations include matters relating to land tenure, drilling, production practices including hydraulic stimulating of wells, environmental protection, agricultural land use, marketing and pricing policies, royalties, various taxes and levies including income tax, foreign trade and investment and government approval of lease and licence transfers and other regulatory approvals that are subject to change from time to time. Current legislation is generally a matter of public record and Valeura cannot predict what additional legislation or amendments may be proposed that will affect Valeura's operations or when any such proposals, if enacted, might become effective. There is no certainty regarding obtaining government approvals. Changes in government policy or laws and regulations could adversely affect Valeura's results of operations and financial condition. In particular, a number of changes in the land tenure regulations associated with the New Petroleum Law are in the early years of implementation and the full effect of these changes remain uncertain. Failure to comply with applicable laws, regulations and legal requirements may result in enforcement actions thereunder, including orders issued by regulatory or judicial authorities causing operations to cease or be curtailed and may include corrective measures requiring capital expenditures, installation of additional equipment or remedial actions which could have an adverse effect on Valeura's business, financial condition or operations.

Political Uncertainty and Civil Unrest in Turkey

During the 2014 to 2016 period, Turkey experienced increased periods of political unrest and civil disobedience primarily associated with the Syrian civil war on its border, the large influx of Syrian refugees to Turkey, the movement of Kurdish fighters from Turkey into Syria and the end of a truce in mid-2015 between the PKK and the Turkish government. During that time there were also suicide bomb attacks in Ankara and Istanbul which increased security concerns in Turkey. In July 2016, Turkey experienced an attempted military coup, which quickly failed. In the aftermath of the coup, the military perpetrators were arrested as well as thousands of other citizens suspected of being followers of the exiled Muslim cleric Fethullah Gulen.

In April 2017, Turkey held a referendum on amendments to the constitution largely centered on replacing the parliamentary system of government with a presidential system. This referendum was endorsed by a narrow margin. In June 2018, President Erdogan and his Justice and Development Party (AKP) won the federal election and solidified control of the country. Based on this win, he was also able to quickly introduce the constitutional reforms passed in the 2017 referendum.

The recent period of political change and uncertainty and challenging international relationships, in particular with the U.S., have resulted in a continued downward slide in the value of the TL. At times these drops have been very sharp and this has led to negative sentiments towards the Turkish banks and businesses. This has also had the effect of sharply increasing inflation to more than 20 per cent. in 2018 after well over a decade of strong growth and relatively stable inflation. In 2018, this negative sentiment to Turkey has at times resulted in a decrease in the value of Valeura shares.

To date, the above events have not impacted the Company's ability to conduct drilling and production operations in the Thrace Basin and no significant delays or security issues have been experienced in these operations. All of the Company's current operations are in the Thrace Basin of northwest Turkey, more than 1,000 kilometres from the Syrian border.

The Company will continue to monitor conditions, including the safety of personnel and operations, the security situation generally, impact on the TL and banking facilities, impact on our joint venture partners and any changes in offtakes by the Company's natural gas customers.

In the future, access to some operating locations in Turkey may be precluded and Valeura may incur substantial costs to maintain the safety of personnel and operations. Despite these precautions, the safety of operator personnel or Valeura personnel in these locations may be at risk, and Valeura may in the future suffer loss of personnel and disruption of operations, any of which could have a material adverse effect on Valeura's business and results of operations.

Bribery and corrupt practices

The Group maintains anti-bribery policies, anti-corruption training programmes, codes of conduct, procedures and other safeguards designed to prevent the occurrence of fraud, bribery and corruption. Valeura has established a Code of Business Conduct and Ethics which includes policies and procedures covering anti-bribery and anti-corruption of foreign public officials, including regular reporting to management and the Board. While the Directors believe these policies are adequate, and despite careful establishment and implementation, there can be no assurance that these or other anti-bribery or anti-corruption policies and procedures are or will be sufficient to protect against corrupt activity. Wherever the Group operates it always needs to be aware of the potential risk of fraud, bribery and corruption. Instances of fraud, bribery and corruption, and violations of laws and regulations could have a material adverse effect on the Group's reputation, business, results of operations, financial condition and the price of the Common Shares.

The Group has and will engage a number of consultants and contractors in Turkey in connection with it projects and, although the Group believes its consultancy agreements are entered into on arm's length commercial terms and seeks appropriate comfort from consultants and contractors, as well as requiring its consultants and contractors to adhere to high standards in line with the Group's policies, there is a risk that agents or other persons or representatives acting on behalf of the Group may engage in corrupt activities without the knowledge of the Group.

In particular, Valeura, in spite of its best efforts, may not always be able to prevent or detect corrupt practices by employees, or third parties, such as sub-contractors or its operating partners, which may result in

reputational damage, civil and/or criminal liability being imposed on Valeura, which could have an adverse effect on Valeura's business, financial condition or operations.

RISKS RELATING TO THE TAXATION OF THE GROUP

Change in the Company's tax status or in taxation law could negatively affect the Company's ability to provide returns to Shareholders

Statements in this document concerning the taxation of the Group or of Shareholders are based on current tax law and practice which is subject to change. The taxation of an investment in the Company also depends on the individual circumstances of the relevant Shareholder. Any Shareholder who is in doubt as to its tax position should consult an appropriate advisor.

Any change in the Company's UK tax status or any change in UK taxation law could affect the Company's ability to provide returns to Shareholders resident in the UK. Adverse changes in tax laws and any other reform of or changes in the interpretation of enforcement of applicable taxation legislation could have a detrimental effect the Group's business, financial condition and results of operations and could affect the Group's ability to provide returns to Shareholders.

Statements in this document concerning the UK taxation of Shareholders are based on current UK tax law and practice, which are subject to change. The taxation of an investment in the Company depends on the individual circumstances of Shareholders.

The Company is not incorporated in the UK. Accordingly, the Company should not be treated as being resident in the UK for corporation tax purposes unless its central management and control is exercised in the UK. The concept of central management and control is indicative of the highest level of control of a company, which is wholly a question of fact. The Company intends to manage its affairs so that it is not resident in the UK for UK tax purposes.

A company not resident in the UK for corporation tax purposes can, nevertheless, be subject to UK corporation tax if it carries on a trade through a permanent establishment in the UK, but the charge to UK corporation tax is limited to profits (including revenue profits and capital gains) attributable directly or indirectly to such permanent establishment.

The Company intends to operate in such a manner that it does not carry on a trade through a permanent establishment in the UK. Nevertheless, because neither case law nor UK statute completely defines the activities that constitute trading in the UK through a permanent establishment, HMRC might contend successfully that the Company is trading in the UK through a permanent establishment in the UK.

If the Company was treated as being resident in the UK for UK corporation tax purposes, or if the Company was to be treated as carrying on a trade in the UK through a permanent establishment or otherwise subject to UK income tax, the results of the Group's operations could be materially adversely affected.

Income Tax

Valeura has filed, and will file, all required income tax returns. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of Valeura, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

RISKS RELATING TO COMMON SHARES

An active trading market may not develop or be sustained in the future

Although the Company has applied to the FCA for admission to the Official List and has applied to the London Stock Exchange for admission to trading on the Main Market, the Company can give no assurance that an active trading market for the Common Shares will develop in the United Kingdom or, if developed, can be sustained. If an active trading market is not developed or maintained, the liquidity and trading price of the Common Shares could be adversely affected.

Substantial future sales of Common Shares, or the perception that such sales might occur, or additional offerings of Common Shares could depress the market price of Common Shares

The Company cannot predict what effect, if any, future sales of Common Shares, or the availability of Common Shares for future sale, or the offer of additional Common Shares in the future, will have on the market price of Common Shares. Sales or an additional offering of substantial numbers of Common Shares in the public market, or the perception or any announcement that such sales or an additional offering could occur, could adversely affect the market price of Common Shares and may make it more difficult for Shareholders to sell their Common Shares at a time and price which they deem appropriate and could also impede the Company's ability to raise capital through the issue of equity securities.

There may be volatility in the value of an investment in Common Shares and the market price for Common Shares may fluctuate

The market price for the Common Shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond the Group's control, including the following: (i) actual or anticipated fluctuations in the Group's results of operations; (ii) actual or anticipated changes in the capital markets; (iii) recommendations by securities research analysts; (iv) changes in the economic performance or market valuations of other companies that investors deem comparable to the Company; (v) addition or departure of the Company's executive officers and other key personnel; (vi) sales or perceived sales of additional Common Shares; (vii) significant acquisitions or business combinations, strategic partnerships, joint ventures or capital commitments by or involving the Group or its competitors; (viii) changes in laws, rules and regulations applicable to the Group and its operations; (ix) general economic, political and other conditions; (x) the Group's involvement in any litigation or dispute, or threat of any litigation or dispute; and (xi) news reports relating to trends, concerns, technological or competitive developments, regulatory changes and other related issues in the Group's industry or target markets.

Financial markets have experienced significant price and volume fluctuations in the last several years that have particularly affected the market prices of equity securities of companies and that have, in many cases, been unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of the Common Shares may decline even if the Group's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause decreases in asset values that are deemed to be other than temporary, which may result in impairment losses. Also, certain institutional investors may base their investment decisions on consideration of the Group's environmental, governance and social practices and performance against such institutions' respective investment guidelines and criteria, and failure to meet such criteria may result in a limited or no investment in the Common Shares by those institutions, which could adversely affect the trading price of the Common Shares. There is no assurance that continuing fluctuations in the price and volume of publicly traded equity securities will not occur. If such increased levels of volatility and market turmoil continue, the Group's operations could be adversely impacted and the trading price of the Common Shares may be adversely affected.

The Company does not currently intend to pay dividends and its ability to pay dividends in the future may be limited

The Company has never declared or paid any dividends on the Common Shares. The Company currently intends to retain future earnings, if any, for future operations, expansion and debt repayment, if necessary. Therefore, at present, there is no intention to pay dividends and a dividend may never be paid. Any decision to declare and pay dividends will be made at the discretion of the Board and will depend on, among other things, the Group's results of operations, financial condition and solvency and distributable reserves tests imposed by corporate law and such other factors that the Board may consider relevant.

In addition to the foregoing, the Company's ability to institute and pay dividends now or in the future is or may be limited by covenants contained in any debt facilities or other agreements governing any indebtedness that the Group may incur in the future, including the terms of any credit facilities the Group may enter into with third party lenders. It is not uncommon that credit facilities will prevent a borrower from declaring or paying any dividends to any of its shareholders or returning any capital (including by way of dividend) to any of its Shareholders.

As a result of the foregoing factors, purchasers of the Common Shares may not receive any return on an investment in the Common Shares unless they sell such Common Shares for a price greater than that which they paid for them.

Certain Shareholders will be issued Depositary Interests in respect of underlying Common Shares

On Admission, holders of Common Shares will be able to hold and transfer interests in the Common Shares within CREST pursuant to a depositary interest arrangement established by the Company. The Common Shares will not themselves be admitted to CREST; rather, the Depositary will issue the Depositary Interests in respect of underlying Common Shares. Holders of Depositary Interests may experience delays in receiving any dividends paid by the Company, may receive proxy forms later than other Shareholders and may have to act earlier than other Shareholders when casting votes at general meetings of the Company, by virtue of the administrative process involved in connection with holding Depositary Interests.

If the Company is wound up, distributions to Shareholders will be subordinated to the claims of creditors

On a winding-up of the Company, holders of the Common Shares will be entitled to be paid a distribution out of the assets of the Company available to its shareholders only after the claims of all creditors of the Company have been met.

The Company is applying for a Standard Listing and, accordingly, the Company will not be required to comply with those protections applicable to a Premium Listing

The Company is seeking a Standard Listing and, as a consequence, additional on-going requirements and protections applicable to a Premium Listing will not apply to the Company. In particular, the provisions of Chapters 6 to 13 of the Listing Rules (other than Rule 7.2.1), being additional requirements for a Premium Listing of equity securities (Premium Listing principles, sponsors, continuing obligations, significant transactions, related party transactions, dealing in own securities and treasury shares and contents of circulars), will not apply. In addition, a Standard Listing will not permit the Company to gain UK FTSE indexation.

Trading in the Common Shares may be suspended

The Company's shares are currently traded on TSX. In certain circumstances, the TSX have, and the LSE will have following Admission, the right to suspend trading in the Common Shares. If the Common Shares are suspended from trading, the holders of Common Shares may not be able to dispose of their Common Shares on the LSE or TSX (as the case may be).

TSX

The TSX may at any time suspend from trading the Common Shares if it is satisfied that the Company has failed to comply with any of the provisions of its listing agreement with TSX, or with any other TSX requirement, or such suspension is determined by the TSX as necessary to protect the public interest.

LSE

The FCA may suspend the Common Shares from trading on the LSE if it determines that the smooth operation of the market is or may be temporarily jeopardised or it is necessary to protect investors.

The Company believes that as at the date of this document there are no circumstances which could provide grounds for the halting or suspending of the Common Shares from the LSE or TSX for the foreseeable future. However, there can be no assurance that any such circumstances will not arise in relation to the Common Shares in the future.

The Company may be excluded from trading

In certain circumstances, the Common Shares may be delisted from the LSE or TSX. Delisting could have an adverse effect on the liquidity of the Common Shares and on investors' ability to sell the Common Shares at a satisfactory price.

The Company believes that as at the date of this document there are no circumstances which could provide grounds for the delisting of the Common Shares from the LSE or TSX for the foreseeable future. There can however be no assurance that any such circumstances will not arise in relation to the Common Shares in the future.

TSX

The TSX may at any time delist the Common Shares if it is satisfied that the Company has failed to comply with any of the provisions of its listing agreement with TSX, or with any other TSX requirement, or such delisting is determined by the TSX as necessary to protect the public interest.

LSE

The FCA may cancel the listing of the Common Shares on the LSE if satisfied that there are special circumstances precluding the normal and regular dealings in the Common Shares.

The listing of the Common Shares on the LSE may also be cancelled at the request of the Company, subject to the Company giving at least 20 Business Days' notice of the proposed cancellation of the listing. Because the Company is intending to list on the Standard Listing segment of the Official List, it would not be required to seek shareholder approval before seeking the cancellation of the listing of the Common Shares on the LSE.

Dual listing on the TSX and LSE may lead to an inefficient market in the Company's shares

Dual listing of the Common Shares will result in differences in liquidity, settlement and clearing systems, trading currencies, prices and transaction costs between the exchanges where the Common Shares will be quoted. These and other factors may hinder the transferability of the Common Shares between the two exchanges.

The Common Shares are already quoted on TSX. An application will be made to list the Common Shares on the LSE. Consequently, the trading in and liquidity of the Common Shares will be split between these two exchanges. The price of the Common Shares may fluctuate and may at any time be different on the TSX and LSE. This could adversely affect the trading of the Common Shares on these exchanges and increase their price volatility and/or adversely affect the price and liquidity of the Common Shares on these exchanges.

The Common Shares are quoted and traded in Canadian Dollars on the TSX. The Common Shares will be quoted and traded in pounds sterling on the LSE. The market price of the Common Shares on those exchanges may also differ due to exchange rate fluctuations.

The rights afforded to Shareholders are governed by Canadian law and non-Canadian Shareholders may have difficulties exercising rights which are governed by Canadian law

As the Company is a Canada resident company, the rights of Shareholders will be governed by Canadian law and the Company's Constitution. The rights of Shareholders under Canadian law may differ from the rights of shareholders of companies incorporated in other jurisdictions. Not all rights available to shareholders under English law will be available to the Shareholders.

The Company is organised and exists under Canadian law. Accordingly, the rights and obligations of the Company's shareholders are regulated by Canadian corporate law and the Company's shareholders must follow Canadian legal requirements in order to exercise their rights, in particular the resolutions of the shareholders in general meeting may be passed with majorities different from the majorities required for the adoption of equivalent resolutions under English law or other laws.

PART 3 – PRESENTATION OF FINANCIAL AND OTHER INFORMATION

1 General

This document comprises a prospectus for the purpose of Article 5 of the Prospectus Directive and is issued in compliance with the Listing Rules. Investors should only rely on the information in this document. No person has been authorised to give any information or to make any representations in connection with Admission, other than those contained in this document and, if given or made, such information or representations must not be relied upon as having been authorised by or on behalf of the Company or the Directors. The Company does not accept any responsibility for the accuracy or completeness of any information reported by the press or other media, nor the fairness or appropriateness of any forecasts, views or opinions expressed by the press or other media regarding the Company. The Company makes no representation as to the appropriateness, accuracy, completeness or reliability of any such information or publication other than this document.

Without prejudice to any obligation of the Company to publish a supplementary prospectus pursuant to FSMA, the delivery of this document shall not under any circumstances, create any implication that there has been no change in the business or affairs of the Group since the date of this document, or that the information contained herein is correct as of any time subsequent to its date.

The contents of this document or any subsequent communications from the Company, the Group or any of their respective affiliates, officers, advisers, directors, employees or agents, are not to be construed as legal, business or tax advice. Each prospective investor should consult its, his or her own lawyer, financial intermediary or tax adviser for legal, financial or tax advice. In making an investment decision, each investor must rely on its, his or her own examination, analysis and enquiry of the Company, including the merits and risks involved.

This document is not intended to provide the basis of any credit or other evaluation and should not be considered as a recommendation by any of the Company or the Directors or any of its representatives that any recipient of this document should subscribe for or purchase Common Shares. Prior to making any decision as to whether to subscribe for or purchase Common Shares, prospective investors should read this document. Investors should ensure that they read the whole of this document carefully and not just rely on key information or information summarised within it. In making an investment decision, prospective investors must rely upon their own examination of the Company and the terms of this document, including the risks involved.

2 Presentation of financial information

The financial information presented in this document includes audited annual consolidated financial statements for the Group as at and for the years ended 31 December 2018, 31 December 2017 and 31 December 2016.

The audited annual consolidated financial statements for the Group (the "**Financial Statements**") have been prepared in accordance with IFRS. For full details of the basis of preparation and significant accounting policies, please refer to Note 3 (Significant Accounting Policies) to the Group's consolidated financial statements for the each of the years ended 31 December 2018, 2017 and 2016 as set out in the Appendix.

As explained in Note 3 ("**Significant Accounting Policies**") to the Financial Statements, for the year ended 31 December 2018, the Company adopted the new standard under IFRS 15 – 'Revenue from Contracts with Customers' on 1 January 2018 on a retrospective basis. The standard requires enhanced disclosure of revenue from contracts with customers, including categories that depict the nature, amount, timing and uncertainty of revenue and cash flows that are affected by economic factors. The Directors reviewed the Company's revenue streams and major contracts with customers and concluded that there were no material impacts on the Company's revenues or cash flows as a result of adopting the new standard. The Company also adopted IFRS 9, Financial Instruments, on 1 January 2018 on a retrospective basis. 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, which is more in line with risk management activities. The Company had no change to the classification of financial liabilities, and the Company does not have financial instrument contracts to which it applies hedge accounting.

Unless otherwise stated in this Prospectus, financial information in relation to the Group referred to in this Prospectus has been extracted without material adjustment from the historical financial information in the Appendix.

3 Currencies

In this document, references to "**Great British Pounds**", "**GBP**", "**pounds sterling**", "**£**", "**pence**" or "**p**" are to the lawful currency of the UK, references to "**$**", "**CAN dollars**", "**CAD**" or "**C$**" are to the lawful currency of Canada, references to "**USD**" or "**US$**" are to the lawful currency of the United States of America, references to "**TL**" are to the lawful currency of Turkey, and references to "**EUR**" are to the lawful currency of 19 Member States of the European Union. The basis of translation of any foreign currency transactions and amounts in the financial information set out in the Appendix to this document, '*Historical Financial Information*', and set out in that Appendix.

4 Rounding

Percentages and certain amounts in this document, including financial, statistical and operating information, have been rounded to the nearest thousand whole number or single decimal place for ease of presentation. As a result, the figures shown as totals may not be the precise sum of the figures that precede them. In addition, certain percentages and amounts contained in this document reflect calculations based on the underlying information prior to rounding, and, accordingly, may not conform exactly to the percentages or amounts that would be derived if the relevant calculations were based upon the rounded numbers.

5 Third party information

The Company confirms that all third party information contained in this document has been accurately reproduced and, so far as the Company is aware and is able to ascertain from information published by that third party, no facts have been omitted that would render the reproduced information inaccurate or misleading. Where third party information has been used in this document, the source of such information has also been identified.

6 Forward-looking statements

Certain statements contained in this document constitute forward-looking statements. These statements, including the explanatory wording in the document in relation to the Group's working capital, relate to future events or the future performance of the Group but do not seek in any way to qualify the working capital statement given by the Company. These statements relate to future events or the future performance of the Group. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as *"seek", "anticipate", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", "expect"* or similar expressions. These statements involve numerous assumptions, known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those expressed, anticipated or implied in such forward-looking statements. The Company believes that the expectations reflected in forward-looking statements contained herein are reasonable but no assurance can be given that such expectations will prove to be correct or accurate and accordingly, such forward-looking statements included in, or incorporated by reference into, this document should not be unduly relied upon. These statements speak only as of the date of this document. Actual operational and financial results or events may differ materially from the Company's expectations contained in the forward-looking statements as a result of various factors, many of which are beyond the control of the Company.

Statements related to "reserves" or "resources" are deemed to be forward-looking information as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources can be profitably produced in the future. The forward-looking statements contained in this Prospectus are expressly qualified by this cautionary statement. The Company does not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities laws.

Forward-looking statements involve 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. Forward-looking statements are based on a number of factors and assumptions which have been used to develop such statements but which may prove to be incorrect. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on forward-looking statements because the Company can give no assurance that such expectations will prove to be correct.

Investors are cautioned that forward-looking statements are not guarantees of future performance. The Company makes no representation, warranty or prediction that the results predicted by such forward-looking statements will be achieved and these forward-looking statements represent, in each case, only one of many possible scenarios and should not be viewed as the most likely or standard scenario. Forward-looking statements may, and often do, differ materially from actual results. Any forward-looking statements in this document speak only as at the date of this document, reflect the Group's current view with respect to future events and are subject to risks relating to future events and other risks, uncertainties and assumptions relating to the Group's operations, results of operations, growth strategy and the availability of new credit. Investors should specifically consider the factors identified in this document that could cause actual results to differ. All of the forward-looking statements made in this document are qualified by these cautionary statements.

Subject to the requirements of the Prospectus Rules, the DGTRs and the Listing Rules, or applicable law, the Company explicitly disclaims any intention or obligation or undertaking publicly to release the result of any revisions to any forward-looking statements in this document that may occur due to any change in the Group's expectations or to reflect events or circumstances after the date of it.

7 Basis of preparation of Competent Person's Reports

The CPRs have been prepared in accordance with the Canadian National Instrument 51-101 (NI 51-101) Standards of Disclosure For Oil and Gas Activities, revised July 1, 2015. The conventional reserves were estimated in accordance with Section 5.3 of NI 51-101 and Section 1.35, 1.3.6, 1.3.7, and 1.3.8 of the Canadian Oil and Gas Evaluation Handbook ("**COGEH**") Consolidated Third Edition, August 2018. The unconventional prospective resources were estimated in accordance Section 5.3 and 5.9 of NI 51-101 and Section 1.2.2, 1.3.5, 1.3.6, 1.3.7, and 1.4.7.2.3 of the COGEH. The CPRs are compliant with the Competent Persons Report requirements as published in the European Securities and Markets Authority ("**ESMA**") update of the Committee of European Securities Regulators' recommendations of the European Commission Regulation on Prospectuses No. 809/2004 dated March 20, 2013 (ESMA/2013/319).

In preparation of the CPR with respect to reserves, D&M relied upon, without independent verification, information furnished by, or on behalf of, the Company with respect to the property interests being evaluated, production from such properties, current cost of operations and development, current prices for production, agreements related to current and future operations and sale of production, estimation of taxes, and various other information and data that were accepted as represented. The completeness and accuracy of such information was confirmed in a representation letter provided by the Company dated January 23, 2019. A field examination of the properties was not considered necessary for the purposes of the CPR.

In preparation of the CPR with respect to resources, D&M relied upon, without independent verification, information furnished by, or on behalf of, the Company with respect to the property interests to be evaluated, subsurface data as they pertain to the target objectives and prospects, and various other information and technical data, that were accepted as represented. Site visits to the prospects evaluated were not made by D&M. The CPR was based on data available as of December 31, 2018.

8 No incorporation of website

The contents of the Company's website, any website mentioned in this document or any website directly or indirectly linked to these websites have not been verified and do not form part of this document and investors should not rely on such information.

9 Definitions and technical terms

A list of defined terms used in this document is set out in Part 16 of this document, '*Definitions'*. A list of defined technical terms used in this document is set out in Part 17 of this document, '*Glossary of Technical Terms*'.

PART 4 – CONSEQUENCES OF A STANDARD LISTING

After careful consideration, the Directors have concluded that in order to promote liquidity in the Common Shares through a public listing on the London Stock Exchange while allowing a sufficient degree of flexibility for a company of its size and type, it is appropriate for the Company's shares to be admitted to listing on the standard segment of the Official List. In particular, the following are key considerations for the Company's proposed Standard Listing:

- a Standard Listing as compared to a Premium Listing will generally facilitate more cost efficient administration. In this regard, the Company wishes to align its regulatory responsibilities and the associated cost consequences with the Company's size;
- the proposed Standard Listing of the Company will mean that the Company will not be required to comply with the super-equivalent provisions of the Listing Rules that apply to companies with a Premium Listing, which will have a direct cost saving for the Company; and
- the Listing Rules for securities with a Standard Listing are far less demanding and stringent than those applicable to securities with a Premium Listing.

A Standard Listing affords Shareholders and investors in the Company a lower level of regulatory protection than that afforded to investors in companies whose securities are admitted to the premium segment of the Official List, which are subject to additional obligations under the Listing Rules.

It should be noted that the UKLA will not have the authority to (and will not) monitor the Company's compliance with any of the Listing Rules or any of the DGTR, nor to impose sanctions in respect of any failure by the Company to so comply.

Application has been made for the Common Shares to be admitted to listing on the standard segment of the Official List pursuant to Chapter 14 of the Listing Rules, which sets out the requirements for Standard Listings and does not require the Company to comply with, *inter alia*, the provisions of Chapters 6 to 13 of the Listing Rules (excluding Listing Principles 1 and 2). As a result, the Company's securities will not be eligible for inclusion in the UK series of the FTSE indices.

1 Listing Rules which are not applicable to a Standard Listing

Such non-applicable Listing Rules include, in particular:

- Chapter 8 of the Listing Rules regarding the appointment of a listing sponsor to guide the Company in understanding and meeting its responsibilities under the Listing Rules in connection with certain matters. In particular, the Company is not required to appoint a sponsor in relation to the publication of this document or Admission;
- Chapter 9 of the Listing Rules relating to further issues of shares, issuing shares at a discount in excess of 10 per cent. of market value, notifications and contents of financial information;
- Chapter 10 of the Listing Rules relating to significant transactions which requires Shareholder consent for certain acquisitions;
- Chapter 11 of the Listing Rules regarding related party transactions;
- Chapter 12 of the Listing Rules regarding purchases by the Company of its Common Shares; and
- Chapter 13 of the Listing Rules regarding the form and content of circulars to be sent to Shareholders.

2 Listing Rules with which the Company must comply under a Standard Listing

There are, however, a number of principles and continuing obligations set out in Chapter 7 and Chapter 14, respectively, of the Listing Rules that will be applicable to the Company. These include requirements as to:

Chapter 7 – Listing Principles

- the taking of reasonable steps to establish and maintain adequate procedures, systems and controls to enable it to comply with its obligations; and
- the dealing with the FCA in an open and co-operative manner

Chapter 14 – Continuing Obligations

- the forwarding of circulars and other documentation to the UKLA for publication through the document viewing facility and related notification to a regulatory information service;
- the provision of contact details of appropriate persons nominated to act as a first point of contact with the UKLA in relation to compliance with the Listing Rules and the DGTRs;
- the form and content of temporary and definitive documents of title;
- the appointment of a registrar;
- the making of regulatory information service notifications in relation to a range of debt and equity capital issues; and
- at least 25 per cent. of the Common Shares being held by the public in the EEA or the jurisdiction in which the Common Shares are listed.

In addition, as a company whose securities are admitted to trading on a regulated market, the Company will be required to comply with the DGTRs.

3 Disclosure Guidance and Transparency Rules

Under Disclosure Guidance and Transparency Rule 5 (*Vote Holder and Issuer Notification Rules*) ("**DTR5**"), a person must notify the Company and the FCA of the percentage of the Company's voting rights he or she holds as a shareholder (or holds or is deemed to hold through his or her direct or indirect holding of financial instruments) if, as a result of an acquisition or disposal of Common Shares or financial instruments, or as a result of any event changing the breakdown of voting rights of the Company (for example, a buy-back of Common Shares by the Company), the percentage of those voting rights in which he is interested reaches, exceeds or falls below 5 per cent., 10 per cent., 15 per cent., 20 per cent., 25 per cent., 30 per cent., 50 per cent. and 75 per cent.

The form in which such notification must be made is provided by the FCA on its website at:

https://www.fca.org.uk/markets/ukla/regulatory-disclosures/submit-investor-notification

Such notification must be made no later than four trading days after the date upon which the person making the notification (1) learns of the acquisition or disposal or of the possibility of exercising voting rights, or on which, having regards to the circumstances, should have learned of it, regardless of the date on which the acquisition, disposal or possibility of exercising voting rights takes effect, or (2) is informed about the event changing the breakdown of voting rights of the Company.

Any person who is in breach of their obligations under DTR5 is liable to a fine and/or public censure by the FCA and the FCA may apply to court to have such person's voting rights suspended.

National Instrument 55-104, "Insider Reporting Requirements and Exemptions" requires that any person or company that has beneficial ownership of, or control or direction over, whether direct or indirect, securities of a reporting issuer (such as the Company) carrying more than 10 per cent. of the voting rights attached to all the issuer's outstanding voting securities, including securities (issued and unissued) that the person or company is the beneficial owner of, which are convertible into voting securities within 60 days following that date, is required to provide public notice of their holdings. Insider reports are filed electronically using the System for Electronic Disclosure by Insiders ("SEDI") established by the CSA. Further information about SEDI can be found at the SEDI website (www.sedi.ca). Furthermore, a reporting issuer (such as the Company) is required by Form 51-102F5 of National Instrument 51-102, "Continuous Disclosure Obligations", to disclose in its information circulars whether, to the knowledge of its directors or executive officers, any person or company beneficially owns, or controls or directs, directly or indirectly, voting securities carrying 10 per cent. or more of the voting rights attached to any class of voting securities of such reporting issuer.

PART 5 – EXPECTED TIMETABLE OF PRINCIPAL EVENTS

Prospectus published	17 April 2019
Admission and commencement of dealings in Common Shares on the London Stock Exchange	8.00 a.m. on 25 April 2019

These dates and times are indicative only, subject to change and may be brought forward as well as moved back, in which case new dates and times will be announced. The times referred to above are references to the time in London, UK.

ADMISSION STATISTICS AND DEALING CODES

Number of Common Shares in issue on Admission	86,584,989
Number of Common Shares under other options or warrants on Admission	5,821,666
Percentage of issued share capital represented by options or warrants outstanding at Admission	6.3%
Number of Common Shares on a fully diluted basis on Admission	92,406,655
Expected market capitalisation of the Company on Admission	approximately £146 million
ISIN	CA9191444020
LEI	2549003ZBCOPPO06GY48
Tickers	LSE:VLU TSX:VLE

PART 6 – DIRECTORS, SECRETARY, REGISTERED AND HEAD OFFICE AND ADVISERS

Directors	Dr. W. Sean Guest, *President and Chief Executive Officer* Dr. Timothy R. Marchant, *Chairman* Russell Hiscock James D. McFarland Ronald W. Royal Kimberley Wood
Company Secretary	Stephanie Stimpson
Registered Office of the Company	Suite 4600 525 8th Avenue SW Calgary Alberta T2P 1G1 Canada
Head Office of the Company	Suite 1200 202 6th Avenue SW Calgary Alberta T2P 2R9 Canada
Financial Adviser to the Company	FirstEnergy Capital LLP (trading as GMP FirstEnergy) 85 London Wall London EC2M 7AD United Kingdom
English Legal Advisers to the Company	Memery Crystal LLP 165 Fleet Street London EC4A 2DY United Kingdom
Canadian Legal Advisers to the Company	Torys LLP Suite 4600 525 8th Avenue SW Calgary Alberta T2P 1G1 Canada
Turkish Legal Advisers to the Company	Kurucu Law Offices Nenehatun Cd. No:91/3 Çankaya-Ankara Turkey
Independent Auditors to the Company	KPMG LLP 3100, 205 5 Avenue SW Calgary Alberta AB T2P 4B9 Canada

Reporting Accountants	KPMG LLP 15 Canada Square London E14 5GL United Kingdom
Competent Person	DeGolyer & MacNaughton Corp. 5001 Spring Valley Road Suite 800 East Dallas, Texas 75244
Registrar	Computershare Investor Services 100 University Avenue 8th Floor Toronto Ontario M5J 2Y1 Canada
Depository	Computershare Investor Services PLC The Pavilions Bridgewater Road Bristol BS13 8AE United Kingdom

PART 7 – INFORMATION ON VALEURA ENERGY INC.

1 Introduction

Valeura is engaged in the exploration for, and development and production of, petroleum and natural gas in Turkey. Operations are currently solely focused on the Thrace Basin in the northwest of Turkey as shown in Figure 1. The Group currently holds working interests in 20 Production Leases and Exploration Licences covering approximately 0.456 million gross acres (0.374 million net acres of shallow rights and 0.256 million net acres of deep rights), as shown in Figure 2.

The Group is pursuing shallow conventional, normally pressured natural gas and deep unconventional tight gas. This upstream program is complemented by ownership of gas gathering and sales infrastructure to support direct marketing of natural gas to end users.

Conventional gas is produced from structural and/or fault bounded closures in the Tertiary-aged stacked sands in the Danismen and Osmancik formations at relatively shallow depths of 500 to 1,500 metres. The Company has also used a combination of vertical and horizontal drilling and high-pressure stimulation to develop tight, but normally pressured gas resources from the slightly deeper Mezardere and Kesan formations.

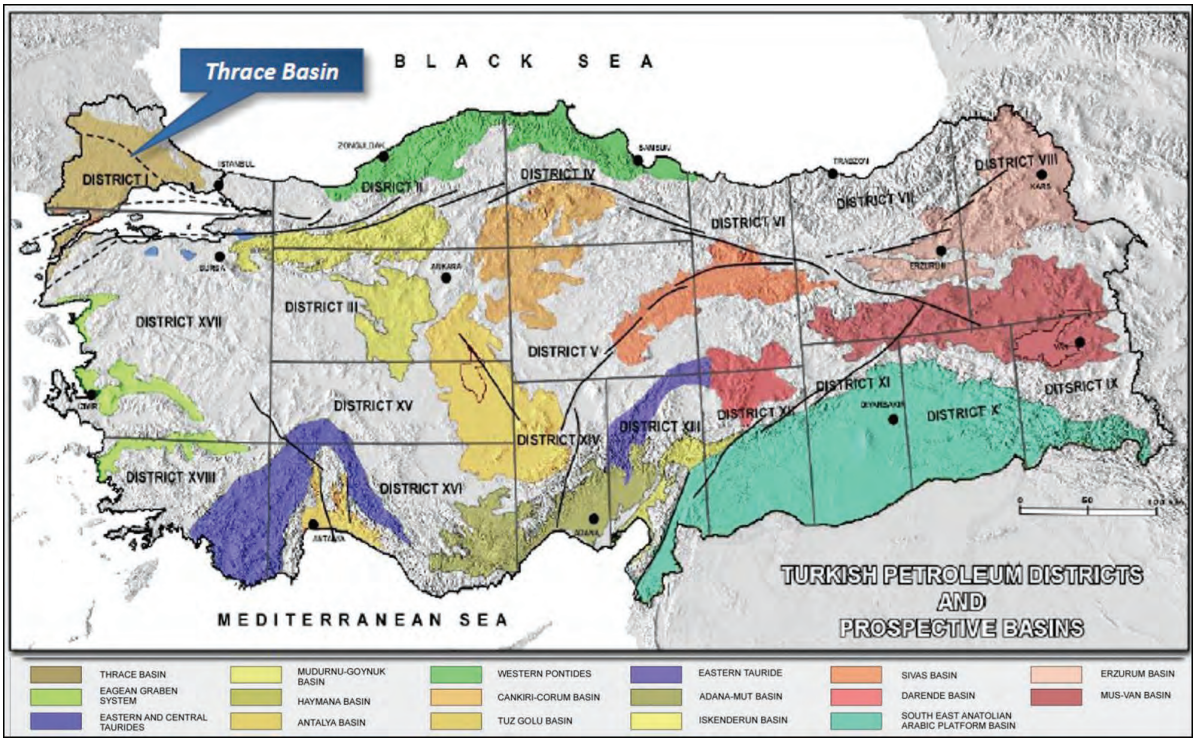


Fig.1 – Geological Basins of Turkey and position of the Thrace Basin

As at 31 December 2018, the Group has proved plus probable (2P) reserves of 43.97 Bcf natural gas and 0.022 MMbbl of oil (7.35MMboe) and company gross unrisked mean prospective resources of 9.5 Tcf natural gas and 236 MMbbl of natural gas liquids (1,815 MMboe) (Source: CPRs).

Valeura's natural gas sales in the Thrace Basin of Turkey during the year ended 31 December 2018 averaged 4.3 MMcf/d and oil sales averaged 8bbl/d. Natural gas sales represent more than 99 per cent. of net petroleum and natural gas sales. The Group also owns and operates gas gathering facilities and sales contracts for its assets in Turkey. The Board believes that the Thrace Basin Assets have potential for continued exploration and development of gas from conventional and tight gas reservoirs.

Many of the Group's lands are believed by the Directors to have potential for a deep, unconventional BCGA play in over-pressured formations below approximately 2,500 metres. A BCGA is an unconventional play where the hydrocarbons are trapped strictly by the poor quality (very low permeability) of the reservoir rocks in the central parts of the basin where no structural trapping occurs. When discovered, the hydrocarbons can be pervasive across the whole basin, but normally require enhanced production technologies such as horizontal wells and high pressure stimulation to create man-made fractures. By applying 3D seismic, modern high-pressure stimulation technology and horizontal drilling, Valeura is aiming to demonstrate that commercial operations from this tight gas resource are possible. Valeura has partnered with Equinor for this deep appraisal as a large, well-respected partner which provides further technical and financial capacity.

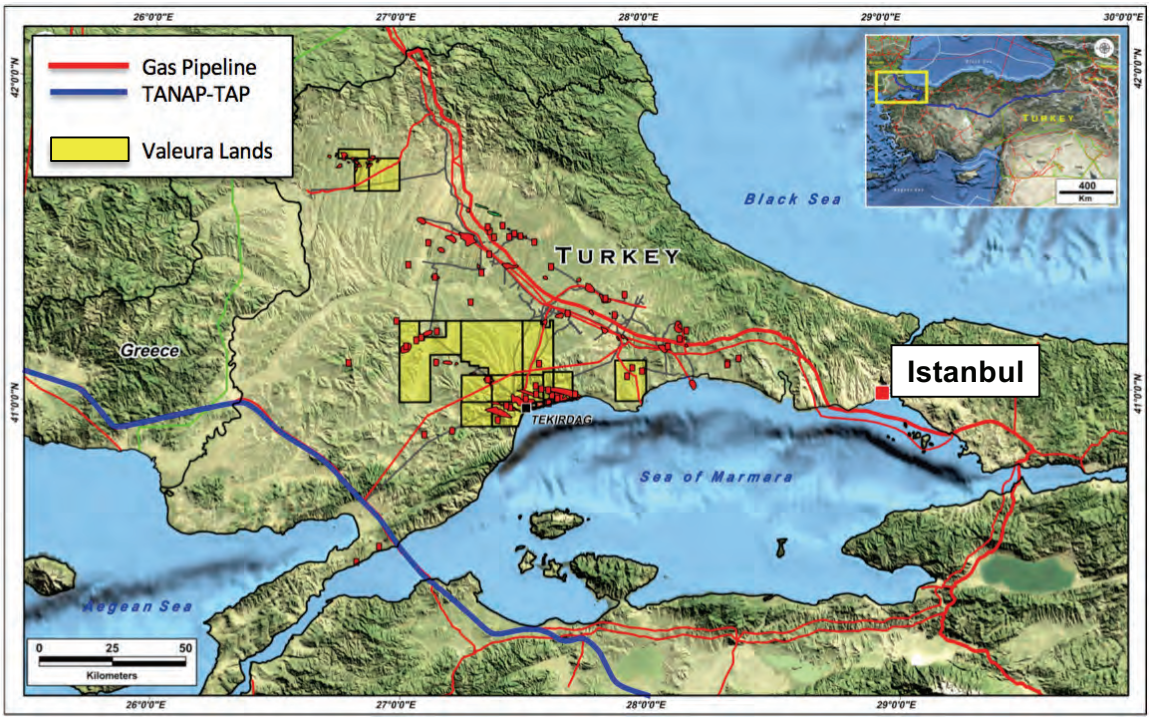


Fig.2 – Position of Valeura's assets in the Thrace Basin, Turkey

Data from eight historic deep wells supported this BCGA thesis and in 2017, Valeura drilled, completed and flow-tested the Yamalik-1 gas-condensate discovery well on the Banarli Exploration Licences, which proved the presence of a BCGA concept in the area of the well.

In 2019 the Company is undertaking an appraisal campaign for the deep BCGA play discovered with Yamalik-1 to prove that the deep gas is pervasive across the basin and to demonstrate that it can flow commercially. The Inanli-1 appraisal well has been drilled and encountered over-pressured gas throughout the objective section. This well will be stimulated and tested in Q2 2019. The drill rig is currently drilling the second well in the campaign which is Devepinar-1, located approximately 20 km to the west of Yamalik-1 and Inanli-1. This appraisal drilling and testing program is expected to continue into late 2019 and will guide plans for further appraisal and/or an early development project in 2020 and 2021.

2 History of Valeura

In 2010, when the Company changed its name from PanWestern Energy Inc. to Valeura Energy Inc., it adopted a mandate to become a global energy company focused on exceptional value creation, with a primary geographic concentration on Turkey.

Through a series of commercial transactions spanning 2010 through 2014, Valeura entered into several farm-in agreements and acquisitions, and acquired new licences, focused on the Anatolian Basin in southeast Turkey, and the Thrace Basin in northwest Turkey. The Company was strategically seeking production opportunities where it recognized upside potential via both development-focused operations and exploration.

In 2014 and 2015, the Group concentrated its focus on the Thrace Basin. Various assets in southeast Turkey were relinquished given the deteriorating political situation in Syria, and/or where the assets did not realise the desired upside potential, and the small legacy oil and gas properties in Canada were sold. The Group's Thrace Basin Assets were primarily operated in joint venture with TransAtlantic Petroleum (the "**TBNG JV**"), but the Group also acquired a 100 per cent. interest in its Banarli Exploration Licences. Valeura made a number of discoveries during this period in both the TBNG JV and its Banarli Exploration Licences that were quickly developed and brought into production. Additionally, the Hayrabolu-10 and Yayli-1 wells were drilled deep and achieved minor gas flow from the deep tight sands and provided important supporting information on the potential BCGA play.

In late 2016 and early 2017 Valeura negotiated and subsequently closed several transformational deals to give it control and ownership of most of the conventional, shallow production and partnered with Statoil ASA, now Equinor, to explore and appraise for the deep, unconventional play. In February 2017, Valeura closed the acquisition of 100 per cent. of the shares of TBNG from TransAtlantic for US$20.7 million. In the first half of 2017, Valeura closed several farm-in and sales agreements with Equinor to give Equinor rights to a 50 per cent. interest in the deep rights in the Banarli and West Thrace lands by paying US$21 million in cash and full funding of two deep exploration wells and 3D seismic costs.

In 2017 after concluding the above transactions, Valeura completed a number of exploration and development wells in the shallow rights that provided modest increases in production throughout the year. To test the BCGA thesis the Company completed approximately 500 square kilometres of 3D seismic and drilled the Yamalik-1 exploration well. The Yamalik-1 well drilled to 4,196 metres and is interpreted to have intersected highly overpressured and gas saturated reservoirs below approximately 2900 metres. High-pressure stimulation and testing of this well demonstrated that gas and condensate would flow to surface post-stimulation. Both of these factors are key components to demonstrate the presence of an unconventional BCGA play.

Activities in 2018 focused on the planning and commencement of an appraisal program for the BCGA play to prove that the overpressured gas is pervasive across the basin and to demonstrate that the gas could be flowed commercially. The notional program agreed with Equinor was to drill three new appraisal wells, which would be high-pressure stimulated and tested if successful, and to further production test one or two historic wells. To fund this program beyond the Equinor work program carry, Valeura closed a public offering in March 2018 for gross proceeds of approximately C$60 million.

In September 2018, Valeura recompleted the Yamalik-1 well to allow for extended production testing and evaluation of this well continues. The first appraisal well, Inanli-1, 6 km from Yamalik-1, was drilled to a depth of 4885 metres and the rig was released in January 2019. High-pressure tight gas was intersected below 3270 metres and a high-pressure stimulation and testing program is currently being finalised. The second appraisal well, Devepinar-1, is approximately 20 km west and was spudded in February 2019.

While the Company is primarily focused on advancing the BCGA play, it continues to efficiently deploy capital towards its conventional production. In 2018, Valeura drilled one new gas discovery, completed a number of workovers on existing production wells and performed re-entry high-pressure stimulations on two wells.

3 Group Structure

Valeura is the parent company of the Group as shown in Figure 3. Via its wholly-owned subsidiaries, North Hunter Energy Inc. and Valeura Energy (Netherlands) Cooperatief UA, Valeura has a 100 per cent. interest in each of three subsidiaries which hold the Group's Production Leases and Exploration Licences, TBNG, CRBV and VENBV, each of which have Turkish branches.

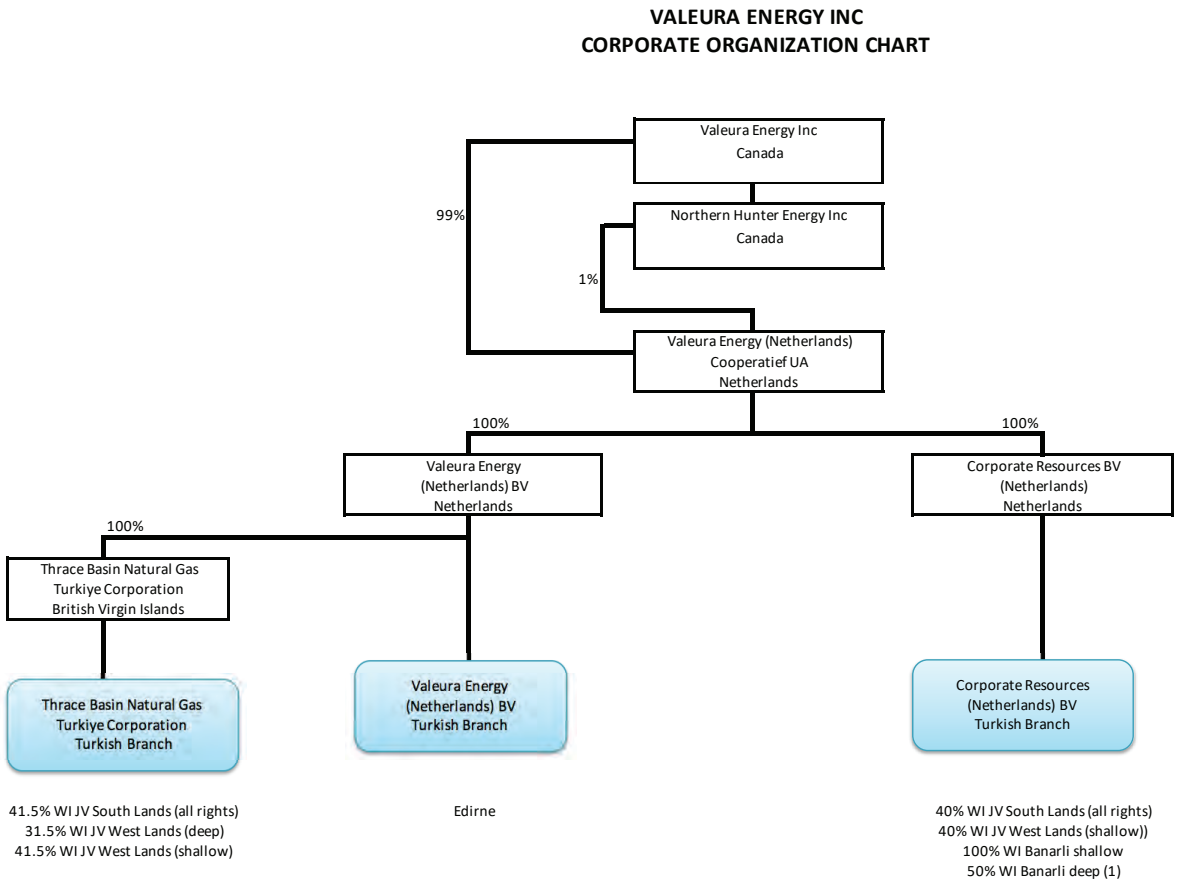


Fig.3 – Valeura Group Structure

4 Key Land Assets

Overview of Land Holdings

Figure 4 below summarises the Group's current land holdings and its working interests in its Production Leases and Exploration Licences; and Figure 5 below shows the Group's holdings on a map.

Exploration Licences are held for an initial period of 5 years. There is a work program obligation (drilling seismic, and/or studies) associated with each year and the annual program must be complete prior to the end of that year. The holder may request two, 2-year extensions subject to agreeing a work program obligation with the government for each of the years in the extension. Additionally, if there has been a discovery, then the holder can request a third, 2-year extension period. Petroleum can be produced during the exploration phase to the benefit of the holder.

Production Leases can be for an initial term of a maximum of 20 years. The initially granted term may be shorter than the maximum, if the expected production life of the discovered fields is less than 20 years. However, if less than the full 20-year term is awarded, this can be increased during the life of the production lease if production life is increased. If there are still reserves and production on the lease after the initial 20 year term then the holder can request two 10 year extensions. There is no work program obligation during a production lease, but the holder is expected to take measures to maintain optimal production from the lease.

		Leases & Licenses	Gross Area (Acres)	Valeura Shallow Rights		Valeura Deep Rights	
				WI	Net Acres	WI	Net Acres
South Thrace Production Leases	Operated	11	170,735	81.5%	139,149	81.5%	139,149
West Thrace Production Leases	Operated	3	13,578	81.5%	11,066	31.5%	4,277
Erdine Production Leases	Non-Operated	3	49,883	35.0%	17,459	35.0%	17,459
Banarli Exploration Licences(1)	Operated	2	133,840	100.0%	133,840	50.0%	66,920
West Thrace Exploration Licences	Operated	1	88,434	81.50%	72,074	31.5%	27,857
Total			**456,470**		**373,588**		**255,662**

(1) To earn their 50% deep rights under the Banarli Farm-In Agreement, Equinor must still fund the fracking and testing of the Inanli-1 well. If this work program is not completed, Valeura reverts to 100% ownership.

Fig.4 – Group Land Holdings

The Group's primary producing assets are located in the South Thrace Lands and the West Thrace Lands (the "**TBNG JV Lands**").

In the South Thrace Lands, the Group holds 11 Production Leases encompassing 170,735 gross acres. Valeura is the operator of the South Thrace Lands and holds an 81.5 per cent. working interest in the shallow rights and deep rights. The South Thrace Lands are jointly held by Valeura's wholly-owned subsidiaries, TBNG (as to 41.5 per cent.) and CRBV (as to 40 per cent.), and PTI holds the other 18.5 per cent. working interest. There is no work program obligation to the government.

In the West Thrace Lands, the Group holds three Production Leases and one Exploration Licence encompassing 102,012 gross acres. The Group's 31.5 per cent. working interest in deep rights is held by TBNG, and the Group's 81.5 per cent. working interest in shallow rights is jointly held by TBNG (as to 41.5 per cent.) and CRBV (as to 40 per cent.). Equinor (as to 50 per cent.) and PTI (as to 18.5 per cent.) hold the remaining working interest in the deep rights, and PTI holds the remaining 18.5 per cent. working interest in the shallow rights. Valeura is the operator of the West Thrace Lands which are subject to the West Thrace JOAs. The Exploration Licence has a two well commitment to fulfill the work program obligation which must be completed by 26 June 2020.

The Group holds two Exploration Licences in the Banarli Lands encompassing 133,840 gross acres. It holds a 100 per cent. working interest in the shallow rights and 50 per cent. working interest in the deep rights through CRBV. Equinor holds the other 50 per cent. working interest in the deep rights. Rights are subject to the Banarli JOAs and the Banarli Farm-In and Valeura is currently the operator. The obligatory seismic and drilling work programs under the terms of the two Banarli Exploration Licences have been completed, except for geological and geophysical studies.

Equinor Turkey has a 50 per cent. working interest in the deep rights under the Banarli Farm-In which requires Equinor Turkey to fully fund: (1) the drilling and testing of the Yamalik-1 well; (2) the acquisition and processing of the Karaca 3D seismic program; and (3) the drilling and testing of Inanli-1 well. It is expected that Equinor will fulfill these obligations in 2019 once the testing of Inanli-1 is complete. If this work is not fully completed, 100 per cent. ownership of deep rights reverts to Valeura.

The boundary between the deep and shallow rights is determined by either a pressure gradient of 0.6 psi/ft (1.39 SG) or 2500 metres depth, whichever is shallower. Valeura remains operator of the deep exploration program on both the Banarli and West Thrace Lands during Equinor Turkey's earning phase in Banarli. Equinor Turkey will have the option to request operatorship of the deep program once they have fully earned. Additionally, under the Banarli Farm-In Equinor Turkey has no pre-emption right related to the Valeura interests and there are some controls for Valeura's benefit related to the pace of appraisal drilling prior to approval of a pilot project for development.

The Group's wholly-owned subsidiary VENBV holds a 35 per cent. working interest in three Production Leases in Edirne encompassing 49,883 gross acres. Otto Energy Limited (a subsidiary of TransAtlantic Petroleum) operates and holds the remaining 65 per cent. working interest. These leases currently do not have active operations or production.

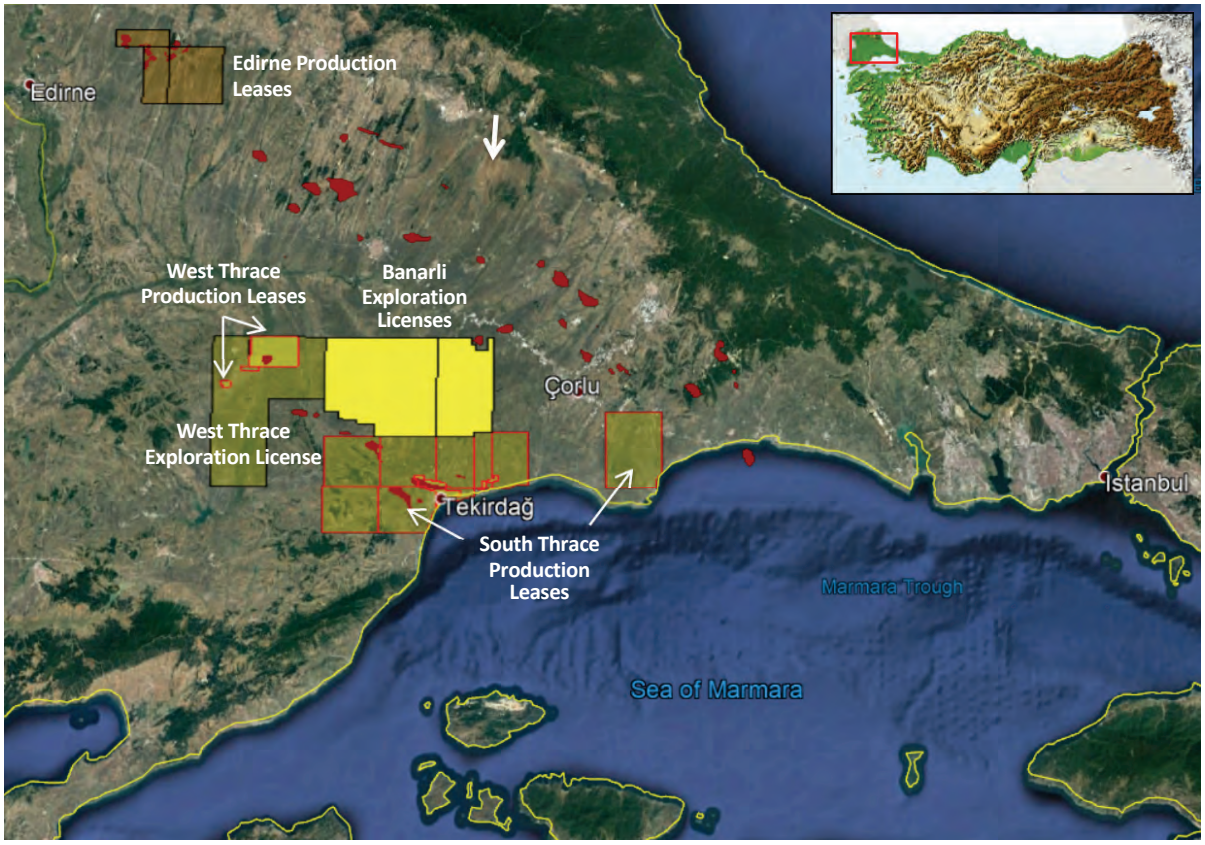


Fig.5 – Map of the Group's land holdings

5 Operations

(i) *Shallow Conventional Gas*

Gas sales from TBNG JV Lands in 2018 averaged 4.3 MMcf/d. Oil and natural gas liquids sales totaled 8 bbl/d. Average realized prices for Valeura's gas sales from the South Thrace and West Thrace were $7.56/Mcf in 2018. All of the production from the Group's South Thrace and West Thrace Production Leases in 2018 was conventional shallow gas produced from numerous wells along with a small amount of oil.

The Company drilled one shallow (conventional) gas well in Q2 2018 in one of the West Thrace Licences. The Karanfiltepe-7 well was an obligation well that targeted a conventional fault-bounded trap. The well was a discovery which was immediately tied in to the infrastructure for production. In 2018 the Company completed a number of workovers of existing production wells and two re-entry high-pressure stimulations on existing wells. The Company is also continuing with its plan of selective low-cost workovers throughout the conventional play, to slow the natural decline from the existing fields.

A significant portion of the Group's reserves is undeveloped gas in tight formations. A key risk in relation to these sorts of formations is uncertainty regarding the sustainability of initial production rates and decline rates thereafter. The Directors believe that shallow gas wells and high-pressure stimulated tight gas wells will exhibit relatively high decline rates of 50 per cent. and 75 per cent., or more, respectively, in their first year of production. There are also risks and uncertainties regarding technical drilling challenges and the management of water production, as required.

(ii) *BCGA*

Valeura identified the potential for an unconventional BCGA play in the Thrace Basin. Based on the BCGA thesis, the Company acquired the Banarli Exploration Licences and in 2015 and 2016, drilled the Hayrabula-10 and Yayli-1 wells which were deepened and provided more evidence supporting the BCGA play.

Under the Banarli Farm-In, the Company completed approximately 500 square kilometres of 3D seismic (Karaca) and drilled the Yamalik-1 exploration well. The Yamalik-1 well was drilled as the first well testing the BCGA thesis. The well encountered highly overpressured gas saturated Mezardere and Kesan 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. The average net sand in the objective section was approximately 44 per cent.

In the fourth quarter of 2017, Valeura completed four production tests in the Kesan formation in Yamalik-1 where each test was preceded by two slick-water high-pressure stimulations. The testing successfully demonstrated that gas and condensate would flow to surface post- high-pressure stimulation and a 24-hour aggregate production test rate of 2.9 MMcf/d was achieved. The gas flowed with a significant amount of condensate (with a test data range of 20 to 70 barrels per MMcf). The ability to flow high-pressure gas from an area outside of a structural closure supported the interpretation of an unconventional BCGA play.

Activities in 2018 focused on the planning and commencement of an appraisal program for the BCGA play to determine whether the overpressured gas is pervasive across the basin and to demonstrate that the gas could be flowed commercially. The notional program agreed with Equinor Turkey was to drill three new appraisal wells, which would be high-pressure stimulated and tested if successful, and to further production test one or two historic wells.

In September 2018, Valeura recompleted the Yamalik-1 after tie-in well to allow for a production testing on a comingled basis. At the end of 24 hours of continuous production, the flow rate was 2.53 MMcf/d through a 20/64" choke with a wellhead pressure of 2,535 psi. After a period of intermittent flow of gas, condensate and water, a gas lift compressor was installed to assist in the ongoing flow back of stimulation fluids phase of initial production. Pressures and flow rates stabilized after the introduction of gas lift, and the well has continued to flow a mixture of gas, condensate and water. The Company is continuing to evaluate the well to better understand the flow potential of the different zones in the well and to determine the sources and volumes of any water production.

The first appraisal well, Inanli-1, was spudded in October 2018. The well was approximately 6 km from Yamalik-1 and the key objectives were to determine whether the over-pressured, gas-bearing reservoir discovered in the Yamalik-1 exploration well is laterally continuous and is indicative of a BCGA, to test for effective reservoir and over-pressured gas at deeper depths than Yamalik-1, and to test for the presence of enhanced natural fracturing in the reservoir. Drilling operations carried into January 2019 where the well reached total depth at 4885 metres. Based on drilling and wireline logging data, the well is interpreted to have intersected over-pressured tight gas below 3270 metres down to the total depth. A programme to high-pressure stimulate the well and test select intervals is currently being finalised and is expected to occur through Q2-2019.

The second appraisal well Devepinar-1 is located 20 km west of Yamalik-1 and Inanli-1 and was spudded in late February 2019. It is currently drilling.

A significant portion of the Group's value is in the natural gas prospective resource associated with the deep, unconventional basin-centered, gas/condensate play discovered with the Yamalik-1 exploration well. This play is still in the early phase of exploration and appraisal with large uncertainties and risk. Whilst there are eight historic wells around the basin that are all interpreted to have encountered high-pressure gas at depth, the current well density in the basin and this play is still very low. There are large uncertainties laterally across Valeura's land interests, and vertically in the target Kesan Formation, as to the presence of gas, the pressure of any gas, and the amount of condensate in the gas. The ability to flow and recover gas commercially is still to be demonstrated. Most of the historic wells were drilled prior to high-pressure stimulation being a commonly accepted technique and none achieved a commercial flow rate using the perforation and testing techniques available at the time. Yamalik-1 was high-pressure stimulated and is still being tested and at this point it has not demonstrated a commercial flow rate. High-pressure stimulation and testing is planned for Inanli-1, but this will not be commenced until Q2 2019.

6 Petroleum Sales and Pipeline Infrastructure

The Group has 81.5 per cent. ownership of, and operates, a natural gas gathering grid and associated sales lines, as shown in Figure 6. Natural gas is delivered directly to 49 regional industrial purchasers. The Company has individual sales contracts with these clients with prices referenced to the BOTAS Level 2 Wholesale (Processing) gas price ("**BOTAS Reference Price**"). Historically the Company has realised a discount to the BOTAS Reference Price of approximately 2 per cent., but in Q4 2018 the Company's realised price was approximately equal to the BOTAS Reference Price.

The Company produces a small amount of oil and condensate. These liquids are trucked directly from the individual well sites to the Ophet storage facilities before being barged to the Tupras refinery east of Istanbul. Recently the Company has been realising a sales price similar to Brent Oil pricing.

The Company's natural gas infrastructure is currently underutilized and has the capacity to handle approximately 50 MMcf/d. This is sufficient capacity to allow for growth in the Company's conventional production and for the appraisal of the BCGA play and any potential early development project. If the BCGA project is successful then the Company will require access to infrastructure beyond the capacity of its existing grid. There are multiple options for increased capacity with proximal pipeline infrastructure capable of several Bcf/day. These include tie-in to the regional gas distributor GAZDAZ, an existing export line to Greece, the major line from Russia to Istanbul, and the TANAP line which is currently complete to the Greek border and is expected to connect to Italy via the Trans-Adriatic Pipeline (TAP) in 2020.

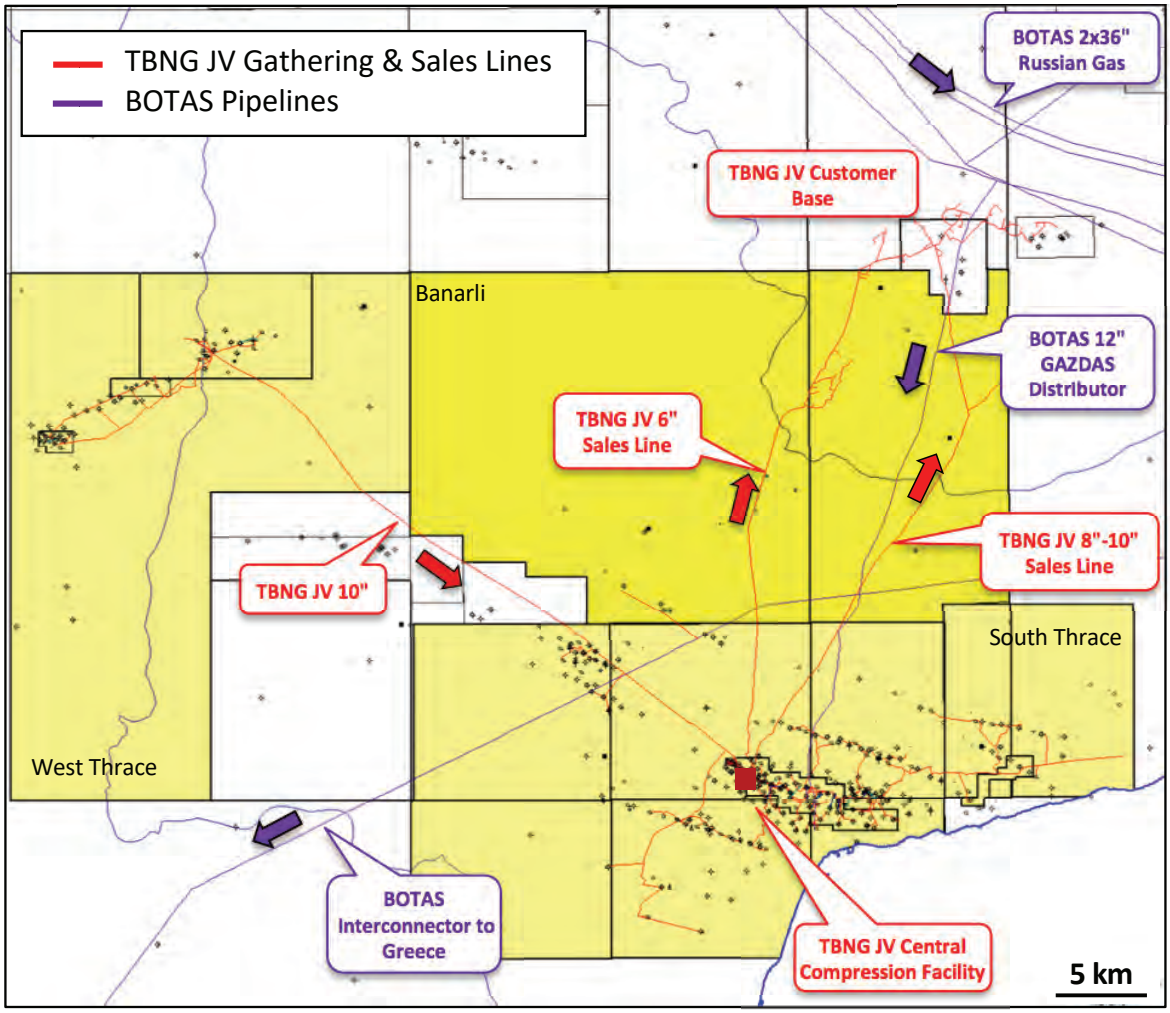


Fig.6 – Map showing the Group's Gas infrastructure and the proximal BOTAS pipelines. Note that the TANAP pipeline which runs via TAP to Italy is just south of the illustrated map area.

7 Summary of Reserves and Resources

Oil and Gas Reserves

The following table summarises Valeura's NI 51-101 and COGEH compliant company gross reserves as provided for in the "**Competent Person's Reports**", as prepared in accordance with NI 51-101 and COGEH by D&M and calculated using D&M's commodity price forecasts at 31 December, 2018. The Competent Person's Reports are set out in full in Part 18 (Competent Person's Reports) of this Prospectus.

	Valeura Working Interest Gross Oil and Gas Reserves				
	Light and Medium Oil Crude Oil Gross (Mbbl)	*Heavy Crude Oil Gross (Mbbl)*	*Conventional Natural Gas Gross (MMcf)*	*Natural Gas Liquids Gross (Mbbl)*	*Total Oil Equivalent Gross (Mboe)*
Proved Developed Producing	14	–	2,927	–	502
Proved Developed Non-Producing	1	–	1,217	–	204
Proved Undeveloped	–	–	7,533	–	1,256
Total Proved	15	–	11,677	–	1,962
Total Probable	6	–	32,289	–	5,388
Total Proved Plus Probable	21	–	43,966	–	7,350
Total Possible	10	–	25,217	–	4,213
Total Proved Plus Probable Plus Possible	31	–	69,183	–	11,563

Estimates of Reserves for individual properties may not reflect the same level of confidence as estimates of reserves for all properties, due to the effect of aggregation.

Oil and Gas Prospective Resources

The following table summarises Valeura's NI 51-101 and COGEH compliant company gross resources as provided for in the Competent Person's Reports.

Conventional Natural Gas

	Unrisked					*Risked*
Company Working Interest Lands	*Low Estimate Gross (Bcf)*	*Best Estimate Gross (Bcf)*	*High Estimate Gross (Bcf)*	*Mean Estimate Gross (Bcf)*	*Probability of Economic Success %*	*Mean Estimate Gross (Bcf)*
Total	3,229	7,652	20,077	10,137	51.1	5,182

The probability of economic success is applied by D&M to estimate the economically recoverable quantities that may actually result from drilling this unconventional prospect.

The following table summarises the amount of condensate that would be recovered in association with the production of the natural gas volumes summarised in the table shown above.

Condensate (Natural Gas Liquids)

		Unrisked		
Company Working Interest Lands	*Low Estimate Gross (MMbbl)*	*Best Estimate Gross (MMbbl)*	*High Estimate Gross (MMbbl)*	*Mean Estimate Gross (MMbbl)*
Total	45	155	504	236

The broad range of recoverable gas from 3.2 to more than 20 Tcf is a function of the uncertainty in the various components of the assessment including recovery factor. There has been very limited stimulation and production testing from the over-pressured Teslimkoy and Kesan Formations in the Thrace Basin, and as yet there is no production data. To determine potential recovery factors, D&M have utilized their experience in analogous basins. The prospective resources in above assume a low, best, high and mean estimate recovery factor of approximately 25 per cent., 40 per cent., 55 per cent. and 40 per cent. respectively. Significantly more delineation drilling, stimulation, and testing will be required to confirm that gas can be commercially recovered from the prospect, and to generate type curves that can be used in a predictive sense.

Chance of Commerciality

D&M has assigned a chance of discovery of 70 per cent. This high chance is driven by: (1) the hundreds of legacy wells drilled in the Thrace Basin which support the geological model for the Teslimkoy and Kesan formations; (2) the over-pressured natural gas which was encountered and tested at Yamalik-1, and (3) the seven legacy wells surrounding the basin which all encountered over-pressured gas below 2,500 metres.

D&M has assigned a chance of development of the natural gas prospective resources of approximately 74 per cent., which is a product of the probability of threshold economic field size and probability of development. This high chance of development reflects that existing hydraulic fracturing technology is being applied, well depths and costs are not expected to be excessive, sales pipeline infrastructure already exists in the area and there are ready domestic markets in Turkey for domestic natural gas and condensate sales.

This results in an overall chance of commerciality of 51.1 per cent. which is the product of chance of discovery and chance of development. The resulting risked mean estimate of 5.2 Tcf of conventional natural gas prospective resources shown in the preceding Conventional Natural Gas table is risked for chance of commerciality.

Significant Positive and Negative Factors Relevant to the Prospective Resources Estimate

Understanding of the extent of this basin-centered gas prospect in the Thrace Basin and its potential commerciality is in the early stages of exploration and appraisal. There are a number of positive and negative factors which are driving large uncertainty.

Positive factors with respect to the estimate of prospective resources include:

- The geological model for the target Kesan reservoir is well calibrated in the Thrace Basin as there have been just under 1000 wells drilled. Many of the wells have been drilled deep so that the behaviour of the Kesan Formation is well understood. Additionally, there are now 12 wells around the basin which have all encountered high-pressure gas at depth. These two factors give the Company confidence that high-pressure gas will be pervasive in the Kesan across the target basin.
- The Company and Equinor are planning a delineation drilling programme comprising three wells which commenced in Q3 2018 and will extend to Q3 2019. The first well in this programme (Inanli-1) reached total depth of 4885 metres in January 2019 and is interpreted to have intersected a gross over-pressured gas column of 1615 metres. Production testing of this well is planned to commence in Q2 2019. The second appraisal well, Devepinar-1 spudded in February 2019.
- The follow-up delineation drilling programme will benefit from the new Karaca 3D seismic in terms of finalizing drilling locations, correlating the seismic to the Yamalik-1 and subsequent well results and targeting sweet-spots in the basin-centered gas prospect. With this new seismic data, the majority of the BCGA target area is covered with 3D seismic data.

- The gas quality is very good without significant CO_2 or other different gases which erode the value of the produced gas and make it more expensive to develop. The natural gas is also expected to yield condensate (test rates range from 20 bbl/mcf to 70bbl/mcf), which can add significantly to the value of the gas and further improve the economics.
- The Company's existing infrastructure and customer base is expected to be capable of handling sales of approximately 50 MMcf/d compared to current sales through the system of less than 10 MMcf/d, thereby providing the opportunity for early production from any future delineation wells. Additionally, the availability of proximal sales infrastructure means that the economic cutoff volume to support development is very low.
- Natural gas prices in Turkey are strong and fiscal terms are internationally competitive. The Company's average natural gas price realization in Q4 2018 was approximately C$9.06/Mcf. This means that wells in the BCGA play in Turkey can be much less productive than wells in analogue plays in North America and still be economic due to the higher gas prices in Turkey.
- Turkey is a captive natural gas market given that 99 per cent. of its natural gas demand is served by imports. This provides an attractive marketing opportunity for a domestic natural gas producer. As the Company's natural gas production volumes potentially grow beyond the limit of its owned infrastructure, there are multiple take-away opportunities within a few 10s of kilometres. These include: a potential to tie-in to a pipeline owned by BOTAS just north of the Banarli Lands; a tie-in to the new TANAP line which will export gas into Europe, a tie-in to another BOTAS interconnector pipeline traversing Banarli and connected to an export line to Greece; and sales to the local gas distributor who currently offtakes gas from the BOTAS pipeline to the north.

Negative factors with respect to the estimate of prospective resources include:

- The BCGA play is in the early exploration and delineation cycle with sparse well control and very limited fracture stimulation and testing data.
- There is as yet no long-term well production performance from the BCGA play to establish that gas can be produced from any of the zones economically. There is insufficient testing and production data to generate a production type curve specific for the prospect, thereby requiring use of analogue information at this time to establish development plans and evaluate the chance of commerciality.
- The target reservoir is very deep and is of relatively low quality (ie. low porosity and permeability).
- The limited amount of deep drilling carried out in the Thrace Basin provides poor visibility on future costs to drill, frack and complete deep development wells to exploit the BCGA play and the associated impact on the chance of commerciality.
- Although oil and gas activity has been underway for many decades in the Thrace Basin area, as activity levels increase, timelines may increase to achieve government and local landowner approvals.

8 Strategy, Recent Developments and Trends

Strategy

The Company is focused on growing its established natural gas business in Turkey which has significant upside potential and yields very high natural gas prices relative to North America. Transactions and financings completed by the Company between 2016 and 2018 have transformed the Company by increasing the size of its asset base, securing operatorship of all key assets, and providing the financial capacity to appraise the large unconventional BCGA play. The Company is partnered in the appraisal of the BCGA with Equinor, which is a large, internationally respected partner that provides further technical and financial capacity.

Valeura is currently focused on two key objectives:

- further delineation and commercial demonstration of the unconventional BCGA play discovered by the Yamalik-1 well in 2017; and
- continuing to optimize production and cash flow from the established conventional shallow gas assets in the Thrace Basin.

As a result of the success of the Yamalik-1 well, the primary focus of Valeura's business has transitioned from shallow gas development drilling to the defining and development of a deep unconventional BCGA play.

Valeura is fully focused on appraising and de-risking its unconventional gas discovery in Turkey. The objective of the 2019 work program is to demonstrate that over-pressured gas is pervasive across the Thrace Basin Assets and to show that commercial flow rates can be achieved. The Directors believe that the combination of the ongoing analysis of Yamalik-1, plus the results from its three-well appraisal program, will provide a strong understanding of the potential of the BCGA play by late 2019. Please refer to Part 11 for further details on the operations of the Company.

The Company remains very well positioned to finance its ongoing BCGA appraisal program and all corporate activities well into 2020. The Company's working capital position is more than adequate to fund its working interest share of the two appraisal wells post-Inanli-1 and all associated stimulation and testing activities.

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 manner.

Recent Developments and Trends

Prices and markets for oil and natural gas are unpredictable and tend to fluctuate significantly, which effects Valeura's profitability and growth potential. Revenues are derived from the sale of oil and gas and potentially from the sale of oil and gas assets whose values tend to vary with the price of oil and gas.

In Turkey the price of natural gas is set by BOTAS, the state-owned enterprise that owns most of the gas pipelines and controls most of the import contracts for natural gas into Turkey. The BOTAS Reference Price is denominated in Turkish Lira ("**TL**"). Historically, the BOTAS Reference Price has behaved in a similar manner to the regional price for natural gas when translated to US$, though price changes have tended to lag the more market-driven natural gas prices in the region. In 2018 BOTAS introduced regular updates to the natural gas price and since mid-2018 the price has been adjusted, if required, on the first day of the month. Analysis suggests that these price adjustments are taking into account variations in the regional price of natural gas, and changes in the TL exchange rate. While indications are that the BOTAS pricing continues to move toward a more market-driven price for natural gas, there is no guarantee that the government will continue this policy in the future.

The oil and gas industry is highly competitive and Valeura faces competition from both local and international companies. Turkey has had an active oil and gas industry for almost a century, but it has generally been small relative to other mature oil and gas jurisdictions. Major international oil and gas companies have generally come into the country during the exploration phase of activity when there is potential for new plays that could yield significant oil and gas volumes, for example, deep water plays in the Black Sea or the Mediterranean. Currently the industry is dominated by TPAO and small to mid-cap oil and gas companies but activity has been steady in line with global oil and gas activity trends.

9 Key Strengths

The Directors believe the Group benefits from the following competitive strengths:

Control of gas/condensate asset with world-class potential

The Group was an early identifier of the potential for a deep unconventional gas play (BCGA), and from 2013 to 2017 was able to secure most of the key acreage in the target basin. By 2017 the Group controlled and was operator of almost half a million acres of the target lands, and had brought in Equinor as a technical and financial partner who agreed to fund the early exploration and testing phase of the BCGA. Following the Yamalik-1 BCGA discovery in late 2017, D&M's external report on the potential of the BCGA ascribed 10.1 Tcfe of unrisked, prospective natural gas resource to Valeura, with an upside of more than 20 Tcfe (net). This asset has the potential to be a world-class discovery and given its location, with access to both Turkish domestic markets and European export pipelines, it offers significant strategic value in addition to the resource value.

Operator of local gas infrastructure and multiple options to access new gas markets

Valeura has majority ownership of the entire gas gathering infrastructure on its lands and sells directly to more than 55 industrial gas purchasers through business to business contracts. The Group is able to control all aspects of the gas production, transportation and sale from the wellhead directly through to the purchaser. The infrastructure capacity and purchaser base has the potential to increase more than 5X from the current level of gas production without any capex requirements. The Group also achieves value from this infrastructure by purchasing and on-selling third party gas to its purchasers.

Valeura's infrastructure will also be used for the testing and early development of the BCGA play. All of the successful appraisal wells, and any potential early development projects, can be tied into the existing infrastructure at low cost and utilise existing commercial agreements for production monetization. Technically, this allows for long-term testing of wells by avoiding any flaring, and commercially this yields early cash flow from appraisal drilling. It should be possible to appraise and understand the BCGA potential prior to negotiating new gas sales agreements.

If the BCGA play is successful then it has the potential to produce between 1 to 2.5 Bcf/d of gas. While this is a very significant amount of new production, there are several existing and under construction pipelines within a few 10's of kilometres from the Group's Thrace Basin Assets with the capacity to handle these volumes. The major import lines from Russia run across the north of the Thrace Basin and the new TANAP line, which was commissioned in 2018, is just south of the Group's lands and is planned to connect to Italy in 2020. Additionally, the new Turkstream 1 and 2 lines from Russia to Europe are planned to land in the north of the Thrace area prior to extending into Europe. While the Turkish domestic market would have the ability to absorb all of the BCGA gas potential, given the assets location in the northwest near the border with Europe, and at the confluence of numerous pipelines, there is potential for this gas to be exported to Europe.

Strong financial position and positive cashflow from existing production

The Group completed a C$56 million (net) capital raise in early 2018 and at the end of 2018 had C$59 million in working capital. These funds are more than sufficient for the planned 2019 capital program of appraisal drilling and testing program and the Group will be funded well into 2020.

The Group's conventional production continues to deliver positive adjusted funds flow. While the shallow production has been declining naturally in 2018, the increase in gas price and the reduction in local costs, increased the netbacks in Q4 2018 to approximately C$32.50/boe. The adjusted funds after covering operating costs and all of the Group's corporate G&A was C$3.1 million.

Control over operations

The Group currently operates all of its assets where there are production and activity. This gives Valeura significant control over its operations and the pace of appraisal and development, hence its capital spend.

Once Equinor Turkey has fully earned under the Banarli Farm-In, they will have the right to request operatorship of the deep program in the Banarli and West Thrace Lands – Valeura will remain operator of the shallow production and the gas sales infrastructure. Contingent upon the timely completion of planned activities for the completion and testing of the Inanli-1 well, Equinor Turkey could request the transfer of operatorship as early as Q4 of 2019. However, the Banarli Farm-In includes provisions that allow Valeura to control the pace of drilling and appraisal for the deep program until the parties have approved a pilot project. Given the timing requirements in the Banarli Farm-In for appraisal well review, prior to the next appraisal well being proposed, it is expected that this would yield approximately one well per year unless Valeura agrees to a more accelerated program.

Experienced International Management Team

Valeura has assembled a high quality management team with significant experience managing and operating international oil and gas companies. Each of the Group's senior managers has between 25 and 35 years of experience and most have direct experience living and operating in the Mediterranean region. Management members have been involved in the full life-cycle of oil and gas assets from acquisition and growth, through exploration, appraisal and development. The management team also includes a senior Turkish professional who has run one of Turkey's largest state-owned enterprises and has been directly involved in the management of oil and gas activities in the Thrace Basin for almost a decade.

10 Reasons for listing

Following consultation with its advisers, the Directors have chosen a Standard Listing as they believe that a listing on the Main Market, in addition to the Company's TSX listing, will enable the Company to reach institutional investors in the UK, Europe, Turkey and the Middle East, to increase share trading liquidity and to further raise the profile of the Group's projects.

11 Competition

The Directors believe that the primary competitors of the Group are other companies in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of Valeura. Valeura's ability to increase production and reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire suitable producing properties or acquire new Exploration Licences. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Valeura may also be subject to competition from the alternative fuel industry or fuel substitution by its customers.

12 Employees

In the past three financial years, the Group has employed, on average, the following numbers of people:

Category of activity	*2018*	*2017*	*2016*
Office and management	42	43	19
Technical and operational	41	41	0
Total	83	84	19

The increase in staff from 2016 to 2017 is associated with the acquisition of TBNG from TransAtlantic and the absorption of many of the staff required to operate the assets.

As at the Last Practicable Date, the Company retained the services of 23 consultant(s).

As at the Last Practicable Date, the number of employees of the Group in (i) office and management, and (ii) technical and operational roles was 42 and 41 respectively.

13 Incentive schemes

The Company believes that long term performance and increases in shareholder value are achieved through an ownership culture that encourages performance by all employees, including executives, through the use of at-risk long term incentives. Long term incentives are required in order for the Company to be competitive from a total remuneration standpoint, particularly given that the current size and stage of the Company prevents it from paying base cash salaries comparable to those of larger companies in the oil and gas industry with whom it must compete for experienced executive officers. Accordingly, the Company has established the Option Plan and the Performance Share Unit ("**PSU**") Plan to provide employees, including executive officers, with incentives to help align those employees' interests with the performance of the Company as reflected in the market price of its Common Shares.

The Company's Governance and Compensation Committee, upon the recommendation of the CEO, reviews and makes recommendations to the Board for its ultimate approval with respect to grants of Options and/or PSUs to executive officers. When making recommendations with respect to Option and/or PSU awards and the size of such awards, the Governance and Compensation Committee will take into consideration the overall number of Options and PSUs that are outstanding relative to the number of outstanding Common Shares.

Grants of Options and PSUs are subject to certain limits, including that the number of Common Shares reserved for issuance under the Option Plan, the PSU Plan and any other security based compensation plans of the Company, in the aggregate shall not exceed 10 per cent. of the Company's issued Common Shares from time to time.

(i) ***Options & Performance Share Unit Plan***

The Option Plan is intended to achieve a number of objectives through the grant of Options including:

- retaining and attracting qualified directors, officers, employees and consultants;
- promoting a proprietary interest in the Company;
- providing a long term incentive element in compensation; and
- promoting profitability of the Company.

As at the Last Practicable Date a total of 5,821,666 Options were outstanding

(ii) ***PSU Plan***

The principal purposes of the PSU Plan are to: (i) to strengthen the ability of the Company to attract and retain qualified directors, officers, employees and consultants which the Company and its subsidiaries require; (ii) to encourage the acquisition of a proprietary interest in the Company by such directors, officers, employees and consultants, thereby aligning their interests with the interests of the Shareholders; and (iii) to focus management of the Company and its subsidiaries on operating and financial performance and total long term Shareholder return by providing an increased incentive to contribute to the Company's growth and profitability.

As at the Last Practicable Date, no awards of PSUs have been granted under the PSU Plan.

(iii) ***Short Term Incentive Bonus Scheme***

Discretionary cash bonuses are part of the Company's compensation program as it is believed that they can be used to help to motivate executive officers and employees to achieve key corporate objectives by rewarding the achievement of these objectives. Currently, cash bonuses are awarded on a discretionary basis following an evaluation of the corporate performance and individual performance factors.

Further details of the Option Plan, the PSU Plan and the Short Term Incentive Bonus Scheme are set out in paragraph 14 of Part 15 of this document.

14 Tax

Further details relating to taxation are set out in Part 14 of this document, *'Taxation'*.

15 Working Capital

In the opinion of the Company, the working capital available to the Group is sufficient for its present requirements, that is, for at least the next 12 months from the date of this Prospectus.

16 Environmental and social

The oil and natural gas industry is subject to extensive and varying environmental regulations in each of the jurisdictions in which the Company operates. Environmental regulations establish standards respecting health, safety and environmental matters and place restrictions and prohibitions on emissions of oil and natural gas and various substances produced concurrently with oil and natural gas. These regulations can have an impact on the selection of drilling locations and facilities, potentially resulting in increased capital expenditures. In addition, environmental legislation may require those wells and production facilities to be abandoned and sites reclaimed to the satisfaction of local authorities. Valeura is committed to complying with environmental and operation legislation wherever the Company operates.

17 Insurance

Valeura's involvement in the exploration for and development of oil and natural gas properties may result in it becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Valeura carries insurance in accordance with industry standards to address certain of these risks. The Company has extensive history of drilling wells in Turkey including drilling into deep over pressured reservoirs.

The insurance program held by Valeura has been developed and defined using agents/advisors with extensive expertise specific to international oil & gas practises for junior public companies. Despite the fact that certain risks may not in all circumstances be insurable, the objective of the Company is to ensure a high degree of health and safety standards and reduce the financial impact, if any, to Valeura if any insurable event was to occur.

18 Dividend policy

The Company has no dividend policy and has not declared or paid any dividends on its Common Shares since incorporation. It is currently not expected that dividends will be paid in respect of the Common Shares during the current phase of development of the Company's business and operations. Any decision to declare and pay dividends will be made at the discretion of the Board and will depend on, among other things, the Group's results of operations, financial condition and solvency and distributable reserves tests imposed by law and such other factors that the Board may consider relevant.

19 Future Shares

For so long as the Company is a reporting issuer in the Province of Alberta, the issuance of any future Common Shares by way of private placement (the "**Future Shares**") will be subject to the securities legislation of such province. Accordingly, certificates representing the Future Shares may include legends (or notices of such legends or restrictions) in accordance with applicable Canadian securities laws and regulatory policies and rules of the TSX which state that unless permitted under securities legislation, the holder of such securities shall not trade them until the date that is four months and one day after the date of distribution thereof. In addition, the Company will direct Computershare, in a future placing, to place a restriction on the Future Shares issued and traded outside of Canada, such that the Future Shares cannot be transferred through CREST to the Company's Canadian share register for a period of four months and one day from the date such placing is completed.

Notwithstanding the imposition of such legends and restrictions, such trading restrictions in relation to the Future Shares will not restrict the settlement of trades in the form of Depositary Interests through CREST provided that certain conditions are satisfied in order for the Company to rely upon exemptions from the prospectus and registration requirements under applicable Canadian securities laws.

PART 8 – DIRECTORS, SENIOR MANAGERS AND CORPORATE GOVERNANCE

1 Directors

The following table lists the names, positions and ages of the Directors and the date they were appointed:

Name	*Age*	*Position*	*Appointed*
Dr. Sean Guest	57	*Director, President and Chief Executive Officer*	10 May 2018
Dr. Timothy Marchant	68	*Chairman*	15 April 2015
Russell Hiscock	67	*Director*	10 January 2018
James McFarland	72	*Director*	29 June 2010
Ronald Royal	70	*Director*	29 June 2010
Kimberley Wood	49	*Director*	26 March 2019

Dr. Sean Guest (President and Chief Executive Officer)

Dr. Guest (Ph.D., Geology) has been working internationally in the oil and gas industry for more than 25 years. Prior to joining Valeura, he was the CEO of two private junior companies. Bukit Energy is a Calgary-based start-up focused on Indonesia, and Pexco Energy holds production and exploration assets in Australia-Asia region and East Africa. During his tenure, Pexco was producing ~10,000 boepd from its assets in Indonesia and Australia. While running Pexco, he resided in Jakarta, Indonesia and oversaw the company's first operated development of an oil field in Sumatra. The company also expanded their gas production in Australia with the development of a new offshore gas field and upgrades and debottlenecking of the associated onshore gas plant. Prior to his CEO roles, he also worked for Woodside in Australia and Libya, and for Shell in the Netherlands, Australia and Malaysia. He started his career with Schlumberger working in Egypt.

Education: B.Sc. Geological Engineering, Queen's University (Kingston, Canada), 1985; Ph.D. Geological Sciences, 1993.

Dr. Timothy Marchant (Chairman)

Dr. Tim Marchant holds a Ph.D in Geology and has more than 35 years of senior executive experience in the oil and gas industry in Canada and internationally, with extensive experience in international operations and foreign growth strategies. In a career that spanned 29 years with Amoco and BP, he held senior executive positions in Canada and a number of countries in the Middle East including Egypt, Saudi Arabia, Abu Dhabi and Kuwait. Dr. Marchant is currently Adjunct Professor of Strategy and Energy Geopolitics at the Haskayne School of Business, University of Calgary. He also serves as a non-executive director of Vermilion Energy Inc. and Cub Energy Inc.

Education: Ph.D. in Geology from Trinity College, University of Dublin, Ireland. He completed the Executive Program at the Ivey School of Business, University of Western Ontario in 1994 and the Institute of Corporate Directors Education Program in 2011.

Russell Hiscock (Director)

Russell Hiscock joined the Valeura board in January 2018 and is the past President and Chief Executive Officer of the CN Investment Division (Montreal), which manages one of the largest corporate pension funds in Canada. He has many years of equity portfolio management experience in both the Canadian and international stock markets, with particular emphasis on the oil and gas sector. He is a past Chairman of the Pension Investment Association of Canada (PIAC). Mr. Hiscock holds a Bachelor of Mathematics degree, a Master of Arts degree in Economics and an MBA. He is a Certified Chartered Financial Analyst and a Certified Management Accountant.

Education: Bachelor of Mathematics degree from the University of Waterloo, Canada, a Master of Arts degree in Economics from the University of Western Ontario and an MBA from the University of Toronto.

James McFarland (Director)

Jim McFarland is a professional engineer with more than 46 years of broad experience in the oil and gas industry in Canada and internationally in both large integrated oil and gas companies and smaller listed E&P

companies. Most recently, he co-founded and was the past President & CEO of Valeura Energy Inc. until his retirement on 31 December 2017, and prior to that, co-founded and was President & CEO of Verenex Energy Inc., which was active in Libya. He has served in other senior executive roles as Managing Director of Southern Pacific Petroleum NL in Australia and President & COO of Husky Oil Limited, and held a number of Vice Presidential roles in his earlier 23-year career with Imperial Oil Limited and other ExxonMobil affiliates in Canada, the USA and Western Europe. He is currently a director of Arrow Exploration Corp., MEG Energy Corp. and Pengrowth Energy Corporation, serves on the Program Committee of the World Petroleum Council and is a past director of Verenex Energy Inc., Vermilion Energy Trust, Aventura Energy Inc., Southern Pacific Petroleum NL and Central Pacific Minerals NL. In 2003 he was awarded the Australian Centenary Medal for "outstanding service through business and commerce".

Education: Bachelor of Science degree in Chemical Engineering (Honours) from Queen's University (Kingston, Canada) and a Master of Science degree in Petroleum Engineering from the University of Alberta. Mr. McFarland completed the Executive Development Program at Cornell University.

Ronald Royal (Director)

Ron Royal is a professional engineer with more than 36 years of experience with Imperial Oil Limited and ExxonMobil's international upstream affiliates. Prior to retiring in 2007, he was President & General Manager of Esso Chad and resided in N'Djamena, Chad from 2002 to 2007. During this period, he oversaw the development of the Chad Development Project, one of the oil industry's largest investments in Sub-Sahara Africa. Previously, he was General Manager & Production Manager of Esso REP in France. He currently serves as a Director of Gran Tierra Energy Inc. In the past, he has served on the Board of Directors of Oando Energy Resources Inc., Caracal Energy Inc., Esso REP, Esso Chad, Tchad Oil Transportation Company, and Cameroon Oil Transportation Company. In 2003, he was awarded the title "Chevalier de l'Ordre National du Chad" for his contribution to the economic development of Chad.

Education: Bachelor of Applied Science degree in Mechanical Engineering from the University of British Columbia.

Kimberley Wood (Director)

Kimberley Wood is an energy lawyer, with over 18 years of experience. She qualified as a Solicitor in England & Wales in 2001 at the US firm of LeBoeuf, Lamb, Greene & MacRae LLP, and is currently a Senior Consultant at Norton Rose Fulbright LLP, having been a partner from 2015-2018. From February 2011 to April 2015, Ms. Wood was a Partner at Vinson & Elkins LLP. Ms. Wood was included as an expert in Energy and Natural Resources in the 2018 "Expert Guide" series, and the 2018 Women in Business Law series, and is a member of the Advisory Board to the City of London Geological Society. Ms. Wood is currently an independent director for Gulf Keystone Petroleum Ltd. an LSE listed E&P company with assets in the Kurdistan region of Iraq, and a non-executive director of Africa Oil Corp., an E&P company listed on the TSX (Canada) and Nasdaq OMX (Stockholm), with assets in Kenya and Ethiopia.

Education: Bachelor of Arts (Political Science) from the University of Western Ontario, Bachelor of Laws from the University of Edinburgh, Masters of Law from University College of London.

2 Senior Managers

The Company's current Senior Managers, in addition to the Directors listed above, are as follows:

Name	*Age*	*Position*	*Appointed*
Steve Bjornson	58	Chief Financial Officer	01 April 2010
Lyle Martinson	62	Chief Operating Officer	01 April 2010
Gord Begg	53	Vice President, Commercial	30 May 2018
Rob Sadownyk	54	Vice President, Exploration	01 April 2010

Stephen Bjornson (Chief Financial Officer)

Mr. Bjornson is a chartered accountant with more than 30 years of finance, business development, strategic planning and tax experience, operating in Canada, France, and Trinidad. In this period, he successfully

negotiated 15 public and private merger and acquisitions. He was previously the interim-CEO of Northern Hunter Energy Inc., a predecessor company of Valeura Energy Inc. He has held the position of CFO at Vermilion Resources Ltd., Clear Energy Inc. and Sound Energy Trust. In addition, Mr. Bjornson is a past director of Bulldog Oil & Gas Inc., Bulldog Resources, and Aventura Energy.

Education: Bachelor of Commerce, University of Calgary, 1983; Chartered Accountant, Alberta, 1987.

Lyle Martinson (Chief Operating Officer)

Mr. Martinson is a professional engineer with more than 39 years of management, operations, and engineering experience in the oil and gas industry in Canada and internationally. Most recently, he held the position of Drilling and Operations Manager for Verenex Energy Area 47 Libya Limited, based in Tripoli. Prior to joining Verenex, he had a successful 28-year career with Chevron Corporation in Canada, the US Gulf of Mexico, California, Australia, and Indonesia, including 22 years in leadership roles managing organizations and projects of varying size and complexity. In his last assignment with Chevron, he was Manager of Well Engineering and Operations at Chevron Canada Resources. He has experience with both onshore and offshore operations, gas production, light oil and heavy oil production, EOR projects and exploratory well drilling. Lyle is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

Education: B.Sc. Civil Engineering, University of Saskatchewan, 1978.

Gord Begg (VP, Commercial)

Gord Begg is a Petroleum Engineering professional with 30 years' experience. He has held roles in nearly all areas of the upstream oil & gas business giving him a wide technical engineering and commercial skillset. He has led teams that range from engineering, geoscience and commercial specialists to offshore platform operations and maintenance personnel. Prior to joining Valeura, he held progressively higher positions with the ERCB, Phillips Petroleum, Talisman Energy and Bukit Energy and has worked in Canada, Indonesia, the United Kingdom and Norway. Throughout his career, Mr. Begg has managed a number of successful oil and gas developments in both offshore and onshore environments, including numerous horizontal well drilling, well stimulation and waterflood projects. Mr. Begg has gained both technical and commercial unconventional experience in tight sand and shale plays in North America, Poland and Indonesia.

Education: B.Sc. in Petroleum Engineering, University of Alberta, 1989.

Rob Sadownyk (VP, Exploration)

Rob Sadownyk is a professional geologist with 28 years of experience in the oil and gas industry. Prior to joining Valeura Energy Inc., Rob was Vice President Exploration and a co-founder of Berland Exploration Ltd., which was a successful privately-funded junior oil & gas company with tight gas assets in western Canada. Before co-founding Berland Exploration, Rob held the position of Senior Geologist with Vermilion Resources Ltd. for seven years and Canadian Hunter Exploration for eight years, gaining broad experience in tight gas reservoirs, carbonate, and foothills plays. Rob is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA), the American Association of Petroleum Geologists (AAPG) and the Canadian Society of Petroleum Geologists (CSPG).

Education: B.Sc.(Honours) Geology, University of Calgary, 1988; Civil Engineering Diploma, Northern Alberta Institute of Technology, 1984.

3 Corporate Governance

(i) *Board of Directors*

The Board currently comprises one executive and five non-executive directors. The Company considers four to be independent.

Any director appointed to the Board by the directors will be subject to election by the Shareholders at the next annual meeting of shareholders after his/her appointment.

The composition of the Board will be reviewed regularly to ensure that the Board has the appropriate mix of expertise and experience. The Constitution provides that the number of directors that may be appointed cannot be fewer than one or greater than nine. Subject to the requirements under the ABCA requiring resident Canadians to be present at any meeting of the board, a majority of directors present and entitled to vote at a board meeting will constitute a quorum.

The Board is responsible for the corporate governance of the Company, and has developed policies to ensure that an appropriate level of corporate governance is in place. The Company's corporate governance system is reviewed regularly by the Board to ensure that it fulfils the needs of Shareholders.

The Common Shares are currently quoted on the TSX and the Company is therefore required to comply with the TSX Principles. The Company's approach in applying the TSX Principles is to ensure that the Company's corporate governance policies and principles are established, implemented, and monitored in such a way so as not to compromise or distract the Board and management from their key goals and to enable the organisation to conduct its business in an efficient and effective manner.

In order to comply with the TSX Principles and to promote good corporate governance, the Company has put in place numerous policies, all of which are described below and some of which may be found on the Company's website:

- Code of Business Conduct and Ethics;
- Confidential Information Policy;
- Security Trading Policy (which is also compliant with MAR and the relevant DGTR);
- Anti-bribery and Anti-Corruption Policy (which is compliant with the UK Bribery Act 2010);
- Continuous Disclosure Policy (which is also compliant with MAR and the relevant DGTR);
- Health, Safety, Security, Environment and Community Policy;
- Share Ownership Policy;
- Diversity Policy;
- Anti-Hedging Policy;
- Reporting of Inappropriate Activity ("Whistleblower Policy"); and
- Majority Voting Policy.

(ii) ***Corporate Governance Statement***

The Company has adopted a corporate governance statement which can be viewed in full on its website and which incorporates the disclosures required by the TSX Company Manual and Canadian securities law. The principles set out and followed by the Company include establishing the functions reserved to the Board and setting out these functions in the Company's Board Charter; adopting a diversity policy; establishing the committees referred to under the heading "*Committees*" below; establishing a continuous disclosure policy; and keeping shareholders informed by uploading information to its website.

(iii) ***Committees***

The Company's Board committees are constituted as follows:

	Chair	*Members*
Audit committee	Russell Hiscock	Tim Marchant, Ron Royal, Kimberley Wood
Governance and Compensation committee	Tim Marchant	Russell Hiscock, Kimberley Wood
Reserves and HSSEC Committee	Ron Royal	Tim Marchant, Jim McFarland

The deliberations of the various committees do not reduce the individual and collective responsibilities of Board members with regard to their fiduciary duties and responsibilities, and they must continue to exercise due care and judgement in accordance with their statutory obligations.

(iv) ***Audit committee***

The key responsibilities of the Audit Committee include:

- reviewing and recommending for approval to the Board financial information that will be made publicly available;
- reviewing: (i) the appropriateness of accounting policies and financial reporting practices used by the Company; (ii) any significant proposed changes in financial reporting and accounting policies and practices to be adopted by the Company; (iii) any new or pending developments in accounting and reporting standards that may affect the Company; (iv) with management, the external auditors and, if necessary, legal counsel, any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Company, and the manner in which these matters may be, or have been, disclosed in the financial statements; and (v) accounting, tax and financial aspects of the operations of the Company as the Audit Committee considers appropriate.
- reviewing and obtaining reasonable assurance that the risk management, internal control and information systems are operating effectively to produce accurate, appropriate and timely management and financial information;
- reviewing the planning and results of external audit activities and the ongoing relationship with the external auditor;
- establishing and periodically reviewing implementation of procedures for: (i) the receipt, retention and treatment of complaints received by the Company regarding accounting, internal accounting controls, or auditing matters; and (ii) the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters; and
- reviewing the adequacy of the Anti-Corruption Policy and reporting on its implementation and matters arising thereunder to the Board.

The Audit Committee has the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties and to determine the compensation of such advisors.

The Audit Committee shall be composed of not fewer than three directors and not more than five directors, all of whom shall be independent and financially literate directors of the Company. The Audit Committee is comprised of Messrs. Hiscock (Chair), Marchant and Royal and Ms. Wood. All four members are independent and financial literate directors.

The Audit Committee holds in camera meetings, without management present, at every regularly scheduled meeting of the Audit Committee, and meets in camera with the Company's independent compensation consultant. The Audit Committee meets at least four times annually.

The Audit Committee has the authority to communicate with the external auditors as it deems appropriate to consider any matter that the Audit Committee or auditors determine should be brought to the attention of the Board or shareholders.

(v) ***Governance and Compensation Committee***

The key responsibilities of the Governance and Compensation Committee include:

- reviewing and considering the current and long term composition of the Board and recommending nominees for election as members of the Board;
- reviewing, monitoring and making recommendations regarding the orientation and ongoing development of directors;
- reviewing the Board manual periodically including the terms of reference for the Board, the Board Chair, the CEO, individual directors and Board committees;

- reviewing the director compensation program and making recommendations to the Board accordingly;
- implementing evaluations of the CEO, the Board, the Board Chair, Board committees and individual directors;
- appointing and overseeing the Company's disclosure committee (a management committee) and public disclosure matters;
- overseeing the Code and ensuring a system to monitor compliance is in place;
- reviewing the corporate governance practices of the Company and, if appropriate, recommending changes to the Board;
- reviewing and recommending corporate goals and objectives for the CEO to be considered in determining his compensation and performance evaluation;
- reviewing management resources and succession plans to ensure that qualified personnel will be available for succession to executive positions;
- reviewing and recommending the compensation philosophy, guidelines and plans for the Company's employees and executives, and consider the risk implications of such policies and practices; and
- in consultation with the CEO, reviewing the compensation principles for base salaries, bonuses, long term incentives and benefit plans and approve the compensation for the executive team (including the CEO).

The Governance and Compensation Committee has the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties and to determine the compensation of such advisors.

The Governance and Compensation Committee shall be composed of not fewer than two directors and not more than five directors, all of whom shall be independent directors of the Company. The Governance and Compensation Committee is comprised of Messrs. Marchant (Chair) and Hiscock and Ms. Wood. All three members are independent directors.

The Governance and Compensation Committee holds in camera meetings, without management present, at every regularly scheduled meeting of the Governance and Compensation Committee, and meets in camera with the Company's independent compensation consultant. The Governance and Compensation Committee meets at least two times annually.

(vi) ***Reserves and HSSEC Committee***

The key responsibilities of the Reserves & Health, Safety, Security, Environment and Community Relations Committee include:

- reviewing the selection and qualifications of the independent engineering firm(s) responsible for the estimate of reserve and resource quantities, the scope of its work and ensuring consistency of its practices and standards and all matters related to the independent engineering firm(s);
- reviewing with the independent engineering firm the evaluation report and summary of the reserves and future cash flows of the Company's oil and gas properties;
- assisting the Board in respect of matters related to evaluations of petroleum and natural gas reserves and resources;
- reviewing the health, safety, security, environment and community relations policies, activities and performance of the Company on behalf of the Board to ensure compliance with applicable laws, regulations, policies and industry standards; and
- advising and making recommendations to the Board, as appropriate on matters relating to health, safety, security, the environment and community relations.

The Reserves & Health, Safety, Security, Environment and Community Relations Committee has the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties and to determine the compensation of such advisors.

The Reserves & Health, Safety, Security, Environment and Community Relations Committee shall be composed of not fewer than two directors and not more than five directors, the majority of whom shall be independent directors of the Company. The Reserves & Health, Safety, Security, Environment and Community is comprised of Messrs. Royal (Chair), Marchant and McFarland. Two members are independent directors.

The Reserves & Health, Safety, Security, Environment and Community Relations Committee holds in camera meetings, without management present, at every regularly scheduled meeting of the Reserves & Health, Safety, Security, Environment and Community Relations Committee, and meets in camera with the Company's independent engineering firm(s). The Reserves & Health, Safety, Security, Environment and Community Relations Committee meets at least two times annually.

The committee shall be composed of not fewer than two directors and not more than five directors, a majority of who shall be independent directors. The committee shall meet at least two times per year. The committee, through its Chair, may contact directly any employee in the Company as it deems necessary, and any employee may bring before the committee on a confidential basis any matter involving the reserves or health, safety, security, environmental or community relations practices of the Company.

(vii) ***Remuneration Report***

The directors shall be paid such remuneration for their services as the Board may from time to time determine. The Company has in the past engaged the services of a third party to provide the Company with a remuneration report.

(viii) ***Insider Trading and Reporting Policy***

In order to comply with the MAR and DGTRs and the TSX Listing Rules, the Company has adopted a Insider Trading and Reporting Policy in relation to the Common Shares and other securities in the Company.

The policy applies to PDMRs and their associates, employees of the Company and other restricted persons, who are prohibited from dealing in the Company's securities if they have in their possession information that they know, or ought reasonably to know, is inside information.

The policy also provides prescribed closed periods during which PDMRs, employees and other restricted persons are prohibited from dealing in the Company's securities. PDMRs and their associates and other restricted persons must obtain written clearance from an approving officer prior to any dealings in the Company's securities.

(ix) ***Corporate disclosure policy***

The Company has adopted, with effect from Admission, a new corporate disclosure policy to ensure that the Company, as a minimum, complies with its continuous disclosure obligations under Canadian securities law, MAR and DGTR as applicable to the Company; provides shareholders and the market with timely, direct and equal access to information issued by the Company; and promotes investor confidence in the integrity of the Company and its securities.

(x) ***Anti-bribery and Anti-corruption policy***

The Group has developed its anti-bribery and anti-corruption policy to be consistent with the UK Bribery Act 2010. The policy specifically addresses facilitation payments or gifts and hospitality, dealings with private individuals, corporates and dealings with public officials, political donations, lobbying and advocacy and charitable donations, and includes provisions dealing with notification, as well as provisions regarding disciplinary action in the event that any part of the anti-bribery and anti-corruption policy has been breached. New and existing staff are required under the policy to be trained and the Group's approach to anti-bribery and anti-corruption must be communicated to its business partners.

PART 9 – INDUSTRY CONDITIONS IN TURKEY

1. Turkey

The oil and natural gas industry in Turkey is subject to controls and regulations governing its operations imposed by legislation enacted by the Turkish governments and with respect to pricing and taxation of oil and natural gas by agreements, all of which should be carefully considered by investors in the oil and gas industry. The Company's activities are affected in varying degrees by government regulations relating to the oil and gas industry and foreign investment. Operations may be affected in varying degrees by government regulations with respect to price controls, export controls, income taxes, value-added taxes, expropriation of property, production restrictions and environmental legislation. It is not expected that any of these controls or regulations will affect the Company's operations in a manner materially different than they would affect other oil and gas companies of similar size operating in Turkey. Outlined below are some of the principal aspects of the legislation, regulations and agreements governing the oil and gas industry in Turkey.

After extensive review and significant input from industry, the Turkish government adopted the New Petroleum Law to replace the Old Petroleum Law on 30 June 2013. The most significant changes as described below relate to land tenure regulations.

2. Commercial Terms

Turkey's fiscal regime for oil and gas operations is presently comprised of royalties and income tax. Royalties are at 12.5 per cent. and the corporate income tax rate is 22 per cent.

A 15 per cent. withholding tax is applied on dividends to be distributed to foreign entities. However, the withholding tax may be reduced to 10 per cent. depending on the bilateral treaties signed between Turkey and the home country of the petroleum rights holder in Turkey.

3. Land Tenure Regime

All of the Company's licences and leases in Turkey are regulated under the New Petroleum Law. The regulator imposed a change to mapping coordinates country wide and the result for the Company was a commencement date for the licences as 27 June 2015. A number of pre-existing exploration licences were converted to production leases during a period from November 2012 to December 2015. Three pre-existing production leases remained intact.

The GDPA, as the GDMPA was then known, adopted a new international grid system associated with the New Petroleum Law, in part to facilitate any exploration and development of unconventional resources. The initial term of new exploration licences will be five years, and these can be extended up to 11 years provided a discovery is made by the end of the ninth year (two two-year extensions plus a single two-year discovery extension). The Company is required to provide a work program obligation for each year of an Exploration Licence and the annual work program must be completed in that year for the block to remain in good standing. Exploration licence awards require the posting of a bond of up to 2 per cent. of the work program for the initial term or any subsequent extensions.

Some uncertainty remains in the tenure of production leases. The recent practice of the GDMPA in awarding new leases over the 2011 to 2016 period to the Company and its partners in the Thrace Basin was to set the initial term for varying periods ranging from five years to 14 years, depending on the expected reserve life, amongst other factors, potentially extendable up to 40 years if the expected reserve life supports such an extension. Note that a few leases were back-dated to November 2012 when the previous licence had expired. Also noteworthy, the 2-year discovery extension is applied to the initial production lease and thus the initial lease term commences on the date of the 2-year discovery extension. Although initial term for unconventional production lease applications remains uncertain, it is expected that an initial term would garner a maximum of 20 years with the possibility for two subsequent extensions of 10 years each. The maximum area that may be awarded as a production lease would be one map sheet, or 4 quadrants under the grid system.

4. Environmental

The oil and natural gas industry is subject to extensive and varying environmental regulations in each of the jurisdictions in which the Company operates. Environmental regulations establish standards respecting health, safety and environmental matters and place restrictions and prohibitions on emissions of oil and natural gas and various substances produced concurrently with oil and natural gas. These regulations can have an impact on the selection of drilling locations and facilities, potentially resulting in increased capital expenditures. In addition, environmental legislation may require those wells and production facilities to be abandoned and sites reclaimed to the satisfaction of local authorities. Valeura is committed to complying with environmental and operation legislation wherever the Company operates.

5. Pricing and Marketing

Turkey imports more than 99 per cent. of its natural gas and 92 per cent. of its crude oil energy needs and as such any new domestic production has a ready market. Consequently, the Company does not foresee any major concern with the marketing of crude oil or natural gas from its operations.

Crude oil pricing in Turkey is determined under the Petroleum Market Law No. 5015 (Gazetted on December 12, 2003). The pricing for the sales of crude oil is established according to the nearest accessible global free market condition. The domestic crude oil price is linked to world market factors with the base market price being the price at the nearest delivery port. Customary transportation and crude oil quality premiums or deductions, as the case may be, are applied to determine the crude oil price at the custody transfer point. Domestic purchasers and refiners are to give priority to domestic crude oil under the above pricing process.

Total natural gas consumption has been increasing significantly in the past two decades at a rate of more than 8 per cent. per year. In Turkey in 2017 consumption increased almost 20 per cent., but then there was a small decrease in consumption in 2018 as the government took steps to try to reduce the amount of imported gas. Consumption in 2018 averaged approximately 5.2 Bcf/d.

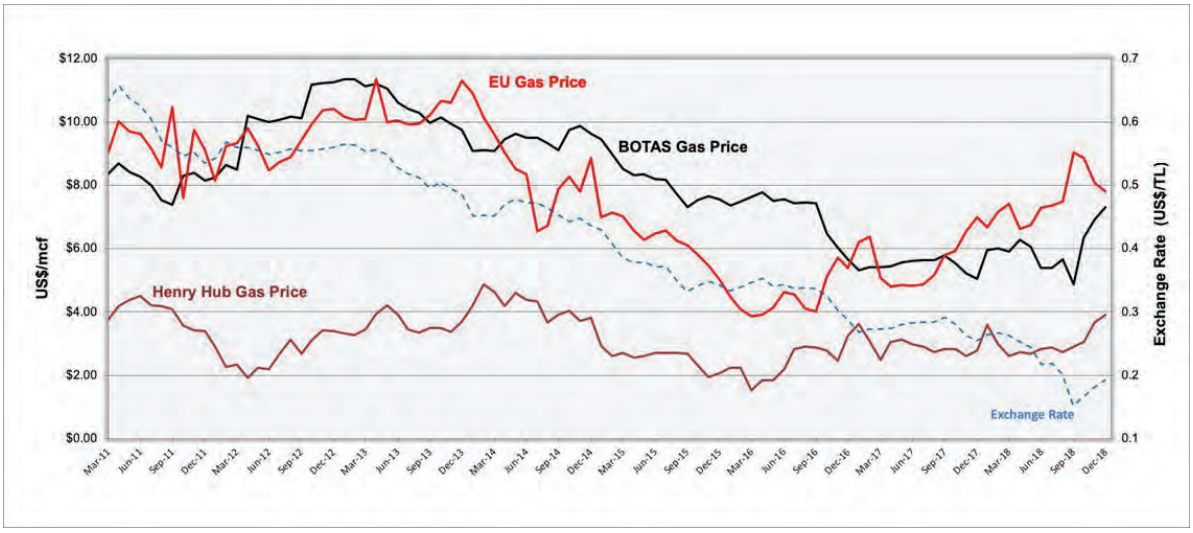


Figure 7: Comparison of BOTAS Reference Price with European and Henry Hub prices. The European gas price is taken as the average of Germany Gaspool, UK NBP and Netherlands TTF quoted prices.

BOTAS is the major importer and distributor of natural gas in Turkey. Although some import contracts have been released to private operators, BOTAS currently controls approximately 80 per cent. of Turkey's natural gas imports. Given the very small domestic production of approximately 0.04 Bcf/d (<1 per cent. of consumption), there is a robust market for additional domestic natural gas production. Due to the dominance of BOTAS in the natural gas market in Turkey, the BOTAS pricing structure effectively sets the domestic market price. In 2016, Russia supplied approximately 53 per cent. of Turkey's natural gas imports followed by Iran at 17 per cent., Azerbaijan at 14 per cent., LNG from Algeria and Nigeria at 12 per cent. and other at 4 per cent. Accordingly, the BOTAS cost tracks regional reference pricing and in turn indirectly influences the price available to domestic producers, translated into TL, at some discount.

At the beginning of 2018 BOTAS adopted a policy of regular updates for its reference prices for gas and these are currently being updated on the first day of every month. All of the Group's gas sales contracts are referenced to the BOTAS Reference Price and denominated in TL. The preceding Figure 7 shows an historic plot of the BOTAS Reference Price against both an average European gas price and Henry Hub gas price. The Company expects the BOTAS Reference Price to continue to be indirectly linked to the weighted average cost of imported gas to Turkey and government policy with respect to the level of consumer subsidies, if any.

The Company expects natural gas pricing under its current and future contracts to continue to be at some negotiated discount to the BOTAS Reference Price (0 per cent. to 15 per cent. discount, dependent on reserve size, the magnitude of daily gas volume deliverable and the nature of the contract). The Company's natural gas production from the TBNG JV Lands are purchased by more than 55 local customers directly tied in to the Company's sales gas distribution system at an average historical discount of approximately 2 per cent. to the BOTAS Reference Price. However, in Q4 2018 the Company was able to realise parity to the BOTAS Reference Price. The Company's natural gas production from the Banarli Exploration Licences is currently tied-in to the TBNG JV facilities and is being purchased by the TBNG JV, net of a transportation and marketing fee (of which Valeura receives 81.5 per cent. as a partner in the TBNG JV), resulting in a net discount of approximately 4 per cent. from the BOTAS Reference Price.

6. Turkish Petroleum Law Regime

(i) Overview

Hydrocarbon resource rights in Turkey are governed by the New Petroleum Law and Regulation on Implementation of Turkish Petroleum ("**Regulations**"), which are administered by the MENR and GDMPA.

The New Petroleum Law and Regulations provide for a licensing regime whereby operators must obtain a "petroleum exploration licence" to explore and develop hydrocarbons in the designated licence area and a "production lease" to produce hydrocarbons from the reservoir area carved out from the predecessor exploration licence.

There is no segregation under the New Petroleum Law for crude oil and natural gas licences or leases. The definition of "Petroleum" under the New Petroleum Law covers both crude oil and natural gas. Therefore, an exploration licence and a production lease grant their holder the right to explore, develop and produce both crude oil and natural gas within the designated licence or lease area.

New Petroleum Law provides differing terms and conditions for onshore and offshore licenses and leases. Offshore licenses and leases are not discussed within the scope of this section as the Group does not hold any offshore licenses or leases in Turkey as of the date hereof.

Petroleum exploration licenses and production leases are granted by the GDMPA, and the application and grant process are summarised in below.

(ii) Exploration Licenses

Petroleum exploration licences in Turkey are granted based on a "grid system", pursuant to which the size of an onshore licence may cover one full 1/50.000 scaled map section at the maximum, or cover one full 1/25.000 scaled map section at the minimum.

Granting of an exploration licence to an applicant by the GDMPA is subject to (a) the technical and financial capability of the applicant, (b) compliance of the application with relevant law, and (c) the "work and investment programme" bid covering the minimum work obligations to be performed in the licence area during the initial five year term of the exploration licence.

Upon submission of an application for open acreage, the application is announced by the GDMPA in the Turkish Official Gazette (the "**Gazette**"). Acreage is then open for applications by other parties for a period of 90 days from the announcement date of the initial application. If there are competing applications to the same open acreage, GDMPA and MENR shall review such applications based on the criteria outlined above and decide on the winning application accordingly. The decision on granting of the exploration licence is announced in the Gazette.

An applicant for an exploration licence must file with the GDMPA an application consisting, *inter alia*, of the following material submissions: (a) technical criteria and coordinates defining the licence area in a manner provided under the Regulations, (b) a five year work and investment programme covering the minimum work obligations to be performed in the licence area during the initial five year term of the exploration licence, (c) a letter of undertaking confirming the applicant's adherence to related laws and regulations and licence requirements. If the applicant is applying to the GDMPA for the first time, in addition to aforementioned documents, a "source file" of the applicant should also be filed to GDMPA. The source file should include, *inter alia*, corporate information and documents regarding the applicant, its authorized representative resident in Turkey, and documents proving the financial capability of the applicant.

Upon granting of the exploration licence, an applicant must file "work and investment bonds" with the GDMPA equal to 2 per cent. of the total monetary value of the operations indicated under the five year work and investment programme agreed with GDMPA. In addition to this, the applicant should also submit a "loss and damage bond" which shall be retained by the GDMPA until the expiry or cancellation of the licence as a security against any environmental liabilities of the applicant. The amount of the loss and damage bond is calculated based on a formula provided under the regulations which is based on the size of the relevant licence.

The term of an onshore exploration licence is five years and it may be renewed at the election of the holder, subject to the GDMPA consent, up to two times for up to an additional two years for each renewal. The operator must submit a new work and investment programme covering the extended term of the licence (which should at least include drilling of one well) and a work and investment bond in the amount equal to 2 per cent. of the total monetary commitment of the new programme. The overall term of an exploration licence may not exceed total nine years (i.e. the five year initial term plus two extensions of two years each). However, if there is a discovery in the licence area, an additional period of two years may be granted to enable the operator to evaluate the commerciality of the discovery.

The holder of an exploration license has the following material rights and obligations:

(a) any foreign entity licence holder must register its branch in Turkey within 60 days following the granting of its first licence and must have an authorized representative resident in Turkey;

(b) an licence holder may explore for and develop hydrocarbons (crude oil, natural gas or both) within the licence area, and if there is a discovery, the licence holder can produce and sell hydrocarbons from the licence area pending conversion to a production lease;

(c) the licence holder must fulfil the minimum work obligations committed under the work and investment programme submitted to the GDMPA. Failure to fulfil work obligations in any given licence year will result in forfeiture of the work and investment bond for such year to the extent related with the unfulfilled portion of the commitment. If the licence holder performs none of the minimum work obligations for two consecutive years, the licence shall be revoked, and all work and investment bonds shall be forfeited;

(d) the licence holder must comply with the environmental requirements defined under applicable laws and regulations during its operations;

(e) the licence holder must compensate the owner of the lands where it performs operations for any damage caused on such lands as well as for loss of product (e.g. agricultural value). The licence holder must also restore the original condition of such lands and abandon the facilities upon completion of operations;

(f) the licence holder has the right to export 35 per cent. of the crude oil and natural gas produced from onshore fields discovered after 1 January 1980, the balance of the production is reserved for local consumption;

(g) the licence holder shall be exempted from custom taxes and duties for the equipment, materials, fuel, vehicles to be imported to Turkey with the approval of GDMPA, for utilization in petroleum operations. The licence holder also enjoys certain exemptions from VAT, Special Consumption Tax and Stamp Tax to the extent defined under relevant laws provided that such exemptions are applicable for operations related with exploration activities;

(h) the licence holder may transfer its exploration licence (or a partial participating interest thereon) to another entity provided that GDMPA's prior consent is obtained. It is also possible to register certain rights and encumbrances on an exploration licence again with the GDMPA's prior consent; and

(i) change of control in the shareholding of a licence holder is subject prior consent of the MENR.

(iii) Production Leases

The granting of a production lease to an applicant by the GDMPA is subject to a commercial discovery within the predecessor exploration licence area and submission of a work and investment programme commitment.

A production lease area shall be carved out from the predecessor exploration licence area based on the commercial reservoir assessment of the applicant which is approved by the GDMPA. The remainder of the exploration licence will continue to be in effect until the end of its term.

An applicant for a production lease must submit to the GDMPA an application consisting, *inter alia*, of the following material submissions: (a) technical criteria and coordinates defining the lease area in a manner provided under the Regulations, (b) technical information regarding the reservoir, geological formations, seismic lines and interpretations, (c) an environmental impact assessment report (if applicable, subject to production volume), (d) a work and investment programme covering proposed seismic lines, wells to be drilled annually, investment amounts and facilities to be built in the lease area, and (e) a letter of undertaking confirming the applicant's adherence to related laws and regulations and licence requirements.

The term of a production lease is 20 years and it may be renewed, subject to the GDMPA consent, up to two times for up to an additional 10 years for each renewal. Renewals shall be granted only if commercial production from the lease area is maintained continuously. With each renewal, the lease holder must submit a new work program covering the renewed term.

At the expiry of production leases, expired lease areas are first offered to Turkish Petroleum A.O., the national oil company of Turkey. If Turkish Petroleum A.O. refuses to take over the expired lease areas, such lease areas shall be offered to operators by means of public auction in a manner described under the New Petroleum Law.

The holder of a production lease has the following material rights and obligations:

(a) a production lease grants its owner the right to produce hydrocarbons (crude oil, natural gas or both if available) from the lease area. The lease holder can also perform exploration activities within the lease area if it considers that unexplored reservoirs are available;

(b) the lease holder must maintain continuous production from the lease area in accordance with its commitments under the work program submitted to the GDMPA. Failure to abide by this obligation may result with cancellation of the lease;

(c) the lease holder may be granted pipeline construction permits for the transportation of produced hydrocarbons;

(d) the lease holder must pay 1/8th of the hydrocarbons produced from the lease area to the Turkish government as a royalty;

(e) the lease holder must comply with the environmental requirements defined under applicable laws and regulations during its operations;

(f) the lease holder must compensate the owner of the lands where it performs operations for any damage caused on such lands as well as for loss of product (e.g. agricultural value). The lease holder shall also restore the original condition of such lands and abandon the facilities upon completion of operations;

(g) at the expiry or cancellation of the lease, the lease holder must comply with and fully satisfy abandonment obligations defined under the New Petroleum Law and Regulations;

(h) the lease holder shall be exempted from custom taxes and duties for the equipment, materials, fuel, vehicles to be imported to Turkey, with the approval of the GDMPA, for utilization in petroleum operations;

(i) the lease holder may transfer its production lease (or a partial participating interest thereon) to another entity provided that the GDMPA's prior consent is obtained. It is also possible to register certain rights and encumbrances on a production lease, with the GDMPA's prior consent; and

(j) change of control in the shareholding of a lease holder is subject prior consent of MENR.

(iv) Marketing

The marketing of natural gas in Turkey is subject to Natural Gas Market Law No. 4646 adopted as of 18 April 2001 (as amended) and its associated regulations ("**Natural Gas Market Law**").

The Natural Gas Market Law covers the import, transmission, distribution, storage, marketing, trade and export of natural gas. Generation of natural gas is defined under the Natural Gas Market Law as the extraction of natural gas from the underground natural gas fields in Turkey. Generation activities are not regarded as market activities. Generation companies, provided that they hold a wholesale licence, may market generated gas to wholesale companies, import companies, distribution companies or free consumers. The generation companies are allowed to sell such amount directly to consumers. Wholesale companies may sale all over the country without any regional restriction. The MENR shall determine the principles and conditions to be taken as basis for the natural gas sale tariffs, including any wholesale tariff. The sale prices, on the other hand, shall be determined freely within the framework of such principles by the parties involved in natural gas purchase and sale.

The marketing of petroleum in Turkey is subject to Petroleum Market Law No. 5015 enacted as of 4 December 2003 and its associated regulations ("**Petroleum Market Law**").

The objective of the Petroleum Market Law is to regulate the guidance, surveillance and supervision activities in order to ensure the transparent, non-discriminatory and stable performance of market activities pertaining to the delivery of petroleum (crude oil) supplied from domestic and foreign resources to consumers, directly or after processing, in a reliable, cost-effective manner within a competitive environment. "Production" is defined as the production, pre-processing and transportation via pipelines to storages within the field, transmission line or to the refinery or storage of petroleum. A licence is not required for the sale of "Production".

Under the Petroleum Market Law, the pricing for the purchase and sales of petroleum shall be constituted according to the nearest accessible global free market conditions. For domestic crude oil, market price formed in the nearest delivery port or refinery shall be accepted as the price. Market price of the domestic crude oil shall be calculated by adding taxes and levies taken for import. Transportation market value formed in the liquid fuel prices shall be taken for the domestic land transportation fees.

A licence is not required for the Company to sell its crude oil production.

PART 10 – SELECTED HISTORICAL FINANCIAL INFORMATION

Group audited financial information

Please refer to the Appendix which contains the audited financial reports of the Group as at and for the years ended 31 December 2018, 31 December 2017 and 31 December 2016.

1. Consolidated Statement of Operations

	Years ended 31 December		
	2018	*2017*	*2016*
	(C$,000)	*(C$,000)*	*(C$,000)*
Revenue			
Petroleum and natural gas sales	11,969	14,646	16,155
Royalties	(1,611)	(1,971)	(2,102)
Other Income	2,245	1,363	846
	12,603	14,038	14,899
Expenses			
Production	3,606	4,423	2,232
General and administrative	3,750	4,606	5,376
Transaction costs	287	1,160	859
Accretion on decommissioning liabilities	2,890	1,779	876
Foreign exchange (gain)/loss	(548)	2,671	3,032
Share-based compensation	1,514	470	386
Exploration and evaluation	–	707	–
Impairment	–	–	1,048
Depletion and depreciation	7,306	9,025	7,436
	18,805	24,841	21,245
Loss for the period before income taxes	(6,202)	(10,803)	(6,346)
Income taxes			
Current tax expense	837	2,371	–
Deferred tax recovery	81	(4,790)	(260)
Net loss	(7,120)	(8,384)	(6,086)
Other comprehensive loss			
Currency translation adjustments	(10,378)	(6,019)	(11,511)
Comprehensive loss	(17,498)	(14,403)	(17,597)
Net loss per share			
Basic and diluted ($/Share)	(0.09)	(0.12)	(0.10)
Weighted average number of shares outstanding (thousands)	83,659	70,944	58,254

2. Consolidated Statement of Financial Position

	As at 31 December		
	2018	*2017*	*2016*
	(C$,000)	*(C$,000)*	*(C$,000)*
Assets			
Current Assets			
Cash	62,380	11,108	1,987
Accounts receivable	9,242	4,052	4,601
Prepaid expenses and deposits	2,090	1,381	1,465
Inventory	195	251	–
Assets held for sale	–	–	16,635
	73,907	16,792	24,688
Licence deposits	127	164	922
Restricted Cash	274	3,173	–
Exploration and evaluation assets	9,385	7,642	14,258
Property, plant and equipment	44,630	62,101	36,022
	128,323	89,872	75,890
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable and accrued liabilities	14,387	13,371	4,267
Decommissioning obligations	15,821	19,206	8,132
Deferred taxes	1,896	2,470	4,885
Shareholders' Equity			
Share capital	205,320	146,694	135,586
Contributed surplus	20,123	19,857	19,343
Accumulated other comprehensive loss	(42,561)	(32,183)	(26,164)
Deficit	(86,663)	(79,543)	(71,159)
	96,219	54,825	58,606
	128,323	89,872	75,890

3. Summary Consolidated Statements of Cash flows

	Years ended 31 December		
	2018	*2017*	*2016*
	(C$,000)	*(C$,000)*	*(C$,000)*
Cash was provided by (used in):			
Cash (used in) provided by operating activities	(584)	3,854	6,294
Cash provided by financing activities	57,320	10,108	437
Cash used in investing activities	(7,839)	(5,372)	(11,212)
Foreign exchange gain (loss) on cash held in foreign currencies	2,375	531	(505)
Net change in cash	51,272	9,121	(4,986)
Cash, beginning of year	11,108	1,987	6,973
Cash, end of year	62,380	11,108	1,987

PART 11 – OPERATING AND FINANCIAL REVIEW

The following discussion and analysis is intended to assist in the understanding and assessment of the trends and significant changes in the Group's results of operations and financial condition during Historical Financial Information Period. Historical results may not be indicative of future financial performance. Forward-looking statements contained in this review that reflect the current view of the Directors, involve risks and uncertainties and are subject to a variety of factors that could cause actual results to differ materially from those contemplated by such statements. Factors that may cause such a difference include, but are not limited to, those discussed in "Forward-Looking Statements" and "Risk Factors". In this document the consolidated financial statements presented are those of the Group. This discussion is based on the consolidated financial statements of the Group and should be read in conjunction with its consolidated financial statements and the accompanying notes contained in the Appendix to this document, as referred to in Part 10 of this document, '*Historical Financial Information*' and with the information relating to the business of the Group included elsewhere in this document. Unless otherwise indicated, all of the financial data and discussions thereof are based upon financial statements prepared in accordance with IFRS. Investors should read the whole of this document and not rely just on summarised information.

1. Key Highlights

Key operating highlights for the years ended 31 December 2018, 2017 and 2016:

- Valeura closed key transformative deals in Q1 2017 to purchase TBNG, and to partner with Equinor for the exploration of the deep, unconventional potential of its Thrace Basin Assets.
- In Q1 2018, the Company released an external resource evaluator's report that assigned to Valeura 10.1 trillion cubic feet ("Tcf") of unrisked, mean recoverable natural gas prospective resources associated with the BCGA play. The report was updated as of 31 December 2018 by the external resource evaluator with no changes to the prospective resource estimates.
- In Q1 2018, Valeura completed a C$60 million (gross) financing (the "Financing") which will fully fund the Company's planned 2018-19 appraisal program of the BCGA play.
- The government has continued to increase the BOTAS reference price thereby offsetting the decline in the value of the TL and the increase in regional gas prices. Effective 1 January 2018, 1 April 2018, 1 August 2018, 1 September 2018 and 1 October 2018 the price was increased by 14 per cent., 10 per cent., 14 per cent., 14 per cent. and 18.5 per cent. respectively. The Company's Q4 2018 average realized natural gas price in Turkey increased to $9.06 per Mcf from $6.61 per Mcf in Q4 2017 due to the price increases in 2018.
- Proved plus Probable Oil and Natural Gas Reserve volumes at 31 December 2018 by product are as follows:

Reserves Category	*Light and Medium Crude Oil (Mbbl)*	*Conventional Natural Gas (Bcf)*	*Total Oil Equivalent (Mboe)*
Proved	15	11.7	1,962
Probable	6	32.3	5,388
Total Proved plus Probable	21	44.0	7,350

- Production for the year ended 31 December 2018 was 717 boe/day, down from 952 boe/day in 2017, reflecting the impact of natural decline rates. Q4 2018 operating netbacks were $32.48 compared to $22.35 for the same quarter in 2017 and 2018 operating netbacks were $25.79/boe in 2018 compared to $23.76/boe in 2017. The increase reflects higher prices received. Operating costs on a boe basis are higher than the comparative periods for both Q4 2018 and the year ended 2018 reflecting declining production and the high level of fixed operating costs.

2. Highlights and Selected Financial Information

	Years ended 31 December		
	2018	*2017*	*2016*
	(C$,000)	*(C$,000)*	*(C$,000)*
Financial			
Petroleum and natural gas sales	11,969	14,646	16,155
Net loss	(7,120)	(8,384)	(6,086)
Per share, basic and diluted ($/Share)	(0.09)	(0.12)	(0.10)
Adjusted funds flow[1]	3,655	(1,205)	6,048
Per share, basic and diluted ($/Share)	0.04	(0.02)	0.10
Exploration and development capital	8,023	12,791	9,535
Acquisitions	–	21,450	–
Dispositions	–	(26,288)	–
Working capital[2]	59,520	3,421	3,786
Cash	62,380	11,108	1,987
Production volumes			
Natural gas (Mcf/d)	4,257	5,662	4,742
Crude oil (bbl/d)	8	8	9
Total (boe/d)	717	952	799
Sales prices			
Natural gas (per Mcf)	7.54	6.98	9.20
Crude oil (per bbl)	91.85	71.84	55.88
Total (per boe)	45.72	42.16	55.22
Weighted average shares outstanding			
Basic and diluted (thousands)[3]	83,659	70,944	58,254

Outstanding Share Data

	Years ended 31 December		
	2018	*2017*	*2016*
Common shares	86,232,988	73,148,321	58,519,321
Stock options	4,598,667	6,370,500	4,914,500
Fully Diluted	90,831,655	79,518,821	63,433,821

[1] Non-GAAP measure

[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.

3. Results of Operations

	Years ended 31 December		
	2018	*2017*	*2016*
	(C$,000)	*(C$,000)*	*(C$,000)*
Petroleum and natural gas sales	11,969	14,646	16,155
Royalties	(1,611)	(1,971)	(2,102)
Production costs	(3,606)	(4,423)	(2,232)
Operating netback[1]	6,752	8,252	11,821
Other income	2,245	1,363	846
General and administrative expenses	(3,750)	(4,606)	(5,376)
Transaction costs	(287)	(1,160)	(794)
Realized foreign exchange loss	(468)	(2,683)	(449)
Current tax expense	(837)	(2,371)	–
Adjusted funds flow (used)[1]	3,655	(1,205)	6,048
Non-cash expenses			
Share-based compensation	(1,514)	(470)	(386)
Accretion on decommissioning liabilities	(2,890)	(1,779)	(876)
Transactions costs	–	–	(65)
Unrealized foreign exchange gain (loss)	1,016	12	(2,583)
Depletion and depreciation	(7,306)	(9,025)	(7,436)
Impairment	–	–	(1,048)
Exploration and evaluation expense	–	(707)	–
Deferred tax recovery (expense)	(81)	4,790	260
Net loss	(7,120)	(8,384)	(6,086)

4.1 Sales Volumes

	Years ended 31 December		
	2018	*2017*	*2016*
Natural gas (Mcf/d)	4,257	5,662	4,742
Crude oil (bbl/d)	8	8	9
Total (boe/d)	717	952	799

Sales volumes for the year ended 31 December 2018 were 717 boe/d compared to 952 boe/d for the same period in 2017. Sales volumes decreased due to natural declines causing lower gross production on both the TBNG JV and Banarli Exploration Licences. The volumes for 2018 do not include production form the Yamalik-1 well. Final completion operations and long term testing on this well occurred in 2018, and the related sales revenue has been included capital expenditures.

Production increased from 799 boe/day in 2016 to 952 boe/day in 2017 due to additions from the acquisition of TBNG, workovers, recompletions and new drills, partially offset by natural declines on both the TBNG Lands and Banarli Exploration Licences.

[1] Non-GAAP measure

4.2 Pricing Information

	Years ended 31 December		
	2018	*2017*	*2016*
Average reference prices			
Natural gas – BOTAS (per Mcf)	TL27.80	TL19.84	TL21.41
Natural gas – BOTAS (per Mcf)	$7.61	$7.07	$9.41
Average exchange rate (TL/CAD)	3.651	2.805	2.276

	Years ended 31 December		
	2018	2017	2016
Average realized prices			
Natural gas (per Mcf)	$7.54	$6.98	$9.20
Crude oil (per bbl)	$91.85	$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.

The government has continued to increase the BOTAS reference price thereby offsetting the decline in the value of the TL and the increase in regional gas prices. Effective 1 January 2018, 1 April 2018, 1 August 2018, 1 September 2018 and 1 October 2018 the price was increased by 14 per cent., 10 per cent., 14 per cent., 14 per cent. and 18.5 per cent. respectively.

In 2018, the Company's average realized natural gas price in Turkey was $7.54 per Mcf, an increase over the 2017 realized price of $6.98. The increase is due to the previously described reference price increase, offset by the weakening of the TL against the Canadian dollar. The realized price for 2018, represents a 1.0 per cent. discount to the BOTAS benchmark price, which is similar to the discount realized for 2017.

Between 1 October 2014 and 30 September 2016 the BOTAS benchmark price remained unchanged but effective 1 October 2016 the price was reduced by 10 percent. The Company's average price for 2017 decreased to $6.98 from $9.20 in 2016 due to the reference price decrease and the weakening of the TL against the Canadian dollar. The average discount to reference price decreased from about 2 per cent. in 2016 to 1 per cent. in 2017.

4.3 Petroleum and Natural Gas Sales Revenues

	Years ended 31 December		
	2018	*2017*	*2016*
	(C$,000)	*(C$,000)*	*(C$,000)*
Natural gas	11,650	14,431	15,971
Crude oil	319	215	184
Total revenues	11,969	14,646	16,155

The composition of petroleum and natural gas sales revenues for the year ended 31 December 2018 was approximately 98 percent natural gas and two percent crude oil. Revenues for the year ended 31 December 2018 decreased in comparison to the same period in 2017 due primarily to lower production volumes, offset partially by higher prices.

The composition of petroleum and natural gas sales revenues for the year ended 31 December 2017 was approximately 98 percent natural gas and two percent crude oil. Revenues for the years ended 31 December 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.

4.4 Royalties

	Years ended 31 December		
	2018	*2017*	*2016*
	(C$,000)	*(C$,000)*	*(C$,000)*
Royalties	1,611	1,971	2,102
Percentage of revenue	13.5%	13.5%	13.0%

Royalties for the year ended 31 December 2018 decreased in comparison to the same period in 2017 as a result of lower petroleum and natural gas sales revenues. Revenues are subject to a 12.5 per cent. government royalty and an overriding royalty only on the TBNG JV Lands of one percent.

Royalties for the year ended 31 December 2017 decreased in comparison to the same period in 2016 as a result of lower petroleum and natural gas sales revenues.

4.5 Production Costs

	Years ended 31 December		
	2018	*2017*	*2016*
	(C$,000)	*(C$,000)*	*(C$,000)*
Production costs	3,606	4,423	2,232
$ per boe	13.77	12.73	7.63

Production costs for the year ended 31 December 2018 decreased in comparison to the same period in 2017 due to improved efficiencies in 2018 compared to higher costs in 2017 associated with integrating the TBNG Acquisition. The higher unit production costs in 2018 are reflective of the level of fixed costs included in total operating costs and lower gross production from the TBNG JV and Banarli Exploration Licences.

Production costs the year ended 31 December 2017 increased in comparison to the same period in 2016 due primarily to Valeura increasing its ownership of the TBNG JV from 40 per cent. to 81.5 per cent. 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.

4.6 Operating Netbacks ($ per boe)

	Years ended 31 December		
	2018	*2017*	*2016*
Petroleum and natural gas sales	45.72	42.16	55.22
Royalties	(6.16)	(5.67)	(7.18)
Production costs	(13.77)	(12.73)	(7.63)
Operating netback	25.79	23.76	40.41

Operating netbacks for the year ended 31 December 2018 increased in comparison to the same period in 2017 due primarily to higher realized prices offset by higher per unit production costs. Readers are directed to the note regarding non-GAAP measures in paragraph 11 of this Part 11.

Operating netbacks for the year ended 31 December 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 further reduced the netbacks.

4.7 General and Administrative Expenses

	Years ended 31 December		
	2018	*2017*	*2016*
	(C$,000)	*(C$,000)*	*(C$,000)*
General and administrative expenses	7,828	6,861	5,941
Business development	–	32	142
Total	7,828	6,892	6,083
Recoveries*	(4,078)	(2,286)	(707)
General and administrative expenses (net of recoveries)	3,750	4,606	5,376

Total general and administrative expenses before recoveries for 2018 increased in comparison to the same period in 2017 as a result of continued increased personnel requirements related to the expansion of the business and assuming operatorship as described below.

Net general and administration costs to Valeura are significantly lower due to increased overhead recoveries, primarily from the deep drilling and testing program on the BCGA.

Total general and administrative expenses net of recoveries for the year ended 31 December 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 correspond 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.

4.8 Foreign Exchange

	Years ended 31 December		
	2018	*2017*	*2016*
	(C$,000)	*(C$,000)*	*(C$,000)*
Unrealized foreign exchange gain (loss)	1,016	12	(2,583)
Realized foreign exchange (loss)	(468)	(2,683)	(449)
Foreign exchange gain (loss)	548	(2,671)	(3,032)

Foreign exchange (realized and unrealized) for the year ended 31 December 2018 was a gain of $0.5 million, respectively, compared to a loss of $2.7 million for the same period in 2017.

During the year ended 31 December 2017, the Company recorded a foreign exchange loss (realized and unrealized) of $2.7 million compared to a foreign exchange loss of $3.0 million for the same period 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.

* Recoveries includes capitalised overheads and overhead recoveries from partners for FY18 and FY17, but capitalised overheads only for FY16.

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

The recent negative volatility in the value of the TL may impair the ability of the Company to effectively manage foreign exchange exposure. Continued devaluation of the TL, 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.

The Company's drilling and seismic operations and related contracts in Turkey are predominantly based in USD. Material changes in the value of the USD against the TL or CAD will impact the Company's capital costs. Operating revenue and costs are primarily denominated in TL. Material changes in the value of the TL against the CAD will effect operating results.

4.9 Other Income

During the year ended 31 December 2018, the Company recorded other income of $2.2 million, compared to $1.4 million for the same period in 2017. Other income is comprised of third party processing and marketing income and interest income related to cash on hand. The majority of the increase can be attributed to higher average cash levels in 2018 in comparison to 2017. During the year ended 31 December 2018 the Company recorded third party processing and marketing income of $0.9 million, respectively, and interest income of $1.3 million.

During the year ended 31 December 2017, the Company recorded other income of $1.4 million compared to $0.8 million for the same period in 2016. The increase during the year ended 31 December 2017 is attributed to higher third party volumes processed, and higher working interest participation in processing revenues due to the TBNG Acquisition.

4.10 Current Tax

	Years ended 31 December		
	2018	*2017*	*2016*
	(C$,000)	*(C$,000)*	*(C$,000)*
Current income taxes	323	2,371	–
Tax amnesty payment	514	–	–
Current tax	837	2,371	–

Current tax for the year ended 31 December 2018 was $0.8 million compared to $2.4 million and nil for the same periods in 2017 and 2016.

In 2018, the Company elected to participate in a tax amnesty program offered by the Government of Turkey, which allowed companies to pay an amount based on a pre-determined formula to close tax assessments for certain years between 2013 and 2017. In deciding to participate in the program, the Company analyzed the costs and risks involved in current tax positions, including those related to companies that were acquired during this time frame, vs the potential financial burden that would be incurred by not participating in the program and then being unsuccessful in defending tax positions against multiple audits.

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 Equinor funded deep exploration play led to the increase in expense.

4.11 Adjusted Funds Flow

Adjusted funds flow for the year ended 31 December 2018 was $3.7 million compared to an outflow of $1.2 million for the same period in 2017. The increase in adjusted funds flow for 2018 was due to increased realized prices and absence of expenses related to the TBNG Acquisition and Banarli Farm-In which negatively impacted 2017 results. The increase was offset by tax amnesty payments described above in the Current Tax section.

Adjusted funds flow for the year ended 31 December 2017 was an outflow of $1.2 million compared to an inflow of $6.0 million for the same period 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 were not considered ongoing expenses.

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

	Years ended 31 December		
	2018	*2017*	*2016*
	(C$,000)	*(C$,000)*	*(C$,000)*
Cash provided by (used in) operating activities	(584)	3,854	6,294
Decommissioning costs incurred	531	270	–
Change in non-cash working capital	3,708	(5,329)	(246)
Adjusted funds flow	3,655	(1,205)	6,048

4.12 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 year ended 31 December 2018 was $1.5 million compared to $0.5 million for the same period in 2017 reflecting the increased share price of the company. During 2018, the Company granted 1,077,500 options at a weighted average exercise price of $4.62 per option.

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

During 2016, the Company granted 613,000 options at a weighted average exercise price of $0.75 per option.

Accretion on Decommissioning Liabilities

Accretion on decommissioning obligations for the year ended 31 December 2018 was $2.9 million compared to $1.8 million for the same period in 2017. The increase is due to high levels of inflation in Turkey during 2018 and the devaluation of the TL against the USD during the year.

Accretion on decommissioning obligations for the year ended 31 December 2017 was $1.8 million compared to $0.9 million for the same period in 2016. The increase was 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 expense ("**E&E Expense**") consists of exploration projects that are deemed to have a lower fair value when compared to book value. There were no E&E Expenses for the year ended 31 December 2018. E&E Expenses for the year ended 31 December 2017 was $0.7 million (2016 – nil) and was comprised of one shallow gas dry hole.

Impairment

No impairment expense was recorded for the years ended 31 December 2018 and 2017. Impairment for the year ended 31 December 2016 was $1.0 million. The carrying value of Valeura's Edirne and Gaziantep assets exceeded the recoverable amount resulting in 2016 impairment charges of $0.2 million and $0.8 million respectively.

Depletion and Depreciation

Depletion and depreciation for the year ended 31 December 2018 was $7.3 million compared to $9.0 million for the same period in 2017 and $7.4 million for the same period in 2016. Depletion is calculated on a unit-of-production basis utilizing proved plus probable reserves.

On a per unit basis, depletion and depreciation the year ended 31 December 2018 was $27.92/boe compared to $25.97/boe for the same period in 2017 and $25.43 for the same period in 2016.

Deferred Tax

Deferred tax for the year ended 31 December 2018 was an expense of $0.1 million compared to a recovery of $4.8 million for the same period in 2017 and a recovery of $0.3 million for the same period 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 the year ended 31 December 2018 was a loss of $10.4 million, compared to a loss of $6.0 million for the same period in 2017 and a loss of $11.5 million for the same period in 2016, reflecting the fluctuation of the TL compared to the Canadian dollar in the respective periods.

4.13 Business Combination

The acquisition of TBNG during the year ended 31 December 2017 has been accounted for as a business combination under IFRS 3. The purchase price equation (in Canadian Dollars), was as follows:

	Year ended 31 December 2017 (C$'000)
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 was $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, which was 24 February 2017. 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 24 February 2017 to 31 December 2017. Had the acquisition closed on 1 January 2017, for the year ended 31 December 2017, the Company estimates that its pro forma revenue and net loss for the year ended 31 December 2017 would have been approximately $15,170 and $(8,816) respectively.

4.14 Capital Expenditures

The following summarizes the Company's capital spending:

	Years ended 31 December		
	2018	*2017*	*2016*
	(C$,000)	*(C$,000)*	*(C$,000)*
Geological and geophysical	229	932	1,094
Drilling & completions	6,859	8,830	7,116
Workovers & recompletions	534	2,287	93
Equipping, facilities & other	401	742	1,232
Total exploration and development capital program	8,023	12,791	9,535
Acquisitions	–	21,450	–
Dispositions	–	(26,288)	–
Total net capital	8,023	7,953	9,535

The Company's Capital spending for 2018 was $8.0 million, including $6.9 million for drilling and completions, $0.5 million for workovers and recompletions, $0.4 million for equipping, facilities and other and $0.2 million for geological and geophysical.

During 2018, the Company's focus was on the deep drilling program. Valeura successfully recompleted the Yamalik-1 well to allow for a long-term production test. The Company's share of costs relating to the final completion and long term test was $2.5 million for 2018. Procurement and planning for a three well appraisal drilling and testing program, including purchase of long lead items for wells to be drilled in 2019 was carried out during 2018 at a cost of $2.4 million to Valeura. In October 2018, the Company spud the first appraisal well, Inanli-1, which was drilled to a total depth of 4,885 metres. The well is being cased and will be left in a state of ready for completion stimulation and production testing and completion operations are planned to commence around the end of Q1 2019. Equinor will fund the drilling, completion and testing of the Inanli-1 well. In November 2018, site preparation commenced for the Devepinar-1 well, which was spudded on 19 February 2019.

In 2018, on the TBNG JV Lands, the Company drilled one well, Karanfiltepe-7 (Valeura 81.5 per cent. working interest). Karanfiltepe-7 was drilled to a measured depth of 1,454 metres and is currently on production. This well was strategically important as it fulfilled a licence commitment at a low cost of $0.8 million for 2018. Valeura also completed workovers on five gross wells on the TBNG JV Lands.

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 per cent. 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 high-pressure stimulations were successfully completed in Kayi-14 and Baglik-1. Both wells are currently on-stream and contributing to the Company's gas sales.

In the Banarli Exploration Licences, 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 Exploration Licences.

Capital spending for 2016 was $9.5 million, including $7.1 million for drilling and completion operations, $1.1 million for geological and geophysical operations and $1.2 million for equipping and facility operations.

During 2016, the Company continued to focus on its 100 percent owned and operated Banarli Exploration Licences in the Thrace Basin. The Company drilled the Bati Gurgen-2 well which was a follow up well to the Bati Gurgen-1 well focusing on the medium-depth conventional stacked sands in the Osmancik formation. The well was placed on-stream 26 September 2016. The drilling and completion cost of the Bati Gurgen-2 well exceeded the budgeted cost of $1.7 million due to a sidetrack drilling operation required to penetrate a higher structural position in the Osmancik formation.

5. Liquidity, Financing and Capital Resources

	Years ended 31 December		
	2018	*2017*	*2016*
	(C$,000)	*(C$,000)*	*(C$,000)*
Opening cash position	11,108	1,987	6,973
Inflow of funds			
Share issuance – net of share issuance costs	55,408	10,108	–
West Thrace Deep Rights sales	–	18,841	–
Equinor Farm-In proceeds	–	7,447	–
Adjusted funds flow[6]	3,655	–	6,048
Restricted cash	2,899	–	–
Proceeds from stock option exercises	1,912	–	437
Foreign exchange on cash	2,375	531	–
Changes in working capital	–	11,083	–
	66,249	48,010	6,485
Outflow of funds			
Capital expenditures[7]	(8,023)	(12,791)	(9,535)
Decommissioning costs incurred	(531)	(270)	–
TBNG Acquisition	–	(21,450)	–
Restricted cash	–	(3,173)	–
Foreign exchange on cash	–	–	(505)
Changes in working capital	(6,423)	–	(1,431)
Adjusted funds flow (used)	–	(1,205)	–
	(14,977)	(38,889)	(11,471)
Closing cash position	62,380	11,108	1,987

[6] Non-GAAP measure

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

5.1 ***Capital Funding and Resources***

As at 31 December 2018, Valeura's working capital[8] balance was $59.5 million (2017 – $3.4 million) including cash of $62.4 million. Valeura's 2018 opening cash position was $11.1 million. The increase in the working capital/cash position in 2018 was mainly due to the net proceeds of $55.4 million from the 2018 Offering. In 2018, the Company utilized this cash balance plus adjusted funds flow to fund an exploration and development capital program of $8.0 million.

As at 31 December 2017, Valeura's working capital[8] balance was $3.4 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 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 31 December 2017 of $11.1 million was 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.

As at 31 December 2016, Valeura's working capital[8] balance was $3.8 million including cash of $2.0 million and excluding assets held for sale. Valeura's 2016 opening cash position was $7.0 million. In 2016, the Company utilized this opening cash balance plus funds flow from operations of $6.0 million to fund an exploration and development capital program of $9.5 million. The resultant cash balance at 31 December 2016 was $2.0 million after reflecting $0.4 million of proceeds from stock options exercised and a $1.9 million outflow of funds attributed to changes in working capital and foreign exchange on cash.

5.2 ***Financial Capacity***

As at 31 December 2018 the Company's working capital[8] was $59.5 million. The working capital position and adjusted funds flow for 2019 are expected to the sufficient to fund the planned capital expenditures for 2019 of $41.7 million as outlined below.

5.3 ***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 31 December 2018, the Company has issued letters of credit totalling US$0.04 million (31 December 2017 – US$0.04 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.

Effective 22 June 2018, the Company has available an Account Performance Security Guarantee ("**APSG**") from Export Development Canada. The APSG, which was issued to National Bank of Canada ("**NBC**") allows the Company to use the APSG as collateral for certain letters of credit issued by NBC. The facility is effective from 16 May 2018 to 31 May 2019 with a limit of US$2.5 million and can be renewed on an annual basis. The Company has issued US$2.5 million in letters of credit under the APSG facility at current exchange rates. This allowed the Company to release approximately US$2.0 million of restricted cash.

6. 2019 Planned Capital Program

Valeura's 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.

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

The plan for capital expenditures for the 2019 BCGA program is as follows:

Operation	*Net VLE Cost (in dollars)*	*Anticipated Timing*
Test and complete Inanli-1 (Banarli)	$0	Q1 2019 – Q2 2019
Drill and Test Devepinar-1 (West Thrace)	$13,500,000	Q1 2019 – Q3 2019
Drill and Test a third planned BCGA appraisal well (Banarli)	$19,700,000	Q3 2019 – Q4 2019
Workovers and Production Testing of BCGA wells	$3,750,000	2019
Facilities Capital and Tie-in for 4 wells	$2,300,000	2019
G&G and studies	$900,000	2019
Total:	$40,150,000	

The table above primarily outlines the deep drilling program. At this time, the third planned BCGA appraisal well has not been agreed to or formally approved by Valeura or its partners. Valeura plans to spend approximately $1.5 million for workovers, abandonment and restoration of non-producing wells and other facilities maintenance projects on the TBNG JV Lands, for a total capital budget for 2019 of approximately $41.7 million.

The Company maintains considerable flexibility in managing its capital budget for 2019. Valeura expects to maintain operatorship of the deep rights on the Banarli Lands and West Thrace Lands for most of 2019 and through the drilling, completion and testing of the three well appraisal program and will tightly manage all capital requirements and commitments. In addition, the drilling and workover capital spending on the TBNG JV Lands is only focused on mitigating natural gas production declines.

6.1 ***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.

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 currently subject to any externally imposed capital requirements while it maintains operatorship over all the lands in the Thrace Basin. Should Equinor Turkey exercise its option to assume operatorship of the Banarli Lands, after completing its earning obligations under the Banarli Farm-In, the Company could become subject to Equinor Turkey imposed capital requirements, subject to the applicable joint operating agreements budget approval terms. As a result, Equinor could propose a more significant drilling program in 2020 including a more extensive pilot project, for which the Company would have to contribute its 50 percent participating interest subject to the applicable joint operating agreements rights and elections afforded to non-operating parties. In Q1, 2018, the Company received net proceeds of $55.4 million from the 2018 Offering. The Company has working capital of $59.5 million at 31 December 2018 in order to meet commitments of the current capital program. If a more significant program is proposed, the Company will be required to assess alternatives including the availability of equity and debt capital to fund the program.

7. Selected Quarterly Information

	Three months ended			
	31 December 2018	*30 September 2018*	*30 June 2018*	*31 March 2018*
Total daily production (boe/d)	623	655	736	859
Average wellhead price ($/boe)	55.00	39.83	44.06	44.87
Petroleum and natural gas sales ($'000)	3,150	2,401	2,949	3,469
Adjusted funds flow (used) ($'000)	3,079	(430)	461	545
Per share, basic and diluted ($/share)	0.04	(0.01)	0.01	0.01
Net loss ($'000)	(634)	(2,647)	(1,404)	(2,435)
Per share, basic and diluted ($/share)	(0.01)	(0.03)	(0.02)	(0.03)

	Three months ended			
	31 December 2017	*30 September 2017*	*30 June 2017*	*31 March 2017*
Total daily production (boe/d)	1,038	1,024	934	807
Average wellhead price ($/boe)	40.03	42.14	44.28	42.49
Petroleum and natural gas sales ($'000)	3,824	3,970	3,764	3,088
Adjusted funds flow ($'000)	(446)	1,165	959	(2,883)
Per share, basic and diluted ($/share)	(0.01)	0.02	0.01	(0.04)
Net loss ($'000)	(946)	(4,911)	(526)	(2,001)
Per share, basic and diluted ($/share)	(0.01)	(0.07)	(0.01)	(0.03)

	Three months ended			
	31 December 2016	*30 September 2016*	*30 June 2016*	*31 March 2016*
Total daily production (boe/d)	795	680	933	792
Average wellhead price ($/boe)	47.97	56.10	56.62	60.09
Petroleum and natural gas sales ($'000)	3,508	3,510	4,809	4,328
Adjusted funds flow ($'000)	915	1,066	2,098	1,969
Per share, basic and diluted ($/share)	0.02	0.02	0.04	0.03
Net loss ($'000)	(3,189)	(1,263)	(642)	(992)
Per share, basic and diluted ($/share)	(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 mitigate 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 2016 reduced wellhead price realizations throughout 2016 and 2017 and the first nine months of 2018. The 2018 increases to the BOTAS reference price combined with the strengthening of the TL in Q4 2018 has resulted in higher wellhead price realization.
- 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.

8. Selected Annual Information

	Years ended 31 December		
	2018	*2017*	*2016*
	(C$,000)	*(C$,000)*	*(C$,000)*
Petroleum and natural gas sales	11,969	14,646	16,155
Cash provided by operations	(584)	3,854	6,294
Adjusted funds flow	3,655	(1,205)	6,048
Per share, basic and diluted	0.04	(0.02)	0.10
Net loss	(7,120)	(8,384)	(6,086)
Per share, basic and diluted ($/share)	(0.09)	(0.12)	(0.10)
Daily production (boe/d)	717	952	799
Sales price ($/boe)	45.72	42.16	55.22
Cash	62,380	11,108	1,987
Total assets	128,323	89,872	75,890
Total long term liabilities	17,717	21,676	13,017
Net working capital[12]	59,520	3,421	3,786

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 2018 decreased 18 percent from 2017 due to natural declines on both the TBNG JV and Banarli Exploration 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. Total assets in 2017 and 2018 increased as a result of the TBNG Acquisition and 2018 Offering but were negatively impacted by the devaluation of the TL against the Canadian Dollar.

9. Basis of Presentation

9.1 *Statement of compliance*

The consolidated financial statements have been prepared in accordance with IFRS as at and for the years ended 31 December 2018 and 2017 and 2016 and have been prepared in accordance with the accounting policies and methods of computation as set forth below.

Operating, transportation and marketing expenses in profit or loss are presented as a combination of function and nature in conformity with industry practices. Depletion, depreciation and finance expenses are presented in separate lines by their nature, while net administrative expenses are presented on a functional basis. Significant expenses such as salaries and benefits and share-based compensation are presented by their nature in the notes to the consolidated financial statements.

9.2 *Basis of measurement*

The consolidated financial statements have been prepared on the historical cost basis except for certain financial and non-financial assets and liabilities, which have been measured at fair value. The methods used to measure fair value are discussed below.

The Company's consolidated financial statements include the accounts of Valeura and its subsidiaries and are expressed in Canadian Dollars, unless otherwise stated.

9.3 *Functional and presentation currency*

The consolidated financial statements are presented in Canadian Dollars which is Valeura's reporting currency. Valeura's foreign subsidiaries transact in currencies other than the Canadian Dollar and have a functional currency of Turkish Lira. The functional currency of a subsidiary is the currency of the primary economic environment in which the subsidiary operates. Transactions denominated in a currency other than the functional currency are translated at the prevailing rates on the date of the transaction. Any monetary items held in a currency which is not the functional currency of the subsidiary are translated to the functional currency at the prevailing rate as at the date of the statement of financial position. All exchange differences arising as a result of the translation to the functional currency of the subsidiary are recorded in net earnings.

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

Translation of all assets and liabilities from the 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 other comprehensive income or loss ("**OCI**") and are held within AOCI until a disposal or partial disposal of a subsidiary. A disposal or partial disposal will then give rise to a realized foreign exchange gain or loss which is recorded in net earnings.

9.4 ***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:

- 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 Exploration and evaluation 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.

9.5 ***Turkey operational update***

Turkey has gone through a period of political change and uncertainty from 2016 to 2018. However, with the successful passing of the referendum on constitutional change, and the successful election in mid-2018, the incumbent, President Erdogan remains in office.

Recent geopolitical events have resulted in a continued downward slide in the value of the TL, and at times these drops have been very sharp. This has also had the effect of sharply increasing inflation to more than 20 per cent. in 2018 after well over a decade of strong growth and relatively stable inflation. In 2018, the resulting negative sentiment to Turkey has at times resulted in a decrease in the value of Valeura shares.

To date, the above events have not impacted the Company's ability to conduct drilling and production operations in the Thrace Basin and no significant delays or security issues have been experienced in these operations. All of the Company's current operations are in the Thrace Basin of northwest Turkey, more than 1,000 kilometres from the Syrian border.

The Company will continue to monitor conditions, including the safety of personnel and operations, the security situation generally, impact on the TL and banking facilities, impact on our joint venture partners and any changes in offtakes by the Company's 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 these consolidated financial statements were approved by the Board of Directors. The situation in Turkey remains uncertain and significant changes could occur which could materially impact the assumptions and estimates made in these consolidated financial statements. Changes in assumptions are recognized in the financial statements prospectively.

10. Significant Accounting Policies

The accounting policies set out below have been applied consistently to all years presented in the consolidated financial statements and have been applied consistently by the Company and its subsidiaries.

10.1 ***Basis of consolidation***

(i) *Subsidiaries:*

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, substantive potential voting rights are taken into account. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

The acquisition method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in earnings.

(ii) *Jointly controlled operations and jointly controlled assets:*

A portion of the Company's exploration and development activities are conducted jointly with others. The joint interests are accounted for on a proportionate consolidation basis and as a result the financial statements reflect only the Company's proportionate share of the assets, liabilities, revenues, expenses and cash flows from these activities.

Valeura has two joint venture arrangements as follows:

Name of the joint arrangement	*Nature of the relationship with the joint arrangement*	*Principal place of business of joint arrangement*	*Proportion of participating share*
TBNG Joint Venture	Operator	Turkey	81.5% (all rights)
Equinor Joint Venture	Operator	Turkey	50% on Banarli Exploration Licences (deep rights); 31.5% on West Thrace Lands (deep rights)

(iii) *Transactions eliminated on consolidation:*

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

10.2 ***Financial instruments***

(i) *Non-derivative financial instruments:*

Valeura adopted IFRS 9, Financial Instruments on 1 January 2018 on a retrospective basis.

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, which is more in line with risk management activities. IFRS 9 has been adopted on a retrospective basis by Valeura on 1 January 2018. IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost, fair value through other comprehensive income ("FVOCI"), or fair value through profit or loss ("FVTPL").

Under IFRS 9, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity's own credit risks is recorded through other comprehensive income or loss rather than net income or loss. The classification of financial assets under IFRS 9 is generally based on the business model in which a financial asset is managed and the characteristics of its contractual cash flows.

A financial asset is subsequently measured at amortized cost if it meets both of the following conditions: (a) the asset is held with a business model whose objective is to hold assets to collect contractual cash flows; and (b) the contractual terms of the financial assets give rise to cash flows on specified dates that are solely payments of principal and interest on principal amounts outstanding.

Financial assets that meet criteria (b) above that are held within a business model whose objective is achieved by both collecting contractual cash flows and selling financial assets is

subsequently measured at FVOCI. All other financial assets and liabilities are subsequently measure at FVTPL. There was no change to the measurement categories of financial liabilities.

Accounts receivable, prepaid expenses and deposits, accounts payable and accrued liabilities continue to be measured at amortized cost and are now classified as "amortized cost".

Valeura does not currently have financial instrument contracts to which it applies hedge accounting.

(ii) *Share capital:*

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares and share options are recognized as a deduction from equity, net of any tax effects.

10.3 ***Property, plant and equipment and exploration and evaluation assets***

(i) *Recognition and measurement:*

Exploration and evaluation expenditures:

Pre-licence costs are recognized in earnings as incurred. Exploration and evaluation costs, including the costs of acquiring licences and directly attributable general and administrative costs, are initially capitalized as exploration and evaluation assets. The costs are accumulated in cost centres by well, field or exploration area pending determination of technical feasibility and commercial viability.

Exploration and evaluation assets are assessed for impairment if sufficient data exists to determine technical feasibility and commercial viability, and facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are allocated to cash-generating units. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved and/or probable reserves are determined to exist. A review of each exploration CGU is conducted, at least annually, to ascertain whether proved and/or probable reserves have been discovered. Upon determination of proved and/or probable reserves, the CGU within which the intangible exploration and evaluation assets attributable to those reserves is first tested for impairment and then the applicable value is reclassified from exploration and evaluation assets to property, plant and equipment.

Development and production costs:

Items of property, plant and equipment ("**PP&E**"), which include oil and gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development and production assets are grouped into CGUs for impairment testing. When significant parts of an item of PP&E, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (components).

Gains and losses on disposal of an item of property, plant and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of PP&E and are recognized in earnings.

(ii) *Subsequent costs:*

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of PP&E are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in earnings as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in earnings as incurred.

(iii) *Depletion and depreciation:*

The net carrying value of development or production assets is depleted using the unit of production method by reference to the ratio of production in the year to the related proved plus probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually.

Other corporate assets are recorded at cost on acquisition and amortized on a declining-balance basis at rates of 20 percent to 50 percent per year.

(iv) *Exploration and evaluation expense:*

Upon determination that an exploration and evaluation CGU is impaired, the Company will transfer costs associated with the applicable CGU to exploration and evaluation expense in the period.

10.4 ***Impairment***

(i) *Financial assets:*

Loss allowances are recognized for expected credit losses ("**ECL's**") on its financial assets measured at amortized cost. Due to the nature of the financial assets, loss allowances are measured at an amount equal to expected lifetime ECL's. Lifetime ECL's are the anticipated ECL's that result from all possible default events over the expected life of a financial asset. ECL's are a probability-weighted estimate of credit loss and are discounted at the effective interest rate of the related financial asset.

(ii) *Non-financial assets:*

The carrying amounts of the Company's non-financial assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, the asset's recoverable amount is estimated via an impairment test.

Exploration and evaluation assets are assessed for impairment when they are reclassified to property, plant and equipment, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets, or CGUs. The recoverable amount of an asset or a CGU is the greater of its value-in-use and its fair value less costs to sell. Fair value less costs to sell is determined as the amount that would be obtained from the sale of the assets in an arm's length transaction between knowledgeable and willing parties.

In assessing value-in-use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value-in-use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved plus probable reserves. Exploration and evaluation assets are allocated to related CGUs when they are assessed for impairment, both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to PP&E.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in earnings. Impairment losses recognized in respect of CGUs are allocated to reduce the carrying amounts of the assets in the unit (group of units) on a pro-rata basis.

An impairment loss in respect of PP&E and exploration and evaluation assets, recognized in prior years, is assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

10.5 ***Share Based Payments***

The grant date fair value of options and performance warrants granted to employees is recognized as compensation expense, with a corresponding increase in contributed surplus over the vesting period. A forfeiture rate is estimated on the grant date and is subsequently adjusted to reflect the actual number of options that vest.

10.6 ***Provisions***

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

(i) *Decommissioning obligations:*

The Company's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category. Decommissioning obligations are measured at the present value of management's best estimate of expenditure required to settle the present obligation at the statement of financial position date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

10.7 ***Revenue from contracts with customers***

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, to be adopted for annual periods beginning on or after 1 January 2018. Valeura adopted the new standard on 1 January 2018 on a retrospective basis. The standard requires enhanced disclosure of revenue from contracts with customers as detailed in Note 8, including categories that depict the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors. Valeura management reviewed its revenue streams and major contracts with customers and concluded that there were no material impacts on the Company's revenues or cash flows for the period as a result of adopting the new standard.

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's petroleum and natural gas revenues from the sale of natural gas and crude oil are based on the consideration specified in the contracts with customers. For natural gas, pricing is linked to BOTAS benchmark pricing, while crude oil pricing is linked to Brent benchmark pricing. Valeura recognizes revenue when it transfers control of the product to the customer, which is generally when legal title passes to the customer and collection is reasonably assured.

Valeura evaluates its arrangements with third parties and partners to determine if Valeura is acting as the principal or as the agent. Valeura is considered the principal in a transaction when it has primary responsibility for the transaction. If Valeura acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net basis, only reflecting the fee, if any realized by Valeura from the transaction.

10.8 ***Finance income and expenses***

Finance expense comprises interest expense on any borrowings, accretion of the discount on provisions and impairment losses recognized on financial assets.

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. All other borrowing costs are recognized in earnings using the effective interest method. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Company's outstanding borrowings during the period.

Interest income is recognized as it accrues in earnings, using the effective interest method.

10.9 ***Income tax***

Income tax expense comprises current and deferred tax. Income tax expense is recognized in earnings except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected taxes payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to taxes payable in respect of previous years.

Deferred tax is recognized using the statement of financial position method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination.

Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

10.10 ***Earnings per share***

Basic per share amounts are calculated by dividing the net income or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted per share amounts are determined by adjusting the net income or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options granted to employees.

10.11 ***Standards issued but not yet effective***

In January 2016, the IASB issued the Complete IFRS 16 Leases ("IRS 16"), which replaces IAS 17 Leases. The effective date of IFRS 16 is for annual periods beginning on or after 1 January 2019 and early adoption is permitted. Under IFRS 16, a single recognition and measurement model will apply for lessees which will require recognition of assets and liabilities for most leases. The Company is in the final stages of analysing identified contracts, developing business and accounting processes, making applicable changes to the Company's internal controls and calculating the impact that the adoption of this standard will have on its financial statements. Valeura has elected to use the modified retrospective approach upon adoption and elected to apply the optional exemptions for short-term and low-value leases. The actual full impact of adoption will depend on the Company's incremental borrowing rate, lease liabilities, and practical expedients applied. However, the Company anticipates that the most significant impact of adopting IFRS 16 will be the recognition of the right-of-use ("**ROU**") assets and corresponding lease liabilities on its leases for office space and surface leases for facilities.

Upon adoption of IFRS 16, the Company will recognize ROU assets and lease liabilities for all leases identified except for optional exemptions taken. The lease liability will be measured at the present value of the remaining lease payments, discounted using the Company's incremental borrowing rate as at 1 January 2019. The ROU asset will be measured at the amount equal to the lease liability on 1 January 2019 with no impact on retained earnings.

Adoption of IFRS 16 will also result in an increase to depletion, depreciation and amortization expense due to the recognition of the ROU assets, increase in interest and financing charges, and a decrease to general and administrative and operating expenses, as applicable. Cash flow from operating activities will increase as a result of the decrease in general and administrative and operating expenses, as applicable, partially offset by interest and financing charges. Cash flow from financing activities will decrease due to the addition of principal payments included in lease payments for former operating leases.

10.12 ***Determination of Fair Values***

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the methods described below. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

(i) *Property, plant and equipment and intangible exploration and evaluation assets:*

The fair value of PP&E recognized in an acquisition, is based on market values. The market value of PP&E is the estimated amount for which property, plant & equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of oil and natural gas interests (included in PP&E) is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions. The market value of exploration and evaluation assets is estimated based on either internally or externally prepared evaluations of these assets.

(ii) *Cash, deposits, accounts receivable, accounts payable and accrued liabilities:*

The fair value of cash, deposits, accounts receivable, accounts payable and accrued liabilities are estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At 31 December 2018, 31 December 2017 and 31 December 2016, the fair value of these balances approximated their carrying values due to their short term to maturity.

(iii) *Stock options:*

The fair value of employee stock options is measured using a Black Scholes option pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility based on the weighted average historic volatility adjusted for changes expected due to publicly available information, weighted average expected life of the instruments based on historical experience and general option holder behaviour, expected dividends, the risk-free interest rate based on government bonds, and an estimated forfeiture rate.

11. Special Note Regarding Non-GAAP Measures

This Historical Financial Information 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.

PART 12 – CREST AND DEPOSITARY INTERESTS

The Company has established arrangements to enable investors to settle interests in the Common Shares through the CREST system. CREST is a paperless settlement system allowing securities to be transferred from one person's CREST account to another without the need to use share certificates or written instruments of transfer. Securities issued by non-UK companies, such as the Company, cannot be held or transferred electronically in the CREST system. However, Depositary Interests allow such securities to be dematerialised and settled electronically through CREST. Where investors choose to settle interests in the Common Shares through the CREST system, and pursuant to depositary arrangements established by the Company, the Custodian will hold the Common Shares and issue dematerialised Depositary Interests representing the underlying Common Shares, which will be held on trust for the holders of the Depositary Interests. The Depositary Interests will be independent securities constituted under English law which may be held and transferred through the CREST system. Investors should note that it is the Depositary Interests which will be admitted to and settled through CREST and not the Common Shares.

The Constitution is consistent with CREST membership in respect of Depositary Interests and the holding and transfer of Depositary Interests in uncertified form. Under the Corporations Act, companies are not prohibited from issuing shares in book-entry form but shareholders have the right to require the companies to issue physical certificates. The Board has passed a resolution authorising the issuance of shares in book-entry form.

The Company and the Depositary entered into a depositary agreement on 2 April 2019, the principal terms of which are summarised below.

The Depositary Interests have been created pursuant to and issued on the terms of a deed poll that was executed on 2 April 2019 by the Depositary in favour of the holders of the Depositary Interests from time to time. Holders of Depositary Interests should note that they will have no rights against Euroclear UK & Ireland (the operators of CREST) or its subsidiaries in respect of the underlying Common Shares or the Depositary Interests representing them.

If a holder of Common Shares so requests, its Common Shares will be transferred to an account of the Depositary or its nominated custodian and the Depositary will issue Depositary Interests to participating CREST members. Each Depositary Interest will be treated as one Common Share for the purposes of determining, for example, eligibility for any dividends. The Depositary will pass on to holders of Depositary Interests any stock or cash benefits received by it as holder of Common Shares on trust for such Depositary Interest holder. Depositary Interest holders, through the Depositary, will also be able to receive notices of meetings of holders of Common Shares and other notices issued by the Company to its Shareholders.

The Depositary Interests have the same security code (ISIN) as the underlying Common Shares and will not require a separate admission to the Main Market. The Depositary Interests can then be traded and settled within the CREST system in the same way as any other CREST securities. Application will be made for the Depositary Interests to be admitted to CREST with effect from Admission.

If a holder wishes to cancel its Depositary Interest, it will either directly or through its broker instruct the applicable CREST participant to initiate a CREST withdrawal (where such withdrawal is sent to the Depositary) for the name that appears on the Register. The Depositary Interest will then be cancelled by the Depositary and the related Common Shares will be credited to the account on the Register by the Registrar. The Registrar will then send the holder a new Common Share certificate.

The information included within this section relating to the obtaining and cancellation of Depositary Interests by a holder is intended to be a summary only and is not to be construed as legal, business or tax advice. Each investor should consult his or her own lawyer, financial adviser, broker or tax adviser for legal, financial or tax advice in relation to Depositary Interests.

1. Deed Poll

The Deed Poll executed by the Depositary prior to Admission contains the following provisions:

- The Depositary will hold (itself or through the Custodian), as bare trustee, the underlying Shares and all and any rights and other securities, property and cash attributable to the underlying Shares

pertaining to the Depositary Interests for the benefit of the holders of the relevant Depositary Interests as tenants in common. The Depositary will re-allocate securities or Depositary Interests distributions allocated to the Depositary or Custodian *pro rata* to the Shares held for the respective accounts of the holders of Depositary Interests, but will not be required to account for fractional entitlements arising from such re-allocation.

- Holders of Depositary Interests agree to give such warranties and certifications to the Depositary as the Depositary may reasonably require. In particular, holders of Depositary Interests warrant, *inter alia*, that the securities in the Company transferred or issued to the Depositary or Custodian on behalf of the Depositary for the account of the Depositary Interest holder are free and clear of all liens, charges, encumbrances or third party interests and that such transfers or issues are not in contravention of the Company's constitutional documents or any contractual obligation, or applicable law or regulation binding or affecting such holder, and holders of Depositary Interests agree to indemnify the Depositary against any liability incurred as a result of any breach of such warranty.
- The Depositary and any Custodian shall pass on to the Depositary Interest holders and, so far as they are reasonably able, exercise on behalf of the Depositary Interest holders all rights and entitlements received or to which they are entitled in respect of the underlying Shares which are capable of being passed on or exercised. Rights and entitlements to cash distributions, to information, to make choices and elections and to call for, attend and vote at meetings shall, subject to the Deed Poll, be passed on in the form in which they are received, together with amendments and additional documentation necessary to effect such passing-on, or, as the case may be, exercised in accordance with the Deed Poll. If arrangements are made which allow a holder to take up rights in the Company's securities requiring further payment, the holder must put the Depositary in cleared funds before the relevant payment date or other date notified by the Depositary if it wishes the Depositary to exercise such rights.
- The Depositary will be entitled to cancel Depositary Interests and treat the holders thereof as having requested a withdrawal of the underlying securities in certain circumstances, including where a Depositary Interest holder fails to furnish to the Depositary with such certificates or representations as to material matters of fact, including his identity, as the Depositary deems appropriate.
- The Depositary warrants that it is an authorised person under the FSMA and is duly authorised to carry out custodian and other activities under the Deed Poll. It also undertakes to maintain that status and authorisation.
- The Deed Poll contains provisions excluding and limiting the Depositary's liability. For example, the Depositary shall not be liable to any Depositary Interest holder or any other person for liabilities in connection with the performance or non-performance of obligations under the Deed Poll or otherwise except as may result from its negligence or wilful default or fraud or that of any person for whom it is vicariously liable, provided that the Depositary shall not be liable for the negligence, wilful default or fraud of any Custodian or agent which is not a member of its group unless it has failed to exercise reasonable care in the appointment and continued use and supervision of such Custodian or agent. Except in the case of personal injury or death, any liability incurred by the Depositary to a holder under the Deed Poll is limited to the lesser of:
  - the value of the Shares that would have been properly attributable to the Depositary Interests to which the liability relates; and
  - that proportion of £5 million which corresponds to the portion which the amount the Depositary would otherwise be liable to pay to the holder bears to the aggregate of the amounts the Depositary would otherwise be liable to pay to all such holders in respect of the same act, omission or event which gave rise to such liability or, if there are no such amounts, £5 million.
- The Depositary is entitled to charge holders of Depositary Interests fees and expenses for the provision of its services under the Deed Poll.
- Each holder of Depositary Interests is liable to indemnify the Depositary and any Custodian (and their agents, officers and employees), and hold each of them harmless, from and against all liabilities arising from or incurred in connection with, or arising from any act related to, the Deed Poll so far as they relate to the property held for the account of that holder, other than those caused by or resulting from the wilful default, negligence or fraud of: (i) the Depositary; or (ii) the Custodian or any agent if such Custodian or agent is a member of the Depositary's group or if, not being a member of the same

group, the Depositary shall have failed to exercise reasonable care in the appointment and continued use of such Custodian or agent.

- The Depositary is entitled to make deductions from the deposited property or any income or capital arising therefrom, or to sell such deposited property and make deductions from the sale proceeds thereof, in order to discharge the indemnification obligations of Depositary Interest holders.
- The Depositary may terminate the Deed Poll by giving not less than 90 days' notice. During such notice period, Depositary Interest holders may cancel their Depositary Interests and withdraw their deposited property and, if any Depositary Interests remain outstanding after termination, the Depositary shall, as soon as reasonably practicable and amongst other things: (i) deliver the deposited property in respect of the Depositary Interests to the relevant Depositary Interest holder; or at the Depositary's discretion; (ii) sell all or part of such deposited property. It shall, as soon as reasonable practicable, deliver the net proceeds of any such sale, after deducting any sums due to the Depositary, together with any other cash held by it under the Deed Poll, *pro rata* to the Depositary Interest holders in respect of their Depositary Interests.
- The Depositary or the Company may require from any holder: (i) information as to the capacity in which Depositary Interests are owned or held by such holders and the identity of any other person with any interest of any kind in such Depositary Interests or the underlying Shares and the nature and amounts of such interests; (ii) evidence or declaration of nationality or residence of the legal or beneficial owner(s) of Depositary Interests and such information as is required to transfer the relevant Depositary Interests or Shares to the holder; and (iii) such information as is necessary or desirable for the purposes of the Deed Poll or CREST system, and holders are bound to provide such information requested. The holders of Depositary Interests consent to the disclosure of such information by the Depositary, Custodian or Company to the extent necessary or desirable to comply with their respective legal or regulatory obligations.
- Furthermore, to the extent that the Company's constitutional documents, applicable laws or regulations, the Ground Rules for the Management of the FTSE UK Index Series (if applicable), or any court or legal or regulatory authority may require or the Company deems it necessary or desirable in connection therewith (including in response to requests for information), the disclosure to the Company of, or limitations in relation to, beneficial or other ownership of, or interests of any kind whatsoever in the Company's securities, the Depositary Interest holders are to comply with such provisions and with the Company's securities, the Depositary Interest holders are to comply with such provisions and with the Company's instructions with respect thereto, and consent to the disclosure of such information for such purposes.
- It should also be noted that holders of Depositary Interests may not have the opportunity to exercise all of the rights and entitlements available to holders of Shares, including, for example, the ability to vote on a show of hands. In relation to voting, it will be important for holders of Depositary Interests to give prompt instructions to the Registrar or its nominated Custodian, in accordance with any voting arrangements made available to them, to vote the underlying Shares on their behalf or, to the extent possible, to take advantage of any arrangements enabling holders of Depositary Interests to vote such Shares as a proxy of the Registrar or its nominated Custodian.

2. Depositary Agreement

The Depositary Agreement entered into between the Company and the Depositary prior to Admission contains the following provisions:

- Under the Depositary Agreement, the Company appoints the Depositary to constitute and issue from time to time, upon the terms of the Deed Poll, a series of Depositary Interests representing Shares and to provide certain other services (including depositary services, custody services and dividend services) in connection with such Depositary Interests.
- The Depositary agrees that it will comply with the terms of the Deed Poll and that it will perform its obligations with reasonable skill and care. The Depositary assumes certain specific obligations, including, for example, to arrange for the Depositary Interests to be admitted to CREST as participating securities and provide copies of, and access to, the register of Depositary Interests.
- The Company acknowledges that it shall be its responsibility and undertakes to advise the Depositary promptly of any securities laws or other applicable laws, rules or regulations in Canada with which the Depositary must comply in providing the services.

- The Company agrees to provide such assistance, information and documentation to the Depositary as is reasonably required by the Depositary for the purposes of performing its duties, responsibilities and obligations under the Depositary Agreement.
- The Depositary is to indemnify the Company and its officers and employees from and against any loss (excluding indirect, consequential or special loss) which any of them may incur in any way as a result of or in connection with the fraud, negligence or wilful default of the Depositary (or its officers, employees, agents or sub-contractors).
- Subject to earlier termination, the appointment of the Depositary shall continue for a fixed period of one year and thereafter until terminated in accordance with the terms of the Depositary Agreement. Should the Depositary Agreement be terminated for any reason, other than arising from the Depositary's fraud, negligence, wilful default or material breach of a term of the Depositary Agreement, the Company shall within 30 days of termination pay to the Depositary the Depositary's reasonable costs and expenses of transferring the Depositary Interest register to its new registrar. Either party may terminate the Depositary Agreement by giving not less than 3 months' notice in writing. Either party may terminate the Depositary Agreement with immediate effect by notice in writing if the other party: (i) shall be in persistent or material breach of any material term (of the Depositary Agreement) and such breach is not remedied within 21 days of a request for such remedy; (ii) goes into insolvency or liquidation or administration or a receiver is appointed over any part of its undertaking or assets, subject to certain provisos; or (iii) shall cease to have the appropriate authorisations which permit it lawfully to perform its obligations under the Depositary Agreement.
- The Depositary will be entitled to employ agents for the purposes of carrying out certain of its obligations under the Depositary Agreement which the Depositary reasonably considers to be of a specialist nature.
- The Company is to pay to the Depositary an annual fee for the services. The Company shall pay a fixed fee for the deposit, cancellation and transfer of the Depositary Interests and the compilation of the initial Depositary Interests register. The Company shall in addition reimburse the Depositary within 30 days of the Depositary's invoice for all network charges, CREST charges, money transmission and banking charges and other out-of-pocket expenses incurred by it in connection with the provision of the services under the Depositary Agreement.
- The Company will indemnify the Depositary from and against all loss suffered by the Depositary as a result of or in connection with the performance of its obligations under the Depositary Agreement.
- The aggregate liability of the Depositary to the Company over any 12-month period under the Depositary Agreement will not exceed twice the amount of the Fees (as defined in the Depositary Agreement) payable in any 12-month period in respect of a single claim or in the aggregate.

PART 13 – CAPITALISATION AND INDEBTEDNESS

The tables below set out the Group's capitalisation as at 31 December 2018 and net financial indebtedness as at 28 February 2019.

1. CAPITALISATION AND INDEBTEDNESS

The capitalisation information as at 31 December 2018 set out below have been extracted without material adjustment from the Group's historical financial information set out in the Appendix to this document:

	As at 31 December 2018 C$'000
Shareholders' equity	
Share capital	205,320
Share premium	20,123
Other reserves[1]	(129,224)
Total	96,219

Note:

(1) Other reserves includes accumulated comprehensive losses and deficit.

There has been no material change in the Group's capitalisation since 31 December 2018.

The following table sets out the Group's indebtedness as at 28 February 2019:

	As at 28 February 2019 C$'000
Current debt	
Guaranteed	–
Secured	–
Unguaranteed/unsecured	–
Total non-current debt (excluding current portion of long-term debt)	
Guaranteed	–
Secured	–
Unguaranteed/unsecured	–
Total gross indebtedness	–

2. NET FINANCIAL INDEBTEDNESS

The following table sets out the Group's net financial indebtedness as at 28 February 2019:

	As at 28 February 2019 C$'000
A. Cash	65,608
B. Cash equivalent	–
C. Trading securities	–
D. Liquidity (A+B+C)	65,608
E. Current financial receivables	–
F. Current bank debt	–
G. Other current portion of non-current debt	–
H. Other current financial debt	–
I. Current financial debt (F+G+H)	–
J. Net current financial assets (D+E+I)	65,608
K. Non-current bank loans	–
L. Bonds issued	–
M. Other non-current loans	–
N. Non-current financial indebtedness (K+L+M)	–
O. Net financial indebtedness (J-N)	65,608

The Group had no other indirect or contingent liabilities, or any contingent commitments as at 28 February 2019.

There has been no material change in the indebtedness of the Group since 28 February 2019.

PART 14 – TAXATION

The information set out below describes the principal UK and Canadian tax consequences of the acquisition, holding and disposal of the Common Shares and is included for general information only. It is not intended to be, nor should it be construed to be, legal or tax advice to any prospective investors. This Section does not take into account the individual circumstances of any prospective investors and should not be relied upon by any prospective investor or any other person. Each prospective investor should obtain, and only rely upon, their own professional tax advice regarding the tax consequences of acquiring, holding and disposing of the Company's Common Shares under the laws of their country and/or state of citizenship, domicile or residence. Should any withholding taxes be payable on amounts payable by the Company, the Company assumes responsibility for withholding of such taxes at the source. This summary is based on tax legislation in force as at the Last Practicable Date, without prejudice to any amendments introduced at a later date and implemented with retroactive effect.

1. Tax Residency

Valeura is incorporated in Canada and considered to be a Canadian tax resident. Companies incorporated in Canada are generally residents of Canada for income tax purposes, as are companies that are not incorporated in Canada but that carry on business in Canada with either their central management and control in Canada or their voting power controlled by Canadian residents. An individual is generally considered to be a tax resident of Canada if he or she is domiciled in Canada or physically present in Canada for a period or periods exceeding in aggregate more than 183 days in any calendar year. A Canadian tax resident is subject to income tax in Canada on its worldwide income, subject to certain exemptions.

Other members of the Group may be subject to the payment of corporate or other tax in jurisdictions outside of Canada either where they have their registered office and/or where they are managed and controlled and/or carry out their operations (subject to the tax laws in the relevant jurisdictions). The tax residency status of other Group companies has not been examined in this document. This section has been limited to outlining the tax rules and rates applicable in the three principle jurisdictions where the Company and/or its Group companies may have business interests and/or where its shareholders may be tax resident for the purposes of preliminarily assessing taxable income derived from shares held in the Company. However, each shareholder should obtain independent professional advice as to the tax implications of its shareholding.

2. UK taxation

The following statements are intended only as a general guide to current UK tax legislation and to the current practice of HMRC and may not apply to certain shareholders in the Company, such as dealers in securities, insurance companies and collective investment schemes. They relate (except where stated otherwise) to persons who are resident, and in the case of individuals, domiciled in (and only in) the UK for UK tax purposes, who are beneficial owners of Common Shares (and any dividends paid on them) and who hold their Common Shares as an investment (and not as employment-related securities and other than via an individual savings account). They are based on current UK legislation and what is understood to be the current practice of HMRC as at the Last Practicable Date, both of which may change, possibly with retroactive effect. The tax position of certain categories of shareholders who are subject to special rules (such as persons acquiring their Common Shares in connection with employment, dealers in securities, insurance companies and collective investment schemes or those who hold 10 per cent. or more of the Common Shares or those who are non-UK domiciled individuals) is not considered.

Any person who is in any doubt as to his or her tax position, or who is subject to taxation in any jurisdiction other than that of the UK, should consult his or her own professional advisers immediately.

Taxation of dividends – Individual Shareholders

UK resident individual Shareholders will be liable to income tax in respect of dividends or other income distributions of the Company. A UK resident individual Shareholder will generally benefit from an allowance in the form of a zero per cent. rate of tax for the first £2,000 of dividend income received in the 2018/19 tax year ("**Dividend Allowance**"). Any dividends above the Dividend Allowance will be taxable at 7.5 per cent.

(to the extent it falls within an individual's basic rate band), 32.5 per cent. (to the extent it falls within an individual's higher rate band) or 38.1 per cent. (to the extent it falls within an individual's additional rate band) for the 2018-19 tax year.

Taxation of dividends – Corporate Shareholders

Dividends paid to a UK resident corporate Shareholder will be taxable income of the UK corporate Shareholder unless the dividends fall within an exempt class and certain other conditions are met. It is likely that most dividends paid to UK resident corporate shareholders may fall within one or more of the classes of dividend qualifying for exemption from corporation tax. However, it should be noted that the exemptions are not comprehensive and are also subject to anti-avoidance rules.

To the extent that dividends are not exempt, UK resident corporate Shareholders may in certain circumstances be able to obtain credit for any withholding tax and any underlying tax paid by the Company, subject to certain conditions. The UK has complex double tax relief where UK resident companies receive dividends from non-UK resident companies and therefore UK resident corporate Shareholders should seek further advice on these issues.

Taxation of dividends – Trustees

The annual dividend allowance available to individuals will not be available to UK resident trustees of a discretionary trust. Generally, dividends received by UK resident trustees of a discretionary trust are liable to income tax at a rate of 38.1 per cent. (save the first £1,000 of trust income which may attract a lower rate of 7.5 per cent.). The £1,000 dividend allowance for trustees must be divided by the total number of trusts which the settlor has settled. However, if the settlor has set up five or more trusts, the standard rate band for each trust is £200.

Taxation of dividends – UK pension funds and charities

UK pension funds and charities are generally exempt from tax on dividends which they receive.

Other Shareholders who are not resident in the UK for tax purposes should consult their own advisers concerning their tax liabilities on dividends received.

Chargeable gains

Shareholders who are resident in the UK for tax purposes and who dispose of their Common Shares at a gain will ordinarily be liable to UK taxation on chargeable gains, subject to any available exemptions or reliefs. The gain will be calculated as the difference between the sale proceeds and any allowable costs and expenses, including the original acquisition cost of the Common Shares.

Shareholders who are not resident in the UK for tax purposes but who carry on business in the UK through a branch, agency or permanent establishment with which their investment in the Company is connected may give rise to a chargeable gain or an allowable loss for the purposes of UK taxation of chargeable gains.

If a UK resident individual Shareholder ceases to be resident in the UK and subsequently disposes of Common Shares, in certain circumstances any gain on that disposal may be liable to UK capital gains tax upon that Shareholder becoming once again resident in the UK.

For UK resident individual Shareholders, capital gains tax at the rate of 10 per cent. (for basic rate taxpayers) or 20 per cent. (for higher or additional rate tax payers) will be payable on any gain. UK resident individual Shareholders may benefit from certain reliefs and allowances (including a personal annual exemption allowance, which for 2018-19 tax year exempts the first £11,700 of gains from tax) depending on their circumstances.

For UK resident corporate Shareholders any chargeable gain will be within the charge to corporation tax. UK corporate Shareholders can benefit from indexation allowance up to 31 December 2017 (which, in general terms, increases the chargeable gains tax base cost of an asset in accordance with the rise in the retail prices index up to 31 December 2017), but indexation allowance for corporate shareholders no longer applies post 31 December 2017. Accordingly, any new (post 31 December 2017) UK tax resident corporate shareholder holding any rolled over tax base cost pre 31 December 2017 may claim indexation allowance

on a subsequent disposal on the shares in Valeura but such indexation allowance will only be up to 31 December 2017.

Stamp duty and stamp duty reserve tax (SDRT)

The statements below are intended as a general guide to the current position under UK tax law. They do not apply to certain intermediaries who may be eligible for relief from stamp duty or SDRT, or to persons connected with depositary arrangements or clearance services (or, in either case, their nominees or agents), who may be liable to stamp duty or SDRT at a higher rate.

Treatment of the transfer of Common Shares into CREST and the trading of Depositary Interests within CREST

Admission of the Common Shares to the standard segment of the Official List should not give rise to a liability to stamp duty or SDRT on the basis that the Admission does not involve a change in title or beneficial ownership in the Common Shares for consideration.

Where there is a transfer of Common Shares into CREST (where Depositary Interests are issued) there should be no SDRT or stamp duty provided that there is no change in beneficial ownership of the Common Shares.

Where there is a transfer of Common Shares into CREST (where Depositary Interests are issued) and there is a change in beneficial ownership of the Common Shares, no charge to SDRT should arise on the basis that:

- the Company is incorporated outside of the UK;
- the register of members of the Company is, and will be, maintained outside of the UK; and
- the Common Shares are not paired with UK shares.

Assuming that no document of transfer is executed for such a transfer there should be no stamp duty either.

Where Depositary Interests are traded (wholly within CREST), no charge to SDRT should arise on the basis that "Chargeable securities" do not include interests in depository receipts for stocks and shares.

Since any transfer of the Depositary Interests will be wholly within CREST, and no documents of transfer will be executed, no charge to stamp duty should arise on the transfer of Depositary Interests (wholly within CREST).

Treatment of the transfer of Common Shares out of CREST and trading of the underlying Common Shares

Where there is a transfer of Common Shares out of CREST (which may involve a collapse of the Depositary Interests) and there is a change in beneficial ownership of the Common Shares, no charge to SDRT should arise, provided that:

- the register of members of the Company continues to be maintained outside the UK; and
- the Common Shares are not paired with shares or marketable securities in UK-incorporated companies.

Provided that the register of members of the Company continues to be maintained outside the UK, and the Common Shares are not paired with shares or marketable securities in UK incorporated companies, there should be no SDRT on any agreement to transfer the Common Shares themselves.

However, any document transferring title to the Common Shares will be technically within the scope of UK stamp duty (at the rate of 0.5 per cent., rounded to the nearest £5) if it is executed in the UK or relates (wheresoever executed) to any matter or thing done or to be done in the UK. Where stamp duty arises, this is generally payable by the purchaser.

Stamp duty is not a directly enforceable tax. As such, any stamp duty which may arise should not generally be required to be paid in respect of transfers of Common Shares, unless the document of transfer is required

to be relied upon as evidence in a UK court or for other official purpose in the UK. However, where the stamp duty is paid late, interest and penalties may arise.

Inheritance Tax

If any individual Shareholder is regarded as domiciled in the UK for inheritance tax purposes, inheritance tax may be payable in respect of the Common Shares on the death of the Shareholder or on certain gifts of the Common Shares during their lifetime, subject to any allowances, exemptions or reliefs.

Non-UK domiciled individual Shareholders may be regarded as deemed domiciled for inheritance tax purposes following a long period of residence in the UK. Further advice should be sought in these circumstances.

Individual Shareholders who are in any doubt about the impact of this change on their tax position should obtain detailed tax advice from their own professional advisers.

UK inheritance tax is a complex area and individuals should obtain their own advice in respect of this.

3. Canadian tax

General

The following is a summary of the principal Canadian federal income tax considerations generally relevant to Shareholders who, at all relevant times, for purposes of the Income Tax Act (Canada) the ("**Canadian Tax Act**"): (i) are not resident in Canada and are not deemed to be resident in Canada; (ii) do not use or hold, and are not deemed to use or hold, Common Shares in connection with carrying on a business in Canada; and (iii) hold their Common Shares as capital property. Shareholders who meet all of the foregoing requirements are referred to in this summary as "non¬resident Shareholder" and this summary applies only to such non-resident Shareholders.

Special rules, which are not discussed in this summary, may apply to a non-resident Shareholder that is an insurer that carries on business in Canada and elsewhere or an "authorized foreign bank" as defined in the Canadian Tax Act. This summary is based upon the current provisions of the Canadian Tax Act and the regulations thereunder, the current provisions of the Canada-United Kingdom Income Tax Convention (the "**UK Treaty**"), and the Company's counsel's understanding of the current administrative policies and assessing practices of the Canada Revenue Agency made publicly available in writing prior to the date hereof. This summary also takes into account specific proposals to amend the Canadian Tax Act announced prior to the date hereof by or behalf of the Minister of Finance (Canada) (the "**Proposed Amendments**") and assumes that the Proposed Amendments will be enacted as proposed. No assurances can be given that the Proposed Amendments will become law. This summary is not exhaustive of all possible Canadian federal income tax considerations and does not take into account or anticipate any changes in law, administrative policy or assessing practice, whether by legislative, governmental, administrative or judicial action, other than the Proposed Amendments. This summary does not deal with foreign, provincial or territorial income tax considerations, which may differ from the federal considerations. This summary is of a general nature only and is not, and is not to be construed as, legal or income tax advice to any particular non-resident Shareholder. Each non-resident Shareholder is urged to obtain independent tax advice as to the Canadian income tax consequences of an investment in Common Shares applicable to the non-resident Shareholder's particular circumstances.

Taxation of Dividends

Any dividend on a Common Share that is paid or credited, or deemed to be paid or credited, by the Company to a non-resident Shareholder will be subject to Canadian withholding tax at the rate of 25 per cent. of the gross amount of the dividend. The rate of withholding tax may be reduced under the provisions of an applicable income tax convention between Canada and the country in which the non-resident Shareholder is resident for tax purposes. Pursuant to the UK Treaty, the rate of withholding tax applicable to a dividend paid (or deemed to be paid) on a Common Share to a non¬resident Shareholder who is a resident of the United Kingdom for purposes of the UK Treaty (a "**UK Shareholder**") will generally be reduced to 15 per cent. of the gross amount of the dividend (or 5 per cent. in the case of a UK Shareholder that is a company that controls, directly or indirectly, at least 10 per cent. of the voting power of the Company). The Company will be required to withhold any such tax from the dividend paid or credited to the non-resident

Shareholder and will remit the withheld tax directly to the Receiver General for Canada for the account of the non-resident Shareholder.

Taxation of Capital Gains

A non-resident Shareholder generally will not be subject to tax under the Canadian Tax Act on any capital gain realized by the non-resident Shareholder on a disposition (or deemed disposition) of a Common Share unless the Common Share constitutes "taxable Canadian property" to the non¬resident Shareholder for purposes of the Canadian Tax Act. Provided that the Common Shares are listed on a "designated stock exchange" as defined in the Canadian Tax Act (which includes tiers 1 and 2 of the TSXV), the Common Shares generally will not constitute taxable Canadian property to the non-resident Shareholder unless at any time during the 60 month period immediately preceding the disposition: (i) the non-resident Shareholder, persons with whom the non-resident Shareholder does not deal at arm's length, or partnerships in which the non-resident Shareholder, or a person with whom the non-resident Shareholder does not deal at arm's length, holds a membership interest directly or indirectly through one or more partnerships, owned 25 per cent. or more of the issued shares of any class of the capital stock of the Company; and (ii) more than 50 per cent. of the fair market value of the Common Shares was derived directly or indirectly from one or any combination of real or immovable property situated in Canada, "Canadian resource properties" (as defined in the Canadian Tax Act), "timber resource properties" (as defined in the Canadian Tax Act) or options in respect of, or interests in, or for civil law rights in, such property whether or not such property exists. Further, Common Shares may be deemed to be taxable Canadian property to a non-resident Shareholder for purposes of the Canadian Tax Act in certain circumstances.

Any non-resident Shareholder that would otherwise be subject to Canadian income tax on a capital gain realized on a disposition of a Common Share that constitutes taxable Canadian property to the non-resident Shareholder may be eligible for relief pursuant to an income tax convention between Canada and the country in which the non-resident Shareholder is resident for tax purposes. Non¬resident Shareholders who may hold Common Shares as "taxable Canadian property" should consult their own tax advisors.

PART 15 – ADDITIONAL INFORMATION

1. Responsibility Statement

The Company and each of the Directors, whose names appear on page 38 of this document, accept responsibility for the information contained in this document. To the best of the knowledge of the Company and the Directors (who have taken all reasonable care to ensure that such is the case), the information contained in this document is in accordance with the facts and does not omit anything likely to affect the import of such information.

2. D&M Responsibility Statement

D&M accepts responsibility for the CPRs contained in Part 18 '*Competent Person's Reports*'. To the best of the knowledge and belief of D&M (which has taken all reasonable care to ensure that such is the case), the information contained in the CPRs is in accordance with the facts and contains no omissions likely to affect the import of such information.

D&M is responsible for the CPRs, all information extracted from the CPRs and included in the Prospectus, estimates of reserves and resources contained therein, as well as references to them, and statements and information attributed to them or extracted from the CPRs and included in the Prospectus in the form and context in which they appear. To the best of the knowledge of D&M (who have taken all reasonable care to ensure that such is the case), the information in the CPRs, all information extracted from the CPRs and included in the Prospectus, estimates of reserves and resources contained therein, as well as references to them, and statements and information attributed to them or extracted from the CPRs, are in accordance with the facts and contain no omissions likely to affect their import.

3. The Company

Valeura Energy Inc. is a public company, incorporated pursuant to the terms of the ABCA on 7 June 2000 in Alberta, Canada with corporate access number 208838144. The Company is domiciled in Alberta, Canada with a registered office of 4600, 525 – 8th Ave SW, Calgary, Alberta, T2P 1G1, and a business address for all of the Directors and Senior Managers, as at the date of this document, being Suite 1200, 202 – 6th Avenue SW, Calgary, Alberta, T2P 2R9, Canada. The Company's telephone number is (+1) 403 237 7102. The principal legislation under which the Company operates is the ABCA. The liability of each Shareholder is limited by the amount, if any, unpaid on the shares held by him.

4. Share capital of the Company

As at the Last Practicable Date, the Company has an issued share capital of 86,584,989 Common Shares, all of which are fully paid up.

The issued share capital of the Company immediately after Admission is expected to be 86,584,989 Common Shares.

On Admission, it is expected that approximately 74 per cent. of the Common Shares will be held in public hands (within the meaning of Listing Rule 14.2.2(4)).

The Common Shares will be registered, and may be held in either certificated or uncertificated form (by way of Depository Interests.

During the period covered by the Historical Financial Information, there have been the following changes to the Company's issued share capital:

(1) 2016 Subscription Receipts Offering: On 14 October 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 at a price of $0.75 per subscription receipt for total gross proceeds of approximately $11 million, subject to certain conditions, including, without limitation, the closing of the TBNG Acquisition described below. On 24 February 2017 the TBNG Acquisition closed, resultantly

14,629,000 common shares were issued pursuant to 14,629,000 subscription receipts and gross proceeds of approximately $11 million were released from escrow.

(2) 2017 TBNG Acquisition: In February 2017, Valeura closed the acquisition of 100% of the shares of TBNG from TransAtlantic for US$20.7 million. Net cash consideration was $21.5 million, representing the cash price paid ($27.1 million) less cash received ($5.6 million). Following closing of the TBNG Acquisition, TBNG entered into a sale and purchase agreement with Statoil Turkey on 10 March 2017 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 $3.9 million.

(3) 2017 Banarli Farm-In: In the first half of 2017, Valeura closed several farm-in and sales agreements with Statoil Turkey to give Statoil Turkey, now Equinor Turkey, rights to 50% interest in the deep rights in the Banarli and West Thrace lands by paying US$21 million in cash and fully funding the drilling and testing of two deep exploration wells and completion of a 3D seismic program, with each respective funding obligation having a minimum expenditure of $10 million.

(4) 2018 Equity offering: The increase in the working capital/cash position in 2018 was mainly due to the net proceeds of $55.4 million from the equity financing (net of share issuance costs) completed in Q1 2018 (the "2018 Offering"). On 1 March 2018, the Company closed an agreement with a syndicate of underwriters agreed to purchase on a bought deal basis 10,527,000 common shares at a price of $5.70 per share, for total gross proceeds of approximately $60.0 million (net $55.4 million after fees and expenses related to the offering).

(5) Natural gas pricing: Between 1 October 2014 and 30 September 2016 the BOTAS benchmark natural gas price remained unchanged but effective 1 October 2016 the price was reduced by 10 percent. The Company's average gas price for 2017 decreased to $6.98 per Mcf from $9.20 per Mcf in 2016 due to the reference price decrease and the weakening of the TL against the Canadian dollar. The average discount to reference price decreased from about 2% in 2016 to 1% in 2017. In 2018, the government has continued to increase the BOTAS Reference Price thereby offsetting the decline in the value of the TL and the increase in regional gas prices. Effective 1 January 2018, 1 April 2018, 1 August 2018, 1 September 2018 and 1 October 2018 the BOTAS Reference Price was increased by 14%, 10%, 14%, 14% and 18.5% respectively. The Company's average realized natural gas price for 2108 was $7.54 per Mcf, an increase over the 2017 realized price of $6.98. The increase is due to the previously described reference price increases, offset by the weakening of the TL against the Canadian dollar. The realized price for 2018 represents a 1.0% discount to the BOTAS benchmark price, which is similar to the discount realized for 2017.

(6) Production and sales: Production increased from 799 boe/day in 2016 to 952 boe/day in 2017 due to additions from the acquisition of TBNG, workovers, recompletions and new drills, partially offset by natural declines on both the TBNG Lands and Banarli Exploration Licences. Sales volumes for the year ended 31 December 2018 were 717 boe/d compared to 952 boe/d for the same period in 2017. Sales volumes decreased due to natural declines causing lower gross production.

(7) Funds flow: Adjusted funds flow for the year ended 31 December 2017 was an outflow of $1.2 million compared to an inflow of $6.0 million for the same period 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 were not considered ongoing expenses. Adjusted funds flow for the year ended 31 December 2018 was $3.7 million compared to an outflow of $1.2 million for the same period in 2017. The increase in adjusted funds flow for 2018 was due to increased realized prices and absence of expenses related to the TBNG Acquisition and Banarli Farm-In which negatively impacted 2017 results. The increase was offset by current tax payments.

In the period following the period covered by the Historical Financial Information, there have been the following changes to the Company's issued share capital:

	Period from 31 December 2018 to the Last Practicable Date	*Y/E 31 Dec 2018*	*Y/E 31 Dec 2017*	*Y/E 31 Dec 2016*
Balance, Beginning of period	86,232,988	73,148,321	58,519,321	57,906,135
Options Exercised	352,001	2,557,667		546,666
Shares issued for services rendered				66,520
Public offering		10,527,000	14,629,000	
Balance, end of period	86,584,989	86,232,988	73,148,321	58,519,321

5. Canadian Takeover Provisions

In Canada, takeover bids are governed by applicable corporate and securities legislation in each province or territory in addition to policy and instruments, namely National Instrument 62-104, Takeover Bids and Issuer Bids, implemented by Canadian Securities Administrators, which is an umbrella organisation of Canada's provincial and territorial securities regulators.

Under Canadian securities laws, any person who directly or indirectly acquires beneficial ownership of, or the power to exercise control or direction over, shares (or securities convertible into shares) of a company that, together with any shares held by that person, would constitute 10 per cent. or more of the outstanding shares, must forthwith issue a news release in Canada announcing, among other things, the number of such securities they hold and their intentions with respect to the securities of the company. A formal report (an "early warning report") setting forth details regarding the acquisition is also required to be filed with the Securities Commissions of the Provinces, within two business days of the acquisition of shares (or convertible securities) that results in the person holding 10 per cent. or more of such securities. If a person's beneficial ownership of, or control or direction over, shares (or securities convertible into shares) decreases to less than 10 per cent. of such securities, that person must issue a news release and file an early warning report disclosing the same information as described above.

Whenever a person who has filed an early warning report acquires or disposes beneficial ownership of, or acquires or ceases to have control over, 2 per cent. of the Company's shares (including securities convertible into shares), or if there is a change in a material fact disclosed in a previously filed report, an additional report must be filed within the same time limits. A determination of whether any parties are acting jointly or in concert is a question of fact that is deemed to exist in certain circumstances such as when one party is dealing with an affiliate, or the existence of an agreement, commitment or understanding with the other party. Certain institutional investors, such as investment managers acting on behalf of investors on a fully discretionary basis, financial institutions, pension funds and private mutual funds, may elect an alternative monthly reporting system whereby they report changes, on a monthly as opposed to a two business day basis, of at least 2.5 per cent. from the last reported position or that the position has decreased below 10 per cent.

In all Canadian jurisdictions, a takeover bid is generally defined as an offer to acquire outstanding voting or equity securities of a class made to any holder , if the securities subject to the offer to acquire, together with securities held by the offeror and any person acting jointly or in concert with the offeror, constitute in aggregate 20 per cent. or more of the outstanding securities of that class of securities at the date of the offer to acquire. A takeover bid does not include an offer to acquire if the offer to acquire is a step in an amalgamation, merger, reorganisation or arrangement that requires the approval in a vote of shareholders. Subject to limited exemptions, a takeover bid must: (i) be made available to all shareholders, (ii) be open for acceptance for a minimum of 105 days, subject to certain exceptions, (iii) require more than 50 per cent. of the applicable securities be deposited under the bid, (iv) offer identical consideration to all shareholders, and (v) be made by a takeover bid circular containing prescribed information about the bidder and its intentions with respect to the Company. The directors of the reporting issuer must deliver a directors' circular not later than 15 days after the date of the bid, either making or declining to make a recommendation to security holders to accept or reject the bid and the reasons for their making or not making a recommendation.

Whilst provincial securities laws in Canada only regulate offers to residents of that particular Province, the CSA has adopted a policy whereby they may issue a cease trade order prohibiting the trading of the securities of a company if a takeover bid is not made to all Canadian security holders. It should be noted that one exemption from the aforementioned provisions is in the case of a foreign takeover bid and various prescribed criteria are applicable to the offeree and its security holders at the time of the issue of such bid.

6. Minority shareholders

The ABCA provides certain statutory remedies to shareholders including derivative actions, personal actions and representative actions. The courts may consider claims by shareholders alleging that a company has acted in a manner oppressive or unfairly prejudicial to a shareholder. The ABCA further provides that any shareholder of a company is entitled to payment of the fair value of their shares upon dissenting from any of the following:

(a) certain amendments to the articles of the company;

(b) an amalgamation, other than in the case of certain wholly owned companies;

(c) a continuation to a jurisdiction other than Alberta;

(d) any sale, lease or exchange all or substantially all its property; or

(e) an arrangement, if permitted by the court.

Generally, any other claims against a company by its shareholders must be based on the general laws of contract or tort applicable in Alberta.

Amalgamations and arrangements generally require the approval of two thirds of the votes entitled to vote and voted at a meeting to approve the transaction. Any sale, transfer, lease or other disposition of all or substantially all of the undertakings of the company, other than in the ordinary course of business, requires the approval of two thirds of the votes entitled to vote and voted at a meeting to approve the transaction.

In addition, the Company is subject to Multilateral Instrument 61-101, "Protection of Minority Security Holders in Special Transactions", that regulates transactions such as "insider bids", "issuer bids," "business combinations" and "related party transactions" in order to ensure equal treatment of shareholders. Pursuant to the Instrument, certain transactions may be subject to valuation and shareholder voting requirements that are in addition to those imposed by the ABCA and the rules of the TSX.

7. Substantial holdings

In addition to the reporting requirements discussed above in "5 Canadian Takeover Provisions", National Instrument 55-104, "Insider Reporting Requirements and Exemptions" requires that any person or company that has beneficial ownership of, or control or direction over, whether direct or indirect, securities of a reporting issuer (such as the Company) carrying more than 10 per cent. of the voting rights attached to all the issuer's outstanding voting securities, including securities (issued and unissued) that the person or company is the beneficial owner of, which are convertible into voting securities within 60 days following that date, is required to provide public notice of their holdings. Insider reports are filed electronically using the System for Electronic Disclosure by Insiders ("SEDI") established by the CSA. Further information about SEDI can be found at the SEDI website (www.sedi.ca). Furthermore, a reporting issuer (such as the Company) is required by Form 51-102F5 of National Instrument 51-102, "Continuous Disclosure Obligations", to disclose in its information circulars whether, to the knowledge of its directors or executive officers, any person or company beneficially owns, or controls or directs, directly or indirectly, voting securities carrying 10 per cent. or more of the voting rights attached to any class of voting securities of such reporting issuer.

Under Disclosure Guidance and Transparency Rule 5 (Vote Holder and Issuer Notification Rules) ("**DGTR5**"), a person must notify the Company and the FCA of the percentage of the Company's voting rights he or she holds as a shareholder (or holds or is deemed to hold through his or her direct or indirect holding of financial instruments) if, as a result of an acquisition or disposal of Common Shares or financial instruments, or as a result of any event changing the breakdown of voting rights of the Company (for example, a buy-back of Common Shares by the Company), the percentage of those voting rights in which he is interested reaches,

exceeds or falls below 5 per cent., 10 per cent., 15 per cent., 20 per cent., 25 per cent., 30 per cent., 50 per cent. and 75 per cent.

The form in which such notification must be made is provided by the FCA on its website at:

https://www.fca.org.uk/markets/ukla/regulatory-disclosures/submit-investor-notification

Such notification must be made no later than four trading days after the date upon which the person making the notification (1) learns of the acquisition or disposal or of the possibility of exercising voting rights, or on which, having regards to the circumstances, should have learned of it, regardless of the date on which the acquisition, disposal or possibility of exercising voting rights takes effect, or (2) is informed about the event changing the breakdown of voting rights of the Company.

Any person who is in breach of their obligations under DGTR5 is liable to a fine and/or public censure by the FCA and the FCA may apply to court to have such person's voting rights suspended.

8. TSX Disclosure requirements

In addition to the numerous ongoing reporting requirements, commonly referred to as continuous disclosure obligations, for reporting issuers pursuant to applicable corporate and securities legislation in Canada, the TSX imposes certain disclosure and notification requirements on listed companies. The TSX's timely disclosure policy requires listed companies to immediately disclose any material information, with limited exceptions for confidentiality.

9. Constitution of the Company

The following is a non-exhaustive summary of the provisions of the Constitution. Please see paragraph 25 '*Documents available for inspection*' of this Part 15 for details of how to obtain a full copy of the Constitution.

(i) Objects

The Constitution does not contain any restrictions on the objects of the Company or the business to be carried out and performed by the Company.

(ii) Issue of shares

The Company has authorized an unlimited number of Common Shares and an unlimited number of Preferred Shares, issuable in series. No Preferred Shares are outstanding.

(iii) Common Shares

The holders of the Common Shares are entitled to dividends (subject to the rights of the Preferred Shares), if, as and when declared by the Board, to one vote per share at meetings of the Shareholders and, upon liquidation, dissolution or winding-up of the Company, to receive such assets of the Company as are distributable to the holders of the Common Shares.

(iv) Preferred Shares

Each series of Preferred Shares will have such designations, rights, privileges, restrictions and conditions as the Board may from time to time determine before issuance, including whether the holders of Preferred Shares are entitled to one vote per share at meetings of Shareholders.

The holders of each series of Preferred Shares will be entitled, in priority to holders of Common Shares, to be paid ratably with holders of each other series of Preferred Shares the amount of dividends, if any, specified as being payable preferentially to the holders of such series and, upon liquidation, dissolution or winding-up of the Company, in priority to holders of Common Shares, to be paid ratably with holders of each other series of Preferred Shares the amount, if any, specified as being payable preferentially to holders of such series.

(v) Variation of Rights

Subject to the ABCA and the terms of issue of shares of a particular class, the Company may by a resolution passed by a majority of not less than 2/3 of the votes cast by the Shareholders who voted in respect of that resolution (or signed by all the Shareholders entitled to vote on that resolution):

(a) change the designation of all or any of its shares, and add, change or remove any rights, privileges, restrictions and conditions, including rights to accrued dividends, in respect of all or any of its shares, whether issued or unissued,

(b) change the shares of any class or series, whether issued or unissued, into a different number of shares of the same class or series or into the same or a different number of shares of other classes or series, or

(c) divide a class of shares, whether issued or unissued, into series and fix the number of shares in each series and the rights, privileges, restrictions and conditions of that series.

Holders of shares of any class, or of a series if the series is affected by an amendment in a manner different from other shares of the same class, are entitled to vote separately as a class or series on a proposal to amend the articles of the Company, by special resolution, to:

(a) increase or decrease the maximum number of authorized shares of that class;

(b) increase the maximum number of authorized shares of a class having rights or privileges equal or superior to the rights or privileges attached to the shares of that class;

(c) effect an exchange, reclassification or cancellation of all or part of the shares of that class;

(d) add, change or remove the rights, privileges, restrictions or conditions attached to the shares of that class and, without limiting the generality of the foregoing, (i) remove or change prejudicially rights to accrued dividends or rights to cumulative dividends, (ii) add, remove or change prejudicially redemption rights, (iii) reduce or remove a dividend preference or a liquidation preference, or (iv) add, remove or change prejudicially conversion privileges, options, voting, transfer or pre-emptive rights, rights to acquire securities of a corporation or sinking fund provisions;

(e) increase the rights or privileges of any class of shares having rights or privileges equal or superior to the rights or privileges attached to the shares of that class;

(f) create a new class of shares having rights or privileges equal or superior to the rights or privileges attached to the shares of that class;

(g) make the rights or privileges of any class of shares having rights or privileges inferior to the rights or privileges of the shares of that class equal or superior to the rights or privileges of the shares of that class;

(h) effect an exchange or create a right of exchange of all or part of the shares of another class into the shares of that class; or

(i) constrain the issue or transfer of the shares of that class or extend or remove that constraint. The preceding entitlements to vote applies whether or not shares of a class or series otherwise carry the right to vote.

(vi) Number and Appointment of Directors

The number of directors must be at least one and not more than nine which number will be determined from time to time by resolution of the directors. The Shareholders shall, by ordinary resolution, at each annual meeting of Shareholder at which an election of directors is required, elect directors to hold office for a term expiring not later than the close of the next annual meeting of Shareholders. Pursuant to the ABCA, at least one-quarter of the directors must be residents of Canada.

The amended and restated by-laws of the Company provide that Shareholders should receive advance notice of nominations of directors ("Advance Notice") in circumstances where nominations for election to the Board are made by Shareholders other than: (a) pursuant to a requisition of a meeting made pursuant to the provisions of the ABCA, or (b) a shareholder proposal made pursuant to the provisions of the ABCA. The Advance Notice provision sets out a clear process for Shareholders to follow to nominate directors and sets out a reasonable time frame for nominee submissions along with a requirement for accompanying information

The Board may, between annual meetings of Shareholders appoint one or more additional directors to serve until the next annual meeting, but the number of additional directors shall not at any time exceed one-third of the number of directors who held office at the expiration of the last annual meeting of Shareholders. A director need not be a Shareholder but must meet the eligibility requirements for a director as prescribed in the ABCA.

(vii) Removal and Resignation of Directors

A director will cease to hold office when: (a) the director dies or resigns, (b) the director is removed by an ordinary resolution at a special meeting of Shareholders, or (c) the director becomes disqualified under the ABCA. A resignation of a director becomes effective at the time a written resignation is sent to the Company, or at the time specified in the resignation, whichever is later.

(viii) Powers of the Board

Pursuant to the ABCA, the management of the business and affairs of the Company is managed or supervised by the Board. Subject to the ABCA, the directors may appoint from their number a managing director, who must be a resident Canadian, or a committee of directors, at least one quarter of which must be resident Canadians, and delegate to the managing director or committee any of the powers of the Board.

The Board operates under written terms of reference that set out its responsibilities. The Board meets regularly and a broad range of matters are discussed and reviewed for approval. These matters include overall corporate plans and strategies, budgets, internal controls and management information systems, risk management as well as interim and annual financial and operating results. The Board is also responsible for the approval of all major transactions, including equity issuances, acquisitions and dispositions, as well as the Corporation's debt and borrowing policies. The Board strives to ensure that actions taken by management correspond closely with the objectives of the Board and Shareholders.

(ix) Interests of Directors

The Constitution does not preclude any director from serving the Company in any other capacity and receiving remuneration therefor. However, pursuant to the ABCA, a director who: (a) is a party to a material contract or material transaction or proposed material contract or proposed material transaction with the Company, or (b) is a director or an officer of, or has a material interest in, any person who is a party to a material contract or material transaction, or proposed material contract or proposed material transaction, with the Company, must disclose in writing to the Company, or request to have entered in the minutes of meetings of the Board, the nature and extent of the director's interest and, in certain circumstances, abstain from voting on such matter.

(x) Quorum of Shareholder Meetings

A quorum for the transaction of business at any meeting of Shareholders shall be at least two persons present in person, each being a Shareholder entitled to vote thereat, or a duly appointed proxy or representative for an absent Shareholder so entitled, and representing in the aggregate not less than twenty-five percent (25 per cent.) of the outstanding Common Shares.

(xi) Notice of Shareholder Meetings

Pursuant to the ABCA, notice of the time and place of a meeting of Shareholders shall be sent not less than 21 days and not more than 50 days before the meeting. Notice of the meeting must be sent to each Shareholder entitled to vote at the meeting, each director, and the auditor of the Company.

(xii) Transfer of Shares

The Constitution does not contain any restrictions on the transfer of Common Shares.

(xiii) Limitation of Liability and Indemnity

No director or officer for the time being of the Company shall be liable for the acts, receipts, neglects or defaults of any other director or officer or employee, or for joining in any receipt or act for conformity, or for any loss, damage or expense happening to the Company through the insufficiency or deficiency of title to any property acquired by the Company or for or on behalf of the Company or for the insufficiency or

deficiency of any security in or upon which any of the moneys of or belonging to the Company shall be placed or invested, or for any loss or damage arising from the bankruptcy, insolvency or tortious act of any person, firm or Company including any person, firm or Company with whom or with which any moneys, securities or effects shall be lodged or deposited, or for any loss, conversion, misapplication or misappropriation of or any damage resulting from any dealings with any moneys, securities or other assets of or belonging to the Company or for any other loss, damage or misfortune whatsoever which may happen in the execution of the duties of his or her respective office or trust or in relation thereto unless the same shall happen by or through his or her failure to exercise the powers and to discharge the duties of his or her office honestly, in good faith and with a view to the best interests of the Company and to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

The Company shall, to the maximum extent permitted under the ABCA or otherwise by law, indemnify a director or officer of the Company, a former director or officer of the Company, and a person who acts or acted at the Company's request as a director or officer, or an individual acting in a similar capacity, of another entity, and their heirs and legal representatives, against all costs, charges and expenses, including any amount paid to settle an action or satisfy a judgment, reasonably incurred by the individual in respect of any civil, criminal, administrative, investigative or other action or proceeding to which he or she is made a party to or involved by reason of that association with the Company or such other entity.

The Company shall, to the maximum extent permitted under the ABCA or otherwise by law, advance moneys to director or officer of the Company to defray the costs, charges and expenses of a proceeding provided such director or officer of the Company shall repay the moneys advanced if he or she does not fulfil the conditions set forth in the ABCA.

The Company shall use reasonable commercial efforts to obtain any court or other approvals necessary for any indemnification pursuant to its amended and restated by-laws.

(xiv) Borrowing powers

Subject to applicable law, the Company may borrow money, and give of security therefor, with such banks, trust companies or other bodies corporate or organizations, as may from time to time be authorized by the Board. Such banking business or any part thereof shall be transacted under such agreements, instructions and delegations of powers as the Board may from time to time prescribe or authorize.

10. Information on the Directors and Senior Managers

The Directors and Senior Managers, their functions within the Group and brief biographies are set out in Part 8 of this document, '*Directors, Senior Management and Corporate Governance*'.

Details of the names of companies and partnerships (excluding directorships in the Group) of which the Directors and Senior Managers are or have been members of the administrative, management or supervisory bodies or partners at any time in the five years preceding the date of this document are set out below:

Name	*Current partnerships/directorships*	*Past partnerships/directorships*
Directors		
Dr. Sean Guest	N/A	Chief Executive Officer of Bukit Energy from February 2014 to May 2017.
Dr. Timothy Marchant	Director of Vermilion Energy Inc. since 2010. Director of Cub Energy Inc. since 2013	
Russell Hiscock	Director of Rife Resources Ltd. since 2008. President and Chief Executive Officer of the CN Investment Division since 2008.	Director of Canpar Holdings Ltd. from 2008 to March 2018.
James McFarland	Director of Pengrowth Energy Corporation since 2010. Director of MEG Energy Corp. since 2010. Director of Arrow Exploration Corp. since 2018.	
Ronald Royal	Director of Gran Tierra Energy Inc. since 2015.	Director of Caracal Energy Inc. from 2011 to 2014. Director of Oando Energy Resources Inc. from 2015 to 2016.
Kimberley Wood	Director of Gulf Keystone Petroleum Inc., since 2015 Director of Africa Oil Corp. since 2018. Director of Peel House Limited since 2018	Norton Rose Fulbright LLP from May 2015 to March 2018 Vinson & Elkins LLP from February 2011 to March 2015
Senior Managers		
Stephen Bjornson	Director of Cematrix Corporation since July 2008	Director of Bulldog Oil & Gas Inc.
Lyle Martinson	N/A	N/A
Gord Begg	N/A	Chief Operating Officer of Bukit Energy Inc. May 2011 to June 2017.
Rob Sadownyk	N/A	N/A

None of the Directors or Senior Managers:

- have any convictions in relation to fraudulent offences for at least the previous five years; or
- have been associated with any bankruptcy, receivership or liquidation while acting in the capacity of a member of the administrative, management or supervisory body or of a senior manager of any company for at least the previous five years; or
- have been subject to any official public incriminations and/or sanctions by any statutory or regulatory authority (including designated professional bodies) for at least the previous five years; or
- have ever been disqualified by a court from acting as a director of a company, or from acting as a member of the administrative, management or supervisor bodies of a company, or from acting the management or conduct of the affairs of any company for at least the previous five years.

There are no family relationships between any of the Directors or Senior Managers.

There are no potential or actual conflicts of interest between any duties owed by the Directors or the Senior Managers to the Company and their private interests and/or other duties, save for their interest as holders of securities of the Company.

11. Directors' and Senior Managers' interests

As at the Last Practicable Date, the Common Shares held by the Directors and Senior Managers (all of which are held beneficially unless otherwise stated) are as follows:

	Immediately following Admission	
Name of Shareholder	*Number of Common Shares*	*Percentage of the share capital*
Directors		
Dr. Tim Marchant	210,000	0.0024%
Jim McFarland	451,134	0.0052%
Ron Royal	314,000	0.0036%
Russ Hiscock	20,000	0.0002%
Dr. Sean Guest	39,990	0.00046%
Kimberley Wood	–	–
Senior Management		
Stephen Bjornson	378,000	0.0044%
Lyle Martinson	152,385	0.0017%
Gord Begg	Nil	Nil
Rob Sadownyk	Nil	Nil

Details of Options granted to the Directors and Senior Managers are set out in paragraph 13 of this Part 15, '*Additional Information*'.

12. Major Shareholders

Save as set out below, as at the Last Practicable Date, the Company is not aware of any person who, directly or indirectly, is interested in 5 per cent. or more of the Company's capital or voting rights:

	Immediately following Admission	
Name of Shareholder	*Number of Common Shares*	*Percentage of the share capital*
Baillie Gifford & Co	15,285,400	17.7%

The Shareholder named in paragraph 12 above has no different voting rights from other Shareholders.

The Company is not aware of any person who, directly or indirectly, owns or controls the Company. The Company is not aware of any arrangements the operation of which may at a subsequent date result in a change of control of the Company.

13. Directors' and Senior Managers' service agreements

(i) Directors

The Company does not have formal service agreements with its Directors but Directors are eligible to participate in the Company's Stock Option Plan and Performance Share Unit Plan.

(ii) Senior Managers

President and Chief Executive Officer, Dr. Sean Guest – Dr Guest is employed as the Company's President and Chief Executive Officer pursuant to an executive employment agreement dated effective 23 May 2017, as amended. Dr Guest's annual salary is set by the Board and is subject review by the Board. Dr Guest is eligible for, at the discretion of the Board, a bonus in addition to his annual salary. At the discretion of the

Board, Dr Guest may be granted Options and Performance Share Units. Dr Guest is eligible to participate in all additional benefits that the Company provides for its executives. Dr Guest is also eligible for additional expatriate benefits based on any assignment term in Turkey and the frequency of travel required to fulfil his employment duties. In the event of termination of Dr Guest's agreement without cause, with cause by Dr Guest, or due to a change of control, Dr Guest is to be paid: 1) all unpaid salary to the date of termination; 2) all outstanding vacation pay; 3) any bonus declared but not yet paid; and upon receipt by the Company of a release from Dr Guest: 4) two times his annual salary; 5) two times the average amount of the bonus payments paid to Dr Guest for the three calendar years prior to the termination, and 6) an amount equal to the Corporation's cost of all benefits that Dr Guest is participating in at the time of termination for a period of two years following the date of termination. In the event of a change of control, the Company may terminate the agreement within ten days of such change in control, and Dr Guest has the option to terminate the agreement within sixty days of the change in control, upon thirty days written notice. Dr Guest is prohibited from competing with the Company during the term of his agreement and for a period of one year after its termination. Dr Guest is prohibited from soliciting employees, contractors and customers of the Company during the term of his agreement and for a period of one year after its termination. The agreement is governed by the laws of the Province of Alberta.

Chief Operating Officer, Lyle Martinson – Mr. Martinson is employed as the Company's Chief Operating Officer pursuant to an executive employment agreement dated effective 17 June 2011, as amended. Mr. Martinson's annual salary is set by the Board and is subject annual review by the Board. Mr. Martinson is eligible for, at the discretion of the Board, a bonus in addition to his annual salary. At the discretion of the Board, Mr. Martinson may be granted Options and Performance Share Units. Mr. Martinson is eligible to participate in all additional benefits that the Company provides for its executives. In the event of termination of Mr. Martinson's agreement without cause, with cause by Mr. Martinson, or due to a change of control, Mr. Martinson is to be paid: 1) all unpaid salary to the date of termination; 2) all outstanding vacation pay; 3) any bonus declared but not yet paid; and upon receipt by the Company of a release from Mr. Martinson: 4) one times his annual salary; 5) one times the average amount of the bonus payments paid to Mr. Martinson for the three calendar years prior to the termination, and 6) an amount equal to the Corporation's cost of all benefits that Mr. Martinson is participating in at the time of termination for a period of one year following the date of termination. In the event of a change of control, the Company may terminate the agreement within ten days of such change in control, and Mr. Martinson has the option to terminate the agreement within sixty days of the change in control, upon thirty days written notice. Mr. Martinson is prohibited from competing with the Company during the term of his agreement and for a period of one year after its termination. Mr. Martinson is prohibited from soliciting employees, contractors and customers of the Company during the term of his agreement and for a period of one year after its termination. The agreement is governed by the laws of the Province of Alberta.

Chief Financial Officer, Steve Bjornson – Mr. Bjornson is employed as the Company's Chief Financial Officer pursuant to an executive employment agreement dated effective 17 June 2011, as amended. Mr. Bjornson's annual salary is set by the Board and is subject annual review by the Board. Mr. Bjornson is eligible for, at the discretion of the Board, a bonus in addition to his annual salary. At the discretion of the Board, Mr. Bjornson may be granted Options and Performance Share Units. Mr. Bjornson is eligible to participate in all additional benefits that the Company provides for its executives. In the event of termination of Mr. Bjornson's agreement without cause, with cause by Mr. Bjornson, or due to a change of control, Mr. Bjornson is to be paid: 1) all unpaid salary to the date of termination; 2) all outstanding vacation pay; 3) any bonus declared but not yet paid; and upon receipt by the Company of a release from Mr. Bjornson: 4) one and a half times his annual salary; 5) one and a half times the average amount of the bonus payments paid to Mr. Bjornson for the three calendar years prior to the termination, and 6) an amount equal to the Corporation's cost of all benefits that Mr. Bjornson is participating in at the time of termination for a period of one and a half years following the date of termination. In the event of a change of control, the Company may terminate the agreement within ten days of such change in control, and Mr. Bjornson has the option to terminate the agreement within sixty days of the change in control, upon thirty days written notice. Mr. Bjornson is prohibited from competing with the Company during the term of his agreement and for a period of one year after its termination. Mr. Bjornson is prohibited from soliciting employees, contractors and customers of the Company during the term of his agreement and for a period of one year after its termination. The agreement is governed by the laws of the Province of Alberta.

(iii) Summary of remuneration and benefits

A summary of the amount of remuneration paid by the Group to the Directors and Senior Managers (including any contingent or deferred compensation) and benefits in kind for the financial year ended 31 December 2018 for their services, in all capabilities, to the Group is set out below:

	Short-Term		*Long Term Incentives*		
Name	*Basic Salary & Fees (C$)*	*STI Bonus (C$)*	*Common Shares (C$)*	*Options (C$)*	*Total (C$)*
Directors					
Dr. Tim Marchant	68,500	0	0	103,600	172,100
Ronald Royal	57,000	0	0	103,600	160,600
Russell Hiscock	54,075	0	0	296,000	350,075
James McFarland	161,500	0	0	103,600	265,100
Dr. Sean Guest	297,500	225,000	0	814,000	1,336,500
Kimberley Wood*	N/A	N/A	N/A	N/A	N/A
Steve Bjornson	232,500	100,000	0	222,000	554,500
Lyle Martinson	228,750	135,000	0	281,200	644,950
Gordon Begg**	130,167	56,000	0	442,500	628,667
Robert Sadownyk	202,500	75,000	0	251,600	529,100

*Ms. Wood joined the board on 26 March 2019
** compensation for a pro-rated period in 2018 due to Mr. Begg's 30 May 2018 start date with the Company

Directors are not entitled to any benefits upon termination of their services.

The Company maintains directors' and officers' insurance and agrees to indemnify its directors and officers to the full extent allowed under the ABCA. The Company has entered into individual indemnity agreements with each of the Directors and Senior Managers.

(iv) Pension Arrangements

The Group does not provide pension, retirement or similar benefits to the Directors or Senior Managers.

14. Incentive Schemes

(i) Overview

The Company believes that long term performance and increases in shareholder value are achieved through an ownership culture that encourages performance by all employees, including executives, through the use of at-risk long term incentives. Long term incentives are required in order for the Company to be competitive from a total remuneration standpoint, particularly given that the current size and stage of the Company prevents it from paying base cash salaries comparable to those of larger companies in the oil and gas industry with whom it must compete for experienced executive officers. Accordingly, the Company has established the Option Plan and the Performance Share Unit Plan to provide employees, including executive officers, with incentives to help align those employees' interests with the performance of the Company as reflected in the market price of its Common Shares.

The Company's Governance and Compensation Committee, upon the recommendation of the CEO, reviews and makes recommendations to the Board for its ultimate approval with respect to grants of Options and/or PSUs to executive officers. When making recommendations with respect to Option and/or PSU awards and the size of such awards, the Governance and Compensation Committee will take into consideration the overall number of Options and PSUs that are outstanding relative to the number of outstanding Common Shares.

(ii) Plan Limits

Subject to the policies of the TSX, the number of Common Shares reserved for issuance under the Option Plan, the PSU Plan and any other security based compensation plans of the Company, in the aggregate shall not exceed:

- 10 per cent. of the Company's issued Common Shares from time to time;
- for any individual in any 12 month period, 5 per cent. of the Company's issued Common Shares from time to time outstanding (or 2 per cent. in the case of either a consultant or an employee conducting investor relations activities);
- 10 per cent. of the total number of Common Shares held by Insiders (as defined in the TSX Company Manual); and
- 10 per cent. of the total number of Common Shares held by Insiders in any 12 month period.

(iii) Option Plan

The Option Plan is intended to achieve a number of objectives through the grant of Options including:

- retaining and attracting qualified directors, officers, employees and consultants;
- promoting a proprietary interest in the Company;
- providing a long term incentive element in compensation; and
- promoting profitability of the Company.

As at the Last Practicable Date, the following Options were outstanding:

Expiry date	*Exercise Price (C$)*	*Number of Common Shares upon Exercise*
18 March 2020	1.00	240,000
31 March 2021	0.64	478,000
13 March 2022	0.57	674,000
15 April 2022	0.68	100,000
23 March 2023	0.75	353,333
17 March 2024	0.73	638,333
17 May 2024	0.75	600,000
31 May 2024	0.80	150,000
23 March 2025	4.62	862,500
30 May 2025	4.60	150,000
7 January 2026	3.51	150,000
8 February 2026	3.02	1,425,000

Participation and Change in Employment

The Option Plan provides that:

- participation in the Option Plan shall be entirely voluntary and any decision not to participate shall not affect a person's relationship or employment with the Company. Similarly, the Option Plan specifies that the granting of Options pursuant to the Option Plan shall in no way be construed as conferring on any holder any right with respect to continuance as a director, officer, employee or consultant of the Company or of any of its subsidiaries; and
- Options shall not be affected by any change of employment of the holder or by the holder ceasing to be a director, officer, employee or consultant of the Company or a subsidiary, where the holder becomes or continues to be a director, officer, employee or consultant of the Company or another subsidiary.

Ceasing to be a Director, Officer, Employee or Consultant

The Option Plan gives the Board discretion when issuing Options to determine whether Options may be exercised at all or for a limited period of time following a holder ceasing to be an employee, officer, director

or consultant for any reason other than death or permanent disability, provided however, that Options held by such persons must expire within a reasonable period following the date of such cessation as required under TSX policies. In the event of the death or permanent disability of a holder, Options held by such holder, whether or not vested, shall be exercisable for 12 months following the death or permanent disability of the holder or the expiry time of such Options, whichever occurs first and thereafter shall be of no further force or effect.

Exercise Price

Subject to the policies of the TSX and any limitations imposed by any relevant regulatory authority, the exercise price of an Option granted under the Option Plan shall be as determined by the Board when such Option is granted and shall be an amount at least equal to the last per Common Share closing price of the Common Shares on the TSX before the date of grant of an Option.

Vesting

The vesting of an Option granted under the Option Plan shall be as determined by the Board when such Option is granted; however, Options generally have a vesting schedule of one third per year over three years.

Term and Black-out Periods

Under the Option Plan, all Options shall be for a term as determined at the discretion of the Board at the time of the grant, provided that no Options shall have a term exceeding 10 years.

The Option Plan also allows for the extension of the expiry date for an Option during a black-out period imposed by the Company. In the event that the expiration date of an Option falls within such a black-out period or within five business days after a black-out period, the expiry date of such Options shall be altered to be 10 business days after the black-out period ends, provided that in no case shall such extension create an Option having a term exceeding 10 years.

Change of Control Transactions and Unsolicited Offers

The Option Plan contains a comprehensive definition of 'Change of Control Transaction' and 'Unsolicited Offer' and provides that, unless otherwise determined by the Board, in the event of a Change of Control Transaction or an Unsolicited Offer all Options shall vest and become immediately exercisable.

In addition, if the Board approves a Change of Control Transaction, the Board may provide notice to the holders of Options of the time period during which such holders must purchase all or a portion of that number of Common Shares to which such holders are entitled pursuant to the unexercised Options. Any Options not exercised at the expiry of such period shall terminate and expire, unless such Change of Control Transaction is not completed. Any Options remaining unexercised following the earlier of the withdrawal of an Unsolicited Offer and the expiry of such Unsolicited Offer in accordance with its terms again become subject to the original terms of such options as if the Unsolicited Offer had not been made.

Amendment, Termination and Adjustments

The Option Plan contains provisions specifically outlining amendments to the Option Plan which may be made by the Board without the further approval of Shareholders. While this is not specifically required by the policies of the TSX, these provisions provide clarity and are consistent with the rules of the TSX which require that in order for amendments to proceed without requiring securityholder approval, the plan must specify if securityholder approval is required for each type of amendment to a stock option plan.

The Option Plan gives the Board discretion to may make adjustments to Options to prevent substantial dilution or enlargement of the rights granted to Option holders in the context of certain specified corporate events.

Non Assignability

The Options are not transferable or assignable, except for a limited right of assignment on the death or permanent disability of a holder.

(iv) PSU Plan

No awards of PSUs have been granted under the PSU Plan.

Purpose of the PSU Plan

The principal purposes of the PSU Plan are to: (i) to strengthen the ability of the Company to attract and retain qualified directors, officers, employees and consultants which the Company and its subsidiaries require; (ii) to encourage the acquisition of a proprietary interest in the Company by such directors, officers, employees and consultants, thereby aligning their interests with the interests of the Shareholders; and (iii) to focus management of the Company and its subsidiaries on operating and financial performance and total long term Shareholder return by providing an increased incentive to contribute to the Company's growth and profitability.

(v) Short-Term Incentive Bonus Scheme

Discretionary cash bonuses are part of the Company's compensation program as it is believed that they can be used to help to motivate executive officers and employees to achieve key corporate objectives by rewarding the achievement of these objectives. Currently, cash bonuses are awarded on a discretionary basis following an evaluation of the corporate performance and individual performance factors.

At the beginning of the year the Board defines a corporate performance scorecard to drive the desired strategic and operational direction of the Company for that year. After completion of that year, the Board will consider the Company's scoring against the corporate performance scorecard and then apply appropriate, in its opinion, discretion in determining the success of the Company in that year.

15. Subsidiaries, investments and principal establishments

The Company has the following directly held subsidiaries:

Name	*Country of Incorporation*	*Proportion of ownership interest (per cent.)*	*Principal activity*
Valeura Energy (Netherlands) Cooperatief UA	Netherlands	99% (remaining 1% is held by Northern Hunter Energy Inc., a wholly owned subsidiary of the Company)	Intermediary Investment Holding

Valeura Energy (Netherlands) Cooperatief UA has the following directly held subsidiary:

Name	*Country of Incorporation*	*Proportion of ownership interest (per cent.)*	*Principal activity*
Valeura Energy (Netherlands) BV	Netherlands	100%	Operating Company
Corporate Resources (Netherlands) BV	Netherlands	100%	Operating Company

Valeura Energy (Netherlands) BV has the following directly held subsidiary:

Name	*Country of Incorporation*	*Proportion of ownership interest (per cent.)*	*Principal activity*
Thrace Basin Natural Gas Turkiye Corporation	British Virgin Islands	100%	Operating Company

16. Material contracts

The following contracts are outside the course of business and either: (a) have been entered into by the Group within two years immediately preceding the date of this document; or (b) contain provisions under which the Group has an obligation or entitlement that is or may be material to the Group as at the date of this document.

(i) Banarli Farm-In

On 19 August 2016, Valeura announced that CRBV had entered into definitive transaction documents (the "**Definitive Agreements**") with Statoil Turkey, now Equinor Turkey for a farm-in agreement for the exploration of the deeper formations below approximately 2,500 meters on the Banarli Exploration Licences. The Definitive Agreements included the Banarli Farm-In agreement, joint operating agreements, and a number of ancillary agreements. Under the terms of the Banarli Farm-In, Equinor Turkey has the option to earn a 50 per cent. participating interest in the deep formations on the Banarli Exploration Licences by solely funding and paying for the three prescribed commitment phases. Phase 1 requires Equinor Turkey to fund and pay for (i) CRBV to conduct drilling operations for the Phase 1 well (Yamalik-1), (ii) CRBV to conduct the completion and testing operations of the Phase 1 well, and (ii) the prepatory work for Phase 2. Phase 2 requires Equinor Turkey to fund and pay for (i) the acquisition of $10 million 3D seismic over the Banarli Lands, and (ii) the processing by Equinor Turkey of the seismic data in a prescribed time period. Phase 3 requires Equinor Turkey to fund and pay for (i) CRBV to conduct drilling operations for the Phase 3 well (Inanli-1), and (ii) CRBV to conduct the completion and testing operations of the Phase 3 well. CRBV is the initial designated operator under the Banarli Farm-In and Equinor Turkey is afforded the option to become the operator under the terms of the joint operating agreements after completion of Phase 3.

On 24 July 2017, Valeura announced that the first deep exploration well, Yamalik-1, under Phase 1 of the Banarli Farm-In, was drilled to a total depth of 4,196 metres. Since such time the parties have confirmed that the balance of the Phase 1 obligations have been completed by Equinor Turkey.

In the third quarter of 2017, Valeura completed approximately 500 square kilometres of 3D seismic, which has provided coverage of the target area of the BCGA play fairway. The 3D seismic survey was funded by Equinor Turkey pursuant to Equinor Turkey's Phase 2 obligations under the Banarli Farm-In.

On 28 January 2019, Valeura announced that the Inanli-1 well, under Phase 3 of the Banarli Farm-in, was drilled to a total depth of 4,885 metres. The Company continues to conduct testing and completion operations on behalf of the parties in respect of the Inanli-1 well.

After completion of Phase 3 of the Banarli Farm-In, Equinor Turkey's obligation to fund and pay for CRBV's expenditures under the Banarli Farm-In will cease and the Company will be responsible for its working interest share of all expenditures incurred under the Banarli JOA's.

(ii) Banarli JOAs

The Banarli joint operating agreements each dated effective 6 January 2017 among CRBV and Statoil Turkey, now Equinor Turkey governing the joint operations of the deep rights participating interest owners of (i) Banarli exploration licence related to quadrants F18-C1, C2, C3 and C4, and (ii) Banarli exploration licence related to quadrants F19-D1 and D4, respectively, and each includes considerations for the relationship between the deep rights and shallow rights participating interest owners in the subject lands (the shallow rights are owned 100 per cent. by CRBV). CRBV is designated as the initial deep operator and at any time after Equinor Turkey is deemed to have earned a 50 per cent. interest in the Banarli Exploration Licences under the Banarli Farm-In's terms, Equinor Turkey has the option to take over as the deep operator under the agreement. There are no rights of first refusal afforded to the parties. In addition to other restrictions on transfer, a party may not transfer a portion of their participating interest if the resulting transferor or transferee holds less than a 10 per cent. participating interest. A party subject to a change in control must obtain any necessary government approvals and furnish any replacement security required by the Government or the leases.

For certain matters specified in the agreement, the voting pass mark for the deep operating committee is the affirmative vote of 2 or more parties that are not affiliates, having collectively at least 100 per cent. of the participating interests, and for all other matters to be decided upon by the deep operating committee, the affirmative vote of 2 or more parties that are not affiliates, having collectively at least 75 per cent. of the

participating interests shall be required. If a party votes against any proposal approved by the operating committee, and such proposal is of a type that could be conducted as an exclusive operation, then such party will have the right not to participate in the approved operation.

Exclusive deep operations may be conducted only if, among other conditions, such exclusive deep operations are essentially the same as a joint deep operation proposed to, but not approved by, the deep operating committee. No exclusive deep operation may be conducted if it (a) conflicts with, hinders or jeopardize a previously approved joint deep operation, or (b) conflicts with or otherwise fail to adhere to the coordination provisions governing deep and shallow interests. All operations to fulfill minimum work obligations must be proposed and conducted as joint operations, unless there is an agreement that a party has no obligation to participate in a minimum work obligation.

If a defaulting party fails to fully remedy all its defaults in a timely fashion, at any time afterwards until the defaulting party has cured its defaults, in addition to other remedies, a non-defaulting party will have the option to require the defaulting party to offer to sell and assign all or part of its participating interest to any non-defaulting party wishing to purchase same at an agreed to price or fair market value less the amount in default, costs and 30 per cent. of the determined fair market value.

CRBV is designated as the shallow rights operator and all operations in respect of the shallow rights will be conducted by shallow operator as an exclusive shallow operation and only include shallow rights owners. The shallow owners will provide to the deep operator all information and data required to meet the obligations under the leases and meet the requests of the GDMPA.

The deep owners and shallow owners will cooperate and use reasonable efforts to ensure that any activity does not materially impact the existing operations of the other. Where there is a conflict of locations in respect of an approved activity, the deep owners will take priority over the shallow owners so long as such activity is commenced within 6 months of the notification of such activity.

The agreement is governed by the laws of England and Wales.

(iii) CRBV Acquisition

On 8 June 2011, VENC entered into a share purchase agreement with Mustafa Mehmet Corporation for the purchase of all of the issued and outstanding shares of CRBV for cash consideration of US$ 61,538,461 and other consideration. Through the acquisition of CRBV, the Company acquired a 40 per cent. participating interest in the then West Thrace Lands and South Thrace Lands.

(iv) West Thrace Deep Rights Sale

On 6 January 2017, Valeura announced the closing of the sale to Statoil Turkey of a 40 per cent. participating interest in the West Thrace Lands for the deep formations below approximately 2,500 metres depth, for cash consideration of US$12 million pursuant to the sale and purchase agreement dated 13 October2016 between CRBV and Equinor.

(v) TBNG Acquisition

On 24 February 2017, the Company announced the closing of the acquisition of 100 per cent. of the outstanding shares of TBNG for US$20.7 million (CAD$27.1 million) pursuant to the share purchase agreement dated 13 October 2016 between VENBV (as buyer) and TransAtlantic (as seller). The TBNG Acquisition increased the Company's existing 40 per cent. ownership in the West Thrace Lands and South Thrace Lands to 81.5 per cent. ownership and provided operating control of the West Thrace Lands.

(vi) Subsequent West Thrace Deep Rights Sale

On 22 June 2017, Valeura announced the closing of the sale to Statoil Turkey of a further 10 per cent. participating interest in the West Thrace Lands for the deep formations below approximately 2,500 metres depth, for cash consideration of US$3 million pursuant to the sale and purchase agreement dated 10 March 2017 between TBNG and Equinor.

(vii) West Thrace JOAs

The ***West Thrace Joint Operating Agreements*** (also the "**Deep Rights JOAs**") each dated effective 24 February 2017 among TBNG, CRBV, PTI and Statoil Turkey governing the joint operations of the deep rights participating interest owners of (a) West Thrace Leases 2926, 3659 and 3734-5122, and (b) West Thrace Licences F18-d1, d2 and d4, respectively, and each includes considerations for the relationship between the deep rights and shallow rights participating interest owners in the subject lands (the shallow rights are subject to separate joint operating agreements described below). TBNG is designated as the initial deep operator and at any time after Statoil Turkey is deemed to have earned a 50 per cent. interest in the Banarli Exploration Licences under the Banarli Farm-In's terms, Statoil Turkey has the option to take over as the deep operator under the agreement. There are no rights of first refusal afforded to the parties. In addition to other restrictions on transfer, a party may not transfer a portion of their participating interest if the resulting transferor or transferee holds less than a 10 per cent. participating interest. A party subject to a change in control must obtain any necessary government approvals and furnish any replacement security required by the Government or the leases.

The voting pass mark for matters before the operating committee will be, for all decisions, approvals and other actions relating to: (a) surrender, relinquishment, extension, conversion and new work commitments, the affirmative vote of 2 or more parties that are not affiliates, having collectively at least 100 per cent. of the participating interests; or (b) all other matters, the affirmative vote of 2 or more parties that are not affiliates, having collectively at least 75 per cent. of the participating interests. If a party votes against any proposal approved by the operating committee, and such proposal is of a type that could be conducted as an exclusive operation, then such party will have the right not to participate in the approved operation.

Exclusive deep operations may be conducted only if, among other conditions, such exclusive deep operations are essentially the same as a joint deep operation proposed to, but not approved by, the deep operating committee. No exclusive deep operation may be conducted if it (a) conflicts with, hinders or jeopardize a previously approved joint deep operation, or (b) conflicts with or otherwise fail to adhere to the coordination provisions governing deep and shallow interests. All operations to fulfill minimum work obligations must be proposed and conducted as joint operations, unless there is an agreement that a party has no obligation to participate in a minimum work obligation.

If a defaulting party fails to fully remedy all its defaults in a timely fashion, at any time afterwards until the defaulting party has cured its defaults, in addition to other remedies, a non-defaulting party will have the option to require the defaulting party to offer to sell and assign all or part of its participating interest to any non-defaulting party wishing to purchase same at an agreed to price or fair market value less the amount in default, costs and 30 per cent. of the determined fair market value.

TBNG is designated as the shallow rights operator and all operations in respect of the shallow rights will be conducted by shallow operator as an exclusive shallow operation and only include shallow rights owners. The shallow owners will provide to the deep operator all information and data required to meet the obligations under the leases and meet the requests of the GDMPA.

The deep owners and shallow owners will cooperate and use reasonable efforts to ensure that any activity does not materially impact the existing operations of the other. Where there is a conflict of locations in respect of an approved activity, the deep owners will take priority over the shallow owners so long as such activity is commenced within 6 months of the notification of such activity.

The agreements are governed by the laws of England and Wales.

The ***West Thrace Shallow Rights Joint Operating Agreements*** (also, the "**Shallow Rights JOAs**") each dated effective 24 February 2017 among TBNG, CRBV and PTI governing the joint operations of the shallow rights participating interest owners of (a) West Thrace Production Leases 2926, 3659 and 3734-5122, and (b) West Thrace Exploration Licence F18-d1, d2 and d4, respectively, and each includes considerations for the relationship between the deep rights and shallow rights participating interest owners in the subject lands. TBNG is designated as the initial operator. There are no rights of first refusal afforded to the parties. In addition to other restrictions on transfer, a party may not transfer a portion of their participating interest if the resulting transferor or transferee holds less than a 10 per cent. participating interest. A party subject to a change in control must obtain any necessary government approvals and furnish any replacement security required by the Government or the leases and satisfy the terms and conditions of the Deep Rights JOA's. Any withdrawal from a JOA and the Production Leases or Exploration Licence shall be governed by the Deep Rights JOA's.

The voting pass mark for matters before the operating committee will be, for all decisions, approvals and other actions, except as expressly provided, be decided by the affirmative vote of 2 or more parties that are not affiliates, having collectively at least 65 per cent. of the participating interests. If a party votes against any proposal approved by the operating committee, and such proposal is of a type that could be conducted as an exclusive operation, then such party will have the right not to participate in the approved operation.

If less than all parties elect to participate is in operation, then any party may present to the other parties a written proposal to conduct such operation as an Independent Prospect Operation ("**IPO**"). IPO's are exceptions to the joint operations so certain operations may not be conducted as an IPO.

If a defaulting party fails to fully remedy all its defaults in a timely fashion, at any time afterwards until the defaulting party has cured its defaults, in addition to other remedies, a non-defaulting party will have the option to require the defaulting party to offer to sell and assign all or part of its participating interest to any non-defaulting party wishing to purchase same at an agreed to price or fair market value less the amount in default, costs and 30 per cent. of the determined fair market value.

All shallow operations shall be conducted by the operator in compliance with the coordination provisions of the Deep Rights JOA's. In the event of a direct conflict between a Shallow Rights JOA and a Deep Rights JOA as pertains to Shallow Rights, the coordination of operations between Deep Rights and Shallow Rights and/or the rights, duties and obligations of the operator and/or parties, the provisions of the Deep Rights JOA shall prevail.

The agreements are governed by the laws of the State of Texas.

(viii) South Thrace JOA

The Joint Operating Agreement dated effective 24 February 2017 among TBNG, CRBV and PTI governing the joint operations of the South Thrace Leases and Licences. TBNG is designated as the operator. There are no restrictions on transfer other than a party may not transfer a portion of their participating interest if the resulting transferor or transferee holds less than a 10 per cent. participating interest. A party subject to a change in control must obtain any necessary government approvals and furnish any replacement security required by the Government or the leases.

The voting pass mark for matters before the operating committee, other than as expressly provided in the agreement, is the affirmative vote of 2 or more parties that are not affiliates, then having collectively at least 65 per cent. of the participating interests. If a party votes against any proposal approved by the operating committee, and such proposal is of a type that could be conducted as an exclusive operation, then such party will have the right not to participate in the approved operation.

There is also be an executive committee composed of one senior executive representing each party holding a participating interest of not less than 15 per cent. The executive committee has the following functions and authority:

- allocation of the parties' technical and financial resources in relation to the contracts;
- resolving any matters where the operating committee cannot agree;
- taking such other decisions as contemplated by the agreement; and
- such other matters as the executive committee may determine.

All decisions of the executive committee will be determined by the affirmative vote of 2 or more parties (which are not affiliates) having collectively at least 85 per cent. of the combined participating interests of the parties eligible to vote.

In the event of a conflict between a decision of the executive committee and a decision of the operating committee, the decision of the executive committee shall govern.

Independent prospect operations are the exception to joint operations. The following operations may be proposed and conducted as independent prospect operations:

- drilling and/or testing of exploration wells, appraisal wells and development wells;
- completion of exploration wells, appraisal wells and development wells not then completed as productive of hydrocarbons;

- deepening, sidetracking, plugging back and/or recompletion of exploration wells, appraisal wells and development wells;
- acquisition of geological, geophysical and geochemical data; and
- any operations specifically authorized to be undertaken as an independent prospect operation.

The participating parties shall bear in accordance with the participating interests the entire cost and liability of conducting an independent prospect obligation and shall indemnify the non-participating parties from any and all costs and liabilities incurred incident to such independent prospect operation.

If a defaulting party fails to fully remedy all its defaults in a timely fashion, at any time afterwards until the defaulting party has cured its defaults, in addition to other remedies, a non-defaulting party will have the option to require the defaulting party to offer to sell and assign all or part of its participating interest to any non-defaulting party wishing to purchase same at an agreed to price or fair market value less the amount in default, costs and 30 per cent. of the determined fair market value.

The agreement is governed by the laws of the State of Texas.

(ix) C$60m Bought Deal Financing

On 1 March 2018, Valeura announced the closing of the 2018 Offering. The Common Shares were sold through a syndicate of underwriters led by GMP FirstEnergy, as to 90 per cent., and Cormark Securities Inc., as to 10 per cent. (together the "**Underwriters**"). The 2018 Offering was completed pursuant to the terms of a letter agreement between GMP and the Company dated 8 February 2018. The Company agreed to pay the Underwriters a cash commission equal to six (6) percent of the gross proceeds of the sale of offered shares and GMP was entitled to a five (5 per cent.) percent step-up fee out of the Underwriters commission. The terms of the letter agreement did not afford any rights to the Underwriters in respect of future offerings or financings of the Company.

17. Exploration Licences and Production Leases

The Group holds the following leases and licences:

Valeura Working Interest Lands	*Block*	*Operated*	*Working Interest Shallow*	*Deep*	*Gross Acres*	*Phase*	*Expiry of Current Phase*
South Thrace Production Leases	3860	Yes	81.5%		3,457	Initial Production	02-Dec-21
	3861	Yes	81.5%		808	Initial Production	02-Dec-23
	F18-c3-1	Yes	81.5%		22,655	Initial Production	10-Nov-23
	F18-c4-2	Yes	81.5%		23,658	Initial Production	10-Nov-26
	F19-d4-1	Yes	81.5%		15,634	Initial Production	10-Nov-22
	F19-d4-2	Yes	81.5%		8,458	Initial Production	08-Nov-20
	G19-a1-1	Yes	81.5%		2,879	Initial Production	20-May-23
	G18-b2-1	Yes	81.5%		20,411	Initial Production	10-Sep-23
	G18-b1-1	Yes	81.5%		21,664	Initial Production	14-Oct-20
	F19-d3-1	Yes	81.5%		15,765	Initial Production	05-Nov-20
	F19-c3-1	Yes	81.5%		35,346	Initial Production	09-Dec-20
West Thrace Production Leases	2926	Yes	81.5%	31.5%	12,429	First Extension	16-Feb-20
	3659	Yes	81.5%	31.5%	709	First Extension	08-Jun-27
	5122	Yes	81.5%	31.5%	440	Initial Production	15-Nov-29
West Thrace Exploration Licence	F18-d1,d2,d4	Yes	81.5%	31.5%	88,434	Initial Exploration	27-Jun-20
Banarli Exploration Licences	F18-c1, c2,c3,c4	Yes	100.0%	50.0%	88,197	Initial Exploration	27-Jun-20
	F19-d1,d4	Yes	100.0%	50.0%	45,643	Initial Exploration	27-Jun-20
Edirne Production Leases	E17-b4-1	No	35.0%		7,989	Initial Production	31-Oct-21
	E17c1-1	No	35.0%		13,331	Initial Production	31-Oct-19
	E17-c2-1	No	35.0%		28,563	Initial Production	31-Oct-20

18. Statutory auditors

The auditors of the Group for the financial years ended on 31 December 2018, 31 December 2017, and 31 December 2016 have been KPMG, whose registered address is at 3100, 205 5 Avenue Southwest, Calgary, AB T2P 4B9, Canada.

KPMG has audited the annual consolidated financial statements for the Group, which have been prepared in accordance with the Rules of Professional Conduct of the Institute of Chartered Professional Accountants of Alberta, IFRS Accounting Standards and other authoritative pronouncements of Canada. The audited annual consolidated financial statements also comply with IFRS, as issued by the International Accounting Standards Board.

19. Working capital

In the opinion of the Company, the working capital available to the Group is sufficient for its present requirements, that is, for at least the next 12 months from the date of this Prospectus.

20. No significant change

There has been no significant change in the financial or trading position of the Group since 31 December 2018, being the end of the last financial period of the Group for which Historical Financial Information is included in Part 10 of this document, '*Historical Financial Information*' and the Appendix to this document.

21. CPRs

The Company confirms that no material changes have occurred since the date of the CPRs the omission of which would make the CPRs misleading.

22. Litigation

There are no governmental, legal or arbitral proceedings (including any such proceedings which are pending or threatened and of which the Company is aware) which may have, or have had during the 12 months prior to the date of this document, a significant effect on the Company and/or the Group's financial position or profitability.

23. Related Party Transactions

The Company confirms that there are no related party transactions.

24. Consents

(i) D&M (in its capacity as an independent competent person) has given and not withdrawn its written consent to the inclusion of the CPRs in Part 18 of this Prospectus (Competent Person's Reports), and references to the CPRs and its name in the form and context in which they appear and has authorised the contents of those parts of the Prospectus which comprise its report for the purposes of Rule 5.5.3R(2)(f) of the Prospectus Rules.

(ii) GMP FirstEnergy has given and not withdrawn its written consent to the inclusion of references to its name in this document in the form in which they appear.

25. Miscellaneous

(i) The total costs (including fees and commissions, but exclusive of VAT) payable by the Company in connection with the Offer and Admission are estimated to be £400,000.

(ii) The Company confirms that all third party information contained in this document has been accurately reproduced and, so far as the Company is aware and is able to ascertain from information published by such third parties, no facts have been omitted that would render the reproduced information inaccurate or misleading. Where third party information has been used in this document, the source of such information has also been identified.

26. Documents available for inspection

Copies of the following documents will be available for inspection during normal business hours on any business day at the offices of Memery Crystal LLP for the period of 12 months following Admission:

(i) this document;

(ii) the Constitution of the Company;

(iii) the audited annual consolidated financial statements for the Group in respect of each of the three financial years ended 31 December 2018, 31 December 2017, and 31 December 2016 together with the related audit reports from the independent auditor;

(iv) the Competent Person's Reports set out in Part 18 of this document, 'Competent Person's Reports'; and

(v) the letters confirming the consents referred to in paragraph 24 'Consents' of this Part 15.

Dated 17 April 2019

PART 16 – DEFINITIONS

ABCA	the Business Corporations Act (Alberta), together with any or all regulations promulgated thereunder, as amended from time to time
Admission	the admission of all of the Common Shares to the standard segment of the Official List and to trading on the Main Market for listed securities
Banarli Exploration Licences	those Exploration Licences as set out in para 17 of Part 15 of this Prospectus
Banarli Farm-In	the farm-in agreement for the exploration of the deeper formations below approximately 2,500 meters on the Banarli Exploration Licences between CRBV and Equinor
Banarli JOAs	the joint operating agreements made between CRBV and Equinor Turkey in respect of the Banarli Exploration Licences dated 6 January 2017
Banarli Lands	those lands subject to the Banarli Exploration Licences
Banarli Production Leases	those Production Licences as set out in para 17 of Part 15 of this Prospectus
BCGA	basin-centered gas accumulation
Board	the board of directors of the Company from time to time
BOTAS	Boru Hatlari ile Petrol Tasima Anonim Sirketi, which owns and operates the national crude oil pipeline grid and the national gas pipeline grid in Turkey
BOTAS Reference Price	the BOTAS Level 2 Wholesale (Processing) gas price
COGE Handbook	Canadian Oil and Gas Evaluation Handbook prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time
Common Share	a common share of no par value in the capital of the Company
Company or **Valeura**	Valeura Energy Inc., is a public company incorporated in Alberta, Canada with corporate access number of 208838144 and having its registered and records office at 4600, 525 – 8th Avenue SW, Calgary, Alberta, T2P 1G1
Constitution	the Articles and the Amended and Restated By-law no. 1 of the Company in effect as at the date of this Prospectus
CPRs or **Competent Person's Reports**	the Competent Person's Reports set out in Part 18 of this Prospectus
CRBV	Corporate Resources B.V., a wholly-owned affiliate of Valeura
CREST	the relevant system in respect of which Euroclear UK & Ireland is the operator (as defined in the CREST Regulations)
CREST Manual	the rules governing the operation of CREST, consisting of the CREST Reference Manual, CREST Rules, Registrars Service Standards,

	Settlement Discipline Rules, CCSS Operations Manual, Daily Timetable, CREST Application Procedures and CREST Glossary of Terms promulgated by Euroclear on 15 July 1996 (and as amended since)
CREST Regulations	the Uncertificated Securities Regulations 2001 (SI 2001 No. 3755)
Custodian	Computershare Investor Services PLC or a subsidiary or third party appointed by Computershare Investor Services PLC to provide the Custody Services
D&M or the **Competent Person**	DeGolyer & MacNaughton Corp., 5001 Springs Valley Road, Suite 800 East, Dallas, Texas, USA 75244
Deed Poll	the deed poll executed by the Depositary in favour of the holders of the Depositary Interests from time to time
Deep Rights	those rights as set out in the Deep Rights JOAs
Depository	Computershare Investor Services PLC
Depository Agreement	the agreement entered into between the Company and the Depositary appointing the Depositary
Depository Interests	the dematerialised depositary interests issued by the Depositary in respect of the underlying Common Shares
DGTRs	the Disclosure Guidance and Transparency Rules
Directors	the directors of the Company as at the date of this document, whose names are set out in Part 6 and Part 8 of this Prospectus
Edirne	the Edirne region of Turkey
Edirne Production Leases	those Production Leases as set out in para 17 of Part 15 of this Prospectus
Equinor	the new name of Statoil ASA as a result of a name change on March 15, 2018
Equinor Turkey	the new name Statoil Banarli Turkey B.V., a wholly-owned affiliate of Equinor
ESMA	European Securities and Markets Authority
Exploration Licence	a petroleum exploration licence to explore and develop hydrocarbons in the designated licence area
FCA	the Financial Conduct Authority
FSMA	the Financial Services and Markets Act 2000
GDMPA	Republic of Turkey's General Directorate of Mining and Petroleum Affairs, formerly the General Directorate of Petroleum Affairs (GDPA)
GMP FirstEnergy	FirstEnergy Capital LLP (trading as GMP FirstEnergy) the financial advisers to the Company, whose registered office address is 85 London Wall, London, E2M 7AD, United Kingdom
Government	the Government of the Republic of Turkey

Group	the Company and its Subsidiaries
Historical Financial Information	the consolidated financial statements of the Group and its consolidated financial statements and the accompanying notes contained in the Appendix to this document, as referred to in Part 10 of this Prospectus
Historical Financial Information Period	the period covered by the Historical Financial Information
HMRC	Her Majesty's Revenue and Customs
IFRS	International Financial Reporting Standards
IP	intellectual property
Key Management Personnel	persons having authority and responsibility for planning, directing and controlling the activities of the Company directly or indirectly, including any Director (whether executive or otherwise) of the Company
KPMG	KPMG LLP, the independent auditors to the Company
Last Practicable Date	16 April 2019
Listing Rules	the rules and regulations made by the FCA under Part VI of FSMA
London Stock Exchange or **LSE**	the London Stock Exchange plc
Main Market	the Main Market of the LSE
MAR	the European Union Market Abuse Regulation (596/2014)
Member States	the member states of the European Union
MENR	Ministry of Energy and Natural Resources of Turkey
New Petroleum Law	Turkey's Petroleum Law No. 6491 adopted in 2013 which replaced the Old Petroleum Law
Official List	the Official List of the FCA
Old Petroleum Law	Turkey's Petroleum Law No. 6326 adopted in 1954 which was replaced by the New Petroleum Law
Option	an option to acquire a Common Share
Option Plan	has the meaning give in para 14 of Part 15 of this Prospectus
PDMR	person discharging managerial responsibilities, as defined in Article 3(1)(25) MAR
possible reserves	are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. There is a 10 per cent. probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves

probable reserves	are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves
proved reserves	are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves
Premium Listing	a listing on the premium segment of the Official List
Production Lease	a production lease to produce hydrocarbons from the reservoir area carved out from the predecessor Exploration Area
prospective resources	quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects, prospective resources have an associated chance of discovery
Prospectus	this document
Prospectus Directive	Directive 2003/71/EC of the European Parliament and Council of 4 November 2003 (and amendments thereto, including Directive 2010/73/EU)
Prospectus Rules	the Prospectus Rules published by the FCA under section 73A of FSMA
PSU	a performance share unit that may be granted under the PSU Plan
PSU Plan	the Performance Share Unit Plan of the Company
PTI	Pinnacle Turkey, Inc.
Reserves	estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates
Resources	petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including discovered and undiscovered (recoverable and unrecoverable) plus quantities already produced, total resources is equivalent to total petroleum initially-in-place
Senior Managers	the Chief Executive Officer, Chief Operating Officer, Chief Financial Officer, Vice President Commercial and Vice President Exploration, as set out in Part 8 of this Prospectus
Shallow Rights	those rights as set out in the Shallow Rights JOAs
Shareholders	the holders of common shares from time to time
South Thrace JOA	the joint operating agreement relating to the South Thrace Leases and Licences, made on 24 February 2017 between TBNG, PIT and CRBV

South Thrace Lands	collectively, the lands comprising the South Thrace Production Leases
South Thrace Production Leases	those Production Leases as set out in para 17 of Part 15 of this Prospectus
Standard Listing	a listing on the standard segment of the Official List
Statoil Turkey	Statoil Banarli Turkey B.V., a wholly-owned affiliate of Statoil ASA
Stock Option Plan	the stock option plan of the Company
Subsidiaries	the subsidiaries (both direct and indirect) of the Company from time to time
TBNG	Thrace Basin Natural Gas Turkiye Corporation, a wholly-owned affiliate of TWL prior to completion of the TBNG Acquisition and thereafter, a wholly-owned affiliate of Valeura
TBNG Acquisition	the acquisition of 100 per cent. of the shares of TBNG for US$20.7 million (CAD$27.1 million) pursuant to the share purchase agreement dated 13 October 2016 between VENBV (as buyer) and TransAtlantic (as seller) which completed on 24 February 2017
TBNG JV	the joint venture formed between CRBV, TBNG and PTI, pursuant to the South Thrace JOA
TBNG JV Lands	collectively, the South Thrace Lands and the West Thrace Lands
Thrace Basin	an area of land in the northwest region of Turkey, located west of Istanbul and extending to the Greek and Bulgarian borders, as shown in *Figure 1– Geological Basins of Turkey and position of the Thrace Basin* of Part 7 of this Prospectus
Thrace Basin Assets	together, the Group's projects on the South Thrace Lands, West Thrace Lands, Banarli Lands and Edirne Lands
TPAO	Türkiye Petrolleri Anonim Ortaklığı, the Turkish state oil and gas company
TransAtlantic	TransAtlantic Petroleum Ltd
TSX	Toronto Stock Exchange
TSX Listing Rules	the official listing rules of the TSX
TSX Principles	the corporate governance principles and recommendations of the TSX
TWL	TransAtlantic Worldwide, Ltd., a wholly-owned affiliate of TransAtlantic
UKLA	the United Kingdom Listing Authority
USD	United States dollar, the lawful currency of the United States
VENBV	Valeura Energy (Netherlands) B.V., a wholly-owned affiliate of Valeura
VENC	Valeura Energy Valeura Energy (Netherlands) Cooperatief UA, a wholly owned affiliate of Valeura

VWAP	Volume weighted average price
West Thrace Exploration Licence	the Exploration Licence set out in para 17 of Part 15 of this Prospectus
West Thrace JOAs	the West Thrace Joint Operating Agreements and the West Thrace Shallow Rights Joint Operating Agreements
West Thrace Joint Operating Agreements or **Deep Rights JOAs**	the joint operating agreements, each dated 24 February 2017, among TBNG, CRBV, PTI and Statoil Turkey governing the joint operations of the deep rights participating interest owners of (a) West Thrace Production Leases 2926, 3659 and 3734-5122 and (b) West Thrace Exploration Licence F18-d1, d2 and d4
West Thrace Lands	collectively, the lands comprising the West Thrace Licences and the West Thrace Production Leases as set out in *Figure 4 – Group Land Holdings* in para 4 of Part 7 of this Prospectus
West Thrace Production Leases	those Production Leases as set out in para 17 of Part 15 of this Prospectus
West Thrace Shallow Rights Joint Operating Agreements or **Shallow Rights JOAs**	the joint operating agreements, each dated 24 February 2017, among TBNG, CRBV and PTI governing the joint operations of the shallow rights participating interest owners of (a) West Thrace Production Leases 2926, 3659 and 3734-5122 and (b) West Thrace Exploration Licence F18-d1, d2 and d4
Working Capital Period	the 12 month period from the date of this Prospectus
WI	working interest

PART 17 – GLOSSARY OF TECHNICAL TERMS AND CONVERSIONS

Oil and Natural Gas Liquids

bbl	barrel
Mbbl	thousand barrels
bbl/d	barrel per day
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMcf	million cubic feet
MMcf/d	Million cubic feet per day
MMBtu	million British Thermal Units
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day

Other

BOE	barrel of oil equivalent.
BOE/d	barrel of oil equivalent per day.
BOTAS	Boru Hatlari ile Petrol Tasima Anonim Sirketi ("**BOTAS**") owns and operates the national crude oil pipeline grid and the national gas pipeline grid in Turkey. BOTAS regularly posts natural gas prices and its Industrial Interruptible Tariff benchmark is shown herein as a reference price.
M$	thousands of dollars.
MM$	millions of dollars.
McfGE	thousand cubic feet of sales gas equivalent.
NYMEX	New York Mercantile Exchange.
TL/m3	Turkish Lira per cubic metre.
TL	Turkish Lira.
C$	Canadian dollars.
US$	U.S. dollars.
IP	Initial on-stream production rate.
psi	pounds per square inch.

Conversions

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units)

To convert to	*From*	*Multiply by*
1,000 cubic metres of gas	Mcf	35.494
bbl	cubic metres of oil	0.158
cubic metres of oil	bbl	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

PART 18 – COMPETENT PERSON'S REPORTS

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 28, 2019

Valeura Energy Inc.
Bow Valley Square 1
Suite 1200, 202-6th Avenue SW
Calgary, Alberta T2P 2R9
Canada

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates, as of December 31, 2018, of the extent of the proved, probable, and possible oil, condensate, and sales gas reserves and the value of the proved and proved-plus-probable reserves for certain properties in Turkey in which Valeura Energy Inc. (Valeura) has represented it holds certain interests. Figure 1 included with this report shows the locations in Turkey for the fields evaluated herein.

Estimates of reserves presented in this report have been prepared using reserves definitions established by the Canadian National Instrument 51-101. These reserves definitions are discussed in detail under the Definition of Reserves heading of this report.

This report is compliant with the Competent Person's Report requirements as published in the European Securities and Markets Authority (ESMA) update of the Committee of European Securities Regulators' recommendations for the implementation of the European Commission Regulation on Prospectuses No. 809/2004 dated March 20, 2013 (ESMA/2013/319).

Reserves estimated in this report are expressed as gross reserves, company gross reserves, and net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2018. Company gross reserves are defined as the portion of the gross reserves attributable

to the working interest held by Valeura before deduction of royalty obligations. Net reserves are defined as the company gross reserves after deducting all royalties and interests held by others.

This report presents values for proved and proved-plus-probable reserves that were estimated using initial prices, expenses, and costs provided by Valeura and the forecast prices, expenses, and costs presented herein. Prices, expenses, and costs were provided in United States dollars (U.S.$), and all monetary values in this report are expressed in U.S.$. A detailed explanation of the forecast price, expense, and cost assumptions is included under the Valuation of Reserves heading of this report.

Values for proved and proved-plus-probable reserves in this report are expressed in terms of future gross revenue, future net revenue, and present worth. Future gross revenue is defined as that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting operating expenses, capital costs, abandonment costs, and Turkey income taxes (where indicated as such) from future gross revenue. Operating expenses include field operating expenses, transportation and processing expenses, and an allocation of overhead that directly relates to production activities. Capital costs include drilling and completion costs, facilities costs, and field maintenance costs. Abandonment costs are represented by Valeura to be inclusive of those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment. At the request of Valeura, future Canadian income taxes were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a specified arbitrary discount rate compounded monthly over the expected period of realization. The future net revenue estimated herein, discounted or undiscounted, should not be construed to represent fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold. In this report, present worth values using discount rates of 10 and 20 percent are reported as totals.

Estimates of reserves and revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

In this report, key information has been provided by Valeura on the fields evaluated herein. As far as we are aware, there are no special factors that would affect the interests held by Valeura that would require additional information for the proper evaluation of the fields. Reserves estimated herein were based on the prices and costs as described herein. All evaluations herein are considered in the context of current agreements and regulations and do not consider uncertainties that might be associated with political conditions.

Information used in the preparation of this report was obtained from Valeura. In the preparation of this report we have relied, without independent verification, upon information furnished by Valeura with respect to the property interests being evaluated, agreements relating to future operations and sale of production, and various other information and data that were accepted as represented. The completeness and accuracy of this information was confirmed in the Representation Letter provided by Valeura dated January 23, 2019. Although we have not had independent verification, the information used in this report appears reasonable. The technical staff of Valeura involved with the assessment and implementation of development of Valeura's petroleum assets are represented as adherent to the generally accepted practices of the petroleum industry. The staff members appear to be experienced and technically competent in their fields of expertise. No site visit was made to the fields evaluated herein, since the properties are in an area of ongoing field operations and reports from third parties, photographic evidence of the fields, and public domain information were available.

As an independent evaluation, DeGolyer and MacNaughton is responsible for the preparation of this report and its contents subject to the stated conditions herein. To the best of our knowledge, having taken all reasonable care, the information contained in this report is in accordance with the material facts presented to us for the preparation of the report and contains no known omissions likely to affect the import of such information.

Executive Summary

Valeura has represented that it holds interests in certain fields in the Thrace Basin of Turkey evaluated in this report.

Reserves

The estimated gross, company gross, and net proved, probable, and possible reserves, as of December 31, 2018, of the properties evaluated herein are summarized as follows, expressed in barrels (bbl) and thousands of cubic feet (10^3ft^3):

	Reserves Summary					
	Oil and Condensate			Sales Gas		
	Proved (bbl)	Probable (bbl)	Possible (bbl)	Proved (10^3ft^3)	Probable (10^3ft^3)	Possible (10^3ft^3)
Gross	22,879	9,341	16,353	14,620,631	39,448,601	30,684,375
Company Gross	15,673	6,101	10,331	11,677,686	32,288,854	25,217,357
Net	13,605	5,312	9,000	10,102,563	27,942,579	21,832,795

Notes:
1. Probable and possible reserves are presented as required by the Canadian National Instrument 51-101 and are not equivalent to proved reserves.
2. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the quantities actually recovered will equal or exceed the sum of the proved, probable, and possible reserves.

Revenue values in this report were prepared using initial prices, expenses, and costs provided by Valeura and forecast price, expense, and cost assumptions described herein. Estimates of future net revenue and present worth of proved and proved-plus-probable reserves were prepared using a Base Case scenario and two price sensitivities as described herein. Gross and net reserves estimated herein were based on the Base Case price and cost assumptions.

The estimated future net revenue and present worth, discounted at 10 percent, of the future net revenue to be derived from the production and sale of the proved and proved-plus-probable reserves, as of December 31, 2018, of the properties evaluated under the Base Case economic assumptions described herein are summarized as follows, expressed in United States dollars (U.S.$):

	Valuation Summary – Base Case			
	Proved		Proved plus Probable	
	Future Net Revenue (U.S.$)	Present Worth at 10 Percent (U.S.$)	Future Net Revenue (U.S.$)	Present Worth at 10 Percent (U.S.$)
Base Case	23,114,191	14,731,384	101,584,017	48,874,943

Note: Values associated with probable reserves are presented as required by Canadian National Instrument 51–101 and are not equivalent to values associated with proved reserves.

Two price sensitivity cases were evaluated in this report in order to present alternative outcomes to the future revenue estimates for estimated reserves. Prices in

the sensitivity cases vary from initial conditions and differ from the Base Case. Reserves estimates herein were based on the Base Case scenario, and quantities in the sensitivity cases were those estimated prior to the limit of projected production under the Base Case scenario or when an annual economic limit is reached, whichever occurs first. Unless noted otherwise, all other components of the evaluation for the sensitivity cases are the same as stated for the Base Case herein.

The estimated future net revenue and present worth, discounted at 10 percent, of the future net revenue to be derived from the production and sale of the proved and proved-plus-probable quantities, as of December 31, 2018, of the properties evaluated under the Low Case and High Case economic assumptions described herein are summarized as follows, expressed in United States dollars (U.S.$):

	Valuation Summary – Sensitivity Cases			
	Proved		**Proved plus Probable**	
	Future Net Revenue (U.S.$)	**Present Worth at 10 Percent (U.S.$)**	**Future Net Revenue (U.S.$)**	**Present Worth at 10 Percent (U.S.$)**
Low Case	17,202,167	10,478,854	78,292,722	35,424,271
High Case	29,115,920	19,021,546	124,857,587	62,398,455

Notes:
1. Values for probable quantities are presented as required by the Canadian National Instrument 51-101 and are not equivalent to values for proved quantities. Reserves have been estimated using the Base Case scenario, and quantities in the sensitivity cases should not be confused with reserves.
2. Future Canadian income taxes were not taken into account in the preparation of these estimates.
3. The future net revenue, discounted or undiscounted, should not be construed to represent fair market value.

Ownership and Infrastructure

Valeura has represented that it holds interests in certain fields in Turkey as of December 31, 2018, which are listed as follows:

Properties Evaluated		
Asset Group Field	**Working Interest (percent)**	**License Expiration Date**
Banarli		
Banarli	100	NA
TBNGC		
Atakoy	81.5	NA
Aydede	81.5	NA
Bekirler	81.5	NA
Gazi	81.5	NA
Gelindere	81.5	NA
Karaevli	81.5	NA
Kayi	81.5	NA
Kazanci	81.5	NA
Osmanli	81.5	NA
Tekirdag	81.5	NA
Yagci	81.5	NA

Note: The Hayrabolu-10 well in the Kazanci field has a 31.5-percent working interest. The Yamalik-1 well in the Banarli field has a 50-percent working interest.

The licenses are represented by Valeura to be held by production until economic limits are reached. As such, the license expiration is not applicable for these properties.

The interests attributable to Valeura are held through contractual instruments that are common in the petroleum industry. We had an opportunity to review certain segments of pertinent agreements; however, we, as engineers, cannot express an opinion as to the accounting or legal aspects of those agreements.

For this report, technical and commercial uncertainties have been considered in each case exclusive of ongoing political events in a given venue. All contracts, regulations, and agreements in place on December 31, 2018, have been considered to be valid for their stated terms, as represented by Valeura.

The infrastructure in the area of these evaluated properties is well developed. The Thrace Basin is a mature petroleum-producing region. There are numerous established pipelines, production facilities, and processing facilities in the area. There is an extensive established network of service companies to allow gas and/or oil

developments throughout the area under varying circumstances. Power options, including electrical, gas, and diesel sources, are available to operators in this venue.

Environmental Consideration

There are certain environmental considerations in any venue of petroleum production. We are not aware of any extraordinary environmental elements associated with the property evaluated herein. As such, we have included abandonment costs, as appropriate, to accomplish routine and safe removal of subsurface and surface equipment at a given well site. Reclamation costs, if any, are considered to be zero for the evaluation herein, as Valeura has represented that it will not be responsible for such costs in Turkey.

Definition of Reserves

Petroleum reserves included in this report are categorized by degree of proof as proved, probable, or possible. For purposes of this report, reserves are those quantities of oil or gas anticipated to be economically recoverable from known accumulations. The definitions of reserves shown below serve as the basis for the estimates contained herein. These definitions are in accordance with the Canadian National Instrument 51-101 as presented in the *Canadian Oil and Gas Evaluation Handbook* (COGEH) *Consolidated Third Edition August 2018: Reserves Definitions and Evaluation Practices and Procedures*, Section 1. The petroleum reserves are categorized in accordance with Sections 1.3.5, 1.3.6, 1.3.7, and 1.3.8 of COGEH, which contains the complete and official explanation of the reserves definitions utilized herein.

Reserves Categories – Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

- analysis of drilling, geological, geophysical, and engineering data;
- the use of established technology;
- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

Reserves are categorized according to the degree of certainty associated with the estimates.

> *Proved Reserves* – Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
>
> *Probable Reserves* – Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved + probable reserves.
>
> *Possible Reserves* – Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved + probable + possible reserves.

Development and Production Status – Each of the reserves categories (proved, probable, and possible) may be divided into developed and undeveloped categories.

> *Developed Reserves* – Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling and completing a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
>
> > *Developed Producing Reserves* – Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
> >
> > *Developed Non-Producing Reserves* – Developed non-producing reserves are those reserves that either have not been on

production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

Undeveloped Reserves – Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling and completing a well) is required to render them capable of production. They must fully meet the requirements of the reserves categorization (proved, probable, possible) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities, and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves – The qualitative certainty levels contained in the definitions in Section 1.3.8 [*Reserves Categories above*] are applicable to individual Reserves Entities, which refers to the lowest level at which reserves calculations are performed, and to Reported Reserves, which refers to the highest level sum of individual entity estimates for which reserves estimates are presented. Reported Reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;

- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved + probable reserves;

- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved + probable + possible reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide

a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Estimation of Reserves

Estimates of reserves were prepared by the use of standard geological and engineering methods generally accepted by the petroleum industry. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by Valeura, and analyses of areas offsetting existing wells with test or production data, reserves estimated herein were categorized as proved, probable, or possible.

Valeura has represented that its senior management is committed to the development plan provided by Valeura and that Valeura has the financial capability to execute the development plan, including the drilling and completion of wells and the installation of equipment and facilities.

When applicable, the volumetric method was used to estimate the original gas in place (OGIP) and the original oil in place (OOIP). Structure maps were prepared to delineate each reservoir, and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation.

Where appropriate, estimates of ultimate recovery were obtained after applying recovery factors to OGIP or OOIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships.

In certain cases, reserves were estimated by incorporating elements of analogy to similar wells or reservoirs for which more complete data were available.

Data provided by Valeura from wells drilled through December 31, 2018, and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of monthly and cumulative production data available for certain properties only through October 31, 2018. Estimated cumulative production, as of December 31, 2018, was deducted from the estimated gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 2 months.

Oil and condensate reserves reported herein are to be recovered by normal field separation. Estimates of oil and condensate reserves are expressed in barrels (bbl). In these estimates, 1 barrel equals 42 United States gallons. For the fields evaluated herein, condensate reserves have been estimated to be zero.

Gas quantities estimated herein are expressed as sales gas. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel usage, flare, and shrinkage resulting from field separation and processing. Gas reserves estimated herein are reported as sales gas in thousands of cubic feet ($10^3 ft^3$) and expressed at a temperature base of 60 degrees Fahrenheit (°F) and a pressure base of 14.65 pounds per square inch absolute (psia).

Valeura has represented that it holds working interests in a number of licenses located within the Thrace Basin northwest of the city of Istanbul. The licenses are represented by Valeura to be held by production until economic limits are reached. The Banarli field, as designated herein, includes only those wells in which Valeura holds an interest. The fields range from mature to newer developments. All of the fields have the potential for recompletion, and some contain identified drilling locations. Field designations herein were provided by Valeura.

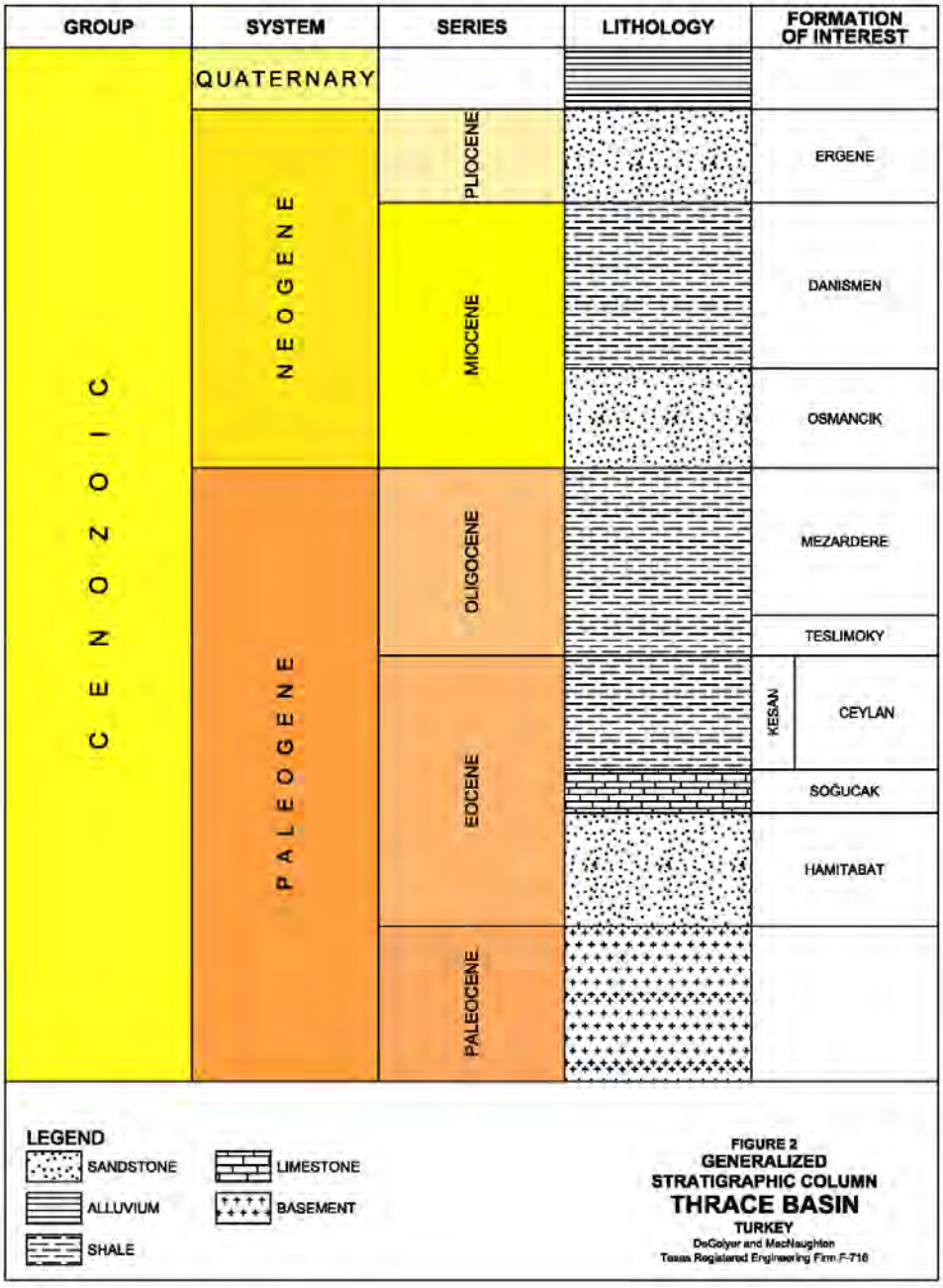
The fields have been grouped into two asset groups as shown in Table 1: the Thrace Basin National Gas Corporation (TBNGC) asset group and the Banarli asset group (consisting of the Banarli field). Each asset group has its own economic considerations, which are explained under the Valuation of Reserves heading of this report. The location map and generalized stratigraphic column of the fields are shown on Figures 1 and 2.

Procedure and Methodology

The Thrace Basin is a large, triangular-shaped, onshore Tertiary basin located in Turkey, with over 4,300 penetrating wells predominately producing gas. The first hydrocarbon field in the Thrace Basin was discovered in 1934. Since then, over 20 oil and gas fields have been discovered in the clastic reservoirs of the Oligocene-Miocene age.

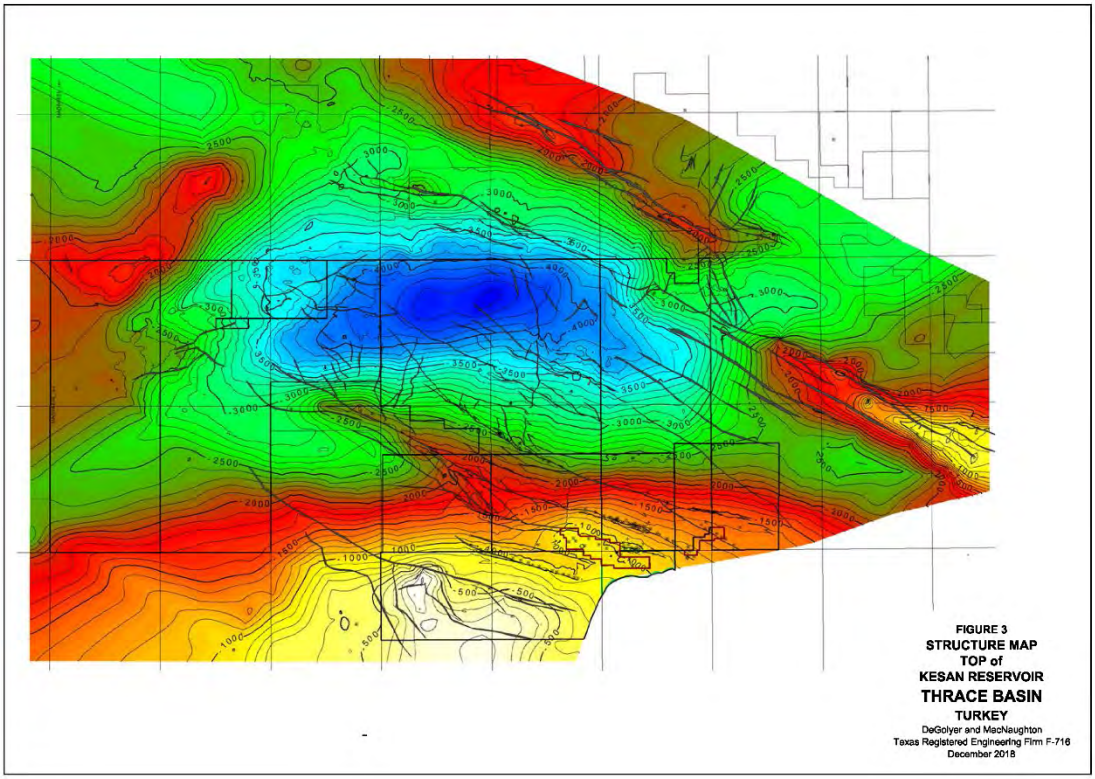
The sedimentary basin evolution began in the Eocene with extensional faulting and regional volcanism. Deposition of lithic sandstones resulted where the major rock fragments are volcanic. Deltaic sedimentation ensued in the Oligocene epoch as a foreland sag basin evolved, sourced by progradation of sediments from the south. Compression and transpression created flower structures and high-angle reverse faulting, and inverted fault blocks in the early Miocene. This orogenic activity, due to Arabian and Eurasion plate collision, produced the Anatolian fault zones, accommodating westward displacement. The uplift and subsequent erosion created a regional angular disconformity (a seismically mappable horizon). Continental deposition ensued. The Anatolian fault zone propagated during the Pliocene, breaching many of the late Miocene traps/structures. The regional fault strike is

northwest to southeast. These major sequences can be organized as the second-order Tejas B super cycle and the Tejas TB2 third-order super cycle. The clastics of the major reservoirs and exploration targets can therefore be interpreted as a lowstand tract deposition system, including basin floor fan facies (the Kesan Formation of Oligocene age), slope fan-channel facies (the Mezardere/Teslimkoy Formations of lower Miocene age), and the prograding wedge complex (the Danismen and Osmanicik Formations of upper Miocene age).



Estimated porosity ranges from 3 to 10 percent and permeability is typically about 1 millidarcy. Irreducible water saturation gleaned from capillary pressure data ranges from 20 to greater than 40 percent. Estimated gas saturation from formation evaluation ranges between 30 and 75 percent.

Oil and gas fields are sourced by the hydrocarbon-generation potential of the Neogene mudstones/shales, which can have total organic content (TOC) as high as 12 percent. Most oil and gas fields of the Thrace Basin are interpreted to be sourced by the shales deposited in the center of the basin. The source rocks are interbedded with the reservoir forming couplets of source-reservoir in the sedimentary section. Primary migration pathways in the Thrace Basin are interpreted to be from the source rock directly to the reservoirs, and secondary migration by way of carrier beds and faults.



Valeura began producing gas in the Thrace Basin in late 1998 from the Tekirdag field from the Osmancik reservoir. There are currently 12 fields on production in 2 asset groups: the TBNGC asset group, which is composed of the Atakoy, Aydede, Bekirler, Gazi, Gelindere, Karaevli, Kayi, Osmanli, Tekirdag, and Yagci fields, and the Banarli asset group, which is composed of the Banarli field. The

majority of production is gas, with some oil and condensate production from the Banarli and Kazanci fields.

Production commenced in 1998 from the Tekirdag field and as of December 31, 2018, approximately 52,825 bbl of oil and condensate and approximately 112,216,000 $10^3 ft^3$ of gas have been produced from the Thrace Basin by Valeura in this field.

Valeura's development of the Thrace Basin is ongoing with a substantial number of development wells planned for several fields. In the Tekirdag field, the Teslimkoy-Kesan reservoirs are planned to be targeted by 14 proved undeveloped wells, 48 probable undeveloped wells, and 19 possible undeveloped wells. In the Kayi field, the Teslimkoy is to be targeted by two proved undeveloped wells. In the Aydede field, the Mezardere Formation is to be targeted by six possible undeveloped wells. In the Kazanci and Banarli fields, the Osmancik Formation is to be targeted by one probable well and one possible undeveloped well in each field.

Proved developed producing reserves have been estimated based on performance trends of existing wells and completions. Proved developed non-producing reserves have been estimated for recompletions using a combination of analogous performance and volumetric analysis. Proved undeveloped reserves have been estimated for scheduled drilling and sidetracks based on statistical analysis of the performance of existing wells and recent drilling experience, as well as volumetric analysis where sufficient data were available. Probable and possible reserves were based on better well performance than projected for the proved reserves plus incremental volumetric recovery relating to the drilling and recompletion expectations. In addition, the proved undeveloped, probable, and possible reserves include a new, expanded development plan in the Tekirdag field (TBNGC asset group), which will target the larger undeveloped areas of this field. While this development plan may expand in the future, the estimates herein are limited to the schedule of wells and activities currently established and agreed upon by Valeura.

The estimated gross, company gross, and net proved, probable, and possible reserves, as of December 31, 2018, of the properties evaluated herein are summarized as follows, expressed in barrels (bbl) and thousands of cubic feet (10^3ft^3):

	Reserves Summary					
	Oil and Condensate			Sales Gas		
	Proved (bbl)	Probable (bbl)	Possible (bbl)	Proved (10^3ft^3)	Probable (10^3ft^3)	Possible (10^3ft^3)
Gross	22,879	9,341	16,353	14,620,631	39,448,601	30,684,375
Company Gross	15,673	6,101	10,331	11,677,686	32,288,854	25,217,357
Net	13,605	5,312	9,000	10,102,563	27,942,579	21,832,795

Notes:
1. Probable and possible reserves are presented as required by the Canadian National Instrument 51-101 and are not equivalent to proved reserves.
2. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the quantities actually recovered will equal or exceed the sum of the proved, probable, and possible reserves.

The appendix bound with this report includes additional details on the reserves estimated herein.

Valuation of Reserves

Revenue values in this report were estimated using initial prices, expenses, and costs provided by Valeura. The future net revenue estimated herein, discounted and undiscounted, should not be construed to represent fair market value.

Estimates of future net revenue and present worth of the proved and proved-plus-probable reserves were based on projections of estimated future production and revenue using a Base Case and two price sensitivity cases. The Base Case was evaluated as described below. Low Case and High Case sensitivity cases were evaluated with future prices that varied from those used in the Base Case.

Values for proved and proved-plus-probable reserves were based on projections of estimated future production and revenue prepared for these properties. Probable reserves involve substantially higher risk than proved reserves. Production of probable reserves is less likely to be realized than proved reserves, and any projection including probable reserves should be considered in that context. Revenue values associated with probable reserves are presented as required by the Canadian National Instrument 51-101 and are not equivalent to revenue values associated with proved reserves.

The following economic assumptions were used for estimating the Base Case revenue values reported herein:

Oil, Condensate, and Gas Prices

Historical prices for consideration in this evaluation were provided by Valeura. The forecast price schedule shown below was utilized for the evaluation herein, expressed in United States dollars per barrel (U.S.$/bbl) and United States dollars per thousand cubic feet (U.S.$/$10^3$ft^3):

	Oil and Condensate Price		Sales Gas Price	
Year	Banarli Asset Group (U.S.$/bbl)	TBNGC Asset Group (U.S.$/bbl)	Banarli Asset Group (U.S.$/$10^3$ft^3)	TBNGC Asset Group (U.S.$/$10^3$ft^3)
2019	57.35	57.35	7.04	7.24
2020	58.08	58.08	7.13	7.33
2021	58.52	58.52	7.18	7.39
2022	58.88	58.88	7.23	7.44
2023	59.07	59.07	7.25	7.46

Note: Oil, condensate, and gas prices are escalated 2 percent per year from 2023 forward.

Royalty

All fields are subject to a royalty of 12.5 percent. Fields in the TBNGC asset group are subject to an additional 1.0-percent overriding royalty interest. There is no overriding royalty interest for the Banarli field.

Operating Expenses and Capital Costs

Estimates of operating expenses based on current expenses and an escalation of 2 percent per year beginning in 2020 were used in this report to estimate future net revenue. In certain cases (before application of escalation), future expenses, either higher or lower than current expenses, may have been used because of anticipated changes in operating conditions. Operating expenses were estimated using fixed gross well costs and variable costs based on analysis of information provided by Valeura. Initial fixed gross well costs were U.S.$2,640 per month per well for all fields in the TBNGC and Banarli asset groups. Initial variable costs were U.S.$0.16 per thousand cubic feet (10^3ft^3) for all fields in the TBNGC and Banarli asset groups. Future capital expenditures were estimated using budgets and historical cost

information provided by Valeura and were also escalated at 2 percent per year beginning in 2020.

Abandonment Costs

Abandonment costs were provided by Valeura. As used in this report, abandonment costs are those costs associated with the removal of equipment, abandonment and plugging of wells, and reclamation and restoration associated with abandonment. These costs were based on current estimates by Valeura and were escalated at 2 percent per year. Reclamation costs, if any, are considered to be zero in the evaluation herein, as Valeura has represented that it will not be responsible for such costs in Turkey.

The economic models used in the evaluation in this report have been constructed based upon fiscal terms applicable under the current production license. A summary of the major components of the terms is as follows:

Production Taxes

Valeura has represented that no production taxes are to be paid in Turkey.

Taxes

A Turkey national income tax is assessed on revenues less costs, at a statutory rate of 22 percent. Taxable income (net to Valeura) has been adjusted for historic tax-loss carry-forward and capital depreciation balances, as of December 31, 2018, provided by Valeura:

Tax Balance	U.S.$7,720,000
Tax Loss Carry Forward	U.S.$0

The tax balance is defined as costs that are not depreciated and includes U.S.$1,460,000 for petroleum rights, U.S.$5,390,000 for well tangibles, and U.S.$870,000 for plant and pipeline tangibles. All future intangible costs are expenses in the year

incurred. Future well tangible costs are depreciated at 14.28 percent per year on a declining-balance basis.

Future Canadian income taxes were not taken into account in the preparation of this report.

In the tables and appendix in this report, summaries of the future gross, company gross, and net production and reserves are presented. For presentation purposes, capital and abandonment costs have been aggregated and the various taxes have been aggregated.

Production forecasts of the proved and proved-plus-probable reserves were based on development plan information provided by Valeura. Valeura has represented that the rates used for the production forecasts herein are within the capacity of the wells or reservoirs to produce.

The estimated future revenue attributable to Valeura's interests in the proved and proved-plus-probable reserves, as of December 31, 2018, of the properties evaluated under the Base Case economic assumptions described herein is summarized as follows, expressed in United States dollars (U.S.$):

	Valuation Summary – Base Case	
	Proved (U.S.$)	**Proved plus Probable (U.S.$)**
Future Gross Revenue	76,380,974	295,889,127
Operating Expenses	14,377,616	43,015,492
Capital Costs	26,280,740	113,786,354
Abandonment Costs	5,608,505	7,383,100
Income Taxes	6,999,922	30,120,164
Future Net Revenue	23,114,191	101,584,017
Present Worth at 10 Percent	14,731,384	48,874,943
Present Worth at 20 Percent	9,791,329	25,113,326

Notes:
1. Values for probable reserves are presented as required by the Canadian National Instrument 51-101 and are not equivalent to values for proved reserves.
2. Future Canadian income taxes were not taken into account in the preparation of these estimates.
3. The future net revenue, discounted or undiscounted, should not be construed to represent fair market value.

Sensitivities

Two price sensitivity cases were evaluated in this report in order to present alternative outcomes to the future revenue estimates for estimated reserves. Prices in the sensitivity cases vary from initial conditions and differ from the Base Case. Projections of reserves estimates summarized herein were based on the Base Case scenario, and quantities in the sensitivity cases are those included prior to the limit of projected production under the Base Case scenario or when an annual economic limit is reached, whichever occurs first. Unless noted otherwise, all other components of the evaluation for the sensitivity cases are the same as stated for the Base Case herein.

For the Low Case, the price forecast is as follows, expressed in United States dollars per barrel (U.S.$/bbl) and United States dollars per thousand cubic feet (U.S.$/$10^3$ft^3):

	Oil and Condensate Price		Sales Gas Price	
Year	**Banarli Asset Group (U.S.$/bbl)**	**TBNGC Asset Group (U.S.$/bbl)**	**Banarli Asset Group (U.S.$/$10^3$ft^3)**	**TBNGC Asset Group (U.S.$/$10^3$ft^3)**
2019	51.62	51.62	6.34	6.52
2020	52.27	52.27	6.41	6.60
2021	52.67	52.67	6.47	6.65
2022	52.99	52.99	6.51	6.70
2023	53.16	53.16	6.53	6.71

Note: Oil, condensate, and gas prices are escalated 2 percent per year from 2023 forward.

The estimated future revenue attributable to Valeura's interests in the proved and proved-plus-probable quantities, as of December 31, 2018, of the properties evaluated under the Low Case economic assumptions described herein is summarized as follows, expressed in United States dollars (U.S.$):

	Valuation Summary – Low Case	
	Proved (U.S.$)	**Proved plus Probable (U.S.$)**
Future Gross Revenue	67,931,884	264,533,087
Operating Expenses	13,532,210	41,268,307
Capital Costs	26,273,807	113,779,421
Abandonment Costs	5,588,379	7,347,431
Income Taxes	5,335,321	23,845,206
Future Net Revenue	17,202,167	78,292,722
Present Worth at 10 Percent	10,478,854	35,424,271
Present Worth at 20 Percent	6,572,300	16,849,917

Notes:
1. Values for probable quantities are presented as required by the Canadian National Instrument 51-101 and are not equivalent to values for proved quantities. Reserves have been estimated using the Base Case scenario, and quantities in the sensitivity cases should not be confused with reserves.
2. Future Canadian income taxes were not taken into account in the preparation of these estimates.
3. The future net revenue, discounted or undiscounted, should not be construed to represent fair market value.
4. Oil, condensate, and sales gas quantities in the Low Case are those included prior to the limit of projected production under the Base Case scenario or when an annual economic limit is reached, whichever occurs first.

For the High Case, the price forecast is as follows, expressed in United States dollars per barrel (U.S.$/bbl) and United States dollars per thousand cubic feet (U.S.$/$10^3$ft^3):

	Oil and Condensate Price		Sales Gas Price	
Year	**Banarli Asset Group (U.S.$/bbl)**	**TBNGC Asset Group (U.S.$/bbl)**	**Banarli Asset Group (U.S.$/$10^3$ft^3)**	**TBNGC Asset Group (U.S.$/$10^3$ft^3)**
2019	63.09	63.09	7.74	7.96
2020	63.89	63.89	7.84	8.06
2021	64.37	64.37	7.90	8.13
2022	64.77	64.77	7.96	8.18
2023	64.98	64.98	7.98	8.21

Note: Oil, condensate, and gas prices are escalated 2 percent per year from 2023 forward.

The estimated future revenue attributable to Valeura's interests in the proved and proved-plus-probable quantities, as of December 31, 2018, of the properties evaluated under the High Case economic assumptions described herein is summarized as follows, expressed in United States dollars (U.S.$):

	Valuation Summary – High Case	
	Proved (U.S.$)	**Proved plus Probable (U.S.$)**
Future Gross Revenue	84,877,860	327,309,576
Operating Expenses	15,185,643	44,650,508
Capital Costs	26,282,539	113,788,153
Abandonment Costs	5,621,343	7,412,056
Income Taxes	8,672,416	36,601,272
Future Net Revenue	29,115,920	124,857,587
Present Worth at 10 Percent	19,021,546	62,398,455
Present Worth at 20 Percent	13,021,668	33,308,066

Notes:

1. Values for probable quantities are presented as required by the Canadian National Instrument 51-101 and are not equivalent to values for proved quantities. Reserves have been estimated using the Base Case scenario, and quantities in the sensitivity cases should not be confused with reserves.
2. Future Canadian income taxes were not taken into account in the preparation of these estimates.
3. The future net revenue, discounted or undiscounted, should not be construed to represent fair market value.
4. Oil, condensate, and sales gas quantities in the High Case are those included prior to the limit of projected production under the Base Case scenario or when an annual economic limit is reached, whichever occurs first.

Professional Qualifications

DeGolyer and MacNaughton is a Delaware Corporation with offices at 5001 Spring Valley Road, Suite 800 East, Dallas, Texas 75244, U.S.A. The firm has been providing petroleum consulting services throughout the world since 1936. The firm's professional engineers, geologists, geophysicists, petrophysicists, and economists are engaged in the independent evaluation of oil and gas properties, evaluation of hydrocarbon and other mineral prospects, basin evaluations, comprehensive field studies, equity studies, and studies of supply and economics related to the energy industry. Except for the provision of professional services on a fee basis, DeGolyer and MacNaughton has no commercial arrangement with any other person or company involved in the interests which are the subject of this report.

The evaluation has been supervised by Mr. Regnald Boles. Mr. Boles is a Senior Vice President with DeGolyer and MacNaughton, Manager of the firm's Europe Africa Division, a Registered Professional Engineer in the State of Texas, and a member of the Society of Petroleum Engineers. He has more than 35 years of oil and gas industry experience.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

STATE OF TEXAS
REGNALD A. BOLES
65092
LICENSED
PROFESSIONAL ENGINEER

Regnald A. Boles

Regnald A. Boles, P.E.
Senior Vice President
DeGolyer and MacNaughton

DeGolyer and MacNaughton
F-716
Texas Registered Engineering Firm

TABLE 1
PROPERTIES EVALUATED
as of
DECEMBER 31, 2018
for
VALEURA ENERGY INC.
in
TURKEY

Asset Group Field	Working Interest (%)	License Expiration Date
Banarli		
Banarli	100	NA
TBNGC		
Atakoy	81.5	NA
Aydede	81.5	NA
Bekirler	81.5	NA
Gazi	81.5	NA
Gelindere	81.5	NA
Karaevli	81.5	NA
Kayi	81.5	NA
Kazanci	81.5	NA
Osmanli	81.5	NA
Tekirdag	81.5	NA
Yagci	81.5	NA

Notes:
1. Valeura has represented that license expiration dates are not applicable (NA) for the properties evaluated.
2. The Hayrabolu-10 well in the Kazanci field has a 31.5% working interest. The Yamalik-1 well in the Banarli field has a 50.0% working interest.

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TEXAS REGISTERED ENGINEERING FIRM

TABLE 2
SUMMARY of NET RESERVES and FUTURE NET REVENUE
as of
DECEMBER 31, 2018
attributable to
VALEURA ENERGY INC.
in
TURKEY

	Proved				
	Developed	**Undeveloped**	**Total**	**Probable**	**Possible**
Reserves					
Gross					
Oil and Condensate, bbl	22,879	0	22,879	9,341	16,353
Sales Gas, 10^3ft^3	5,377,357	9,243,274	14,620,631	39,448,601	30,684,375
Company Gross					
Oil and Condensate, bbl	15,673	0	15,673	6,101	10,331
Sales Gas, 10^3ft^3	4,144,414	7,533,272	11,677,686	32,288,854	25,217,357
Net					
Oil and Condensate, bbl	13,605	0	13,605	5,312	9,000
Sales Gas, 10^3ft^3	3,586,295	6,516,268	10,102,563	27,942,579	21,832,795
Revenue - Base Case					
Before Turkey Income Tax					
Future Net Revenue, U.S.$	12,457,745	17,656,368	30,114,113	101,590,068	108,442,916
Present Worth at 10 Percent, U.S.$	10,036,510	9,257,733	19,294,243	44,812,724	44,730,209
After Turkey Income Tax					
Future Net Revenue, U.S.$	9,619,735	13,494,456	23,114,191	78,469,826	84,705,711
Present Worth at 10 Percent, U.S.$	7,873,651	6,857,733	14,731,384	34,143,559	34,565,691

Notes:
1. Probable and possible reserves and values for probable and possible reserves are presented as required by the Canadian National Instrument 51-101 and are not equivalent to proved reserves or values for proved reserves.
2. Possible reserves and values for possible reserves are those additional reserves and values that are less certain to be recovered than probable reserves or values for probable reserves. It is unlikely that the quantities actually recovered will equal or exceed the sum of the proved, probable, and possible reserves and values thereof.
3. Future Canada income tax expenses were not taken into account in the preparation of these estimates.
4. The future net revenue, discounted and undiscounted, should not be construed to represent fair market value.
5. For the fields evaluated in this report, condensate reserves have been estimated to be zero.

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TEXAS REGISTERED ENGINEERING FIRM

TABLE 3
GROSS RESERVES by FIELD
as of
DECEMBER 31, 2018
with interests attributable to
VALEURA ENERGY INC.
in
TURKEY

	Proved						Probable		Possible	
	Developed		Undeveloped		Total					
Asset Group Field	**Oil and Condensate (bbl)**	**Sales Gas (10^3ft^3)**	**Oil and Condensate (bbl)**	**Sales Gas (10^3ft^3)**	**Oil and Condensate (bbl)**	**Sales Gas (10^3ft^3)**	**Oil and Condensate (bbl)**	**Sales Gas (10^3ft^3)**	**Oil and Condensate (bbl)**	**Sales Gas (10^3ft^3)**
Banarli										
Banarli	9,486	252,143	0	0	9,486	252,143	6,061	1,335,426	11,448	2,103,663
TBNGC										
Atakoy	0	478,666	0	0	0	478,666	0	115,877	0	195,076
Aydede	0	10,807	0	0	0	10,807	0	3,495	0	1,594,601
Bekirler	0	0	0	0	0	0	0	0	0	0
Gazi	0	3,823	0	0	0	3,823	0	1,906	0	2,698
Gelindere	0	32,641	0	0	0	32,641	0	6,672	0	8,312
Karaevli	0	71,457	0	0	0	71,457	0	59,990	0	40,316
Kayi	0	515,602	0	646,420	0	1,162,022	0	261,359	0	332,117
Kazanci	13,393	396,047	0	0	13,393	396,047	3,280	417,323	4,905	622,569
Osmanli	0	938,122	0	0	0	938,122	0	363,087	0	370,199
Tekirdag	0	2,678,049	0	8,596,854	0	11,274,903	0	36,883,309	0	25,413,456
Yagci	0	0	0	0	0	0	0	157	0	1,368
Total TBNGC	**13,393**	**5,125,214**	**0**	**9,243,274**	**13,393**	**14,368,488**	**3,280**	**38,113,175**	**4,905**	**28,580,712**
Grand Total	**22,879**	**5,377,357**	**0**	**9,243,274**	**22,879**	**14,620,631**	**9,341**	**39,448,601**	**16,353**	**30,684,375**

Notes:
1. Probable and possible reserves are presented as required by the Canadian National Instrument 51-101 and are not equivalent to proved reserves.
2. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the quantities actually recovered will equal or exceed the sum of the proved, probable, and possible reserves.
3. For the fields evaluated in this report, condensate reserves have been estimated to be zero.

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TEXAS REGISTERED ENGINEERING FIRM

TABLE 4
COMPANY GROSS RESERVES by FIELD
as of
DECEMBER 31, 2018
with interests attributable to
VALEURA ENERGY INC.
in
TURKEY

	Proved						Probable		Possible	
	Developed		Undeveloped		Total					
Asset Group Field	**Oil and Condensate (bbl)**	**Sales Gas (10^3ft^3)**	**Oil and Condensate (bbl)**	**Sales Gas (10^3ft^3)**	**Oil and Condensate (bbl)**	**Sales Gas (10^3ft^3)**	**Oil and Condensate (bbl)**	**Sales Gas (10^3ft^3)**	**Oil and Condensate (bbl)**	**Sales Gas (10^3ft^3)**
Banarli										
Banarli	4,757	137,448	0	0	4,757	137,448	3,428	1,271,554	6,334	1,979,648
TBNGC										
Atakoy	0	390,112	0	0	0	390,112	0	94,440	0	158,988
Aydede	0	8,808	0	0	0	8,808	0	2,849	0	1,299,600
Bekirler	0	0	0	0	0	0	0	0	0	0
Gazi	0	3,116	0	0	0	3,116	0	1,553	0	2,199
Gelindere	0	26,603	0	0	0	26,603	0	5,438	0	6,775
Karaevli	0	58,238	0	0	0	58,238	0	48,893	0	32,858
Kayi	0	420,216	0	526,832	0	947,048	0	213,006	0	270,676
Kazanci	10,916	152,695	0	0	10,916	152,695	2,673	295,170	3,997	451,825
Osmanli	0	764,568	0	0	0	764,568	0	295,917	0	301,711
Tekirdag	0	2,182,610	0	7,006,440	0	9,189,050	0	30,059,906	0	20,711,962
Yagci	0	0	0	0	0	0	0	128	0	1,115
Total TBNGC	**10,916**	**4,006,966**	**0**	**7,533,272**	**10,916**	**11,540,238**	**2,673**	**31,017,300**	**3,997**	**23,237,709**
Grand Total	**15,673**	**4,144,414**	**0**	**7,533,272**	**15,673**	**11,677,686**	**6,101**	**32,288,854**	**10,331**	**25,217,357**

Notes:
1. Probable and possible reserves are presented as required by the Canadian National Instrument 51-101 and are not equivalent to proved reserves.
2. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the quantities actually recovered will equal or exceed the sum of the proved, probable, and possible reserves.
3. For the fields evaluated in this report, condensate reserves have been estimated to be zero.

TABLE 5
NET RESERVES by FIELD
as of
DECEMBER 31, 2018
attributable to
VALEURA ENERGY INC.
in
TURKEY

	Proved									
	Developed		Undeveloped		Total		Probable		Possible	
Asset Group Field	**Oil and Condensate (bbl)**	**Sales Gas (10^3ft^3)**	**Oil and Condensate (bbl)**	**Sales Gas (10^3ft^3)**	**Oil and Condensate (bbl)**	**Sales Gas (10^3ft^3)**	**Oil and Condensate (bbl)**	**Sales Gas (10^3ft^3)**	**Oil and Condensate (bbl)**	**Sales Gas (10^3ft^3)**
Banarli										
Banarli	4,163	120,267	0	0	4,163	120,267	3,000	1,112,611	5,542	1,732,193
TBNGC										
Atakoy	0	337,449	0	0	0	337,449	0	81,690	0	137,523
Aydede	0	7,619	0	0	0	7,619	0	2,464	0	1,124,153
Bekirler	0	0	0	0	0	0	0	0	0	0
Gazi	0	2,695	0	0	0	2,695	0	1,343	0	1,902
Gelindere	0	23,011	0	0	0	23,011	0	4,703	0	5,860
Karaevli	0	50,375	0	0	0	50,375	0	42,291	0	28,423
Kayi	0	363,487	0	455,710	0	819,197	0	184,252	0	234,134
Kazanci	9,442	132,080	0	0	9,442	132,080	2,312	255,322	3,458	390,828
Osmanli	0	661,352	0	0	0	661,352	0	255,968	0	260,980
Tekirdag	0	1,887,960	0	6,060,558	0	7,948,518	0	26,001,824	0	17,915,835
Yagci	0	0	0	0	0	0	0	111	0	964
Total TBNGC	**9,442**	**3,466,028**	**0**	**6,516,268**	**9,442**	**9,982,296**	**2,312**	**26,829,968**	**3,458**	**20,100,602**
Grand Total	**13,605**	**3,586,295**	**0**	**6,516,268**	**13,605**	**10,102,563**	**5,312**	**27,942,579**	**9,000**	**21,832,795**

Notes:
1. Probable and possible reserves are presented as required by the Canadian National Instrument 51-101 and are not equivalent to proved reserves.
2. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the quantities actually recovered will equal or exceed the sum of the proved, probable, and possible reserves.
3. For the fields evaluated in this report, condensate reserves have been estimated to be zero.

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE 6
BASE CASE FORECAST PRICE and COST SCHEDULE
as of
DECEMBER 31, 2018
for
VALEURA ENERGY INC.
in
TURKEY

	Oil and Condensate Price		Sales Gas Price	
Year	Banarli Asset Group (U.S.$/bbl)	TBNGC Asset Group (U.S.$/bbl)	Banarli Asset Group (U.S.$/$10^3$ft^3)	TBNGC Asset Group (U.S.$/$10^3$ft^3)
2019	57.35	57.35	7.04	7.24
2020	58.08	58.08	7.13	7.33
2021	58.52	58.52	7.18	7.39
2022	58.88	58.88	7.23	7.44
2023	59.07	59.07	7.25	7.46

Notes:
1. Oil, condensate, and gas prices are escalated 2 percent per year from 2023 forward.
2. Costs are escalated 2 percent per year beginning in 2020.

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 28, 2019

Valeura Energy Inc.
Bow Valley Square 1
Suite 1200, 202-6th Avenue SW
Calgary T2P 2R9
Canada

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates, as of December 31, 2018, of the extent and potential volumes of the petroleum unconventional prospective resources of the Teslimkoy/Kesan BCG prospect located in the Banarli, West Thrace, and South Thrace license blocks in Turkey, in which Valeura Energy Inc. (Valeura) has represented it holds various working interests.

Information and data provided by Valeura were reviewed and analyzed and form the basis for the interpretations, opinions, results, and conclusions presented herein.

This report has been prepared pursuant to the Canadian National Instrument 51-101 (NI 51-101) Standards of Disclosure For Oil and Gas Activities, revised July 1, 2015, Sections 5.3 and 5.9. The unconventional prospective resources presented herein were estimated in accordance with Section 5.3 of NI 51-101 and Section 1.4.7.2.3 of the *Canadian Oil and Gas Evaluation Handbook* (COGEH) *Consolidated Third Edition August 2018*.

This report is compliant with the Competent Person's Report requirements as published in the European Securities and Markets Authority (ESMA) update of the Committee of European Securities Regulators' recommendations of the European Commission Regulation on Prospectuses No. 809/2004 dated March 20, 2013 (ESMA/2013/319).

The unconventional prospective resources estimated in this report are expressed as gross unconventional prospective resources and working interest unconventional prospective resources. Gross unconventional prospective resources are defined as the total estimated petroleum that is potentially recoverable from undiscovered accumulations after December 31, 2018. Working interest prospective resources incorporate the fraction of potential hydrocarbon pore volume held or partially held by Valeura and Valeura's working interest ownership.

A possibility exists that the prospect will not result in successful discovery and development, in which case there could be no future revenue. There is no certainty that any portion of the unconventional prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the unconventional prospective resources evaluated in this report.

Estimates of unconventional prospective resources should be regarded only as estimates that may change as additional information becomes available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information. Unconventional prospective resources quantities estimates should not be confused with those quantities that are associated with contingent resources or reserves due to the additional risks involved. The quantities that might actually be recovered, should they be discovered and developed, may differ significantly from the estimates presented herein.

The unconventional prospective resources estimated herein are those quantities of petroleum that are potentially recoverable from accumulations yet to be discovered. Because of the uncertainty of commerciality and the lack of sufficient exploration drilling, the unconventional prospective resources estimated herein cannot be classified as contingent resources or reserves. The unconventional prospective resources estimates in this report are not provided as a means of comparison to contingent resources or reserves.

In the preparation of this report we have relied, without independent verification, upon information furnished by or on behalf of Valeura with respect to the property interests being evaluated, subsurface data as they pertain to the target objectives and prospects, and various other information and technical data that were accepted as represented. Site visits to the prospect evaluated herein were not made by DeGolyer and MacNaughton, as this potential accumulation is undrilled

and prospective; therefore, production facilities are not relevant. This report was based on data available as of December 31, 2018. The completeness and accuracy of this information was confirmed in the Representation Letter provided by Valeura dated January 23, 2019.

As an independent evaluation, DeGolyer and MacNaughton is responsible for the preparation of this report and its contents subject to the stated conditions herein. To the best of our knowledge, having taken all reasonable care, the information contained in this report is in accordance with the material facts presented to us for the preparation of the report and contains no known omissions likely to affect the import of such information.

Executive Summary

Unconventional prospective resources for the Teslimkoy/Kesan BCG prospect have been evaluated as of December 31, 2018, in the Banarli, West Thrace, and South Thrace license blocks in Turkey. Valeura has represented that it currently holds various working interests in these blocks under the terms of the exploration and production licenses issued.

Unconventional Prospective Resources

The portfolio statistical aggregate probability of geologic success (P_g) for the Teslimkoy/Kesan BCG prospect is 0.700. The unconventional prospective resources estimates presented below are summarized using statistical aggregation. Estimates of the gross and working interest raw natural gas and condensate unconventional prospective resources, as of December 31, 2018, are summarized as follows, expressed in English units in millions of cubic feet ($10^6 ft^3$) and thousands of barrels ($10^3 bbl$):

	Low Estimate	Best Estimate	High Estimate	Mean Estimate
Gross Raw Natural Gas Unconventional Prospective Resources, $10^6 ft^3$	4,949,348	17,727,620	66,542,820	30,099,480
Gross Condensate Unconventional Prospective Resources, $10^3 bbl$	92,883	415,189	1,766,062	762,102
Working Interest Raw Natural Gas Unconventional Prospective Resources, $10^6 ft^3$	3,059,866	8,544,493	18,033,983	9,477,322
Working Interest Condensate Unconventional Prospective Resources, $10^3 bbl$	58,648	189,060	470,751	236,384

Notes:
1. Low, Best, High, and Mean estimates in this table are P_{90}, P_{50}, P_{10}, and Mean, respectively.
2. P_g has not been applied to the volumes in this table.
3. Application of any geological and economic chance factor does not equate unconventional prospective resources to contingent resources or reserves.
4. Recovery efficiency is applied to unconventional prospective resources in this table.
5. The unconventional prospective resources presented above are based on the statistical aggregation method.
6. There is no certainty that any portion of the unconventional prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the unconventional prospective resources evaluated.

The gross and working interest statistical aggregate P_g-adjusted mean estimate raw natural gas and condensate unconventional prospective resources, as of December 31, 2018, are summarized as follows, expressed in English units in $10^6 ft^3$ and in $10^3 bbl$:

	Mean Estimate
Gross P_g-Adjusted Raw Natural Gas Unconventional Prospective Resources, $10^6 ft^3$	21,069,636
Gross P_g-Adjusted Condensate Unconventional Prospective Resources, $10^3 bbl$	533,4[illegible]
Working Interest P_g-Adjusted Raw Natural Gas Unconventional Prospective Resources, $10^6 ft^3$	6,634,125
Working Interest P_g-Adjusted Condensate Unconventional Prospective Resources, $10^3 bbl$	165,469

Notes:
1. Application of any geological and economic chance factor does not equate unconventional prospective resources to contingent resources or reserves.
2. Recovery efficiency is applied to unconventional prospective resources in this table.
3. The unconventional prospective resources presented above are based on the statistical aggregation method.
4. P_g is predicated and correlated to the minimum case unconventional prospective resources gross recoverable volume(s). The P_g is not linked to economically viable volumes, economic flow rates, or economic field size assumptions.
5. The range in probability of occurrence for the statistical aggregate P_g-adjusted mean gas estimate is 0.26 to 0.40.
6. There is no certainty that any portion of the unconventional prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the unconventional prospective resources evaluated.

Estimates of the gross and working interest truncated, TEFS-adjusted raw natural gas unconventional prospective resources, as of December 31, 2018, are summarized as follows, expressed in English units in $10^6 ft^3$:

	Low Estimate	Best Estimate	High Estimate	Mean Estimate
Gross Truncated, TEFS-Adjusted Raw Natural Gas Unconventional Prospective Resources, $10^6 ft^3$	6,892,411	19,667,127	69,708,334	32,403,311
Working Interest Truncated, TEFS-Adjusted Raw Natural Gas Unconventional Prospective Resources, $10^6 ft^3$	5,321,840	9,239,640	16,041,622	10,136,674

Notes:
1. Low, Best, High, and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean, respectively.
2. P_g and probability of economic success (P_e) have not been applied to the volumes in this table.
3. Application of any geological and economic chance factor does not equate unconventional prospective resources to contingent resources or reserves.
4. Recovery efficiency is applied to unconventional prospective resources in this table.
5. The unconventional prospective resources presented above are based on the statistical aggregation method.
6. There is no certainty that any portion of the unconventional prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the unconventional prospective resources evaluated.

The gross and working interest truncated, TEFS-adjusted, P_e-adjusted mean estimate raw natural gas unconventional prospective resources, as of December 31, 2018, are summarized as follows, expressed in English units in $10^6 ft^3$:

	Mean Estimate
Gross	
Gross Truncated, TEFS-Adjusted, P_e-adjusted Raw Natural Gas Unconventional Prospective Resources, $10^6 ft^3$	16,655,571
Working Interest	
Working Interest Truncated, TEFS-Adjusted, P_e-adjusted Raw Natural Gas Unconventional Prospective Resources, $10^6 ft^3$	5,181,728

Notes:
1. Application of any geological and economic chance factor does not equate unconventional prospective resources to contingent resources or reserves.
2. Recovery efficiency is applied to unconventional prospective resources in this table.
3. The unconventional prospective resources presented above are based on the statistical aggregation method.
4. There is no certainty that any portion of the unconventional prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the unconventional prospective resources evaluated.

Ownership and Infrastructure

For the Teslimkoy/Kesan BCG Prospect evaluated herein, Valeura has represented that it holds interests as follows:

Prospect	Working Interest (decimal)	License Expiration
Teslimkoy/Kesan BCG		
Banarli AR/CBV-STT/K/F18-C License Block	0.500	06-27-2020
Banarli AR/CBV-STT/K/F19-d1-d4 License Block	0.500	06-27-2020
West Thrace AR/TGT-PIN-STT/K/F18-d1-d2-d4 License Block	0.315	06-27-2020
South Thrace ARI/TGT-PIN-CBV/F18-c3-1 License Block	0.815	11-10-2023
South Thrace ARI/TGT-PIN-CBV/F18-c4-2 License Block	0.815	11-10-2026
South Thrace ARI/TGT-PIN-CBV/F19-d4-1 License Block	0.815	11-10-2022
South Thrace ARI/TGT-PIN-CBV/F19-d4-2 License Block	0.815	11-08-2020

Valeura's interests are held through contractual instruments that are common in the petroleum industry. We had an opportunity to review certain segments of pertinent agreements; however, we, as engineers, cannot express an opinion as to the accounting or legal aspects of those agreements. For this report, technical and commercial uncertainties have been considered in each case exclusive of ongoing political events in a given venue. All contracts, regulations, and agreements in place on December 31, 2018, have been considered to be valid for their stated terms, as represented by Valeura.

The infrastructure in the area of these prospective resources is adjacent to development infrastructure. The Thrace Basin is a mature petroleum-producing region. There are numerous established pipelines, production facilities, and processing facilities in the area. There is an extensive established network of service companies to allow gas and/or oil developments throughout the area under varying circumstances. Power options, including electrical, gas, and diesel sources, are available to operators in this venue.

Definition of Unconventional Prospective Resources

Estimates of petroleum resources included in this report are classified as unconventional prospective resources and have been prepared on the basis of the definitions shown below. These definitions are in accordance with the Canadian National Instrument 51-101 as presented in the *Canadian Oil and Gas Evaluation Handbook* (COGEH) *Consolidated Third Edition August 2018*. The unconventional prospective resources are estimated and categorized in accordance with Sections 1.2.2, 1.3.5, 1.3.6, 1.3.7, and 1.4.7.2.3 of COGEH, which contains the complete and official explanation of the unconventional prospective resources definitions utilized herein. Because of the lack of commerciality or sufficient drilling, the unconventional prospective resources estimated herein cannot be classified as contingent resources or reserves. The unconventional petroleum prospective resources are classified as follows:

> *Unconventional Prospective Resources* – Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further categorized according to the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity. Unconventional Prospective Resources exist in petroleum accumulations that are pervasive throughout a large area and are not significantly affected by hydrodynamic influences (also called continuous-type deposit). Typically, such accumulations require specialized extraction technology.

In contrast to conventional reservoirs, natural gas or oil can also be found in more difficult to extract unconventional deposits, such as coal beds, shales, low-quality reservoirs, as gas hydrates, and high-viscosity oil at shallow depths.

> *Shale Oil, Shale Gas, and Coal Seam Gas (Coal Bed Methane)* are examples where the natural gas or oil is still within the source rock, not having migrated to a porous and permeable reservoir.

> *Tight Gas or Oil* occurs within low permeability reservoir rocks. Tight gas can be regionally distributed (for example, basin-centered gas),

rather than accumulated in a readily producible reservoir in a discrete structural closure as in a conventional gas field. Tight oil is crude oil that is trapped in pore space and may be liquid under reservoir conditions or become liquid at surface conditions.

Gas Hydrates are naturally occurring ice-like solids (clathrates) in which water molecules trap gas molecules in deep-sea sediments and in and below the permafrost soils of the polar regions.

Bitumen, high viscosity oil, results from the oxidation and/or bacterial transformation of lighter petroleum that has migrated from elsewhere. Under the prevailing conditions, trapping occurs, and it becomes immobile because of its high viscosity.

The estimation of petroleum resources is subject to both technical and commercial uncertainties and, in general, may be quoted as a range. The range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities. In all cases, the range of uncertainty is dependent on the amount and quality of both technical and commercial data that are available and may change as more data become available.

1U (Low), 2U (Best), 3U (High), and Mean Estimates – Estimates of unconventional prospective resources in this report are expressed using the terms low estimate, best estimate, high estimate, and mean estimate to reflect the range of uncertainty.

A detailed explanation of the probabilistic terms used herein and identified with an asterisk (*) is included in the glossary bound with this report. For probabilistic estimates of petroleum resources, the low estimate reported herein is the P_{90}* quantity derived from probabilistic analysis. This means that there is at least a 90-percent probability that, assuming the prospect is discovered and developed, the quantities actually recovered will equal or exceed the low estimate. The best (median) estimate is the P_{50}* quantity derived from probabilistic analysis. This means that there is at least a 50-percent probability that, assuming the prospect is discovered and developed, the quantities actually recovered will equal or exceed the best (median) estimate. The high estimate is the P_{10}* quantity derived from

probabilistic analysis. This means that there is at least a 10-percent probability that, assuming the prospect is discovered and developed, the quantities actually recovered will equal or exceed the high estimate. The expected value* (EV), an outcome of the probabilistic analysis, is the mean estimate.

Uncertainties Related to Prospective Resources – The quantity of petroleum discovered by exploration drilling depends on the number of prospects that are successful as well as the quantity that each success contains. Reliable forecasts of these quantities are, therefore, dependent on accurate predictions of the number of discoveries that are likely to be made if the entire portfolio of prospects is drilled. The accuracy of this forecast depends on the portfolio size, and an accurate assessment of the probability of geological success.

Probability of Geologic Success – The probability of geologic success (P_g) is defined as the estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum. The P_g is estimated by quantifying with a probability each of the following individual geologic chance factors: trap, source, reservoir, and migration. The product of the probabilities of these four chance factors is P_g. P_g is predicated and correlated to the minimum case prospective resources gross recoverable quantity(ies). Consequently, the P_g is not linked to economically viable quantities, economic flow rates, or economic field size assumptions.

In this report estimates of prospective resources are presented both before and after adjustment for P_g. Total prospective resources estimates are based on the probabilistic summation (statistical aggregation) of the quantities for the total inventory of prospects. The statistical aggregate P_g-adjusted mean estimate, or "aggregated geologic chance-adjusted mean estimate," is a probability-weighted average geologic success case expectation (average) of the hydrocarbon quantities potentially recoverable if all of the prospects in a portfolio were drilled. The P_g-adjusted mean estimate is a "blended" quantity; it is a product of the statistically aggregated mean quantity estimate and the portfolio's probability of geologic success. This statistical measure considers and stochastically quantifies the geological success and geological failure outcomes. Consequently, it represents the average or mean "geologic success case"

quantity outcome of drilling all of the prospects in the exploration program.

Application of P_g to estimate the P_g-adjusted prospective resources quantities does not equate prospective resources with reserves or contingent resources. P_g-adjusted prospective resources quantities cannot be compared directly to or aggregated with either reserves or contingent resources. Estimates of P_g are interpretive and are dependent on the quality and quantity of data currently made available. Future data acquisition, such as additional drilling or seismic acquisition, can have a significant effect on P_g estimation. These additional data are not confined to the study area, but also include data from similar geologic settings or technological advancements that could affect the estimation of P_g.

Predictability versus Portfolio Size – The accuracy of forecasts of the number of discoveries that are likely to be made is constrained by the number of prospects in the exploration portfolio. The size of the portfolio and P_g together are helpful in gauging the limits on the reliability of these forecasts. A high P_g, which indicates a high chance of discovering measurable petroleum, may not require a large portfolio to ensure that at least one discovery will be made (assuming the P_g does not change during drilling of some of the prospects). By contrast, a low P_g, which indicates a low chance of discovering measurable petroleum, could require a large number of prospects to ensure a high confidence level of making even a single discovery. The relationship between portfolio size, P_g, and the probability of a fully unsuccessful drilling program that results in a series of wells not encountering measurable hydrocarbons is referred to herein as the predictability versus portfolio size (PPS) relationship*. It is critical to be aware of PPS, because an unsuccessful drilling program, which results in a series of wells that do not encounter measurable hydrocarbons, can adversely affect any exploration effort, resulting in a negative present worth.

For a large prospect portfolio, the P_g-adjusted mean (statistical aggregate) estimate of the prospective resources quantity should be a reasonable estimate of the recoverable petroleum quantities found if all prospects are drilled. When the number of prospects in the portfolio is small and the P_g is low, the recoverable petroleum actually found

may be considerably smaller than the statistical aggregate P_g-adjusted mean estimate would indicate. It follows that the probability that all of the prospects will be unsuccessful is smaller when a large inventory of prospects exist.

Prospect Technical Evaluation Stage – A prospect can often be subclassified based on its current stage of technical evaluation. The different stages of technical evaluation relate to the amount of geologic, geophysical, engineering, and petrophysical data as well as the quality of available data.

Prospect – A project associated with an undrilled potential accumulation that is sufficiently well defined to be a viable drilling target. For a prospect, sufficient data and analyses exist to identify and quantify the technical uncertainties, to determine reasonable ranges of geologic chance factors and engineering and petrophysical parameters, and to estimate prospective resources.

Lead – A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect. An example would be a poorly defined closure mapped using sparse regional seismic data in a basin containing favorable source and reservoir(s). A lead may or may not be elevated to prospect status depending on the results of additional technical work. A lead must have a P_g equal to or less than 0.05 to reflect the inherent technical uncertainty.

Play – A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific Leads or Prospects.

Threshold Economic Field Size – The threshold economic field size (TEFS) is the minimum amount of the producible petroleum required to recover the total capital and operating expenditure used to establish the potential accumulation as having a potential present worth at 10 percent equal to zero using the most likely price scenario.

Probability of Development – The probability of development (P_d) is defined as the estimated probability that a known accumulation, once discovered, will be

commercially developed. P_d takes into account the chance that the discovered target zone will flow the predicted hydrocarbon phase(s) at a commercial rate. It also considers the chance that the target zone can be mechanically completed and appraised in a reasonable time and in compliance with the projected cost schedule. The P_d is estimated by the quantification and product of these two chance factors.

Probability of Threshold Economic Field Size – The probability of threshold economic field size (P_{TEFS}) is defined as the probability of discovering an accumulation that is large enough to be economically viable. P_{TEFS} is estimated by using the prospective resources potential recoverable quantities distribution in conjunction with the TEFS. The probability associated with the TEFS is estimated from the potential gross recoverable quantities distribution.

Probability of Economic Success – The probability of economic success P_e is defined as the estimated probability that the project will achieve commercial maturity to be developed. It takes into account P_g, TEFS, P_{TEFS}, P_d, capital costs, operating expenses, the proposed development plan, the economic model (discounted cash flow analysis), and other business and economic factors. P_e is calculated as follows:

$$P_e = P_g \times (P_{TEFS}) \times P_d$$

Geology

The Thrace Basin is a large onshore Tertiary tranform/transcurrent (plate boundary transform fault) basin located in north-central Turkey bordering Greece and Bulgaria, shown on Figure 1.

Figure 1 – Location Map

The Thrace Basin extends over an area of about 15,000 square kilometers. It is tectonically associated with the African, Eurasian, and Arabian plates. Within the basin, northwest/southeast-striking reverse and wrench faults define the structural style. The North Anatolian strike-slip fault is a salient feature that defines the basin and provides structural evidence of the transpressive influence on the traps and geology of the petroleum geology of the region. The basin basement is primarily floored by Paleozoic metamorphic rocks and is surrounded by metamorphic massifs. Sedimentary thickness reaches up to 9,000 meters (29,500 feet) in the central portion of the basin.

Thrace Petroleum Geology

The first hydrocarbon field in the Thrace Basin was discovered in 1934. Since then, over 20 oil and gas fields have been discovered in the clastics reservoirs of the

Oligocene-Miocene age. The basin has been penetrated by over 1,200 oil and gas wells. The predominate productive hydrocarbon to date has been gas.

The sedimentary basin evolution began in the Eocene with extensional faulting and regional volcanism. Deposition of lithic sandstones resulted where the major rock fragments are volcanic. Deltaic sedimentation ensued in the Oligocene epoch as a foreland sag basin evolved, sourced by progradation of sediments from the south. Compression and transpression created flower structures and high-angle reverse faulting, and inverted fault blocks in the early Miocene. This orogenic activity, due to Arabian and Eurasion plate collision, produced the Anatolian fault zones, accommodating westward displacement. The uplift and subsequent erosion created a regional angular disconformity (a seismically mappable horizon). Continental deposition ensued. The Anatolian fault zone propagated during the Pliocene, breaching many of the late Miocene traps/structures. The regional fault strike is northwest to southeast. These major sequences can be organized as the second-order Tejas B super cycle and the Tejas TB2 third-order super cycle. The clastics of the major reservoirs and exploration targets can therefore be interpreted as a lowstand tract deposition system, including basin floor fan facies (the Kesan Formation of Oligocene age), slope fan-channel facies (the Mezardere/Teslimkoy Formations of lower Miocene age), and the prograding wedge complex (the Danismen and Osmanicik Formations of upper Miocene age). The maximum gross thicknesses associated with the Kesan, Mezardere/Teslimkoy, Danismen, and Osmanicik Formations are 1,000, 800, 2,000, and 1,500 meters, respectively.

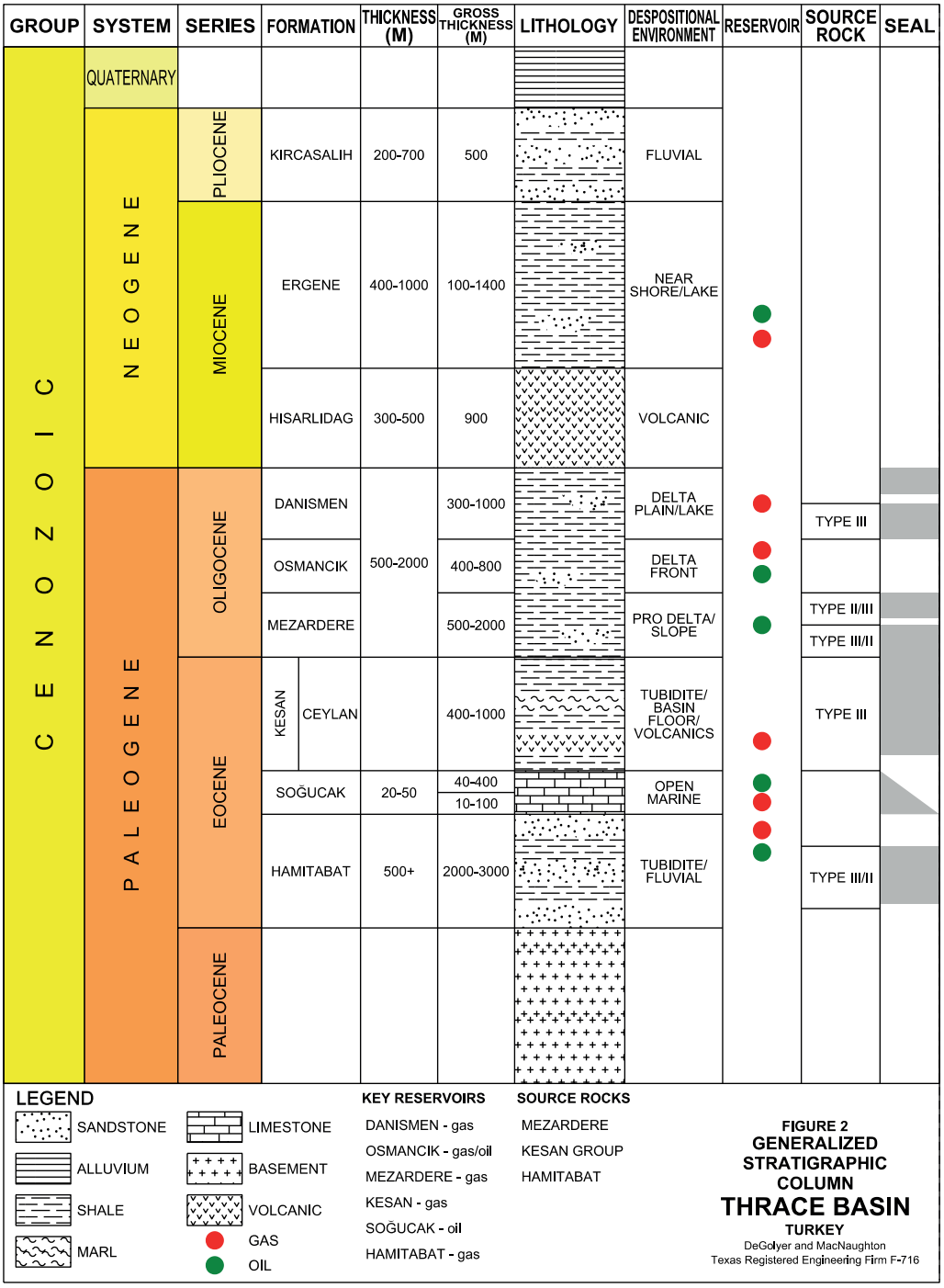

Figure 2 – Generalized Chronostratigraphic Chart

Porosity is poor (0.03 to 0.10 percent); and permeability is poor to negligible (1.0 to less than 0.10 millidarcy) in the target intervals. Pore throats range in size from 0.003 to 1.00 micron. Primary porosity is the dominant porosity type with minor secondary porosity associated with dissolution of feldspars. Compaction and calcite cement are the main causes of porosity destruction/reduction. Core data and sandstone petrographic analyses show the clastics to be predominantly feldspathic litharenites.

Irreducible water saturation gleaned from capillary pressure data range from 20 to greater than 40 percent. Estimated gas saturation from formation evaluation range between 30 and 75 percent. Reservoirs in the play area are slightly to highly overpressured.

Gas and oil fields are sourced by the hydrocarbon-generation potential of the Neogene mudstones/shales, which can have total organic content (TOC) as high as 12 percent. Most oil and gas fields of the Thrace Basin are interpreted to be sourced by the shales deposited in the center of the basin. The source rocks are interbedded with the reservoir, forming couplets of source-reservoir in the sedimentary section. Primary migration pathways in the Thrace Basin are interpreted to be from the source rock directly to the reservoirs, and secondary migration by way of carrier beds and faults. Many of the zones can be interpreted as "self-sourced."

The regional and effective top seal lithofacies are non-permeable sandstones, siltstones, and shale/mudstones. Traps can be interpreted as "unconventional" or stratigraphic. The prospect is interpreted to be a potential gas accumulation where gas composition could range from 70- to 95-percent methane, with a condensate yield range of 5 to 50 barrels per million cubic feet of gas.

Valeura has an acreage position in three license areas: West Thrace, Banarli, and South Trace. This position is in the center of the basin, where the unconventional targets are expected to produce gas with variable condensate yield.

The prospects evaluated herein, if discovered and developed, will be subject to certain appraisal, development, and production challenges. The prospects have the advantage of being in an area of developed infrastructure, with potential markets for produced hydrocarbons. However, the unconventional nature of the reservoirs will require careful planning for development, including well location, well spacing, completion techniques applied, and post-drill surveillance. As such, the notional development plans considered herein are conceptual and not the result

of a detailed study of options. Total development costs can vary greatly but are likely to be between 2.606 and 15.539 billion United States dollars (U.S.$) for the Teslimkoy/Kesan prospect evaluated herein. With the current state of exploration and adjacent appraisal and development, any discovered resources are likely to be developed within 5 years of discovery.

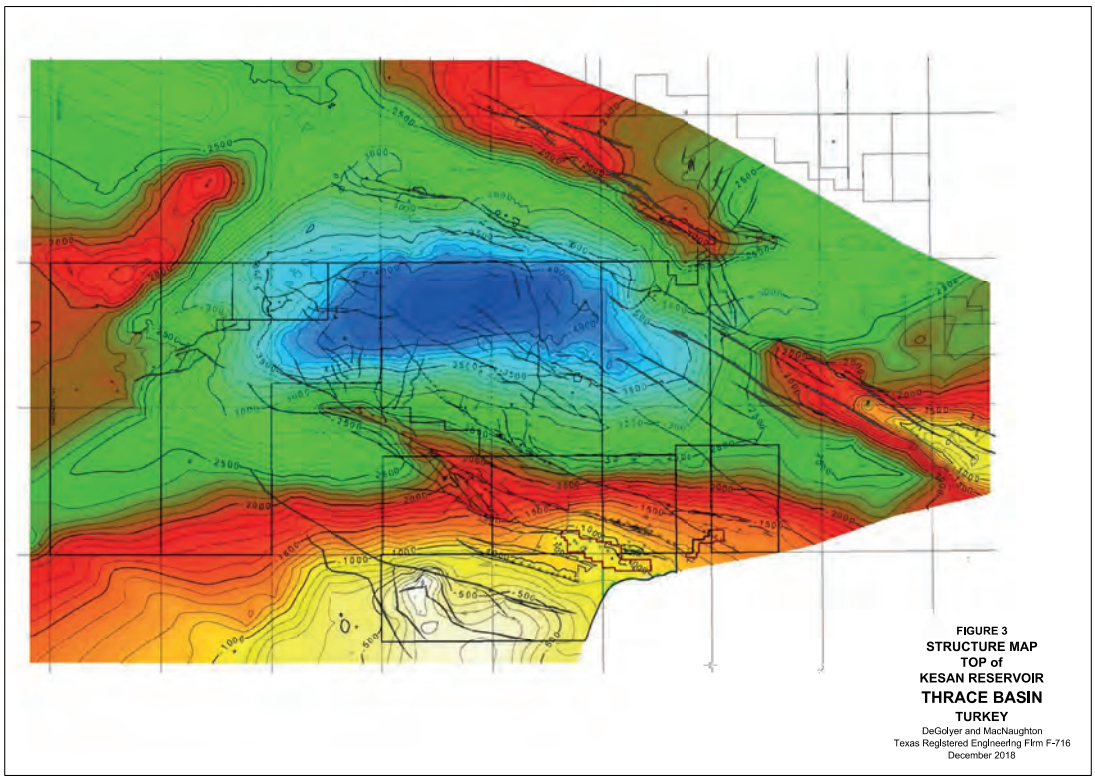

Figure 3 – Structure Map

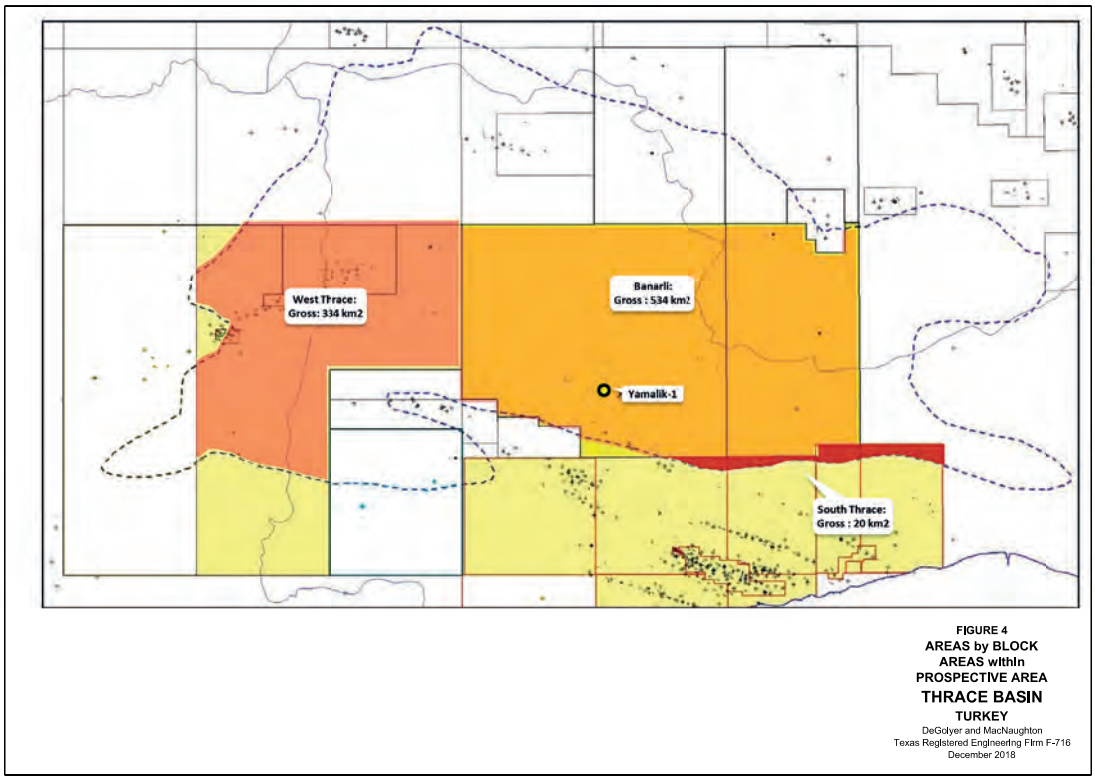

Figure 4 – Areas by Block

Estimation of Unconventional Prospective Resources

Estimates of unconventional prospective resources were prepared by the use of standard geological and engineering methods generally accepted by the petroleum industry. The method or combination of methods used in the analysis of the reservoirs was tempered by experience with similar reservoirs, stage of development, and quality and completeness of basic data.

The probabilistic analysis of the unconventional prospective resources in this study considered the uncertainty in the amount of petroleum that may be discovered and the P_g. The uncertainty analysis addresses the range of possibilities for any given volumetric parameter. Minimum, maximum, low, best, high, and mean estimates of unconventional prospective resources were estimated to address this

uncertainty. The P_g analysis addresses the probability that the identified prospect will contain petroleum that flows at a measurable rate.

Estimates of recovery efficiency presented in this report are based on analog data and global experience and reflect the potential range in recovery for the potential reservoirs considered. Recovery efficiency estimates do not incorporate development or economic input and are subject to change upon selection of specific development options and costs, economic parameters, and product price scenarios.

Volumetrics, Quantitative Risk Assessment, and the Application of P_g

Minimum, low, modal, best, mean, high, and maximum representations of potential productive area were interpreted from maps, available seismic data, and/or analogy. Representations for the petrophysical parameters (porosity, hydrocarbon saturation, and net hydrocarbon thickness) and engineering parameters (recovery efficiency and fluid properties) were also estimated based on available well data, regional data, analog field data, and global experience.

The distributions for the variables were derived from (1) scenario-based interpretations, (2) the geologic, geophysical, petrophysical, and engineering data available, (3) local, regional, and global knowledge, and (4) field and case studies in the literature. The parameters used to model the recoverable quantities were potential productive area, net hydrocarbon thickness, geometric correction factor, porosity, hydrocarbon saturation, formation volume factor, and recovery efficiency. Minimum, mean, and maximum representations were used to statistically model and shape the input P_{90}, P_{50}, and P_{10} parameters. Potential productive area, net hydrocarbon thickness, and recovery efficiency were modeled using truncated lognormal distributions. Truncated normal distributions were used to model formation volume factor, porosity, and hydrocarbon saturation. Latin hypercube sampling was used to better represent the tails of the distributions.

Each individual volumetric parameter was investigated using a probabilistic approach with attention to variability. Deterministic data were used to anchor and shape the various distributions. The rock volume parameters had the greatest range of variability, and therefore had the greatest impact on the uncertainty of the simulation. The volumetric parameter variability was based on the structural and stratigraphic uncertainties due to the depositional environment and quality of the seismic data. Analog field data were statistically incorporated to derive uncertainty limits and constraints on the net hydrocarbon thickness pore volume. Uncertainty

associated with the depth conversion, seismic interpretation, gross interval thickness mapping, and net hydrocarbon thickness assumptions were also derived from studies of analogous reservoirs, multiple interpretative scenarios, and sensitivity analyses.

A P_g analysis was applied to estimate the quantities that may actually result from drilling this unconventional prospect. In the P_g analysis, the P_g estimates were made from the product of the probabilities of the four geologic chance factors: trap, reservoir, migration, and source. The P_g is predicated and correlated to the minimum case prospective resources gross recoverable volume(s). The P_g is not linked to economically viable volumes, economic flow rates, or economic field size assumptions. The P_g is predicated and correlated to the minimum case unconventional prospective resources gross recoverable volume(s).

The following equation was used in the probabilistic volumetric model:

For Sandstones:

$$PGUR = 43560 \times A \times h \times \phi \times E_g \times S_g \times R_f$$

where:
- PGUR = Prospective gross ultimate recovery (scf)
- A = Productive area (acres)
- h = Net hydrocarbon thickness (feet)
- ϕ = Porosity (fraction)
- E_g = Gas expansion factor (scf/rcf)
- S_g = Gas saturation (fraction)
- R_f = Recovery efficiency (decimal)

The P_g-adjusted mean estimate of the unconventional prospective resources was then made by the probabilistic product of P_g and the resources distributions for the prospect. These results were then stochastically summed (zero dependency) to produce the statistical aggregate P_g-adjusted mean estimate unconventional prospective resources. The range in probability of the mean occurrence (P_{MEAN})* for the unconventional prospective resources volumes were estimated as defined in the glossary of this report. The range in P_{MEAN} for the statistical aggregate P_g-adjusted mean gas estimate is 0.26 to 0.40.

Application of the P_g factor to estimate the P_g-adjusted unconventional prospective resources quantities does not equate unconventional prospective resources with reserves or contingent resources. The P_g-adjusted estimates

of unconventional prospective resources quantities cannot be compared directly to or aggregated with either reserves or contingent resources. Estimates of P_g are interpretive and are dependent on the quality and quantity of data currently available. Future data acquisition, such as additional drilling or seismic acquisition, can have a significant effect on P_g estimation. These additional data are not confined to the area of study, but also include data from similar geologic settings or from technological advancements that could affect the estimation of P_g or impact the interpretation of the petroleum system.

Nonassociated gas is gas at initial reservoir conditions with no crude oil present in the reservoir. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in crude oil at initial reservoir conditions. In known accumulation, solution gas and gas-cap gas are sometimes produced together and, as a whole, referred to as associated gas. Unconventional prospective raw natural gas quantities (nonassociated and associated) included herein are defined as the total gas potentially producible from the prospective reservoirs before any reduction for shrinkage for potential field and/or platform handling, separation, processing, fuel usage, flaring, reinjection, and/or pipeline losses.

It is not certain whether prospective reservoirs will be gas bearing, oil bearing, or water bearing. Hydrocarbon phase determination is based on the phase chance of occurrence per the present interpretation of the petroleum system. Unconventional prospective resources volumes in this report are identified herein as raw natural gas and condensate. In this report, one potential accumulation (Teslimkoy/Kesan BCG) is referred to as prospect to reflect the current stage of technical evaluation.

In this report, gas quantities are expressed in English units at a temperature base of 60 degrees Fahrenheit (°F) and at a pressure base of 14.7 pounds per square inch absolute (psia).

Application of P_e

A P_e analysis was applied to estimate the economically recoverable quantities that may actually result from drilling this unconventional prospect. TEFS was used to truncate and redistribute the estimated unconventional prospective resources probability distributions. The truncated, TEFS-adjusted, P_e-adjusted estimates of the unconventional prospective resources were then estimated by the probabilistic product of P_e and the truncated, TEFS-adjusted unconventional

prospective resources distributions. These results were then stochastically (zero dependency) summed and redistributed to produce the truncated, TEFS-adjusted, P_e-adjusted unconventional prospective resources estimates.

Various price scenarios were utilized: operating expenses, capital costs, prices, potential production, depreciation, taxes, time value of money, field life, development well costs, development timing, and abandonment costs, with consideration of other factors.

Application of the P_e factor to estimate the P_e-adjusted unconventional prospective resources quantities does not equate unconventional prospective resources with contingent resources or reserves. Estimates of P_e are interpretive and are dependent on the quality and quantity of data currently available. Future data acquisition, technical developments, or changing economic scenarios can have a significant effect on P_e estimation. These additional data are not confined to the area of study, but also include data from similar geologic settings or technological advancements that could affect the estimation of P_e. Estimates of P_e are interpretive and are dependent on the quality and quantity of data currently made available. Future changes in the fiscal environment and/or the infrastructure of the area can change these values significantly.

Estimates of unconventional prospective resources and related distributions herein are the results of probabilistic estimation. These estimates are expressed as a distribution rather than a single value. Probabilistic outcomes involve thousands of iterations using distributions. Deterministic estimations utilizing non-stochastic mathematical operations (addition, subtraction, multiplication, and division) performed on the unconventional prospective resources distributions estimated herein produce results that are not comparable.

The assessed Teslimkoy/Kesan BCG prospect and it's relevant ownership, potential hydrocarbon phase, prospect location, and economic-related metrics are summarized below:

Prospect Summary

Prospect	Country	Potential Target	Basin	Working Interest (decimal)	Potential Hydrocarbon Phase
Teslimkoy/Kesan BCG					
Banarli License Block	Turkey	Teslimkoy/Kesan	Thrace	0.500	Gas
West Thrace License Block	Turkey	Teslimkoy/Kesan	Thrace	0.315	Gas
South Thrace License Block	Turkey	Teslimkoy/Kesan	Thrace	0.815	Gas

The estimated gross and working interest P_g-adjusted raw natural gas and condensate unconventional prospective resources, as of December 31, 2018, are summarized as follows, expressed in English units in millions of cubic feet ($10^6 ft^3$) and thousands of barrels (10^3bbl):

				Gross Raw Natural Gas Unconventional Prospective Resources Summary					
Prospect	**Country**	**Potential Target**	**Basin**	**Low Estimate ($10^6 ft^3$)**	**Best Estimate ($10^6 ft^3$)**	**High Estimate ($10^6 ft^3$)**	**Mean Estimate ($10^6 ft^3$)**	**Probability of Geologic Success, P_g (decimal)**	**P_g-Adjusted Mean Estimate ($10^6 ft^3$)**
Teslimkoy/Kesan BCG	Turkey	Teslimkoy/Kesan	Thrace	4,949,348	17,727,620	66,542,820	30,099,480	0.700	21,069,636
Statistical Aggregate				**4,949,348**	**17,727,620**	**66,542,820**	**30,099,480**	**0.700**	**21,069,636**
Arithmetic Summation				4,949,348	17,727,620	66,542,820	30,099,480	0.700	21,069,636

Notes:
1. Low, Best, High, and mean estimates follow the NI 51-101 guidelines for unconventional prospective resources.
2. Low, Best, High, and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean, respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate unconventional prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to unconventional prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of probabilistic estimates is presented in this table in compliance with NI 51-101 guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the unconventional prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the unconventional prospective resources evaluated.
10. The range in (P_{mean}) for the statistical aggregate P_g-adjusted mean estimate is 0.26 to 0.40.

				Working Interest Raw Natural Gas Unconventional Prospective Resources Summary					
License Block	**Country**	**Potential Target**	**Basin**	**Low Estimate ($10^6 ft^3$)**	**Best Estimate ($10^6 ft^3$)**	**High Estimate ($10^6 ft^3$)**	**Mean Estimate ($10^6 ft^3$)**	**Probability of Geologic Success, P_g (decimal)**	**P_g-Adjusted Mean Estimate ($10^6 ft^3$)**
Banarli	Turkey	Teslimkoy/Kesan	Thrace	1,437,586	4,293,284	11,424,410	5,714,166	0.700	3,999,916
West Thrace	Turkey	Teslimkoy/Kesan	Thrace	866,357	2,556,826	7,409,385	3,545,961	0.700	2,482,173
South Thrace	Turkey	Teslimkoy/Kesan	Thrace	52,154	156,374	462,567	217,195	0.700	152,036
Statistical Aggregate				**3,059,866**	**8,544,493**	**18,033,983**	**9,477,322**	**0.700**	**6,634,125**
Arithmetic Summation				2,356,097	7,006,484	19,296,362	9,477,322	0.700	6,634,125

Notes:
1. Low, Best, High, and mean estimates follow the NI 51-101 guidelines for unconventional prospective resources.
2. Low, Best, High, and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean, respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate unconventional prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to unconventional prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of probabilistic estimates is presented in this table in compliance with NI 51-101 guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the unconventional prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the unconventional prospective resources evaluated.
10. The range in (P_{mean}) for the statistical aggregate P_g-adjusted mean estimate is 0.26 to 0.40.
11. Working interest volumes incorporate fraction of potential hydrocarbon pore volume held or partially held by Valeura and Valeura's working interest ownership.

				Gross Condensate Unconventional Prospective Resources Summary					
Prospect	**Country**	**Potential Target**	**Basin**	**Low Estimate (10^3bbl)**	**Best Estimate (10^3bbl)**	**High Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**	**Probability of Geologic Success, P_g (decimal)**	**P_g-Adjusted Mean Estimate (10^3bbl)**
Teslimkoy/Kesan BCG	Turkey	Teslimkoy/Kesan	Thrace	92,883	415,189	1,766,062	762,102	0.700	533,471
Statistical Aggregate				**92,883**	**415,189**	**1,766,062**	**762,102**	**0.700**	**533,471**
Arithmetic Summation				92,883	415,189	1,766,062	762,102	0.700	533,471

Notes:
1. Low, Best, High, and mean estimates follow the NI 51-101 guidelines for unconventional prospective resources.
2. Low, Best, High, and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean, respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate unconventional prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to unconventional prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of probabilistic estimates is presented in this table in compliance with NI 51-101 guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the unconventional prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the unconventional prospective resources evaluated.

				Working Interest Condensate Unconventional Prospective Resources Summary					
License Block	**Country**	**Potential Target**	**Basin**	**Low Estimate (10^3bbl)**	**Best Estimate (10^3bbl)**	**High Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**	**Probability of Geologic Success, P_g (decimal)**	**P_g-Adjusted Mean Estimate (10^3bbl)**
Banarli	Turkey	Teslimkoy/Kesan	Thrace	27,365	94,418	295,888	144,100	0.700	100,870
West Thrace	Turkey	Teslimkoy/Kesan	Thrace	16,800	57,019	196,369	86,857	0.700	60,800
South Thrace	Turkey	Teslimkoy/Kesan	Thrace	994	3,592	11,446	5,427	0.700	3,799
Statistical Aggregate				**58,648**	**189,060**	**470,751**	**236,384**	**0.700**	**165,469**
Arithmetic Summation				45,159	155,029	503,703	236,384	0.700	165,469

Notes:
1. Low, Best, High, and mean estimates follow the NI 51-101 guidelines for unconventional prospective resources.
2. Low, Best, High, and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean, respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate unconventional prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to unconventional prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of probabilistic estimates is presented in this table in compliance with NI 51-101 guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the unconventional prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the unconventional prospective resources evaluated.
10. Working interest volumes incorporate fraction of potential hydrocarbon pore volume held or partially held by Valeura and Valeura's working interest ownership.

The estimated gross and working interest truncated, TEFS-adjusted, P_e-adjusted unconventional prospective resources, as of December 31, 2018, are summarized as follows, expressed in English units in millions of cubic feet ($10^6 ft^3$):

				Gross Truncated, TEFS-Adjusted Raw Natural Gas Unconventional Prospective Resources Summary					
Prospect	**Country**	**Potential Target**	**Basin**	**Low Estimate ($10^6 ft^3$)**	**Best Estimate ($10^6 ft^3$)**	**High Estimate ($10^6 ft^3$)**	**Mean Estimate ($10^6 ft^3$)**	**Probability of Economic Success, P_e (decimal)**	**P_e-Adjusted Mean Estimate ($10^6 ft^3$)**
Teslimkoy/Kesan BCG	Turkey	Teslimkoy/Kesan	Thrace	6,892,411	19,667,127	69,708,334	32,403,311	0.514	16,655,571
Statistical Aggregate				**6,892,411**	**19,667,127**	**69,708,334**	**32,403,311**	**0.514**	**16,655,571**
Arithmetic Summation				6,892,411	19,667,127	69,708,334	32,403,311	0.514	16,655,571

Notes:
1. TEFS is defined as the threshold economic field size.
2. Low, Best, High, and mean estimates follow the NI 51-101 guidelines for unconventional prospective resources.
3. Low, Best, High, and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean, respectively.
4. P_e is defined as the probability that a given discovery will be economically viable for commercial development.
5. P_e has been rounded for presentation purposes. Multiplication using this presented P_e may yield imprecise results. Dividing the P_e-adjusted mean estimate by the mean estimate yields the precise P_e.
6. Application of any geological and economic chance factor does not equate unconventional prospective resources to contingent resources or reserves.
7. Recovery efficiency is applied to unconventional prospective resources in this table.
8. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of probabilistic estimates is presented in this table in compliance with NI 51-101 guidelines.
9. Summations may vary from those shown here due to rounding.
10. There is no certainty that any portion of the unconventional prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the unconventional prospective resources evaluated.

				Working Interest Truncated, TEFS-Adjusted Raw Natural Gas Unconventional Prospective Resources Summary					
License Block	**Country**	**Potential Target**	**Basin**	**Low Estimate ($10^6 ft^3$)**	**Best Estimate ($10^6 ft^3$)**	**High Estimate ($10^6 ft^3$)**	**Mean Estimate ($10^6 ft^3$)**	**Probability of Economic Success, P_e (decimal)**	**P_e-Adjusted Mean Estimate ($10^6 ft^3$)**
Banarli	Turkey	Teslimkoy/Kesan	Thrace	1,932,131	4,632,100	11,813,453	6,049,236	0.517	3,128,492
West Thrace	Turkey	Teslimkoy/Kesan	Thrace	1,166,882	2,790,699	7,704,745	3,793,136	0.513	1,946,522
South Thrace	Turkey	Teslimkoy/Kesan	Thrace	130,535	229,697	559,116	294,302	0.363	106,714
Statistical Aggregate				**5,321,840**	**9,239,640**	**16,041,622**	**10,136,674**	**0.511**	**5,181,728**
Arithmetic Summation				3,229,548	7,652,496	20,077,314	10,136,674	0.511	5,181,728

Notes:
1. TEFS is defined as the threshold economic field size.
2. Low, Best, High, and mean estimates follow the NI 51-101 guidelines for unconventional prospective resources.
3. Low, Best, High, and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean, respectively.
4. P_e is defined as the probability that a given discovery will be economically viable for commercial development.
5. P_e has been rounded for presentation purposes. Multiplication using this presented P_e may yield imprecise results. Dividing the P_e-adjusted mean estimate by the mean estimate yields the precise P_e.
6. Application of any geological and economic chance factor does not equate unconventional prospective resources to contingent resources or reserves.
7. Recovery efficiency is applied to unconventional prospective resources in this table.
8. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of probabilistic estimates is presented in this table in compliance with NI 51-101 guidelines.
9. Summations may vary from those shown here due to rounding.
10. There is no certainty that any portion of the unconventional prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the unconventional prospective resources evaluated.
11. Working interest volumes incorporate fraction of potential hydrocarbon pore volume held or partially held by Valeura and Valeura's working interest ownership.

Professional Qualifications

DeGolyer and MacNaughton is a Delaware Corporation with offices at 5001 Spring Valley Road, Suite 800 East, Dallas, Texas 75244, U.S.A. The firm has been providing petroleum consulting services throughout the world since 1936. The firm's professional engineers, geologists, geophysicists, petrophysicists, and economists

are engaged in the independent evaluation of oil and gas properties, evaluation of hydrocarbon and other mineral prospects, basin evaluations, comprehensive field studies, equity studies, and studies of supply and economics related to the energy industry. Except for the provision of professional services on a fee basis, DeGolyer and MacNaughton has no commercial arrangement with any other person or company involved in the interests which are the subject of this report.

The evaluation has been supervised by Dr. John W. Hornbrook, Senior Vice President with DeGolyer and MacNaughton, a Registered Professional Engineer in the State of Texas, a member of the Society of Petroleum Engineers, and a member of the Society of Petroleum Evaluation Engineers. He has over 25 years of oil and gas industry experience.

Submitted,

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

STATE OF TEXAS
JOHN WIRT HORNBROOK
86128
LICENSED
PROFESSIONAL ENGINEER

John W. Hornbrook, P.E.
Senior Vice President
DeGolyer and MacNaughton

TABLE 1
PROSPECT PORTFOLIO SUMMARY
as of
DECEMBER 31, 2018
for
VALEURA ENERGY INC.
in the
THRACE BASIN
TURKEY

Prospect	Country	Potential Target	Basin	Threshold Economic Field Size ($10^6 ft^3$)	Working Interest (decimal)	Potential Hydrocarbon Phase
Teslimkoy/Kesan BCG				350,000		
Banarli License Block	Turkey	Teslimkoy/Kesan	Thrace		0.500	Gas
West Thrace License Block	Turkey	Teslimkoy/Kesan	Thrace		0.315	Gas
South Thrace License Block	Turkey	Teslimkoy/Kesan	Thrace		0.815	Gas

TABLE 2
ESTIMATE of the GROSS RAW NATURAL GAS PROSPECTIVE RESOURCES
as of
DECEMBER 31, 2018
for
VALEURA ENERGY INC.
in the
THRACE BASIN
TURKEY

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

				Gross Raw Natural Gas Prospective Resources Summary					
Prospect	**Country**	**Potential Target**	**Basin**	**Low Estimate ($10^6 ft^3$)**	**Best Estimate ($10^6 ft^3$)**	**High Estimate ($10^6 ft^3$)**	**Mean Estimate ($10^6 ft^3$)**	**Probability of Geologic Success, P_g (decimal)**	**P_g-Adjusted Mean Estimate ($10^6 ft^3$)**
Teslimkoy/Kesan BCG	Turkey	Teslimkoy/Kesan	Thrace	4,949,348	17,727,620	66,542,820	30,099,480	0.700	21,069,636
Statistical Aggregate				**4,949,348**	**17,727,620**	**66,542,820**	**30,099,480**	**0.700**	**21,069,636**
Arithmetic Summation				4,949,348	17,727,620	66,542,820	30,099,480	0.700	21,069,636

Notes:

1. Low, Best, High, and mean estimates follow the NI 51-101 guidelines for prospective resources.
2. Low, Best, High and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate.
   Arithmetic summation of probabilistic estimates is presented in this table in compliance with NI 51-101 guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the prospective resources estimated herein will be discovered.
   If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.
10. The range in P_{mean} for the statistical aggregate P_g-adjusted mean estimate is 0.26 to 0.40.

TABLE 3
ESTIMATE of the GROSS RAW NATURAL GAS PROSPECTIVE RESOURCES
TRUNCATED and ADJUSTED for TEFS
as of
DECEMBER 31, 2018
for
VALEURA ENERGY INC.
in the
THRACE BASIN
TURKEY

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

				Summary of Gross Raw Natural Gas Prospective Resources, Truncated and Adjusted for TEFS					
Prospect	**Country**	**Potential Target**	**Basin**	**Low Estimate ($10^6 ft^3$)**	**Best Estimate ($10^6 ft^3$)**	**High Estimate ($10^6 ft^3$)**	**Mean Estimate ($10^6 ft^3$)**	**Probability of Economic Success, P_e (decimal)**	**P_e-Adjusted Mean Estimate ($10^6 ft^3$)**
Teslimkoy/Kesan BCG	Turkey	Teslimkoy/Kesan	Thrace	6,892,411	19,667,127	69,708,334	32,403,311	0.514	16,655,571
Statistical Aggregate				**6,892,411**	**19,667,127**	**69,708,334**	**32,403,311**	**0.514**	**16,655,571**
Arithmetic Summation				6,892,411	19,667,127	69,708,334	32,403,311	0.514	16,655,571

Notes:

1. TEFS is defined as the threshold economic field size.
2. Low, Best, High, and mean estimates follow the NI 51-101 guidelines for prospective resources.
3. Low, Best, High and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean respectively.
4. P_e is defined as the probability that a given discovery will be economically viable for commercial development.
5. P_e has been rounded for presentation purposes. Multiplication using this presented P_e may yield imprecise results. Dividing the P_e-adjusted mean estimate by the mean estimate yields the precise P_e.
6. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
7. Recovery efficiency is applied to prospective resources in this table.
8. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate.
   Arithmetic summation of probabilistic estimates is presented in this table in compliance with NI 51-101 guidelines.
9. Summations may vary from those shown here due to rounding.
10. There is no certainty that any portion of the prospective resources estimated herein will be discovered.
    If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

TABLE 4
ESTIMATE of the GROSS CONDENSATE PROSPECTIVE RESOURCES
as of
DECEMBER 31, 2018
for
VALEURA ENERGY INC.
in the
THRACE BASIN
TURKEY

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

				Gross Condensate Prospective Resources Summary					
Prospect	**Country**	**Potential Target**	**Basin**	**Low Estimate (10^3bbl)**	**Best Estimate (10^3bbl)**	**High Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**	**Probability of Geologic Success, P_g (decimal)**	**P_g-Adjusted Mean Estimate (10^3bbl)**
Teslimkoy/Kesan BCG	Turkey	Teslimkoy/Kesan	Thrace	92,883	415,189	1,766,062	762,102	0.700	533,471
Statistical Aggregate				**92,883**	**415,189**	**1,766,062**	**762,102**	**0.700**	**533,471**
Arithmetic Summation				92,883	415,189	1,766,062	762,102	0.700	533,471

Notes:

1. Low, Best, High, and mean estimates follow the NI 51-101 guidelines for prospective resources.
2. Low, Best, High and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate.
   Arithmetic summation of probabilistic estimates is presented in this table in compliance with NI 51-101 guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the prospective resources estimated herein will be discovered.
   If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

DEGOLYER AND MACNAUGHTON F-716 TEXAS REGISTERED ENGINEERING FIRM

TABLE 5
ESTIMATE of the WORKING INTEREST RAW NATURAL GAS PROSPECTIVE RESOURCES
as of
DECEMBER 31, 2018
for
VALEURA ENERGY INC.
in the
THRACE BASIN
TURKEY

				Working Interest Raw Natural Gas Prospective Resources Summary					
License Block	Country	Potential Target	Basin	Low Estimate ($10^6 ft^3$)	Best Estimate ($10^6 ft^3$)	High Estimate ($10^6 ft^3$)	Mean Estimate ($10^6 ft^3$)	Probability of Geologic Success, P_g (decimal)	P_g-Adjusted Mean Estimate ($10^6 ft^3$)
Banarli	Turkey	Teslimkoy/Kesan	Thrace	1,437,586	4,293,284	11,424,410	5,714,166	0.700	3,999,916
West Thrace	Turkey	Teslimkoy/Kesan	Thrace	866,357	2,556,826	7,409,385	3,545,961	0.700	2,482,173
South Thrace	Turkey	Teslimkoy/Kesan	Thrace	52,154	156,374	462,567	217,195	0.700	152,036
Statistical Aggregate				**3,059,866**	**8,544,493**	**18,033,983**	**9,477,322**	**0.700**	**6,634,125**
Arithmetic Summation				2,356,097	7,006,484	19,296,362	9,477,322	0.700	6,634,125

Notes:

1. Low, Best, High, and mean estimates follow the NI 51-101 guidelines for prospective resources.
2. Low, Best, High and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate.
   Arithmetic summation of probabilistic estimates is presented in this table in compliance with NI 51-101 guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the prospective resources estimated herein will be discovered.
   If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.
10. Working interest volumes incorporate fraction of potential hydrocarbon pore volume held or partially held by Valeura and Valeura's working interest ownership.

DEGOLYER AND MACNAUGHTON F-716 TEXAS REGISTERED ENGINEERING FIRM

TABLE 6
ESTIMATE of the WORKING INTEREST RAW NATURAL GAS PROSPECTIVE RESOURCES
TRUNCATED and ADJUSTED for TEFS
as of
DECEMBER 31, 2018
for
VALEURA ENERGY INC.
in the
THRACE BASIN
TURKEY

				Summary of Working Interest Raw Natural Gas Prospective Resources, Truncated and Adjusted for TEFS					
License Block	Country	Potential Target	Basin	Low Estimate ($10^6 ft^3$)	Best Estimate ($10^6 ft^3$)	High Estimate ($10^6 ft^3$)	Mean Estimate ($10^6 ft^3$)	Probability of Economic Success, P_e (decimal)	P_e-Adjusted Mean Estimate ($10^6 ft^3$)
Banarli	Turkey	Teslimkoy/Kesan	Thrace	1,932,131	4,632,100	11,813,453	6,049,236	0.517	3,128,492
West Thrace	Turkey	Teslimkoy/Kesan	Thrace	1,166,882	2,790,699	7,704,745	3,793,136	0.513	1,946,522
South Thrace	Turkey	Teslimkoy/Kesan	Thrace	130,535	229,697	559,116	294,302	0.363	106,714
Statistical Aggregate				**5,321,840**	**9,239,640**	**16,041,622**	**10,136,674**	**0.511**	**5,181,728**
Arithmetic Summation				3,229,548	7,652,496	20,077,314	10,136,674	0.511	5,181,728

Notes:

1. TEFS is defined as the threshold economic field size.
2. Low, Best, High, and mean estimates follow the NI 51-101 guidelines for prospective resources.
3. Low, Best, High and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean respectively.
4. P_e is defined as the probability that a given discovery will be economically viable for commercial development.
5. P_e has been rounded for presentation purposes. Multiplication using this presented P_e may yield imprecise results. Dividing the P_e-adjusted mean estimate by the mean estimate yields the precise P_e.
6. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
7. Recovery efficiency is applied to prospective resources in this table.
8. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of probabilistic estimates is presented in this table in compliance with NI 51-101 guidelines.
9. Summations may vary from those shown here due to rounding.
10. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.
11. Working interest volumes incorporate fraction of potential hydrocarbon pore volume held or partially held by Valeura and Valeura's working interest ownership.

TABLE 7
ESTIMATE of the WORKING INTEREST CONDENSATE PROSPECTIVE RESOURCES
as of
DECEMBER 31, 2018
for
VALEURA ENERGY INC.
in the
THRACE BASIN
TURKEY

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

				Working Interest Condensate Prospective Resources Summary					
License Block	Country	Potential Target	Basin	Low Estimate (10^3bbl)	Best Estimate (10^3bbl)	High Estimate (10^3bbl)	Mean Estimate (10^3bbl)	Probability of Geologic Success, P_g (decimal)	P_g-Adjusted Mean Estimate (10^3bbl)
Banarli	Turkey	Teslimkoy/Kesan	Thrace	27,365	94,418	295,888	144,100	0.700	100,870
West Thrace	Turkey	Teslimkoy/Kesan	Thrace	16,800	57,019	196,369	86,857	0.700	60,800
South Thrace	Turkey	Teslimkoy/Kesan	Thrace	994	3,592	11,446	5,427	0.700	3,799
Statistical Aggregate				**58,648**	**189,060**	**470,751**	**236,384**	**0.700**	**165,469**
Arithmetic Summation				45,159	155,029	503,703	236,384	0.700	165,469

Notes:

1. Low, Best, High, and mean estimates follow the NI 51-101 guidelines for prospective resources.
2. Low, Best, High and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate.
   Arithmetic summation of probabilistic estimates is presented in this table in compliance with NI 51-101 guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the prospective resources estimated herein will be discovered.
   If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.
10. Working interest volumes incorporate fraction of potential hydrocarbon pore volume held or partially held by Valeura and Valeura's working interest ownership.

TABLE 8
GROSS PROBABILITY DISTRIBUTIONS
for
MONTE CARLO SIMULATION
as of
DECEMBER 31, 2018
for
VALEURA ENERGY INC.
in the
THRACE BASIN
TURKEY

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Prospect	Potential Target	Parameter	P_{100}	P_{90}	P_{50}	P_{10}	P_0	Mean
Pressure Seal Prospect (Total)	Teslimkoy/Kesan	Productive area, acres	17,996	53,891	142,194	374,424	1,125,462	187,041
		Net hydrocarbon thickness, feet	202.11	461.84	955.21	1,973.81	4,413.41	1,116.50
		Porosity, decimal	0.030	0.035	0.051	0.073	0.109	0.053
		Gas saturation, decimal	0.302	0.382	0.502	0.626	0.746	0.504
		Gas Expansion Factor, Eg	270	280	317	354	365	317
		Recovery efficiency, decimal	0.150	0.247	0.400	0.552	0.649	0.400
		Prospective OGIP, cubic feet	2,338,507,000,000	13,318,360,000,000	46,270,880,000,000	161,533,600,000,000	979,426,800,000,000	76,132,380,000,000
		Prospective gross ultimate recovery, cubic feet	576,494,600,000	4,949,348,000,000	17,727,620,000,000	66,542,820,000,000	316,965,100,000,000	30,099,480,000,000
		Condensate, barrels	10,458,460	92,882,940	415,188,800	1,766,062,000	12,404,440,000	762,101,500
		Condensate yield, barrels per million cubic feet	5	11	24	40	53	25

TABLE 9
WORKING INTEREST PROBABILITY DISTRIBUTIONS
for
MONTE CARLO SIMULATION
as of
DECEMBER 31, 2018
for
VALEURA ENERGY INC.
in the
THRACE BASIN
TURKEY

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Prospect	Potential Target	Parameter	P_{100}	P_{90}	P_{50}	P_{10}	P_0	Mean
Banarli (Net)	Teslimkoy/Kesan	Productive area, acres	27,246	41,594	60,196	87,013	133,374	62,695
		Net hydrocarbon thickness, feet	200.43	461.77	956.11	1,977.42	4,491.81	1,116.79
		Net ratio, decimal	0.204	0.386	0.542	0.758	1.265	0.561
		Porosity, decimal	0.030	0.035	0.051	0.073	0.112	0.053
		Gas saturation, decimal	0.300	0.382	0.502	0.626	0.748	0.504
		Gas Expansion Factor, Eg	270	280	317	354	365	317
		Recovery efficiency, decimal	0.150	0.228	0.400	0.571	0.649	0.400
		Prospective OGIP, cubic feet	1,084,001,000,000	3,921,570,000,000	11,256,140,000,000	28,524,500,000,000	258,974,900,000,000	14,402,110,000,000
		Prospective gross ultimate recovery, cubic feet	388,771,500,000	1,437,586,000,000	4,293,284,000,000	11,424,410,000,000	109,104,600,000,000	5,714,166,000,000
		Condensate, barrels	5,445,141	27,365,370	94,417,620	295,888,400	3,874,896,000	144,100,000
		Condensate yield, barrels per million cubic feet	5	11	24	40	53	25
West Thrace (Net)	Teslimkoy/Kesan	Productive area, acres	17,023	25,623	37,058	53,532	82,093	38,584
		Net hydrocarbon thickness, feet	207.71	461.28	956.03	1,972.00	4,483.18	1,116.63
		Net ratio, decimal	0.236	0.386	0.542	0.759	1.237	0.561
		Porosity, decimal	0.030	0.035	0.051	0.073	0.110	0.053
		Gas saturation, decimal	0.300	0.382	0.502	0.626	0.747	0.504
		Gas Expansion Factor, Eg	270	280	317	354	364	317
		Recovery efficiency, decimal	0.151	0.247	0.400	0.552	0.650	0.400
		Prospective OGIP, cubic feet	905,952,200,000	2,495,969,000,000	6,518,968,000,000	18,623,270,000,000	92,438,270,000,000	8,980,054,000,000
		Prospective gross ultimate recovery, cubic feet	270,179,400,000	866,356,600,000	2,556,826,000,000	7,409,385,000,000	41,054,170,000,000	3,545,961,000,000
		Condensate, barrels	2,714,320	16,799,800	57,019,460	196,369,100	1,266,779,000	86,857,050
		Condensate yield, barrels per million cubic feet	5	11	24	40	53	25
South Thrace (Net)	Teslimkoy/Kesan	Productive area, acres	1,035	1,550	2,243	3,243	4,919	2,336
		Net hydrocarbon thickness, feet	207.29	462.41	955.75	1,975.94	4,454.32	1,116.55
		Net ratio, decimal	0.205	0.386	0.542	0.758	1.350	0.561
		Porosity, decimal	0.030	0.035	0.051	0.073	0.115	0.053
		Gas saturation, decimal	0.301	0.382	0.502	0.626	0.747	0.504
		Gas Expansion Factor, Eg	270	280	317	354	365	317
		Recovery efficiency, decimal	0.151	0.247	0.400	0.553	0.649	0.400
		Prospective OGIP, cubic feet	27,731,450,000	148,121,100,000	399,976,300,000	1,089,636,000,000	4,052,375,000,000	539,166,500,000
		Prospective gross ultimate recovery, cubic feet	10,433,060,000	52,154,350,000	156,374,000,000	462,567,100,000	1,765,200,000,000	217,194,600,000
		Condensate, barrels	148,563	994,126	3,592,096	11,445,930	48,419,920	5,427,304
		Condensate yield, barrels per million cubic feet	5	11	24	40	53	25

GLOSSARY

Accumulation – An individual body of naturally occurring petroleum. A known accumulation (one determined to contain reserves or contingent resources) must have been penetrated by a well. The well must have clearly demonstrated the existence of moveable petroleum by flow to the surface or at least some recovery of a sample of petroleum through the well. However, log and/or core data from the well may establish an accumulation, provided there is a good analogy to a nearby and geologically comparable known accumulation.

Arithmetic Summation – The process of adding a set of numbers that represent estimates of resources quantities at the reservoir, prospect, or portfolio level and estimates of PPW_{10} at the prospect or portfolio level. Statistical aggregation yields different results.

Best (Median) *Estimate* – The 2U (best) (median) estimate is the P_{50} quantity. P_{50} means that there is a 50-percent chance that an estimated quantity, such as a prospective resources volume or associated quantity, will be equaled or exceeded.

Barrel of Oil Equivalent – Gas quantities are converted to barrels of oil equivalent (BOE) using an energy equivalent factor of 6,000 cubic feet of gas per barrel.

Coal Bed Methane – Coal bed methane (CBM) is a form of natural gas extracted from coal beds. Coals are unconventional reservoirs characterzied by more than 50 percent by weight and more than 70 percent by volume of carbonaceous material formed from compaction and induration of variously altered plant remains similar to those in peaty deposits. Gas is generated as a result of the coalification of the organic matter, and is generally 85 to 99 percent methane. Gas is held to the coal matrix by sorption. CBM is also known as coal seam gas.

Contingent Resources – Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.

Geometric Correction Factor – The geometric correction factor (GCF) is a geometry adjustment correction that takes into account the relationship of the potential fluid contact to the geometry of the reservoir and trap. Input parameters used to estimate the geometric correction factor include trap shape, length-to-width ratio, potential reservoir thickness, and the height of the potential trapping closure (potential hydrocarbon column height).

High Estimate – The 3U (high) estimate is the P_{10} quantity. P_{10} means there is a 10-percent chance that an estimated quantity, such as a prospective resources volume or associated quantity, will be equaled or exceeded.

Lead – A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect. An example would be a poorly defined closure mapped using sparse regional seismic data in a basin containing favorable source and reservoir(s). A lead may or may not be elevated to prospect status depending on the results of additional technical work. A lead must have a P_g equal to or less than 0.05 to reflect the inherent technical uncertainty.

Low Estimate – The 1U (low) estimate is the P_{90} quantity. P_{90} means there is a 90-percent chance that an estimated quantity, such as a prospective resources volume or associated quantity, will be equaled or exceeded.

Mean Estimate – In accordance with petroleum industry standards, the mean estimate is the probability-weighted average (expected value), which typically has a probability in the P_{45} to P_{15} range, depending on the variance of prospective resources volume or associated quantity. Therefore, the probability of a prospect or accumulation containing the probability-weighted average volume or greater is usually between 45 and 15 percent. The mean estimate is the preferred probabilistic estimate of prospective resources volumes.

Median – Median is the P_{50} quantity, where the P_{50} means there is a 50-percent chance that a given variable (such as prospective resources, porosity, or water saturation) is equaled or exceeded. The median of a data set is a number such that half the measurements are below the median and half are above.

The median is the best estimate in probabilistic estimations of prospective resources, as required by the PRMS guidelines.

Migration Chance Factor – Migration chance factor ($P_{migration}$) is defined as the probability that a trap either predates or is coincident with petroleum migration and that there exists vertical and/or lateral migration pathways linking the source to the trap.

Mode – The mode is the quantity that occurs with the greatest frequency in the data set and therefore is the quantity that has the greatest probability of occurrence. However, the mode may not be uniquely defined, as is the case in multimodal distributions.

P_g-adjusted Mean Estimate, statistical aggregate – The statistical aggregate P_g-adjusted mean estimate, or "aggregated geologic chance-adjusted mean estimate," is a probability-weighted average geologic success case expectation (average) of the hydrocarbon quantities potentially discovered if all of the prospects in a portfolio were drilled. The P_g-adjusted mean estimate is a "blended" quantity; it is a product of the statistically aggregated mean volume estimate and the portfolio's probability of geologic success. This statistical measure considers and stochastically quantifies the geological success and geological failure outcomes. Consequently, it represents the average or mean "geologic success case" volume outcome of drilling all of the prospects in the exploration portfolio. The P_g-adjusted mean volume estimate for a single prospect is calculated as follows:

$$P_g\text{-adjusted mean estimate} = P_g \times \text{mean estimate} \quad (1)$$

(mean geological success case volumes)

The probability of the statistical aggregate P_g-adjusted mean estimate is estimated by the product of the portfolio P_g and the probability of the mean volume occurrence for the entire prospect portfolio. The equation is as follows:

$$\text{Statistical aggregate } P_g\text{-adjusted mean estimate, probability of occurrence} = \text{Portfolio } P_g \times \text{mean volume probability estimate for the portfolio} \quad (2)$$

P_n *Nomenclature* – This report uses the convention of denoting probability with a subscript representing the greater than cumulative probability distribution. As such, the notation P_n indicates the probability that there is an n-percent chance that a specific input or output quantity will be equaled or exceeded. For example, P_{90} means that there is a 90-percent chance that a variable (such as prospective resources, porosity, or water saturation) is equaled or exceeded.

Play – A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation to define specific Leads or Prospects.

Predictability versus Portfolio Size – The number of prospects in a prospect portfolio influences the reliability of the forecast of drilling results. The relationship

between predictability versus portfolio size (PPS) is also known in the petroleum industry literature as "Gambler's Ruin." The relationship of probability to portfolio size is described by the binomial probability equation given as follows:

$$P_{x^n} = (C_{x^n})(p)^x(1-p)^{n-x} \tag{3}$$

where: P_{x^n} = the probability of x successes in n trials

C_{x^n} = the number of mutually exclusive ways that x successes can be arranged in n trials

p = the probability of success for a given trial (for petroleum exploration, this is P_g)

x = the number of successes (e.g., the number of discoveries)

n = the number of trials (e.g., the number of wells to be drilled)

Note: For the case of n successive dry holes, C_{x^n} and p each equals 1, so the probability of failure is the quantity (1-p) raised to the number of trials.

Probability of Geologic Success – The probability of geologic success (P_g) is defined as the estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum. The P_g is estimated by quantifying with a probability each of the following individual geologic chance factors: trap, source, reservoir, and migration. The product of the probabilities of these four chance factors is P_g. P_g is predicated and correlated to the minimum case prospective resources gross recoverable volume(s). Consequently, the P_g is not linked to economically viable volumes, economic flow rates, or economic field size assumptions.

Probability of the Mean Occurrence – The probability of the mean occurrence P_{MEAN} is defined as the probability of occurrence of the mean quantity as defined by the distribution(s) in the Monte Carlo simulation. The probability associated with the mean is dependent on the variance of the distribution, and type of distribution from which the mean is estimated. Typically, the range in probability of occurrence for the statistical mean estimate is 0.45 to 0.15 for lognormal (positively skewed) distributions. The statistical mean has a probability of occurrence of 0.50 for normal (symmetric) distributions.

Prospect – A project associated with an undrilled potential accumulation that is sufficiently well defined to be a viable drilling target. For a prospect, sufficient data and analyses exist to identify and quantify the technical uncertainties,

to determine reasonable ranges of geologic chance factors and engineering and petrophysical parameters, and to estimate prospective resources. In addition, a viable drilling target requires that 70 percent of the median potential production area be located within the block or license area of interest.

Prospective Resources – Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

Raw Natural Gas – Raw natural gas is the total gas produced from the reservoir prior to processing or separation and includes all nonhydrocarbon components as well as any gas equivalent of condensate.

Reservoir Chance Factor – The reservoir chance factor ($P_{reservoir}$) is defined as the probability associated with the presence of porous and permeable reservoir-quality rock.

Source Chance Factor – The source chance factor (P_{source}) is defined as the probability associated with the presence of a hydrocarbon source rock rich enough, of sufficient volume, and in the proper spatial position to charge the prospective area or areas.

Standard Deviation – Standard deviation (SD) is a measure of distribution spread. It is the positive square root of the variance. The variance is the summation of the squared distance from the mean of all possible values. Since the units of standard deviation are the same as those of the sample set, it is the most practical measure of population spread.

$$\sigma = \sqrt{\sigma^2} = \sqrt{\frac{\sum_{i=1}^{n} (x_i - \mu)^2}{n-1}} \tag{4}$$

where: σ = standard deviation
σ^2 = variance
n = sample size
x_i = value in data set
μ = sample set mean

Statistical Aggregation – The process of probabilistically aggregating distributions that represent estimates of resources quantities at the reservoir, prospect, or portfolio level and estimates of PPW_{10} at the prospect or portfolio level. Arithmetic summation yields different results, except for the mean estimate.

Threshold Economic Field Size – The threshold economic field size (TEFS) is the minimum amount of the producible petroleum required to recover the total capital and operating expenditure used to establish the potential accumulation as having a potential present worth at 10 percent equal to zero using the mid-price scenario.

Trap Chance Factor – The trap chance factor (P_{trap}) is defined as the probability associated with the presence of a structural closure and/or a stratigraphic trapping configuration with competent vertical and lateral seals, and the lack of any post migration seal integrity events or breaches.

Truncated Mean Estimate – The truncated mean estimate is the resulting statistical mean calculated from the truncation of the resources distribution by the threshold economic field size.

Truncated Volumes Estimates – The truncated volumes estimates are the resulting probabilistically determined volumes from the truncation of the prospective resources distribution by the threshold economic field size. This truncated distribution produces a new set of statistical metrics.

Unconventional Prospective Resources – Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further categorized according to the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity. Unconventional Prospective Resources exist in petroleum accumulations that are pervasive throughout a large area and are not significantly affected by hydrodynamic influences (also called continuous-type deposit). Typically, such accumulations require specialized extraction technology.

Variance – The variance (σ^2) is a measure of how much the distribution is spread from the mean. The variance sums up the squared distance from the mean of all possible values of x. The variance has units that are the squared units of x. The use of these units limits the intuitive value of variance.

$$\sigma^2 = \frac{\sum_{i=1}^{n} (x_i - \mu)}{n-1} \tag{5}$$

where: σ^2 = variance
n = sample size
x_i = value in data set
μ = sample set mean

Working Interest – Working interest prospective resources are that portion of the gross prospective resources to be potentially produced from the properties attributable to the interests held by "Company" before deduction of any associated royalty burdens, net profits payable, or government profit share. Working interest is a percentage of ownership in an oil and gas lease granting its owner the right to explore, drill, and produce oil and gas from a tract of property. Working interest owners are obligated to pay a corresponding percentage of the cost of leasing, drilling, producing, and operating a well or unit. The working interest also entitles its owner to share in production revenues with other working interest owners, based on the percentage of working interest held.

Valeura Energy Inc.

Consolidated Financial Statements

Years ended December 31, 2017 and 2016

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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Valeura Energy Inc.

We have audited the accompanying consolidated financial statements of Valeura Energy Inc., which comprise the consolidated statements of financial position as at December 31, 2017 and December 31, 2016, the consolidated statements of loss and comprehensive loss, changes in shareholders' equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with International Financial Report Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Valeura Energy Inc. as at December 31, 2017 and December 31, 2016, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

"KPMG LLP"
Chartered Professional Accountants
Calgary, Canada

March 20, 2018

Consolidated Statements of Financial Position

(thousands of Canadian Dollars)	**December 31, 2017**	December 31, 2016
Assets		
Current Assets		
Cash	**$ 11,108**	$ 1,987
Accounts receivable	**4,052**	4,601
Prepaid expenses and deposits	**1,381**	1,465
Inventory	**251**	-
Assets held for sale *(note 6)*	**-**	16,635
	16,792	24,688
Licence deposits *(note 7)*	**164**	922
Restricted Cash *(note 7)*	**3,173**	-
Exploration and evaluation assets *(notes 8,9)*	**7,642**	14,258
Property, plant and equipment *(notes 8,9)*	**62,101**	36,022
	$ 89,872	$ 75,890
Liabilities and Shareholders' Equity		
Current Liabilities		
Accounts payable and accrued liabilities	**$ 13,371**	$ 4,267
Decommissioning obligations *(note 10)*	**19,206**	8,132
Deferred taxes *(note 11)*	**2,470**	4,885
Shareholders' Equity		
Share capital *(note 13)*	**146,694**	136,586
Contributed surplus	**19,857**	19,343
Accumulated other comprehensive loss	**(32,183)**	(26,164)
Deficit	**(79,543)**	(71,159)
	54,825	58,606
	$ 89,872	$ 75,890

See accompanying notes to the consolidated financial statements

See Commitments *(note 18)*
See Subsequent Event *(note 19)*
Approved by the Board

("Tim Marchant")
Tim Marchant, Chairman

("Claudio Ghersinich")
Claudio Ghersinich, Director

Consolidated Statements of Loss and Comprehensive Loss
For the years ended December 31, 2017 and 2016

(thousands of Canadian Dollars)	**December 31, 2017**	December 31, 2016
Revenue		
Petroleum and natural gas sales	**$ 14,646**	$ 16,155
Royalties	**(1,971)**	(2,102)
Other Income	**1,363**	846
	14,038	14,899
Expenses		
Production	**4,423**	2,232
General and administrative *(note 12)*	**4,606**	5,376
Transaction costs *(note 17)*	**1,160**	859
Accretion on decommissioning liabilities *(note 10)*	**1,779**	876
Foreign exchange loss	**2,671**	3,032
Share-based compensation *(notes 12,13)*	**470**	386
Exploration and Evaluation *(note 8)*	**707**	-
Impairment *(note 8)*	**-**	1,048
Depletion and depreciation *(note 9)*	**9,025**	7,436
	24,841	21,245
Loss for the period before income taxes	**(10,803)**	(6,346)
Income taxes *(note 11)*		
Current tax expense	**2,371**	-
Deferred tax recovery	**(4,790)**	(260)
Net loss	**(8,384)**	(6,086)
Other comprehensive loss		
Currency translation adjustments	**(6,019)**	(11,511)
Comprehensive loss	**(14,403)**	(17,597)
Net loss per share *(note 13)*		
Basic and diluted	**$ (0.12)**	$ (0.10)
Weighted average number of shares outstanding (thousands)	**70,944**	58,254

See accompanying notes to the consolidated financial statements

Consolidated Statements of Cash Flows
For the years ended December 31, 2017 and 2016

(thousands of Canadian Dollars)	**December 31, 2017**	December 31, 2016
Cash was provided by (used in):		
Operating activities:		
Net loss for the year	**$ (8,384)**	$ (6,086)
Depletion and depreciation *(note 9)*	**9,025**	7,436
Exploration and Evaluation expense *(note 8)*	**707**	-
Impairment *(note 8)*	**-**	1,048
Share-based compensation *(notes 12,13)*	**470**	386
Accretion on decommissioning liabilities *(note 10)*	**1,779**	876
Unrealized foreign exchange loss (gain)	**(12)**	2,583
Transaction Costs	**-**	65
Deferred tax expense (recovery) *(note 11)*	**(4,790)**	(260)
Decommissioning costs incurred *(note 10)*	**(270)**	-
Change in non-cash working capital *(note 15)*	**5,329**	246
Cash provided by operating activities	**3,854**	6,294
Financing activities:		
Share issuance	**10,972**	-
Share issuance costs	**(864)**	-
Proceeds from stock option exercises	**-**	437
Cash provided by financing activities	**10,108**	437
Investing activities:		
TBNG Acquisition cash purchase price*(note 5)*	**(21,450)**	-
West Thrace Deep Rights Sale*(note 6)*	**18,841**	-
Statoil Farm-in proceeds *(note 8)*	**7,447**	-
Property and equipment expenditures *(note 9)*	**(5,873)**	(84)
Exploration and evaluation expenditures *(note 8)*	**(6,918)**	(9,451)
Change in restricted cash	**(3,173)**	-
Change in non-cash working capital *(note 15)*	**5,754**	(1,677)
Cash used in investing activities	**(5,372)**	(11,212)
Foreign exchange gain (loss) on cash held in foreign currencies	**531**	(505)
Net change in cash	**9,121**	(4,986)
Cash, beginning of year	**1,987**	6,973
Cash, end of year	**$ 11,108**	$ 1,987

See accompanying notes to the consolidated financial statements

Consolidated Statements of Changes in Shareholders' Equity
For the years ended December 31, 2017 and 2016

(thousands of Canadian Dollars and thousands of shares)	Number of Shares	Share Capital	Share Purchase Warrants	Contributed Surplus	Deficit	Accumulated Other Comp. Loss	Total Shareholders' Equity
Balance, January 1, 2017	58,519	$ 136,586	$ -	$ 19,343	$ (71,159)	$ (26,164)	$ 58,606
Net loss for the year	-	-	-	-	(8,384)	-	(8,384)
Shares issued	14,629	10,972	-	-	-	-	10,972
Shares issuance costs	-	(864)	-	-	-	-	(864)
Currency translation adjustments	-	-	-	-	-	(6,019)	(6,019)
Share-based Compensation	-	-	-	514	-	-	514
December 31, 2017	**73,148**	**$ 146,694**	**$ -**	**$ 19,857**	**$ (79,543)**	**$ (32,183)**	**$ 54,825**

(thousands of Canadian Dollars and thousands of shares)	Number of Shares	Share Capital	Share Purchase Warrants	Contributed Surplus	Deficit	Accumulated Other Comp. Loss	Total Shareholders' Equity
Balance, January 1, 2016	57,906	$ 135,778	$ 5,971	$ 13,238	$ (65,073)	$ (14,653)	$ 75,261
Net loss for the year	-	-	-	-	(6,086)	-	(6,086)
Warrants (expired)	-	-	(5,971)	5,971	-	-	-
Options exercised	547	743	-	(306)	-	-	437
Shares issued for services	66	65	-	-	-	-	65
Currency translation adjustments	-	-	-	-	-	(11,511)	(11,511)
Share-based Compensation	-	-	-	440	-	-	440
December 31, 2016	**58,519**	**$ 136,586**	**$ -**	**$ 19,343**	**$ (71,159)**	**$ (26,164)**	**$ 58,606**

See accompanying notes to the consolidated financial statements

1. Reporting Entity

Valeura Energy Inc. ("Valeura" or the "Company") and its subsidiaries are currently engaged in the exploration, development and production of petroleum and natural gas in Turkey. Valeura is incorporated in Alberta, Canada and has subsidiaries in the Netherlands, British Virgin Islands and Turkey. Valeura's shares are traded on the Toronto Stock Exchange ("TSX") under the trading symbol VLE. Valeura's head office address is 1200, 202 – 6 Avenue SW, Calgary, AB.

On October 13, 2016, the Company entered into a share purchase agreement to acquire 100 percent of the shares of Thrace Basin Natural Gas (Turkiye) Corporation ("TBNG") (the "TBNG Acquisition"). On February 24, 2017, the Company's wholly-owned affiliate, Valeura Energy (Netherlands) B.V ("VENBV") completed the TBNG Acquisition for a cash payment of $27.1 million (US$20.7 million). The Company's participating interest in the shallow rights on the TBNG JV Lands has increased to 81.5% from the 40% previously held and Valeura became the operator. See note 5.

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 "2017 Offering") and was subject to certain conditions, including, without limitation, the closing of the TBNG Acquisition. On February 24, 2017 the TBNG Acquisition closed, 14,629,000 common shares were issued pursuant to 14,629,000 subscription receipts and gross proceeds of approximately $11 million were released from escrow. Valeura used the net proceeds to partially fund the TBNG Acquisition and to a ramp-up the shallow gas drilling program on the TBNG JV lands and Banarli licences in 2017.

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 licences and the three production leases (the "West Thrace lands"), for cash consideration of $16.64 million (US$12 million) which was received in January 2017. These assets were included in Assets held for sale in the financial statements for Valeura as at December 31, 2016.

Following closing the West Thrace Deep Rights Sale and the TBNG Acquisition, TBNG entered into a sale and purchase agreement with Statoil on March 10, 2017 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 $3.9 million (US$3.0 million) (the "Subsequent West Thrace Deep Rights Sale"). Upon the closing of the Subsequent West Thrace Deep Rights Sale, Valeura retains a 31.5 percent participating interest and Statoil acquires a 50 percent participating interest in the deep formations on the West Thrace lands. On June 22, 2017 the Subsequent West Thrace Deep Rights Sale closed upon receiving Turkish government approval for the associated licence interest transfers. 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.

On February 8, 2018, 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 a bought deal basis 10,527,000 common shares of the Company at a price of $5.70 per common share, for total gross proceeds of approximately $60.0 million (the "2018 Offering"). The 2018 Offering closed on March 1, 2018. Net proceeds were approximately $55.7 million after underwriters fees of approximately $3.6 million and other expenses of $0.7 million.

2. Basis of Preparation

(a) Statement of compliance

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") 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 below.

Operating, transportation and marketing expenses in profit or loss are presented as a combination of function and nature in conformity with industry practices. Depletion, depreciation and finance expenses are presented in separate lines by their nature, while net administrative expenses are presented on a functional basis. Significant expenses such as salaries and benefits and share-based compensation are presented by their nature in the notes to the consolidated financial statements.

The consolidated financial statements were authorized for issue by the Board of Directors on March 20, 2018.

(b) Basis of measurement

The consolidated financial statements have been prepared on the historical cost basis except for certain financial and non-financial assets and liabilities, which have been measured at fair value. The methods used to measure fair value are discussed in note 4.

The Company's consolidated financial statements include the accounts of Valeura and its subsidiaries and are expressed in Canadian Dollars, unless otherwise stated.

(c) Functional and presentation currency

The consolidated financial statements are presented in Canadian Dollars which is Valeura's reporting currency. Valeura's foreign subsidiaries transact in currencies other than the Canadian Dollar and have a functional currency of Turkish Lira. The functional currency of a subsidiary is the currency of the primary economic environment in which the subsidiary operates. Transactions denominated in a currency other than the functional currency are translated at the prevailing rates on the date of the transaction. Any monetary items held in a currency which is not the functional currency of the subsidiary are translated to the functional currency at the prevailing rate as at the date of the statement of financial position. All exchange differences arising as a result of the translation to the functional currency of the subsidiary are recorded in net earnings.

Translation of all assets and liabilities from the 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 other comprehensive income or loss ("OCI") and are held within accumulated other comprehensive income or loss ("AOCI") until a disposal or partial disposal of a subsidiary. A disposal or partial disposal will then give rise to a realized foreign exchange gain or loss which is recorded in net earnings.

(d) 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:

- 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.

(e) Turkey operational update

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 delays or security issues have been experienced. The impact so far has been a further devaluation in the Turkish Lira, sovereign debt ratings downgrades and a state of emergency declaration. As of the date hereof, this state of emergency remains in place. 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 during the third quarter of 2017, including the detention of a US embassy worker, have destabilized the Turkish Lira value again. 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 these consolidated financial statements were approved by the Board of Directors. The situation in Turkey remains uncertain and significant changes could occur which could materially impact the assumptions and estimates made in these consolidated financial statements. Changes in assumptions are recognized in the financial statements prospectively.

3. Significant Accounting Policies

The accounting policies set out below have been applied consistently to all years presented in the consolidated financial statements and have been applied consistently by the Company and its subsidiaries.

(a) Basis of consolidation

(i) Subsidiaries:

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, substantive potential voting rights are taken into account. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

The acquisition method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in earnings.

(ii) Jointly controlled operations and jointly controlled assets:

A portion of the Company's exploration and development activities are conducted jointly with others. The joint interests are accounted for on a proportionate consolidation basis and as a result the financial statements reflect only the Company's proportionate share of the assets, liabilities, revenues, expenses and cash flows from these activities.
Valeura has two joint venture arrangements as follows:

Name of the joint arrangement	Nature of the relationship with the joint arrangement	Principal place of business of joint arrangement	Proportion of participating share
TBNG Joint Venture	Operator	Turkey	81.5% (all rights)
Statoil Joint Venture	Operator	Turkey	50% on Banarli Licenses (deep rights); 31.5% on West Thrace Lands (deep rights)

(iii) Transactions eliminated on consolidation:

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

(b) Financial instruments

(i) Non-derivative financial instruments:

Valeura's non-derivative financial instruments include cash, accounts receivable and accounts payable and accrued liabilities.

- Cash is comprised of cash on hand and deposits held with banks.
- Accounts receivable are classified as loans and receivables and are measured at amortized cost using the effective interest method. Typically, the fair value of these balances approximates their carrying value due to their short term to maturity.
- Accounts payable and accrued liabilities are classified as other liabilities and are measured at amortized cost using the effective interest method. Due to the short term nature of accounts payable and accrued liabilities, their carrying values approximate their fair values.
- The Company's outstanding credit facilities are used only to issue letters of credit and any balance potentially carried on the credit facilities will be short-term in nature. Accordingly, the fair market value would approximate the carrying value before the carrying value is reduced for any remaining unamortized costs.

Non-derivative financial instruments carried at fair value are assessed using the following hierarchy based on the amount of observable inputs used to value the instrument:

- Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.
- Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

There were no transfers within the hierarchy during the year.

(ii) Share capital:

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares and share options are recognized as a deduction from equity, net of any tax effects.

(c) Property, plant and equipment and exploration and evaluation assets

(i) Recognition and measurement:

Exploration and evaluation expenditures:

Pre-licence costs are recognized in earnings as incurred. Exploration and evaluation ("E&E") costs, including the costs of acquiring licences and directly attributable general and administrative costs, are initially capitalized as exploration and evaluation assets. The costs are accumulated in cost centres by well, field or exploration area pending determination of technical feasibility and commercial viability.

Exploration and evaluation assets are assessed for impairment if sufficient data exists to determine technical feasibility and commercial viability, and facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are allocated to cash-generating units. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved and/or probable reserves are determined to exist. A review of each exploration CGU is conducted, at least annually, to ascertain whether proved and/or probable reserves have been discovered. Upon determination of proved and/or probable reserves, the CGU within which the intangible exploration and evaluation assets attributable to those reserves is first tested for impairment and then the applicable value is reclassified from exploration and evaluation assets to property, plant and equipment.

Development and production costs:

Items of property, plant and equipment ("PP&E"), which include oil and gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development and production assets are grouped into CGUs for impairment testing. When significant parts of an item of PP&E, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (components).

Gains and losses on disposal of an item of property, plant and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of PP&E and are recognized in earnings.

(ii) Subsequent costs:

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of PP&E are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in earnings as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in earnings as incurred.

(iii) Depletion and depreciation:

The net carrying value of development or production assets is depleted using the unit of production method by reference to the ratio of production in the year to the related proved plus probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually.

Other corporate assets are recorded at cost on acquisition and amortized on a declining-balance basis at rates of 20 percent to 50 percent per year.

(iv) Exploration and evaluation expense:

Upon determination that an exploration and evaluation CGU is impaired, the Company will transfer costs associated with the applicable CGU to exploration and evaluation expense in the period.

(d) Impairment

(i) Financial assets:

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset. An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics. All impairment losses are recognized in earnings. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in earnings.

(ii) Non-financial assets:

The carrying amounts of the Company's non-financial assets, other than E&E assets and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, the asset's recoverable amount is estimated via an impairment test.

E&E assets are assessed for impairment when they are reclassified to property, plant and equipment, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets, or CGUs. The recoverable amount of an asset or a CGU is the greater of its value-in-use and its fair value less costs to sell. Fair value less costs to sell is determined as the amount that would be obtained from the sale of the assets in an arm's length transaction between knowledgeable and willing parties.

In assessing value-in-use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value-in-use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved plus probable reserves. E&E assets are allocated to related CGUs when they are assessed for impairment, both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to PP&E.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in earnings. Impairment losses recognized in respect of CGUs are allocated to reduce the carrying amounts of the assets in the unit (group of units) on a pro-rata basis.

An impairment loss in respect of PP&E and E&E assets, recognized in prior years, is assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

(e) Share based payments

The grant date fair value of options and performance warrants granted to employees is recognized as compensation expense, with a corresponding increase in contributed surplus over the vesting period. A forfeiture rate is estimated on the grant date and is subsequently adjusted to reflect the actual number of options that vest.

(f) Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

(i) Decommissioning obligations:

The Company's activities give rise to dismantling, decommissioning and site disturbance re-mediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category. Decommissioning obligations are measured at the present value of management's best estimate of expenditure required to settle the present obligation at the statement of financial position date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

(g) Revenue

Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer which is usually when legal title passes to the external party. This is generally at the time product enters the pipeline. Royalty income is recognized as it accrues in accordance with the terms of the royalty agreements.

(h) Finance income and expenses

Finance expense comprises interest expense on any borrowings, accretion of the discount on provisions and impairment losses recognized on financial assets.

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. All other borrowing costs are recognized in earnings using the effective interest method. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Company's outstanding borrowings during the period.

Interest income is recognized as it accrues in earnings, using the effective interest method.

(i) Income tax

Income tax expense comprises current and deferred tax. Income tax expense is recognized in earnings except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected taxes payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to taxes payable in respect of previous years.

Deferred tax is recognized using the statement of financial position method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination.

Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(j) Earnings per share

Basic per share amounts are calculated by dividing the net income or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted per share amounts are determined by adjusting the net income or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options granted to employees.

(k) Standards issued but not yet effective

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 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.

4. Determination of Fair Values

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the methods described below. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

(i) Property, plant and equipment ("PP&E") and intangible exploration and evaluation ("E&E") assets:

The fair value of PP&E recognized in an acquisition, is based on market values. The market value of PP&E is the estimated amount for which property, plant & equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of oil and natural gas interests (included in PP&E) is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions. The market value of exploration and evaluation assets is estimated based on either internally or externally prepared evaluations of these assets.

(ii) Cash, deposits, accounts receivable, accounts payable and accrued liabilities:

The fair value of cash, deposits, accounts receivable, accounts payable and accrued liabilities are estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2017 and December 31, 2016, the fair value of these balances approximated their carrying values due to their short term to maturity.

(iii) Stock options:

The fair value of employee stock options is measured using a Black Scholes option pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility based on the weighted average historic volatility adjusted for changes expected due to publicly available information, weighted average expected life of the instruments based on historical experience and general option holder behavior, expected dividends, the risk-free interest rate based on government bonds, and an estimated forfeiture rate.

5. Business Combination

On October 13, 2016, the Company entered into a share purchase agreement to acquire 100 percent of the shares of TBNG (the "TBNG Acquisition"). On February 24, 2017, VENBV completed the TBNG Acquisition for a cash payment of US$20.7 million (CAD$27.1 million). The Company's participating interest in the shallow rights on the TBNG JV Lands increased to 81.5 percent and Valeura became the operator.

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 outflow is $21,450, which represents the cash price paid ($27,078) less cash received ($5,628). 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.

6. Assets Held for Sale

On October 13, 2016, CRBV entered into a sale and purchase agreement ("the Deep Rights Sale Agreement") with Statoil to sell the Company's 40 percent participating interest in the deep formations below approximately 2,500 metres depth on the West Thrace lands for cash consideration of US$12 million (CAD$14.9 million) (the "West Thrace Deep Rights Sale"). On January 6, 2017 the Company closed this West Thrace Deep Rights Sale. This resulted in $16.6 million being removed from assets held for sale at March 31, 2017, including foreign exchange effects.

Following closing the West Thrace Deep Rights Sale and the TBNG Acquisition, TBNG entered into a sale and purchase agreement with Statoil on March 10, 2017 to sell an additional 10 percent participating interest in the deep formations below approximately 2,500 metres depth on the West Thrace lands. This sale closed on June 22, 2017 upon receipt of Turkish government approval for the associated licence interest transfers for cash consideration of US$3.0 million (CAD$ 3.9 million) (the "Subsequent West Thrace Deep Rights Sale"). This resulted in $4.2 million being removed from assets held for sale at June 30, 2017 including foreign exchange effects. Upon the closing of the Subsequent West Thrace Deep Rights Sale, Valeura retains a 31.5 percent participating interest and Statoil acquires 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.

7. Restricted Cash and Licence Deposits

The Company has restricted cash in the amount of $3.2 million (2016 - $-) that is securing licence deposits with the General Directorate of Petroleum Affairs of the Republic of Turkey ("GDPA"), and a further $0.2 million (2016 - $0.9 million) on deposit with the GDPA. This restricted cash and deposit is security for decommissioning or abandonment obligations and ongoing work programs on the Company's Turkish licences. These deposits and restricted cash equal the amount to satisfy the underlying commitments with the GDPA and there are no other outstanding commitments. As the expected abandonment date and work programs for these assets is more than one year from December 31, 2017, this restricted cash and deposit have been classified as non-current in the Company's financial statements.

8. Exploration and Evaluation Assets

Cost		Total
Balance, December 31, 2015	$	38,132
Additions		9,451
Transfer to property, plant and equipment *(note 9)*		(8,564)
Capitalized share-based compensation		55
Transfer to assets held for sale		(16,635)
Effects of movements in exchange rates		(8,181)
Balance, December 31, 2016	**$**	**14,258**
TBNG Acquisition additions *(note 5)*		6,248
Banarli Farm-in Back Costs		(7,447)
Additions		6,918
Transfers to property, plant and equipment ("PP&E") *(note 9)*		(5,107)
Capitalized share-based compensation		12
Transfer to Assets Held for Sale *(note 6)*		(4,160)
Exploration and Evaluation Expense		(707)
Effects of movements in exchange rates		(2,373)
Balance, December 31, 2017	**$**	**7,642**

Exploration and evaluation ("E&E") assets consist of the Company's exploration projects which are pending the determination of proved or probable reserves. Additions represent the Company's share of costs incurred on E&E assets during the period, including seismic. Costs incurred on E&E drilling remain part of E&E until evaluation of drilling results concludes and determination of any reserves can be completed. E&E assets currently consist of costs of seismic data that was recently acquired and being used and inventory to be used in exploration wells that was recently purchased.

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.

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 100 percent owned and operated Banarli exploration 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 will operate 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 (CDN$7.4 million) for up-front payments as a contribution to back costs incurred on the Banarli licences.

In circumstances where the Company has entered into farm-in arrangements whereby the farm-in partner ("partner") will earn a working interest on certain properties through payment of a pre-determined portion of the costs of exploration or development activities, Valeura recognizes a disposal of the partner's working interest once the commitment has been met and the difference between the proceeds received and the carrying amount of the asset are recognized as a gain or loss in earnings for Property, Plant and Equipment assets and as a reduction of Exploration and Evaluation Assets for instances where the farm in is on undeveloped land. Under this IFRS accounting policy, the entire proceeds of the up-front payments under the Banarli Farm-in were accounted for as a reduction of Exploration and Evaluation Assets.

The ultimate recovery of exploration and evaluation costs in Turkey is dependent upon the Company obtaining government approvals, obtaining and maintaining licences in good standing, the existence and commercially viable exploitation of petroleum and natural gas reserves and undeveloped lands, and other uncertainties.

(a) Recoverability of exploration and evaluation assets

The Company assesses the recoverability of exploration and evaluation assets, before and at the moment of reclassification to property, plant and equipment, by allocating the E&E assets to appropriate CGUs. Valeura tested its E&E assets for any reclassification impairment during 2017 and there was no impairment on these transfer dates. At December 31, 2017, Valeura determined that no indicators of impairment existed with respect to the Company's E&E assets.

Impairment of exploration and evaluation assets is recognized in earnings. E&E expense consists of exploration projects that are considered 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).

9. Property, Plant and Equipment

Cost		Total
Balance, December 31, 2015	$	90,995
Additions		84
Transfer from exploration and evaluation assets *(note 8)*		8,564
Change in decommissioning obligations *(note 10)*		(3,406)
Effects of movements in exchange rates		(18,533)
Balance, December 31, 2016	**$**	**77,704**
Additions		5,873
TBNG Acquisition additions*(note 5)*		28,002
Transfer from exploration and evaluation assets *(note 8)*		5,107
Change in decommissioning obligations *(note 10)*		3,586
Effects of movements in exchange rates		(13,495)
Balance, December 31, 2017	**$**	**106,777**

Accumulated depletion and depreciation		Total
Balance, December 31, 2015	$	42,325
Depletion and depreciation expense		7,436
Impairment		1,050
Effects of movements in exchange rates		(9,129)
Balance, December 31, 2016	$	41,682
Depletion and depreciation expense		9,025
Effects of movements in exchange rates		(6,031)
Balance, December 31, 2017	**$**	**44,676**

Net book value		Total
Balance, December 31, 2016	$	36,022
Balance, December 31, 2017	**$**	**62,101**

The ultimate recovery of property, plant and equipment costs in Turkey is dependent upon the Company obtaining government approvals, obtaining and maintaining licences in good standing, the existence and commercially viable exploitation of petroleum and natural gas reserves and undeveloped lands, and other uncertainties.

(a) Impairment testing

IFRS requires an impairment test to assess the recoverable value of PP&E within each CGU upon initial adoption and, subsequently whenever there is an indication of impairment. The recoverable amount of each CGU is based on the higher of value-in-use or fair value less costs to sell.

The Company conducted an assessment of impairment triggers for the Company's one remaining CGU in the Thrace Basin of Turkey for the year ended December 31, 2017. The triggers assessed were market capitalization compared to the carrying value of PP&E assets, reserve and resource value compared to the carrying value of PP&E assets, instability in the global oil and natural gas resource sectors, regional geopolitical factors, restricted access to capital markets, and the volatility of Canadian Dollar and Turkish Lira foreign exchange rates. After assessing these impairment triggers the Company concluded that there were no indicators of impairment.

The following table summarizes annual and cumulative amounts recognized as impairment for PP&E assets. All impairment relate to non-core CGU's that have been fully impaired:

		Total
Cumulative Impairment, December 31, 2016	$	1,310
Cumulative impairment, December 31, 2017	**$**	**1,310**

(b) Contingencies

Although the Company believes that it has title to its oil and natural gas properties, it cannot control or completely protect itself against the risk of title disputes or challenges.

(c) Depletion - future development costs

For the purposes of calculating depletion, petroleum and natural gas properties in Turkey include estimated future development costs of $143.8 million (December 31, 2016 – $83.2 million) associated with development of the Company's proved plus probable reserves.

The ultimate recovery of property, plant and equipment and exploration and evaluation costs in Turkey is dependent upon the Company obtaining government approvals, obtaining and maintaining licences in good standing, the existence and commercial exploitation of petroleum and natural gas reserves and undeveloped lands, and other uncertainties.

10. Decommissioning Obligations

	December 31, 2017		December 31, 2016	
Decommissioning obligations, beginning of year	**$**	**8,132**	$	13,457
Obligations incurred		**122**		55
Obligations settled		**(270)**		-
Change in estimates		**3,464**		(3,461)
Accretion of decommissioning obligations		**1,779**		876
TBNG Acquisition *(note 5)*		**8,206**		
Effects of movements in exchange rates		**(2,227)**		(2,795)
Decommissioning obligations, end of year	**$**	**19,206**	$	8,132

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and gathering systems. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years.

The following significant assumptions were used to estimate the decommissioning obligations:

	December 31, 2017	December 31, 2016
Undiscounted cash flows	**$ 83,348**	$ 30,242
Risk free rate – Turkey	**11.4%**	11.0%
Inflation rate – Turkey	**11.9%**	9.0%
Timing of cash flows	**3-19 years**	4-20 years

11. Income Taxes

A reconciliation of the expected tax expense to the actual provision for current and deferred taxes is as follows:

	December 31, 2017	December 31, 2016
Loss before taxes from operations	**$ (10,803)**	$ (6,346)
Combined federal and provincial tax rate	**27.00%**	27.00%
Expected income tax recovery	**(2,917)**	(1,713)
Non-taxable items and other	**668**	670
Foreign tax rate differential	**(610)**	200
Change in unrecognized deferred tax assets	**440**	583
Income tax expense (recovery)	**$ (2,419)**	$ (260)

The deferred income tax rate applied to the temporary differences in 2017 was 27.0 percent (2016 – 27.0 percent). The Turkish tax rate for 2017 and 2016 is 20.0 percent.

The components of the deferred tax liability are as follows:

	December 31, 2017	December 31, 2016
Property, plant and equipment and exploration and evaluation assets	**$ (8,844)**	$ (10,484)
Decommissioning obligations	**3,827**	1,566
Non-capital losses and other	**515**	4,032
Foreign Exchange	**2,032**	-
	$ (2,470)	$ (4,886)

The temporary differences that determine the unrecognized deferred tax assets are as follows:

	December 31, 2017	December 31, 2016
Property, plant and equipment and exploration and evaluation assets	**$ 7,296**	$ -
Share issuance costs	**(173)**	-
Non-capital losses and other	**52,415**	50,762
Foreign Exchange	**246**	-
	$ 59,785	$ 50,762

The Company has tax assets of approximately $87.6 million at December 31, 2017 (2016 – $80.4 million) available for deduction against future taxable income. Cumulative non-capital loss carry-forwards in the amount of $55.2 million at December 31, 2017 (2016 - $66.3 million) expire between 2018 and 2036.

A continuity of the deferred income tax liability for 2016 and 2017 is detailed in the following tables:

Movement in temporary differences during the year	December 31, 2015	Recognized in profit or loss	Other comprehensive income (loss)	**December 31, 2016**
Property, plant and equipment and exploration and evaluation assets	$ (13,956)	$ 601	$ 2,898	**$ (10,457)**
Decommissioning obligations	2,691	(473)	(652)	**1,566**
Non-capital losses	3,787	(239)	(806)	**2,742**
Foreign exchange and other	990	371	(97)	**1,264**
	$ (6,488)	$ 260	$ 1,343	**$ (4,885)**

Movement in temporary differences during the year	December 31, 2016	Recognized in profit or loss	Acquisition	Other comprehensive income (loss)	**December 31, 2017**
Property, plant and equipment and exploration and evaluation assets	$ (10,457)	$ 3,165	$ (2,919)	$ 1,366	**$ (8,845)**
Decommissioning obligations	1,566	2,607	-	(345)	**3,828**
Non-capital losses	2,742	(1,969)	-	(258)	**515**
Foreign exchange and other	1,264	987	-	(219)	**2,032**
	$ (4,885)	$ 4,790	$ (2,919)	$ 544	**$ (2,470)**

Deferred income tax is a non-cash item relating to the temporary differences between the accounting and tax basis of Valeura's assets and liabilities and has no immediate impact on the Company's cash flows.

12. Administrative Expenses

The components of administrative expenses are as follows:

For the years ended	**December 31, 2017**	December 31, 2016
Cash:		
Salaries and benefits [1]	**$ 3,352**	$ 3,272
Other [2]	**3,540**	2,811
	6,892	6,083
Capitalized overhead [3]	**(2,286)**	(707)
General and administrative	**4,606**	5,376
Non-cash:		
Share-based compensation	**514**	443
Capitalized share-based compensation [3]	**(44)**	(57)
Share-based compensation	**$ 470**	$ 386

[1] Includes salaries, benefits and bonuses earned by all Directors, Officers and employees of the Company.

(2) Includes costs such as rent, professional fees, insurance, travel, office, and other business expenses incurred by the Company.

(3) Includes a portion of salaries, benefits and share-based compensation directly attributable to the exploration and development activities of the Company.

Compensation for Executive Officers and Directors are comprised of the following:

For the years ended	**December 31, 2017**	December 31, 2016
Salaries and benefits [1]	**$ 1,528**	$ 1,388
Share-based compensation [2]	**372**	326
Executive Officers and Directors compensation	**$ 1,900**	$ 1,714

(1) Includes salaries, benefits and bonuses earned by Executive Officers and Directors comprised of: Chairman of the Board, President and Chief Executive Officer, Vice President and Chief Financial Officer, Vice President of Operations, Vice President of Engineering and other independent Directors.

(2) Represents the amortization of share-based compensation expense in the year associated with options granted to Executive Officers and Directors participating in the Company's Stock Option Plan.

13. Share Capital

(a) Authorized

Unlimited number of common shares
Unlimited number of preferred shares, issuable in series

(b) Per share amounts

Per share amounts have been calculated using the weighted average number of common shares outstanding. The weighted average number of common shares outstanding for the year ended December 31, 2017 is 70,943,951 (2016 – 58,253,508). The average number of common shares outstanding was not increased for outstanding stock options and performance warrants as the effect would be anti-dilutive.

(c) Subscription receipts

On October 14, 2016, the Company entered into an agreement to sell, on an underwritten private placement basis, 14,629,000 subscription receipts of the Company at a price of $0.75 per subscription receipt for total gross proceeds of approximately $11 million (the "2016 Offering"). The subscription receipts and the underlying common shares of the Company issuable pursuant to the Offering were subject to a four month hold period. The 2016 Offering closed on November 3, 2016, and was subject to the completion of the Company's acquisition of Thrace Basin Natural Gas (Turkiye) Corporation ("TBNG") which closed on February 24, 2017. See further discussion in note 5.

(d) Stock options

Valeura has an option program that entitles officers, directors, and employees to purchase shares in the Company. Options are granted at the market price of the shares at the date of grant, have a 7 year term and vest over 3 years.
The number and weighted average exercise prices of share options are as follows:

	Number of Options	Weighted average exercise price
Balance, December 31, 2015	5,177,000	$ 0.72
Granted	613,000	0.75
Exercised	(546,666)	0.80
Forfeited /Cancelled	(328,834)	0.60
Balance, December 31, 2016	4,914,500	$ 0.72
Granted	1,750,000	0.74
Forfeited/cancelled	(294,000)	0.73
Balance, December 31, 2017	**6,370,500**	**$ 0.73**
Exercisable at December 31, 2017	**3,707,324**	**$ 0.74**

The following table summarizes information about the stock options outstanding at December 31, 2017:

Exercise prices	Outstanding at December 31, 2017	Weighted average remaining life (years)	Weighted average exercise price	Exercisable at December 31, 2017	Weighted average exercise price
$0.57 - $0.61	1,569,500	4.2	$ 0.57	1,046,330	$ 0.57
$0.64 - $0.74	2,270,500	4.6	0.68	1,267,166	0.64
$0.75 - $1.00	2,530,500	4.2	0.87	1,393,828	0.97
	6,370,500	4.3	$ 0.73	3,707,324	$ 0.74

The fair value, at the grant date during the year, of the stock options issued was estimated using the Black-Scholes model with the following weighted average inputs:

Assumptions	**December 31, 2017**	December 31, 2016
Risk free interest rate (%)	**1.0**	0.7
Expected life (years)	**4.5**	4.5
Expected volatility (%)	**77.4**	80.7
Forfeiture rate (%)	**3.7**	1.6
Weighted average fair value of options granted	**$ 0.45**	$ 0.46

14. 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.

15. Supplemental Cash Flow Information

	December 31, 2017	December 31, 2016
Change in non-cash working capital:		
Accounts receivable	**$ 549**	$ 699
Prepaid expenses and deposits	**84**	(479)
Inventory	**582**	-
Deposits (non-current)	**758**	229
Accounts payable and accrued liabilities	**9,104**	(1,740)
TBNG Acquisition	**(2,226)**	-
Movements in exchange rates	**2,232**	(140)
	11,083	(1,431)

The change in non-cash working capital has been allocated to the following activities:

Operating	**5,329**	246
Investing	**5,754**	(1,677)
	$ 11,083	$ (1,431)

16. Financial Risk Management

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities such as:

- Credit risk
- Market risk
- Liquidity risk

This note presents information about the Company's exposure to each of the above risks, the Company's objectives, policies and processes for measuring and managing risk, and the Company's management of capital. Further quantitative disclosures are included throughout the consolidated financial statements.

The Board of Directors oversees managements' establishment and execution of the Company's risk management framework. Management has implemented and monitors compliance with risk management policies. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

(a) Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from joint venture partners and oil and natural gas marketers. The maximum exposure to credit risk at year-end is as follows:

	December 31, 2017	December 31, 2016
Joint venture receivable from other partners	**$ 195**	$ -
Revenue receivables from customers	**2,828**	4,601
VAT Receivable	**1,029**	-
Accounts receivable	**$ 4,052**	$ 4,601

Trade and other receivables:

Substantially all of the Company's petroleum and natural gas production is marketed under standard industry terms that are specific by country. The Company's policy to mitigate credit risk associated with the balances is to establish marketing relationships with credit worthy purchasers. The Company historically has not experienced any collection issues with its petroleum and natural gas marketers. Joint venture receivables are typically collected within one to three months of the joint venture invoice being issued to the partner. The Company attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures.

Receivables from participants in the petroleum and natural gas sector, and collection of the outstanding balances can be impacted by industry factors such as commodity price fluctuations, limited capital availability and unsuccessful drilling programs. The Company does not typically obtain collateral from petroleum and natural gas marketers or joint venture partners; however the Company can cash call for major projects and does have the ability, in most cases, to withhold production from joint venture partners in the event of non-payment, or withhold accounts payable remittances.

(b) Market risk

Market risk is the risk that changes in market conditions, such as commodity prices, foreign exchange rates and interest rates will affect the Company's income or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while maximizing the Company's return.

Foreign currency exchange rate risk:

Foreign currency exchange rate risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. World oil prices are quoted in US Dollars and the price received by the Company's Turkish branches can be affected by the Turkish Lira (TL)/United States Dollar (USD) exchange rate, which fluctuates over time. 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) exchange rate. A decrease in the value of the Turkish Lira against the Canadian Dollar will result in a decrease in revenue and a decrease in operating costs in the Company's consolidated financial statements. Correspondingly, an increase in the value of the Turkish Lira against the Canadian Dollar will result in an increase in revenue and an increase in operating costs.

The Company's seismic and drilling operations and related contracts in Turkey are partially based in US Dollars. Material increases in the value of the US Dollar against the Turkish Lira or Canadian Dollar will negatively impact the Company's costs of drilling and completions activities. Future CAD/USD and CAD/TL exchange rates could accordingly 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 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.

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

Interest rate risk:

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is not currently exposed to interest rate risk as it has no debt.

Commodity price risk:

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by the relationship between the Canadian Dollar and Turkish Lira, the Canadian Dollar and United States Dollar, global economic events and Turkish government policies.

The natural gas reference price in Turkey is in part correlated to contract prices for natural gas imports into Turkey and also government policy with respect to subsidies to consumers. As of January 01, 2018 the reference price was increased by 14 percent to 0.8 TL per cubic meter or approximately CDN$7.50/Mcf at an exchange rate of approximately 3.0TL/CDN$.

Liquidity risk:

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with the financial liabilities. The Company's financial liabilities consist of accounts payable. Accounts payable consists of invoices payable to trade suppliers for office, field operating activities and capital expenditures. The Company processes invoices within a normal payment period. Accounts payable have contractual maturities of less than one year. The Company maintains and monitors a certain level of cash which is used to finance all operating and capital expenditures.

Capital management:

The Company's objective when managing capital 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 Company's capital expenditure includes 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 currently 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 2018, upon drilling & completion success at Yamalik 1, 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 including a more extensive pilot project, for which the Company would have to contribute its 50 percent participating interest. Such a program could result in capital commitment more significant that the program disclosed in the Company's recent short term prospectus. If this were the case, the Company will be required to assess alternatives including the availability of equity and debt capital to fund the program.

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. See note 19 for description of an equity issuance which closed on March 1, 2018.

Valeura has not utilized bank loans or debt capital to finance capital expenditures to date. In the future, if the Company establishes and borrows on a bank loan facility for capital expansion, the Company will monitor capital based on the ratio of net debt to annualized funds from operations. This ratio represents the time period it would take to pay off the debt if no further capital expenditures were incurred and if funds from operations remained constant.

17. 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.

18. Commitments

On August 1, 2016 the Company renegotiated its existing 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 $0.3 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.

19. Subsequent Event

On February 8, 2018, 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 a bought deal basis 10,527,000 common shares of the Company at a price of $5.70 per common share, for total gross proceeds of approximately $60.0 million (the "Offering"). The Offering closed on March 1, 2018. Net proceeds were approximately $55.7 million after underwriters fees of approximately $3.6 million and other expenses of $0.7 million.

Valeura Energy Inc.

Consolidated Financial Statements

Years ended December 31, 2018 and 2017

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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Valeura Energy Inc.

Opinion

We have audited the consolidated financial statements of Valeura Energy Inc. (the "Company"), which comprise:

- the consolidated statements of financial position as at December 31, 2018 and December 31, 2017
- the consolidated statements of income (loss) and comprehensive income (loss) for the years then ended
- the consolidated statements of changes in equity for the years then ended
- the consolidated statements of cash flows for the years then ended
- and notes to the consolidated financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2018 and December 31, 2017, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards ("IFRS").

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "*Auditors' Responsibilities for the Audit of the Financial Statements*" section of our auditors' report.

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Other Information

Management is responsible for the other information. Other information comprises:

- the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions.

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions as at the date of this auditors' report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditors' report.

We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.
- Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

The engagement partner on the audit resulting in this auditors' report is Brad William Robertson.

"KPMG LLP"
Chartered Professional Accountants
Calgary, Canada
March 13, 2019

Consolidated Statements of Financial Position

(thousands of Canadian Dollars)	**December 31, 2018**	December 31, 2017
Assets		
Current Assets		
Cash	**$ 62,380**	$ 11,108
Accounts receivable	**9,242**	4,052
Prepaid expenses and deposits	**2,090**	1,381
Inventory	**195**	251
	73,907	16,792
Licence deposits *(note 5)*	**127**	164
Restricted Cash *(note 5)*	**274**	3,173
Exploration and evaluation assets *(notes 6,7)*	**9,385**	7,642
Property, plant and equipment *(notes 6,7)*	**44,630**	62,101
	$ 128,323	$ 89,872
Liabilities and Shareholders' Equity		
Current Liabilities		
Accounts payable and accrued liabilities	**$ 14,387**	$ 13,371
Decommissioning obligations *(note 8)*	**15,821**	19,206
Deferred taxes *(note 10)*	**1,896**	2,470
Shareholders' Equity		
Share capital *(note 12)*	**205,320**	146,694
Contributed surplus	**20,123**	19,857
Accumulated other comprehensive loss	**(42,561)**	(32,183)
Deficit	**(86,663)**	(79,543)
	96,219	54,825
	$ 128,323	$ 89,872

See accompanying notes to the consolidated financial statements

Approved by the Board

("Tim Marchant") ("*Russell Hiscock*")
Tim Marchant, Chairman, Director Russell Hiscock, Director

Consolidated Statements of Loss and Comprehensive Loss
For the years ended December 31, 2018 and 2017

(thousands of Canadian Dollars)	**December 31, 2018**	December 31, 2017
Revenue *(note 9)*		
Petroleum and natural gas sales	**$ 11,969**	$ 14,646
Royalties	**(1,611)**	(1,971)
Other Income	**2,245**	1,363
	12,603	14,038
Expenses		
Production	**3,606**	4,423
General and administrative *(note 11)*	**3,750**	4,606
Transaction costs	**287**	1,160
Accretion on decommissioning liabilities *(note 8)*	**2,890**	1,779
Foreign exchange (gain)/loss	**(548)**	2,671
Share-based compensation *(note 12)*	**1,514**	470
Exploration and Evaluation *(note 6)*	**-**	707
Depletion and depreciation *(note 7)*	**7,306**	9,025
	18,805	24,841
Loss for the year before income taxes	**(6,202)**	(10,803)
Income taxes *(note 10)*		
Current tax expense	**837**	2,371
Deferred tax expense (recovery)	**81**	(4,790)
Net loss	**(7,120)**	(8,384)
Other comprehensive loss		
Currency translation adjustments	**(10,378)**	(6,019)
Comprehensive loss	**(17,498)**	(14,403)
Net loss per share *(note 12)*		
Basic and diluted	**$ (0.09)**	$ (0.12)
Weighted average number of shares outstanding (thousands)	**83,659**	70,944

See accompanying notes to the consolidated financial statements

Consolidated Statements of Cash Flows
For the years ended December 31, 2018 and 2017

(thousands of Canadian Dollars)	**December 31, 2018**	December 31, 2017
Cash was provided by (used in):		
Operating activities:		
Net loss for the year	**$ (7,120)**	$ (8,384)
Depletion and depreciation *(note 7)*	**7,306**	9,025
Exploration and Evaluation expense *(note 6)*	**-**	707
Share-based compensation *(notes 12)*	**1,514**	470
Accretion on decommissioning liabilities *(note 8)*	**2,890**	1,779
Unrealized foreign exchange gain	**(1,016)**	(12)
Deferred tax expense (recovery) *(note 10)*	**81**	(4,790)
Decommissioning costs incurred *(note 8)*	**(531)**	(270)
Change in non-cash working capital *(note 14)*	**(3,708)**	5,329
Cash (used in) provided by operating activities	**(584)**	3,854
Financing activities:		
Share issuance	**60,004**	10,972
Share issuance costs	**(4,596)**	(864)
Proceeds from stock option exercises	**1,912**	-
Cash provided by financing activities	**57,320**	10,108
Investing activities:		
TBNG Acquisition cash purchase price	**-**	(21,450)
West Thrace Deep Rights Sale	**-**	18,841
Statoil Farm-in proceeds	**-**	7,447
Property and equipment expenditures *(note 7)*	**74**	(5,873)
Exploration and evaluation expenditures *(note 6)*	**(8,097)**	(6,918)
Change in restricted cash	**2,899**	(3,173)
Change in non-cash working capital *(note 14)*	**(2,715)**	5,754
Cash used in investing activities	**(7,839)**	(5,372)
Foreign exchange gain (loss) on cash held in foreign currencies	**2,375**	531
Net change in cash	**51,272**	9,121
Cash, beginning of year	**11,108**	1,987
Cash, end of year	**$ 62,380**	$ 11,108

See accompanying notes to the consolidated financial statements

Consolidated Statements of Changes in Shareholders' Equity
For the years ended December 31, 2018 and 2017

(thousands of Canadian Dollars and thousands of shares)	Number of Shares	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comp. Loss	Total Shareholders' Equity
Balance, January 1, 2018	73,148	$ 146,694	$ 19,857	$ (79,543)	$ (32,183)	$ 54,285
Net loss for the year	-	-	-	(7,120)	-	(7,120)
Shares issued	13,085	63,222	(1,306)	-	-	61,916
Shares issuance costs	-	(4,596)	-	-	-	(4,596)
Currency translation adjustments	-	-	-	-	(10,378)	(10,378)
Share-based Compensation	-	-	1,572	-	-	1,572
December 31, 2018	**86,233**	**$ 205,320**	**$ 20,123**	**$ (86,663)**	**$ (42,561)**	**$ 96,219**

(thousands of Canadian Dollars and thousands of shares)	Number of Shares	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comp. Loss	Total Shareholders' Equity
Balance, January 1, 2017	58,519	$ 136,586	$ 19,343	$ (71,159)	$ (26,164)	$ 58,606
Net loss for the year	-	-	-	(8,384)	-	(8,384)
Shares issued	14,629	10,972	-	-	-	10,972
Shares issuance costs	-	(864)	-	-	-	(864)
Currency translation adjustments	-	-	-	-	(6,019)	(6,019)
Share-based Compensation	-	-	514	-	-	514
December 31, 2017	**73,148**	**$ 146,694**	**$ 19,857**	**$ (79,543)**	**$ (32,183)**	**$ 54,825**

See accompanying notes to the consolidated financial statements

1. Reporting Entity

Valeura Energy Inc. ("Valeura" or the "Company") and its subsidiaries are currently engaged in the exploration, development and production of petroleum and natural gas in Turkey. Valeura is incorporated in Alberta, Canada and has subsidiaries in the Netherlands, British Virgin Islands and Turkey. Valeura's shares are traded on the Toronto Stock Exchange ("TSX") under the trading symbol VLE. Valeura's head office address is 1200, 202 – 6 Avenue SW, Calgary, AB.

2. Basis of Preparation

(a) Statement of compliance

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as at and for the years ended December 31, 2018 and 2017 and have been prepared in accordance with the accounting policies and methods of computation as set forth in note 3 below.

Operating, transportation and marketing expenses in profit or loss are presented as a combination of function and nature in conformity with industry practices. Depletion, depreciation and finance expenses are presented in separate lines by their nature, while net administrative expenses are presented on a functional basis. Significant expenses such as salaries and benefits and share-based compensation are presented by their nature in the notes to the consolidated financial statements.

The consolidated financial statements were authorized for issue by the Board of Directors on March 13, 2019.

(b) Basis of measurement

The consolidated financial statements have been prepared on the historical cost basis except for certain financial and non-financial assets and liabilities, which have been measured at fair value. The methods used to measure fair value are discussed in note 4.

The Company's consolidated financial statements include the accounts of Valeura and its subsidiaries and are expressed in Canadian Dollars, unless otherwise stated.

(c) Functional and presentation currency

The consolidated financial statements are presented in Canadian Dollars which is Valeura's reporting currency. Valeura's foreign subsidiaries transact in currencies other than the Canadian Dollar and have a functional currency of Turkish Lira. The functional currency of a subsidiary is the currency of the primary economic environment in which the subsidiary operates. Transactions denominated in a currency other than the functional currency are translated at the prevailing rates on the date of the transaction. Any monetary items held in a currency which is not the functional currency of the subsidiary are translated to the functional currency at the prevailing rate as at the date of the statement of financial position. All exchange differences arising as a result of the translation to the functional currency of the subsidiary are recorded in net earnings.

Translation of all assets and liabilities from the 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 other comprehensive income or loss ("OCI") and are held within accumulated other comprehensive income or loss ("AOCI") until a disposal or partial disposal of a subsidiary. A disposal or partial disposal will then give rise to a realized foreign exchange gain or loss which is recorded in net earnings.

(d) 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:

- 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.

(e) Turkey operational update

Turkey has gone through a period of political change and uncertainty from 2016 to 2018. However, with the successful passing of the referendum on constitutional change, and the successful election in mid-2018, the incumbent, President Erdogan remains in office.

Recent geopolitical events have resulted in a continued downward slide in the value of the TL, and at times these drops have been very sharp. This has also had the effect of sharply increasing inflation to more than 20% in 2018 after well over a decade of strong growth and relatively stable inflation. In 2018, the resulting negative sentiment to Turkey has at times resulted in a decrease in the value of Valeura shares.

To date, the above events have not impacted the Company's ability to conduct drilling and production operations in the Thrace Basin and no significant delays or security issues have been experienced in these operations. All of the Company's current operations are in the Thrace Basin of northwest Turkey, more than 1,000 kilometres from the Syrian border.

The Company will continue to monitor conditions, including the safety of personnel and operations, the security situation generally, impact on the TL and banking facilities, impact on our joint venture partners and any changes in offtakes by the Company's 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 these consolidated financial statements were approved by the Board of Directors. The situation in Turkey remains uncertain and significant changes could occur which could materially impact the assumptions and estimates made in these consolidated financial statements. Changes in assumptions are recognized in the financial statements prospectively.

3. Significant Accounting Policies

The accounting policies set out below have been applied consistently to all years presented in the consolidated financial statements and have been applied consistently by the Company and its subsidiaries, except as described below.

(a) Basis of consolidation

(i) Subsidiaries:

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, substantive potential voting rights are taken into account. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

The acquisition method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in earnings.

(ii) Jointly controlled operations and jointly controlled assets:

A portion of the Company's exploration and development activities are conducted jointly with others. The joint interests are accounted for on a proportionate consolidation basis and as a result the financial statements reflect only the Company's proportionate share of the assets, liabilities, revenues, expenses and cash flows from these activities. Valeura has two joint venture arrangements as follows:

Name of the joint arrangement	Nature of the relationship with the joint arrangement	Principal place of business of joint arrangement	Proportion of participating share
TBNG Joint Venture	Operator	Turkey	81.5% (all rights)
Equinor Joint Venture	Operator	Turkey	50% on Banarli Licenses (deep rights); 31.5% on West Thrace Lands (deep rights)

(iii) Transactions eliminated on consolidation:

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

(b) Financial instruments

(j) Non-derivative financial instruments:

Valeura adopted IFRS 9, Financial Instruments on January 1, 2018 on a retrospective basis.

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, which is more in line with risk management activities. IFRS 9 has been adopted on a retrospective basis by Valeura on January 1, 2018. IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost, fair value through other comprehensive income ("FVOCI"), or fair value through profit or loss ("FVTPL").

Under IFRS 9, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity's own credit risks is recorded through other comprehensive income or loss rather than net income or loss. The classification of financial assets under IFRS 9 is generally based on the business model in which a financial asset is managed and the characteristics of its contractual cash flows.

A financial asset is subsequently measured at amortized cost if it meets both of the following conditions: (a) the asset is held with a business model whose objective is to hold assets to collect contractual cash flows; and (b) the contractual terms of the financial assets give rise to cash flows on specified dates that are solely payments of principal and interest on principal amounts outstanding.

Financial assets that meet criteria (b) above that are held within a business model whose objective is achieved by both collecting contractual cash flows and selling financial assets is subsequently measured at FVOCI. All other financial assets and liabilities are subsequently measure at FVTPL. There was no change to the measurement categories of financial liabilities.
Accounts receivable, prepaid expenses and deposits, accounts payable and accrued liabilities continue to be measured at amortized cost and are now classified as "amortized cost".

Valeura does not currently have financial instrument contracts to which it applies hedge accounting.

(ii) Share capital:

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares and share options are recognized as a deduction from equity, net of any tax effects.

(a) Property, plant and equipment and exploration and evaluation assets

(i) Recognition and measurement:

Exploration and evaluation expenditures:

Pre-licence costs are recognized in earnings as incurred. Exploration and evaluation ("E&E") costs, including the costs of acquiring licences and directly attributable general and administrative costs, are initially capitalized as exploration and evaluation assets. The costs are accumulated in cost centres by well, field or exploration area pending determination of technical feasibility and commercial viability.

Exploration and evaluation assets are assessed for impairment if sufficient data exists to determine technical feasibility and commercial viability, and facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are allocated to cash-generating units. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved and/or probable reserves are determined to exist. A review of each exploration CGU is conducted, at least annually, to ascertain whether proved and/or probable reserves have been discovered. Upon determination of proved and/or probable reserves, the CGU within which the intangible exploration and evaluation assets attributable to those reserves is first tested for impairment and then the applicable value is reclassified from exploration and evaluation assets to property, plant and equipment.

Development and production costs:

Items of property, plant and equipment ("PP&E"), which include oil and gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development and production assets are grouped into CGUs for impairment testing. When significant parts of an item of PP&E, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (components).

Gains and losses on disposal of an item of property, plant and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of PP&E and are recognized in earnings.

(ii) Subsequent costs:

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of PP&E are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in earnings as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in earnings as incurred.

(iii) Depletion and depreciation:

The net carrying value of development or production assets is depleted using the unit of production method by reference to the ratio of production in the year to the related proved plus probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually.

Other corporate assets are recorded at cost on acquisition and amortized on a declining-balance basis at rates of 20 percent to 50 percent per year.

(iv) Exploration and evaluation expense:

Upon determination that an exploration and evaluation CGU is impaired, the Company will transfer costs associated with the applicable CGU to exploration and evaluation expense in the period.

(b) Impairment

(i) Financial assets:

Loss allowances are recognized for expected credit losses ("ECL's) on its financial assets measured at amortized cost. Due to the nature of the financial assets, loss allowances are measured at an amount equal to expected lifetime ECLs. Lifetime ECLs are the anticipated ECLs that result from all possible default events over the expected life of a financial asset. ECLs are a probability-weighted estimate of credit loss and are discounted at the effective interest rate of the related financial asset.

(ii) Non-financial assets:

The carrying amounts of the Company's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, the asset's recoverable amount is estimated via an impairment test.

E&E assets are assessed for impairment when they are reclassified to property, plant and equipment, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets, or CGUs. The recoverable amount of an asset or a CGU is the greater of its value-in-use and its fair value less costs to sell. Fair value less costs to sell is determined as the amount that would be obtained from the sale of the assets in an arm's length transaction between knowledgeable and willing parties.

In assessing value-in-use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value-in-use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved plus probable reserves. E&E assets are allocated to related CGUs when they are assessed for impairment, both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to PP&E.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in earnings. Impairment losses recognized in respect of CGUs are allocated to reduce the carrying amounts of the assets in the unit (group of units) on a pro-rata basis.

An impairment loss in respect of PP&E and E&E assets, recognized in prior years, is assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

(c) Share based payments

The grant date fair value of options and performance warrants granted to employees is recognized as compensation expense, with a corresponding increase in contributed surplus over the vesting period. A forfeiture rate is estimated on the grant date and is subsequently adjusted to reflect the actual number of options that vest.

(d) Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

(i) Decommissioning obligations:

The Company's activities give rise to dismantling, decommissioning and site disturbance re-mediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category. Decommissioning obligations are measured at the present value of management's best estimate of expenditure required to settle the present obligation at the statement of financial position date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

(e) Revenue from contracts with customers

In April 2016 the IASB issued its final amendment to IFRS 15 Revenue from Contracts with Customers, or which replaced IAS 18 Revenue, IAS 11 Construction contracts and related interpretations, to be adopted for annual periods beginning on or after January 1, 2018. Valeura adopted the new standard on January 1, 2018 on a retrospective basis. The standard requires enhanced disclosure of revenue from contracts with customers as detailed in Note 9, including categories that depict the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors. Valeura management reviewed its revenue streams and major contracts with customers and concluded that there were no material impacts on the Company's revenues or cash flows for the period as a result of adopting the new standard. Please see note 9 for additional disclosures required by the new standard.

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's petroleum and natural gas revenues from the sale of natural gas and crude oil are based on the consideration specified in the contracts with customers. For natural gas, pricing is linked to BOTAS benchmark pricing, while crude oil pricing is linked to Brent benchmark pricing. Valeura recognizes revenue when it transfers control of the product to the customer, which is generally when legal title passes to the customer and collection is reasonably assured.

Valeura evaluates its arrangements with third parties and partners to determine if Valeura is acting as the principal or as the agent. Valeura is considered the principal in a transaction when it has primary responsibility for the transaction. If Valeura acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net basis, only reflecting the fee, if any realized by Valeura from the transaction.

(f) Finance income and expenses

Finance expense comprises interest expense on any borrowings, accretion of the discount on provisions and impairment losses recognized on financial assets.

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. All other borrowing costs are recognized in earnings using the effective interest method. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Company's outstanding borrowings during the period. Interest income is recognized as it accrues in earnings, using the effective interest method.

(g) Income tax

Income tax expense comprises current and deferred tax. Income tax expense is recognized in earnings except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected taxes payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to taxes payable in respect of previous years.

Deferred tax is recognized using the statement of financial position method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination.

Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(h) Earnings per share

Basic per share amounts are calculated by dividing the net income or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted per share amounts are determined by adjusting the net income or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options granted to employees.

(i) Standards issued but not yet effective

In January 2016, the IASB issued the complete IFRS 16 Leases ("IFRS 16") which replaces IAS 17, Leases. The effective date of IFRS 16 is for annual periods beginning on or after January 1, 2019 and early adoption is permitted. Under IFRS 16, a single recognition and measurement model will apply for lessees which will require recognition of assets and liabilities for most leases. The Company is in the final stages of analyzing identified contracts, developing business and accounting processes, making applicable changes to the Company's internal controls and calculating the impact that the adoption of this standard will have on its financial statements. Valeura has elected to use the modified retrospective approach upon adoption and elected to apply the optional exemptions for short-term and low-value leases. The actual full impact of adoption will depend on the Company's incremental borrowing rate, lease liabilities, and practical expedients applied. However, the Company anticipates that the most significant impact of adopting IFRS 16 will be the recognition of the right-of-use ("ROU") assets and corresponding lease liabilities on its leases for office space and surface leases for facilities.

Upon adoption of IFRS 16, the Company will recognize ROU assets and lease liabilities for all leases identified except for optional exemptions taken. The lease liability will be measured at the present value of the remaining lease payments, discounted using the Company's incremental borrowing rate as at January 1, 2019. The ROU asset will be measured at the amount equal to the lease liability on January 1, 2019 with no impact on retained earnings.

Adoption of IFRS 16 will also result in an increase to depletion, depreciation and amortization expense due to the recognition of the ROU assets, increase in interest and financing charges, and a decrease to general and administrative and operating expenses, as applicable. Cash flow from operating activities will increase as a result of the decrease in general and administrative and operating expenses, as applicable, partially offset by interest and financing charges. Cash flow from financing activities will decrease due to the addition of principal payments included in lease payments for former operating leases.

4. Determination of Fair Values

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the methods described below. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

(i) Property, plant and equipment ("PP&E") and intangible exploration and evaluation ("E&E") assets:

The fair value of PP&E recognized in an acquisition, is based on market values. The market value of PP&E is the estimated amount for which property, plant & equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of oil and natural gas interests (included in PP&E) is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions. The market value of exploration and evaluation assets is estimated based on either internally or externally prepared evaluations of these assets.

(ii) Cash, deposits, accounts receivable, accounts payable and accrued liabilities:

The fair value of cash, deposits, accounts receivable, accounts payable and accrued liabilities are estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2018 and December 31, 2017, the fair value of these balances approximated their carrying values due to their short term to maturity.

(iii) Stock options:

The fair value of employee stock options is measured using a Black Scholes option pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility based on the weighted average historic volatility adjusted for changes expected due to publicly available information, weighted average expected life of the instruments based on historical experience and general option holder behavior, expected dividends, the risk-free interest rate based on government bonds, and an estimated forfeiture rate.

5. Restricted Cash and Licence Deposits

The Company has restricted cash in the amount of $0.3 million (2017 - $3.1 million) that is securing licence deposits with the General Directorate of Mining and Petroleum Affairs of the Republic of Turkey ("GDMPA"), and a further $0.1 million (2017 - $0.2 million) on deposit with the GDMPA. This restricted cash and deposit is security for decommissioning or abandonment obligations and ongoing work programs on the Company's Turkish licences. These deposits and restricted cash equal the amount to satisfy the underlying commitments with the GDMPA and there are no other outstanding commitments. As the expected abandonment date and work programs for these assets is more than one year from December 31, 2018, this restricted cash and deposit have been classified as non-current in the Company's financial statements.

Effective June 22, 2018, the Company has available an Account Performance Security Guarantee ("APSG") from Export Development Canada ("EDC"). The APSG, which was issued to National Bank of Canada ("NBC") allows the Company to

use the APSG as collateral for certain letters of credit issued by NBC. The facility is effective from May 16, 2018 to May 31, 2019 with a limit of US$2.5 million and can be renewed on an annual basis. The Company has issued US$2.5 million in letters of credit under the APSG facility at current exchange rates.

6. Exploration and Evaluation Assets

Cost	Total
Balance, December 31, 2016	14,258
TBNG Acquisition additions	6,248
Banarli Farm-in Back Costs	(7,447)
Additions	6,918
Transfers to property, plant and equipment ("PP&E") *(note 7)*	(5,107)
Capitalized share-based compensation	12
Transfer to Assets Held for Sale	(4,160)
Exploration and Evaluation Expense	(707)
Effects of movements in exchange rates	(2,373)
Balance, December 31, 2017	**$ 7,642**
Additions	8,097
Transfer to property, plant and equipment *(note 7)*	(4,167)
Capitalized share-based compensation	58
Effects of movements in exchange rates	(2,245)
Balance, December 31, 2018	**$ 9,385**

Exploration and evaluation ("E&E") assets consist of the Company's exploration projects which are pending the determination of proved or probable reserves. Additions represent the Company's share of costs incurred on E&E assets during the period.

In circumstances where the Company has entered into farm-in arrangements whereby the farm-in partner ("partner") will earn a working interest on certain properties through payment of a pre-determined portion of the costs of exploration or development activities, Valeura recognizes a disposal of the partner's working interest once the commitment has been met and the difference between the proceeds received and the carrying amount of the asset are recognized as a gain or loss in earnings for Property, Plant and Equipment assets and as a reduction of Exploration and Evaluation Assets for instances where the farm in is on undeveloped land. Under this IFRS accounting policy, the entire proceeds of the Banarli Farm-in were accounted for as a reduction of Exploration and Evaluation Assets in 2017.

(a) Recoverability of exploration and evaluation assets

The Company assesses the recoverability of exploration and evaluation assets, before and at the moment of reclassification to property, plant and equipment, by allocating the E&E assets to appropriate CGUs. Valeura tested its E&E assets for any transfers during 2018 and there was no impairment on these transfer dates. At December 31, 2018, Valeura determined that no indicators of impairment existed with respect to the Company's E&E assets.

Impairment of exploration and evaluation assets is recognized in earnings. E&E expense consists of exploration projects that are considered to have a lower fair value when compared to book value. E&E expense for the year ended December 31, 2018 was nil (2017 – $0.7 million).

7. Property, Plant and Equipment

Cost		Total
Balance, December 31, 2016	$	77,704
Additions		5,873
TBNG Acquisition additions		28,002
Transfer from exploration and evaluation assets *(note 6)*		5,107
Change in decommissioning obligations *(note 8)*		3,586
Effects of movements in exchange rates		(13,495)
Balance, December 31, 2017	**$**	**106,777**
Additions		(74)
Transfer from exploration and evaluation assets *(note 6)*		4,167
Change in decommissioning obligations *(note 8)*		(4,513)
Effects of movements in exchange rates		(19,842)
Balance, December 31, 2018	**$**	**86,515**

Accumulated depletion and depreciation		Total
Balance, December 31, 2016	$	41,682
Depletion and depreciation expense		9,025
Effects of movements in exchange rates		(6,031)
Balance, December 31, 2017	$	44,676
Depletion and depreciation expense		7,306
Effects of movements in exchange rates		(10,097)
Balance, December 31, 2018	**$**	**41,885**

Net book value		Total
Balance, December 31, 2017	$	62,101
Balance, December 31, 2018	**$**	**44,630**

The ultimate recovery of property, plant and equipment costs in Turkey is dependent upon the Company obtaining government approvals, obtaining and maintaining licences in good standing, the existence and commercially viable exploitation of petroleum and natural gas reserves and undeveloped lands, and other uncertainties.

(a) Impairment testing

IFRS requires an impairment test to assess the recoverable value of PP&E within each CGU upon initial adoption and, subsequently whenever there is an indication of impairment. The recoverable amount of each CGU is based on the higher of value-in-use or fair value less costs to sell.

The Company conducted an assessment of impairment triggers for the Company's one remaining CGU in the Thrace Basin of Turkey for the year ended December 31, 2018. The triggers assessed were market capitalization compared to the carrying value of PP&E assets, reserve and resource value compared to the carrying value of PP&E assets, instability in the global oil and natural gas resource sectors, regional geopolitical factors, restricted access to capital markets, the level of inflation and interest rates, and the volatility of Canadian Dollar and Turkish Lira foreign exchange rates. After assessing these impairment triggers the Company concluded that there were no indicators of impairment.

(b) Contingencies

Although the Company believes that it has title to its oil and natural gas properties, it cannot control or completely protect itself against the risk of title disputes or challenges.

(c) Depletion - future development costs

For the purposes of calculating depletion, petroleum and natural gas properties in Turkey include estimated future development costs of $155,038 million (December 31, 2017 – $143.8 million) associated with development of the Company's proved plus probable reserves.

The ultimate recovery of property, plant and equipment and exploration and evaluation costs in Turkey is dependent upon the Company obtaining government approvals, obtaining and maintaining licences in good standing, the existence and commercial exploitation of petroleum and natural gas reserves and undeveloped lands, and other uncertainties.

8. Decommissioning Obligations

	December 31, 2018	December 31, 2017
Decommissioning obligations, beginning of year	$ 19,206	$ 8,132
Obligations incurred	864	122
Obligations settled	(531)	(270)
Change in estimates	(5,376)	3,464
Accretion of decommissioning obligations	2,890	1,779
TBNG Acquisition	-	8,206
Effects of movements in exchange rates	(1,232)	(2,227)
Decommissioning obligations, end of year	$ 15,821	$ 19,206

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and gathering systems. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years.

The following significant assumptions were used to estimate the decommissioning obligations:

	December 31, 2018	December 31, 2017
Undiscounted cash flows	$ 78,614	$ 83,348
Risk free rate – Turkey	15.8%	11.4%
Inflation rate – Turkey	20.3%	11.9%
Timing of cash flows	2-15 years	3-19 years

9. Revenue

The Company sells its production pursuant to fixed price sales contracts in the country of Turkey, in which natural gas prices for all of the Company's production 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 expected, as the gas sources are similar for both BOTAS and the EU. The Company is paid for its Turkish natural gas production in Turkish Lira. The BOTAS price is a reference price fixed by the Ministry of Energy and Natural Resources. Effective January 1, 2018, April 1, 2018, August 1, 2018, September 1, 2018 and October 1, 2018 the BOTAS reference price was increased by 14%, 10%, 14%, 14% and 18.5% respectively, mostly to offset the effects of the weakening TL.

Under the contracts, the Company is required to deliver a variable volume of natural gas to the contract counter party. Revenue is recognized when a unit of production is delivered to the contract counterparty. The amount of revenue recognized is based on the agreed transaction price, whereby any variability in revenue relates specifically to the Company's efforts to transfer production or the customer's demand for natural gas, and therefore the resulting revenue is allocated to the production delivered in the period during which the variability occurs. As a result, none of the variable revenue is considered constrained.

The Company's contracts have a term of one year or less, whereby delivery takes place throughout the contract period. Revenues are typically collected between the 12th and 25th day of the month following production.

The Company produces a small amount of crude oil that is sold on a spot basis as volumes warrant. Oil is delivered by truck to customers and revenue is recognized in the period in which the delivery occurs.

In addition to selling natural gas that the Company produces, the Company sells natural gas that it purchases from other producers in the area. This purchased natural gas is sold to the same customers, using the same contracts, through the same distribution network as natural gas the Company produces. The Company purchases natural gas from other producers under contracts that are typically one year or less in length at a discount of between 12.5% and 15% to the BOTAS price. These contracts require the Company to deliver the purchased natural gas to customers. The Company does not have the right, nor the ability, to store the purchased natural gas. Since the Company does not have the ability to influence the decision making process for the purchased natural gas volumes or the discretion to set prices, does not experience any inventory risk, does not perform any processing of the product and does not remit royalties to the Turkish government for the product, it considers itself an agent in these transactions. Revenue for this purchased gas is included net of purchase cost in Other income.

Interest and other revenue is comprised mainly of interest on cash in hand.

All of the Company's natural gas is sold in Turkey, in the Thrace Basin, which is the same area in which it is produced.

	December 31, 2018	December 31, 2017
Natural gas	$ 11,650	$ 14,431
Crude oil	319	215
Petroleum and natural gas sales	**$ 11,969**	**$ 14,646**

	December 31, 2018	December 31, 2017
Royalties – natural gas	$ 1,464	$ 1,793
Crude oil	32	24
Gross overriding royalty	116	154
Royalties	**$ 1,611**	**$ 1,971**

	December 31, 2018	December 31, 2017
Third party natural gas sales net of costs	$ 945	$ 902
Interest and other revenue	1,264	461
Other income	**$ 2,245**	**$ 1,363**

10. Income Taxes

A reconciliation of the expected tax expense to the actual provision for current and deferred taxes is as follows:

	December 31, 2018	December 31, 2017
Loss before taxes from operations	$ (6,202)	$ (10,803)
Combined federal and provincial tax rate	27.00%	27.00%
Expected income tax recovery	(1,675)	(2,917)
Non-taxable items and other	892	668
Foreign tax rate differential	97	(610)
Change in unrecognized deferred tax assets	1,090	440
Tax Amnesty Payment	514	-
Income tax expense (recovery)	$ 918	$ (2,419)

The deferred income tax rate applied to the temporary differences in 2018 was 27.0 percent (2017 – 27.0 percent). The Turkish tax rate for 2018 is 22% and 2017 is 20.0 percent.

In the third quarter of 2018, the Company elected to participate in a tax amnesty program offered by the Government of Turkey, which allowed companies to pay an amount based on a pre-determined formula to close tax assessments for certain years between 2013 and 2017. In deciding to participate in the program, the Company analyzed the costs and risks involved in current tax positions vs the potential financial burden that would be incurred by not participating in the program and then being unsuccessful in defending tax positions against multiple audits. The tax amnesty payment is included in current taxes along with current income taxes as indicated in the table above.

The components of the deferred tax liability are as follows:

	December 31, 2018	December 31, 2017
Property, plant and equipment and exploration and evaluation assets	$ (7,720)	$ (8,844)
Decommissioning obligations	3,445	3,827
Non-capital losses and other	63	515
Foreign Exchange	2,316	2,032
	$ (1,896)	$ (2,470)

The temporary differences that determine the unrecognized deferred tax assets are as follows:

	December 31, 2018	December 31, 2017
Property, plant and equipment and exploration and evaluation assets	$ 7,068	$ 7,296
Share issuance costs	(1,092)	(173)
Non-capital losses and other	59,436	52,415
Foreign Exchange	(1,419)	246
	$ 63,993	$ 59,785

The Company has tax assets of approximately $85.0 million at December 31, 2018 (2017 – $87.6 million) available for deduction against future taxable income. Cumulative non-capital loss carry-forwards in the amount of $59.5 million at December 31, 2018 (2017 - $55.2 million) expire between 2018 and 2037.

A continuity of the deferred income tax liability for 2017 and 2018 is detailed in the following tables:

Movement in temporary differences during the year	December 31, 2016	Recognized in profit or loss	Acquisition	Other comprehensive income (loss)	**December 31, 2017**
Property, plant and equipment and exploration and evaluation assets	$ (10,457)	$ 3,165	$ (2,919)	$ 1,366	**$ (8,845)**
Decommissioning obligations	1,566	2,607	-	(345)	**3,828**
Non-capital losses	2,742	(1,969)	-	(258)	**515**
Foreign exchange and other	1,264	987	-	(219)	**2,032**
	$ (4,885)	$ 4,790	$ (2,919)	$ 544	**$ (2,470)**

Movement in temporary differences during the year	December 31, 2017	Recognized in profit or loss	Other comprehensive income (loss)	**December 31, 2018**
Property, plant and equipment and exploration and evaluation assets	$ (8,845)	$ (1,076)	$ 2,201	**$ (7,720)**
Decommissioning obligations	3,828	613	(996)	**3,445**
Non-capital losses	515	(332)	(120)	**63**
Foreign exchange and other	2,032	714	(430)	**2,316**
	$ (2,470)	$ (81)	$ 655	**$ (1,896)**

Deferred income tax is a non-cash item relating to the temporary differences between the accounting and tax basis of Valeura's assets and liabilities and has no immediate impact on the Company's cash flows.

11. Administrative Expenses

The components of administrative expenses are as follows:

For the years ended	**December 31, 2018**	**December 31, 2017**
Cash:		
Salaries and benefits [1]	**$ 3,428**	**$ 3,352**
Other [2]	**4,400**	**3,540**
	7,828	**6,892**
Capitalized overhead and recoveries [3]	**(4,078)**	**(2,286)**
General and administrative	**3,750**	**4,606**
Non-cash:		
Share-based compensation	**1,572**	**514**
Capitalized share-based compensation [3]	**(58)**	**(44)**
Share-based compensation	**$ 1,514**	**$ 470**

(1) Includes salaries, benefits and bonuses earned by all Directors, Officers and employees of the Company.
(2) Includes costs such as rent, professional fees, insurance, travel, office, and other business expenses incurred by the Company.
(3) Includes a portion of salaries, benefits, share-based compensation and other G&A directly attributable to the exploration and development activities of the Company.

Compensation for Executive Officers and Directors are comprised of the following:

For the years ended	December 31, 2018	December 31, 2017
Salaries and benefits [1]	$ 1,939	$ 1,528
Share-based compensation [2]	1,207	372
Executive Officers and Directors compensation	$ 3,146	$ 1,900

[1] Includes salaries, benefits and bonuses earned by Executive Officers and Directors comprised of: Chairman of the Board, President and Chief Executive Officer, Vice President and Chief Financial Officer, Chief Operating Officer, Vice President of Engineering, Vice President, Commercial and other independent Directors.

[2] Represents the amortization of share-based compensation expense in the year associated with options granted to Executive Officers and Directors participating in the Company's Stock Option Plan.

12. Share Capital

(a) Authorized

Unlimited number of common shares
Unlimited number of preferred shares, issuable in series

(b) Per share amounts

Per share amounts have been calculated using the weighted average number of common shares outstanding. The weighted average number of common shares outstanding for the year ended December 31, 2018 is 83,658,687 (2017 – 70,943,951). As a result of the company incurring a net loss during each of the last two years, the average number of common shares outstanding was not increased for outstanding stock options and performance warrants as the effect would be anti-dilutive.

(c) Share Issuance

On February 8, 2018, 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 a bought deal basis 10,527,000 common shares of the Company at a price of $5.70 per common share, for total gross proceeds of approximately $60.0 million (the "Offering"). The Offering closed on March 1, 2018. Net proceeds were approximately $55.4 million after underwriters' fees of approximately $3.6 million and other expenses of $1.0 million.

(d) Stock options

Valeura has an option program that entitles officers, directors, and employees to purchase shares in the Company. Options are granted at the market price of the shares at the date of grant, have a 7 year term and vest over 3 years.
The number and weighted average exercise prices of share options are as follows:

	Number of Options	Weighted average exercise price
Balance, December 31, 2016	4,914,500	$ 0.72
Granted	1,750,000	0.74
Forfeited /Cancelled	(294,000)	0.60
Balance, December 31, 2017	6,370,500	$ 0.73
Granted	1,077,500	4.62
Exercised	(2,557,667)	0.75
Forfeited/cancelled	(291,666)	1.60
Balance, December 31, 2018	**4,598,667**	**$ 1.57**
Exercisable at December 31, 2017	**2,472,840**	**$ 0.70**

The following table summarizes information about the stock options outstanding at December 31, 2018:

Exercise prices	Outstanding at December 31, 2018	Weighted average remaining life (years)	Weighted average exercise price	Exercisable at December 31, 2018	Weighted average exercise price
$0.57 - $0.66	1,285,500	2.8	$ 0.60	1,285,500	$ 0.60
$0.67 - $0.74	816,667	5.0	0.72	336,670	0.72
$0.75 - $0.90	1,150,000	5.0	0.76	516,670	0.75
$0.91 - $4.62	1,346,500	5.0	3.71	334,000	1.00
	4,598,667	4.4	$ 1.57	2,472,840	$ 0.70

The fair value, at the grant date during the year, of the stock options issued was estimated using the Black-Scholes model with the following weighted average inputs:

Assumptions	**December 31, 2018**	**December 31, 2017**
Risk free interest rate (%)	**2.1**	**1.0**
Expected life (years)	**4.5**	**4.5**
Expected volatility (%)	**83.7**	**77.4**
Forfeiture rate (%)	**3.4**	**3.7**
Weighted average fair value of options granted	**$ 2.96**	**$ 0.45**

13. 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, 2018, the Company has issued letters of credit totaling US$0.04 million (December 31, 2017 – 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.

14. Supplemental Cash Flow Information

	December 31, 2018	December 31, 2017
Change in non-cash working capital:		
Accounts receivable	**$ (5,190)**	$ 549
Prepaid expenses and deposits	**(709)**	84
Inventory	**56**	582
Deposits (non-current)	**36**	758
Accounts payable and accrued liabilities	**1,016**	9,104
TBNG Acquisition	**-**	(2,226)
Movements in exchange rates	**(1,632)**	2,232
	(6,423)	11,083

The change in non-cash working capital has been allocated to the following activities:

Operating	**(3,708)**	5,329
Investing	**(2,715)**	5,754
	$ (6,423)	$ 11,083

15. Financial Risk Management

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities such as:

- Credit risk
- Market risk
- Liquidity risk

This note presents information about the Company's exposure to each of the above risks, the Company's objectives, policies and processes for measuring and managing risk, and the Company's management of capital. Further quantitative disclosures are included throughout the consolidated financial statements.

The Board of Directors oversees managements' establishment and execution of the Company's risk management framework. Management has implemented and monitors compliance with risk management policies. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

(a) Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from joint venture partners and oil and natural gas marketers. The maximum exposure to credit risk at year-end is as follows:

	December 31, 2018	December 31, 2017
Joint venture receivable from Equinor	$ 3,486	$ -
Joint venture receivable from other partners	313	195
Revenue receivables from customers	3,485	2,828
Taxes receivable	1,958	1,029
Accounts receivable	$ 9,242	$ 4,052

Trade and other receivables:

Substantially all of the Company's petroleum and natural gas production is marketed under standard industry terms that are specific by country. The Company's policy to mitigate credit risk associated with the balances is to establish marketing relationships with credit worthy purchasers. The Company historically has not experienced any collection issues with its petroleum and natural gas marketers. Joint venture receivables are typically collected within one to three months of the joint venture invoice being issued to the partner. The Company attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures.

Receivables from participants in the petroleum and natural gas sector, and collection of the outstanding balances can be impacted by industry factors such as commodity price fluctuations, limited capital availability and unsuccessful drilling programs. The Company does not typically obtain collateral from petroleum and natural gas marketers or joint venture partners; however the Company can cash call for major projects and does have the ability, in most cases, to withhold production from joint venture partners in the event of non-payment, or withhold accounts payable remittances.

(b) Market risk

Market risk is the risk that changes in market conditions, such as commodity prices, foreign exchange rates and interest rates will affect the Company's income or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while maximizing the Company's return.

Foreign currency exchange rate risk:

Foreign currency exchange rate risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. World oil prices are quoted in US Dollars and the price received by the Company's Turkish branches can be affected by the Turkish Lira (TL)/United States Dollar (USD) exchange rate, which fluctuates over time. 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) exchange rate. A decrease in the value of the Turkish Lira against the Canadian Dollar will result in a decrease in revenue and a decrease in operating costs in the Company's consolidated financial statements. Correspondingly, an increase in the value of the Turkish Lira against the Canadian Dollar will result in an increase in revenue and an increase in operating costs.

The Company's seismic and drilling operations and related contracts in Turkey are partially based in US Dollars. Material increases in the value of the US Dollar against the Turkish Lira or Canadian Dollar will negatively impact the Company's costs of drilling and completions activities. Future CAD/USD and CAD/TL exchange rates could accordingly 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 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.

Changes to the TL/CAD exchange rate would have had the following impact on revenues, royalties and production costs for the year ended December 31, 2018:

+/- 1 percent change in realized TL/CAD exchange rate	Petroleum and natural gas revenues	Royalties	Production costs
Year ended December 31, 2018	$ 120	$ 16	$ 37

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, 2018:

+/- 1 percent change in realized TL/USD exchange rate, upon conversion to presentation currency	Capital expenditures
Year ended December 31, 2018	$ 320

Interest rate risk:

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is not currently exposed to interest rate risk as it has no debt.

Commodity price risk:

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by the relationship between the Canadian Dollar and Turkish Lira, the Canadian Dollar and United States Dollar, global economic events and Turkish government policies.

The natural gas reference price in Turkey is in part correlated to contract prices for natural gas imports into Turkey and also government policy with respect to subsidies to consumers. Natural gas sales for Valeura are under direct sales contracts to industrial buyers and power generation companies in the area and each contract is at a negotiated discount or premium to the BOTAS benchmark price.

The government has continued to increase the BOTAS reference price thereby offsetting the decline in the value of the TL and the increase in regional gas prices. Effective January 1, 2018, April 1, 2018, August 1, 2018, September 1, 2018 and October 1, 2018 the price was increased by 14%, 10%, 14%, 14% and 18.5% respectively. The Company's average realized natural gas price in Turkey for 2018 was $7.54 per Mcf, which represents a 1% discount to the BOTAS price.

Liquidity risk:

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with the financial liabilities. The Company's financial liabilities consist of accounts payable. Accounts payable consists of invoices payable to trade suppliers for office, field operating activities and capital expenditures. The Company processes invoices within a normal payment period. Accounts payable have contractual maturities of less than one year. The Company maintains and monitors a certain level of cash which is used to finance all operating and capital expenditures.

Capital management:

The Company's objective when managing capital 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.

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 currently 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 Equinor (name changed from Statoil in May 2018) elects to complete Phase 3 under the Banarli Farm-in and thereby earns a 50 percent working interest in the deep rights at Banarli. Phase 3 of the Banarli Farm-in can be completed by the drilling and testing of the Inanli-1, which spud on October 8, 2018 and completed drilling in January 2019. Planning of the completion and testing program will be complete during March 2019, and are anticipated to begin in Q2 2019. Once drilling and testing of Inanli-1 is complete, Equinor 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 more extensive pilot project, for which the Company would have to contribute its 50 percent participating interest. In Q1, 2018, the Company received net proceeds of $55.4 million in an equity offering. The company has working capital of $59.5 million at December 31, 2018 in order to meet commitments of the current capital program. If a more significant program is proposed, the Company will be required to assess alternatives including the availability of equity and debt capital to fund the program.

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, lower production volumes and associated revenues or default under the Company's joint operating agreements. Valeura has not utilized bank loans or debt capital to finance capital expenditures to date.