**ANNUAL INFORMATION FORM**

**For the Year Ended December 31, 2018**

**Dated March 13, 2019**

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## ABBREVIATIONS AND CONVERSION

In this Annual Information Form, the following abbreviations have the meanings set forth below.

| **Oil and Natural Gas Liquids** | | **Natural Gas** | |
|---|---|---|---|
| bbl | barrel | Mcf | thousand cubic feet |
| Mbbl | thousand barrels | MMcf | million cubic feet |
| bbl/d | barrel per day | Mcf/d | thousand cubic feet per day |
| NGLs | natural gas liquids | 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. |
| $ | 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 |

## DEFINITIONS

In this Annual Information Form, the following words and phrases have the meanings set forth below, unless otherwise indicated.

"**2016 Offering**" has the meaning set forth under the heading "*General Development of the Business – Three Year History*".

"**2018 Offering**" has the meaning set forth under the heading "*General Development of the Business – Three Year History*".

"**abandonment and reclamation costs**" means all costs associated with the process of restoring a reporting issuer's property that has been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities.

"**ABCA**" means the *Business Corporations Act* (Alberta), together with any or all regulations promulgated thereunder, as amended from time to time.

"**Banarli Farm-in**" has the meaning set forth under the heading "*General Development of the Business – Three Year History*".

"**Banarli Lands**" means, collectively, the lands comprising the Banarli Licences.

"**Banarli Licences**" or "**Banarli Exploration Licences**" mean, collectively, the two Banarli licences described under the heading "*Description of the Business and Operations – Land Holdings*".

"**BCGA**" means basin-centered gas accumulation.

"**Board**" means the board of directors of Valeura.

"**BOTAS Reference Price**" has the meaning set forth under the heading "*Description of the Business and Operations – Petroleum Sales*".

"**COGE Handbook**" means the 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 Shares**" means the common shares in the capital of the Company.

"**Company**" or "**Valeura**" means Valeura Energy Inc. and, where applicable, includes its subsidiaries and affiliates.

"**CRBV**" means Corporate Resources B.V., a wholly-owned affiliate of Valeura.

"**crude oil**" or "**oil**" as described in the COGE Handbook means a mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons but does not include liquids obtained from the processing of natural gas.

"**D&M**" means DeGolyer and MacNaughton, independent petroleum engineering consultants.

"**D&M Reserves Report**" means the independent engineering evaluation of the oil and natural gas reserves attributable to the properties of Valeura in Turkey prepared by D&M with a preparation date of March 13, 2019 and effective December 31, 2018.

"**D&M Resources Report**" means the independent engineering evaluation of the unconventional prospective resources attributable to the properties of Valeura in the Thrace Basin prepared by D&M with a preparation date of March 13, 2019 and effective December 31, 2018.

"**Definitive Agreements**" has the meaning set forth under the heading "*General Development of the Business – Three Year History*".

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying and acquiring well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

"**development well**" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"**Edirne Leases**" means, collectively, the three production leases described under the heading "*Description of the Business and Operations – Licence Term and Commitments*".

"**Equinor**" means Equinor Turkey B.V., a wholly-owned affiliate of Equinor ASA.

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

"**exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well.

"**frack**" means hydraulic fracturing whereby fractures are propagated in an underground rock layer by injecting fluids, typically mixtures of sand and water, under high pressures.

"**field**" means a defined geographical area consisting of one or more hydrocarbon pools.

"**forecast prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future;

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

"**forward-looking statements**" has the meaning set forth under the heading "*Forward-Looking Statements*".

"**future net revenue**" means a forecast of revenue, estimated using forecast prices and costs or constant prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs and abandonment and reclamation costs.

"**GDMPA**" means the Republic of Turkey's General Directorate of Mining and Petroleum Affairs.

"**gross**" means:

(a) in relation to the Company's interest in production or reserves, its "company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company;

(b) in relation to wells, the total number of wells in which the Company has an interest; and

(c) in relation to properties, the total area of properties in which the Company has an interest.

"**ICFR**" has the meaning set forth under the heading "*Risk Factors – Internal Controls Over Financial Reporting*".

"**MENR**" means the Republic of Turkey's Ministry of Energy and Natural Resources.

"**natural gas**" means a naturally occurring mixture of hydrocarbon gases and other gases.

"**natural gas liquids**" or "**NGLs**" means those hydrocarbon components that can be recovered from natural gas as a liquid including, but not limited to, ethane, propane, butanes, pentanes plus, and condensates.

"**Natural Gas Market Law**" has the meaning set forth under the heading "*Industry Conditions – Turkish Petroleum Law Regime – Marketing*".

"**net**" means:

(a) in relation to the Company's interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves;

(b) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and

(c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

"**New Petroleum Law**" means Turkey's Petroleum Law No. 6491 adopted in 2013 which replaced the Old Petroleum Law.

"**NI 51-101**" means National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities*.

"**Old Petroleum Law**" means Turkey's Petroleum Law No. 6326 adopted in 1954 which was replaced by the New Petroleum Law.

"**operating costs**" or "**production costs**" means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

"**Option**" means an option to acquire a Common Share pursuant to the Stock Option Plan.

"**Preferred Shares**" has the meaning set forth under the heading "*Description of Capital Structure*".

"**production**" means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

"**property**" includes:

(a) fee ownership or a lease, concession, agreement, permit, licence or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;

(b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and

(c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

"**property acquisition costs**" means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:

(a) costs of lease bonuses and options to purchase or lease a property;

(b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee; and

(c) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

"**proved property**" means a property or part of a property to which reserves have been specifically attributed.

"**PTI**" means Pinnacle Turkey, Inc.

"**reservoir**" as described in the COGE Handbook means a subsurface rock unit that contains an accumulation of petroleum.

"**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

"**Shareholders**" means the holders of Common Shares and "**Shareholder**" means any one of them.

"**solution gas**" means gas dissolved in crude oil.

"**South Thrace Lands**" means, collectively, the lands comprising the South Thrace Production Leases.

"**South Thrace Production Leases**" means, collectively, the 11 South Thrace production leases described under the heading "*Description of the Business and Operations – Licence Term and Commitments*".

"**Stock Option Plan**" means the stock option plan of the Company.

"**stratigraphic test well**" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as:

(a) "exploratory type" if not drilled into a proved property; or

(b) "development type", if drilled into a proved property. Development type stratigraphic wells are also referred to as "evaluation wells".

"**Subsequent Deep Rights Sale Agreement**" has the meaning set forth under the heading "*General Development of the Business – Three Year History*".

"**support equipment and facilities**" means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

"**TBNG**" means 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**" has the meaning set forth under the heading "*General Development of the Business-Three Year History*".

"**TBNG JV**" means the joint venture formed between CRBV, TBNG and PTI.

"**TBNG JV Lands**" has the meaning set forth under the heading "*General Development of the Business – Land Holdings*"

"**Thrace Basin**" means an area of land in the northwest region of Turkey, located west of Istanbul and extending to the Greek and Bulgarian borders.

"**TPAO**" means Türkiye Petrolleri Anonim Ortaklığı, the Turkish state oil and gas company.

"**TransAtlantic**" means TransAtlantic Petroleum Ltd.

"**TSX**" means the Toronto Stock Exchange.

"**TWL**" means TransAtlantic Worldwide, Ltd., a wholly-owned affiliate of TransAtlantic.

"**U.S.**" or "**United States**" means the United States of America, its territories and possessions, any state of the United States, and the District of Columbia.

"**VENBV**" means Valeura Energy (Netherlands) B.V., a wholly-owned affiliate of Valeura.

"**well abandonment costs**" means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. These costs do not include costs of abandoning the gathering system or reclaiming the wellsite.

"**West Thrace Deep Rights Sale**" has the meaning set forth under the heading "*General Development of the Business – Three Year History*".

"**West Thrace Lands**" means, collectively, the lands comprising the West Thrace Licences and the West Thrace Production Leases.

"**West Thrace Licence**" or "**West Thrace Exploration Licence**" means, the one West Thrace license described under the heading "*Description of the Business and Operations – Licence Term and Commitments*".

"**West Thrace Production Leases**" means, collectively, the three West Thrace production leases described under the heading "*Description of the Business and Operations – Licence Term and Commitments*".

## PRESENTATION OF RESERVES AND RESOURCES INFORMATION

All oil and natural gas reserves and resources information contained in this Annual Information Form has been prepared and presented in accordance with NI 51-101 and the COGE Handbook. The reserves and prospective resource estimates provided in this Annual Information Form are estimates only. Actual reserves and prospective resources and future production from such reserves and resources may be greater than or less than the estimates provided herein.

Numbers in the reserves and resources tables and other oil and gas information contained in this Annual Information Form may not add due to rounding.

### Definitions

With respect to the reserves and resources data contained herein, the following terms have the meanings indicated:

"**best estimate**" or "**P50**" means there is a 50% chance that the estimated quantity will be equaled or exceeded.

"**chance of commerciality**" is defined as the product of the chance of discovery and the chance of development.

"**chance of development**" is the estimated probability that, once discovered, a known accumulation will be commercially developed.

"**chance of discovery**" is the estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum.

"**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 a well) to put the reserves on production.

"**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 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.

"**high estimate**" or "**P10**" means there is a 1% chance that the estimated quantity will be equaled or exceeded.

"**low estimate**" or "**P90**" means there is a 90% chance that the estimated quantity will be equaled or exceeded.

"**mean estimate**" is the probability-weighted average (expected value).

"**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% 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.

"**prospective resources**" are those 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 both an associated chance of discovery and a chance of development.

"**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.

"**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: (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**" are 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.

"**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 a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

**Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.**

**Use of Unrisked Estimates**

The unrisked estimates of prospective resources referred to in this Annual Information Form have not been risked for either the chance of discovery or the chance of development. There is no certainty that any portion of the prospective resources will be discovered. See "*APPENDIX* A-2 – *Prospective Resources Data*" for details regarding risked estimates. 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 Annual Information Form 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% and 75%, 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.

## FORWARD-LOOKING STATEMENTS

Certain information contained in this Annual Information Form constitutes forward-looking statements and forward-looking information (collectively, "**forward-looking statements**") under applicable securities legislation. Such forward-looking statements are included for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such forward-looking statements may not be appropriate for other purposes, such as making investment decisions. Forward-looking statements typically include words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "target", "goal", "propose", "project" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this Annual Information Form include, but are not limited to, statements with respect to:

- management's belief regarding the potential of Valeura's BCGA play and shallow gas business in the Thrace Basin;
- the potential of a BCGA play in the Thrace Basin;
- Valeura's reserves and prospective resources in the Thrace Basin;
- the anticipated delineation drilling and development programme to exploit the BCGA play on Valeura's working interest lands;
- completion of Phase 3 of the Banarli Farm-in and completion of the second earning well to be funded by Equinor;

- the plans, timing and cost to complete and test the Inanli-1 well;
- the plans, timing and cost to drill, complete and test the Devepinar-1 well;
- the ability to target sweet spots in the BCGA prospect and the extent of the prospect;
- the ability of the Yamalik-1 well to achieve commercial gas sales;
- the anticipated capital spending programme that underpins Valeura's current probable and possible reserves;
- the capacity of Valeura's existing infrastructure in the Thrace Basin and future needs should future production volumes exceed the capacity of Valeura's existing infrastructure;
- Valeura's commitment to safety and optimising operational and administrative functions;
- Valeura's business strategy and outlook;
- the ability to execute and agree with partners on work programmes (and the nature and extent of such work programmes) and budgets, which are subject to change based on, amongst other things, the actual results of drilling and related activity, the availability of equipment and service providers, unexpected delays and changes in market conditions;
- the ability to obtain approvals and permits for drilling programmess or high pressure stimulation programmes
- the ability to finance future developments;
- tying-in other new wells and getting these on-stream;
- results of future seismic programmes;
- future production rates and associated cash flow;
- continued operations of and approvals forthcoming from the GDMPA in a manner consistent with past conduct;
- future economic conditions;
- future currency and exchange rates;
- the Company's continued ability to obtain and retain qualified staff, and equipment and services in a timely and cost efficient manner;
- technical decision making;
- the ability to obtain necessary government and stock exchange approvals;
- volume and product mix of Valeura's natural gas and oil production;
- the amount and timing of future asset retirement obligations;

- future liquidity, creditworthiness and financial capacity;
- future interest rates;
- future exploration, development and other expenditures; and
- future costs, expenses and royalty rates.

Statements related to “reserves” or “prospective resources” are deemed to be forward-looking information as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and prospective resources can be profitably produced in the future. Specifically, forward-looking information contained herein regarding “reserves” and “prospective resources” may include:

- estimated volumes and value of Valeura’s oil and natural gas reserves;
- estimated volumes of Valeura’s prospective resources; and
- the ability to finance future developments.

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. In addition to other factors and assumptions which may be identified in this Annual Information Form, assumptions have been made regarding and are implicit in, among other things:

- the ability of the Company to execute its strategy;
- political stability of the areas in which Valeura is operating and completing transactions;
- the ability of the Company to satisfy the drilling and other requirements under its licences and leases;
- the ability of the Company to replace and expand oil and natural gas reserves through exploration, exploitation, development and acquisition;
- continued operations of and approvals forthcoming from the Turkish government in a manner consistent with past conduct;
- future seismic and drilling activity on the expected timelines;
- the prospectivity of the TBNG JV Lands and Banarli Licences, including the BCGA potential;
- the continued favourable pricing and operating netbacks in Turkey;
- future production rates and associated operating netbacks and cash flow;
- the ability to reach agreement with partners;
- the ability of the Company to successfully manage the political and economic risks inherent in pursuing oil and gas opportunities in Turkey;
- field production rates and decline rates;

- the ability of the Company to secure adequate product transportation;
- the impact of increasing competition in or near the Company's plays;
- the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner to develop its business and execute work programmes;
- the Company's ability to operate the properties in a safe, environmentally responsible, efficient and effective manner;
- the timing and costs of pipeline, storage and facility construction and expansion;
- future oil and natural gas prices;
- currency, exchange and interest rates;
- the regulatory framework regarding royalties, taxes and environmental matters;
- the ability of the Company to successfully market its oil and natural gas products;
- the ability to successfully manage the political and economic risks inherent in pursuing oil and gas opportunities in foreign countries;
- the state of the capital markets; and
- the ability of the Company to obtain financing on acceptable terms.

Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions which have been used.

In addition, Valeura's work programmes and budgets are in part based upon expected agreement among joint venture partners and associated exploration, development and marketing plans and anticipated costs and sales prices, which are subject to change based on, among other things, the actual results of drilling and related activity, availability of drilling, fracking and other specialised oilfield equipment and service providers, changes in partners' plans and unexpected delays and changes in market conditions. Although Valeura believes the expectations and assumptions reflected in such forward-looking information are reasonable, they may prove to be incorrect.

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. A number of factors could cause actual results to differ materially from those anticipated by the Company including, but not limited to:

- the risks associated with the oil and gas industry (e.g. operational risks in exploration, inherent uncertainties in interpreting geological data, and changes in plans with respect to exploration or capital expenditures, the uncertainty of estimates and projections in relation to costs and expenses, and health, safety and environmental risks);
- uncertainty regarding the contemplated timelines for the completion and testing of the Inanli-1 well and drilling, completing and testing the Devepinar-1 well;
- completion of the Banarli Farm-in programme and BCGA delineation drilling programme;
- uncertainty regarding the sustainability of initial production rates and decline rates thereafter;

- uncertainty regarding the ability to address technical drilling challenges and manage water production;
- uncertainty regarding the state of capital markets and the availability of future financings;
- the risk of being unable to meet drilling deadlines and the requirements under licences and leases;
- uncertainty regarding the availability of drilling rigs and associated equipment on the contemplated timelines for shallow and deep drilling programmes;
- the risks of disruption to operations and access to worksites, threats to security and safety of personnel and potential property damage related to political issues, terrorist attacks, insurgencies or civil unrest;
- the risks of increased costs and delays in timing related to protecting the safety and security of Valeura's personnel and property;
- political stability in Turkey, including potential changes in political leaders or parties or a resurgence of a coup or other political turmoil;
- the risk of changing commodity prices and BOTAS Reference Prices (priced in TL);
- the risk of foreign exchange rate fluctuations, particularly the TL;
- the uncertainty associated with negotiating with third parties in Turkey;
- the risk of partners having different views on work programmes and potential disputes among partners;
- counterparty risks;
- the uncertainty regarding government and other approvals (potential changes in laws and regulations);
- the risks associated with weather delays and natural disasters; and
- the risk associated with international activity.

The forward-looking statements contained herein are expressly qualified by this cautionary statement.

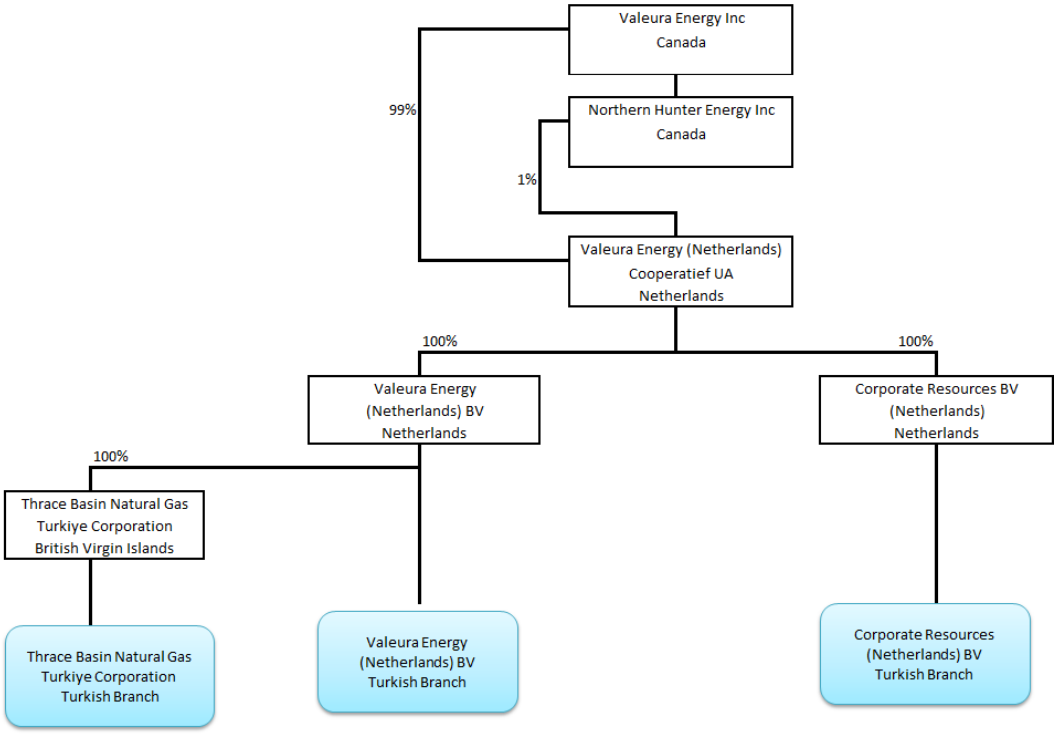
The forward-looking statements contained herein are made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking statement, whether as a result of new information, future events or otherwise, unless required by applicable securities laws.

**VALEURA ENERGY INC.**

Valeura and its subsidiaries are currently engaged in the exploration, development and production of oil and natural gas in Turkey. Valeura's operations are focused on the Thrace Basin in the northwest of Turkey. The Common Shares are listed and posted for trading on the TSX under the symbol VLE. 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. Valeura was incorporated under the ABCA.

**Inter-Corporate Relationships**

The following diagram describes the inter-corporate relationships among the Company and each of its subsidiaries as at December 31, 2018:




## GENERAL DEVELOPMENT OF THE BUSINESS

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 0.46 million gross acres (0.37 million net acres of shallow rights and 0.26 million net acres of deep rights).

The Thrace Basin assets include an 81.5% working interest in the shallow rights and deep rights of 11 production leases in the South Thrace Lands; an 81.5% (shallow rights) working interest and 31.5% (deep rights) working interest in three production leases and one exploration licences in the West Thrace Lands; and a 100% (shallow rights) and a 50% (deep rights) working interest in the Banarli Licences. In addition, Valeura holds a 35% working interest in three other production leases (Edirne, Turkey) that currently do not have active operations. See "*Description of the Business and Operations – Land Holdings*".

TBNG has been producing natural gas from shallow, conventional and tight reservoirs for several decades. More than 99% of Valeura's current production is natural gas from these reservoirs. Management believes the Thrace Basin lands have potential for continued exploration and development of gas from these conventional and tight gas reservoirs. Valeura continues to work on its shallow gas development programme associated with the proved plus probable reserves disclosed herein.

The Company is pursuing shallow conventional, normally pressured natural gas and deep unconventional tight gas. This upstream programme 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 fracking to develop tight, but normally pressured gas resources from the slightly deeper Mezardre, Teslimkoy and Kesan Formations.

Many of the Company's lands are believed by management to have potential for a deep, unconventional basin-centered gas accumulation play ("**BCGA**") 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 fracking. By applying 3D seismic, modern fracture stimulation technology and horizontal drilling, Valeura is aiming to demonstrate that commercial operations from this tight gas resource are possible. For this deep appraisal, Valeura has partnered with Equinor as a large, well-respected partner which provides further technical and financial capacity.

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 Licences, which proved the presence of a BCGA concept in the area of the well.

Building on its 2018 efforts, in 2019 the Company is undertaking an appraisal campaign for the deep BCGA play discovered with Yamalik-1 to demonstrate whether the deep gas is pervasive across the basin and to demonstrate that it can flow commercially. Further description can be found under the heading "*Description of the Business and Operations – Operations – BCGA Play"*.

**Three Year History**

The following describes the development of Valeura's business over the last three completed financial years.

***2016***

Operations in 2016 were focused the Company's Banarli Lands. In the first quarter of 2016, the Bati Gurgen-1 gas discovery well was tied into the TBNG JV gas gathering system and commenced production. This was followed in Q2 2016 with the Bati Gurgen-2 gas discovery which was also then immediately tied into the TBNG JV gas gathering system. To progress understanding of the potential BCGA play, two small fracks were carried out on the Yayli-1 well in tight, over-pressured sands near the base of the well at 2,700 to 2,900 metres, each of which achieved initial gas flow, but flow could not be sustained. By demonstrating that some gas would flow, the Yayli-1 well provided important information on the BCGA play.

Valeura completed a number of commercial transactions in the latter half of 2016 which would allow it to increase its interests in many of its lands, increase its reserves and production, assume operatorship of the majority of its lands, and bring in Equinor as a partner to explore for the BCGA play in the deep. The majority of these deals were agreed in 2016 and then closed in Q1 2017.

- On August 19, 2016, Valeura announced that CRBV had entered into definitive transaction documents (the "**Definitive Agreements**") with Equinor for a farm-in agreement for the exploration of the deeper formations below approximately 2,500 metres on the Banarli Licences (the "**Banarli Farm-in**"). The Definitive Agreements included a farm-in agreement, a joint operating agreement to apply post-earning and a number of ancillary agreements. Under the terms of the Definitive Agreements, Equinor was granted the option to earn a 50% participating interest in the deep formations on the Banarli Licences by investing in an exploration programme that includes cash payment and full funding of two deep exploration wells and 3D seismic costs. See "*Description of the Business and Operations – Land Holdings*".

- On October 13, 2016 Valeura announced that CRBV had entered into a sale and purchase agreement with Equinor to sell CRBV's 40% participating interest in the deep formations below approximately 2,500 metres depth on the West Thrace Lands for cash consideration of US$12 million (the "**West Thrace Deep Rights Sale**").

- On October 13, 2016 Valeura announced that VENBV had entered into a share purchase agreement with TransAtlantic to acquire 100% of the shares of TBNG for US$20.7 million (CAD$27.1 million) (the "**TBNG Acquisition**")

On November 3, 2016, Valeura announced the closing of a private placement offering of subscription receipts at a price of $0.75 per subscription receipt for gross proceeds of approximately $10.9 million (the "**2016 Offering**"). The subscription receipts were sold through a syndicate of underwriters led by Cormark Securities Inc. and including GMP FirstEnergy.

***2017***

In Q1 2017 the Company announced the closing of a several deals that were agreed in 2016. On January 6, 2017, Valeura announced the closing of the Banarli Farm-in and the West Thrace Deep Rights Sale and received US$18 million in back costs and purchase price. On February 24, 2017, Valeura announced the closing of TBNG Acquisition

On June 22, 2017, Valeura announced the closing of the sale to Equinor of a further 10% participating interest in the deep formations below approximately 2,500 metres depth on the West Thrace Lands for cash consideration of US$3 million pursuant to the sale and purchase agreement dated March 10, 2017 between TBNG and Equinor (the "**Subsequent Deep Rights Sale Agreement**").

In Q3 2017, Valeura completed approximately 500 square kilometres of 3D seismic, and on July 24, 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. See "*Description of the Business and Operations – Operations - BCGA Play*" for further technical information.

During 2017, Valeura drilled 6 wells as part of its shallow exploration and development program. Four exploration and one development well were drilled on the TBNG JV Lands. The development well and two exploration wells were successful and tied in for production. One well was dry and one well was suspended. One well was drilled on the Banarli Lands and was suspended. Valeura also performed 35 workovers and extensive work on facility repair and maintenance upon taking over operatorship of the TBNG JV Lands.

***2018***

On January 2, 2018 Valeura completed the CEO succession plan and Mr.Sean Guest succeeded Mr. Jim McFarland as CEO and on January 12, 2018 Valeura announced Board changes including the retirement of Mr. William T. Fanagan and Mr. Claudio A. Ghersinich, the appointment of Russell Hiscock to the Board and the succession of Tim Marchant to Chair of the Board.

On February 6, 2018 Valeura announced the summary results of an independent evaluation of the prospective resources attributable to the properties of Valeura in the Thrace Basin, prepared by D&M, dated December 31, 2017. 10.1 Tcf of estimated working interest unrisked mean prospective resources of natural gas, which includes 236 MMbbl of condensate were assigned by D&M. This equates to 5.2 Tcf of estimated working interest risked mean prospective resources of natural gas which includes 165 MMbbl of condensate.

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 at a price of $5.70 per Common Share, for total proceeds of approximately $60.0 million (the "**2018**

**Offering**"). The 2018 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.

In Q2 2018, Valeura drilled one shallow conventional gas well on one of the West Thrace Production Leases, which was successful and tied in to production infrastructure, and satisfied a license requirement. The Company also performed a number of workovers, two re-entry high pressure stimulations, and some abandonment and reclamation activities.

Operations resumed at Yamalik-1 in August 2018 following the tie-in of the well to the gathering system The well was recompleted for production purposes during August and September and produced gas during Q4 2018 as part of a long-term production test.

On October 8, 2018, the Inanli-1 appraisal well was spudded. The well reached final total depth of 4,885 metres on January 28, 2019. See "*Description of the Business and Operations – Operations - BCGA Play*" for further technical information.

The government continued to increase the BOTAS Reference Price during 2018 thereby offsetting the decline in the value of the TL and tracking 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 average BOTAS Reference Price for 2018 was $7.07/Mcf, and the average price for Q4 2018 was $9.18/Mcf.

## DESCRIPTION OF THE BUSINESS AND OPERATIONS

Valeura is a Canada-based public company currently engaged in the exploration, development and production of oil and natural gas in the Thrace Basin of northwest Turkey.

### Corporate 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 who is a large, internationally respected partner that provides further technical and financial capacity.

Valeura is currently focused on two key objectives:

1. further delineation and commercial demonstration of the unconventional BCGA play discovered by the Yamalik-1 well in 2017; and

2. 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 whether over-pressured gas is pervasive across the Thrace Basin lands and to show that commercial flow rates can be achieved. Management believes 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.

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.

**Personnel**

As at December 31, 2018, Valeura had eight full-time employees in its head office in Calgary, as well as 14 full-time employees in its office in Ankara, Turkey and 60 employees at its field office in Tekirdag, Turkey.

**Land Holdings**

The following table and figure below set forth Valeura's land holdings as at December 31, 2018:

| | | 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 Licenses[1] | Operated | 2 | 133,840 | 100.0% | 133,840 | 50.0% | 66,920 |
| West Thrace Exploration Licenses | 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.

The Company'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 Company holds 11 production leases encompassing 170,735 gross acres. Valeura is the operator of the South Thrace Lands and holds an 81.5% 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%) and CRBV (as to 40%), and PTI holds the other 18.5% working interest. There is no work programme obligation to the government.

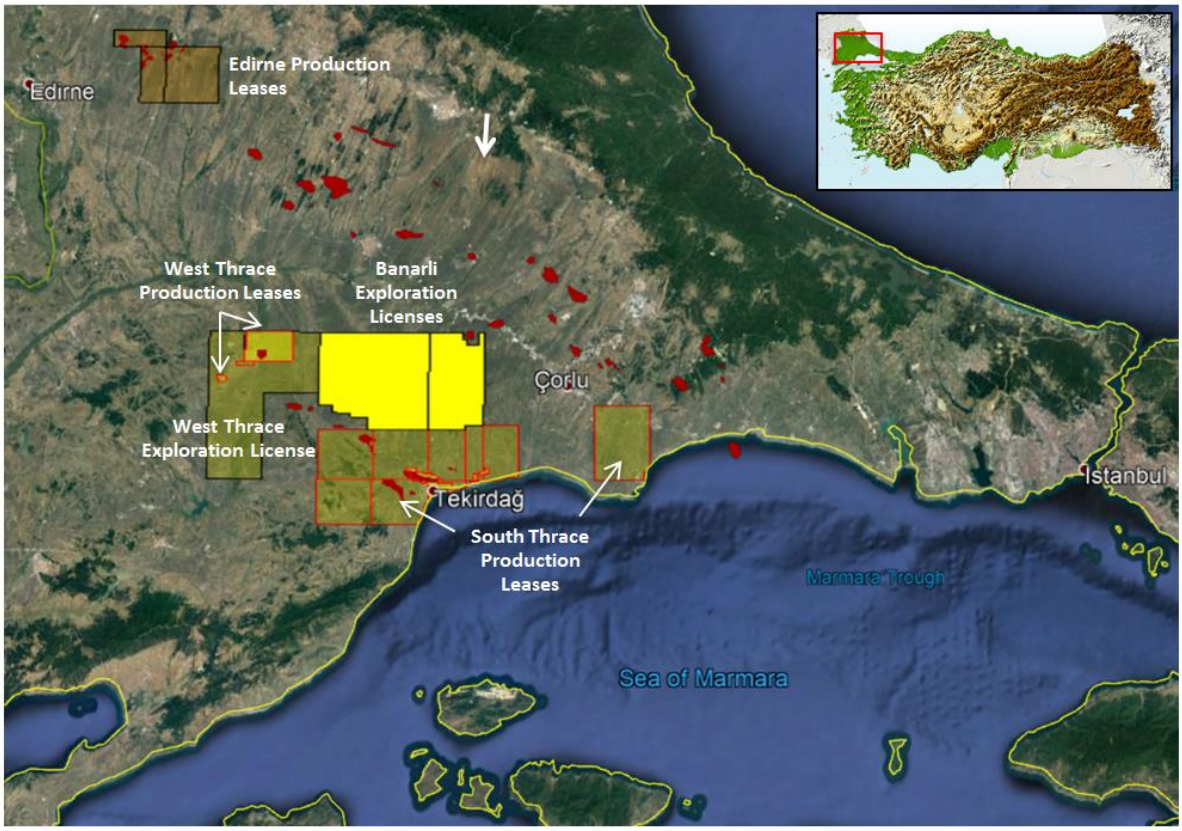
In the West Thrace Lands, the Company holds three production leases and one exploration licence encompassing 102,012 gross acres. The Company's 31.5% working interest in deep rights is held by TBNG, and the Company's 81.5% working interest in shallow rights is jointly held by TBNG (as to 41.5%) and CRBV (as to 40%). Equinor (as to 50%) and PTI (as to 18.5%) hold the remaining working interest in the deep rights, and PTI holds the remaining 18.5% working interest in the shallow rights. Valeura is the operator of the West Thrace Lands which are subject to joint operating agreements. The West Thrace Exploration Licence has a two well commitment to fulfill the work programme obligation which must be completed by June 26, 2020.

The Company holds two exploration licences in the Banarli Lands encompassing 133,840 gross acres. The Company holds a 100% working interest in the shallow rights and 50% working interest in the deep rights through CRBV. Equinor holds the other 50% working interest in the deep rights. Rights are subject to joint operating agreements and the Banarli Farm-In and Valeura is currently the operator. The seismic and drilling work programme obligation to the government has been completed, except for geological and geophysical studies.

Equinor has a 50% working interest in the deep rights under the Banarli Farm-in which requires Equinor to fully fund: (1) the drilling and testing of the Yamalik-1 well; (2) the acquisition and processing of the Karaca 3D seismic programme; 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% 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 2,500 metres depth, whichever is shallower. Valeura remains operator of the deep exploration programme on both the Banarli Licences and West Thrace Lands during Equinor's earning phase on Banarli. Equinor will have the option to request operatorship of the deep programme once it has fully earned. Additionally, under the Banarli Farm-in Equinor has no pre-emptive right related to Valeura's 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 Company's wholly-owned subsidiary, VENBV, holds a 35% 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% working interest. These leases currently do not have active operations or production.



**Licence Term and Commitments**

The following table sets forth the current expiration dates for Valeura's leases and licences.

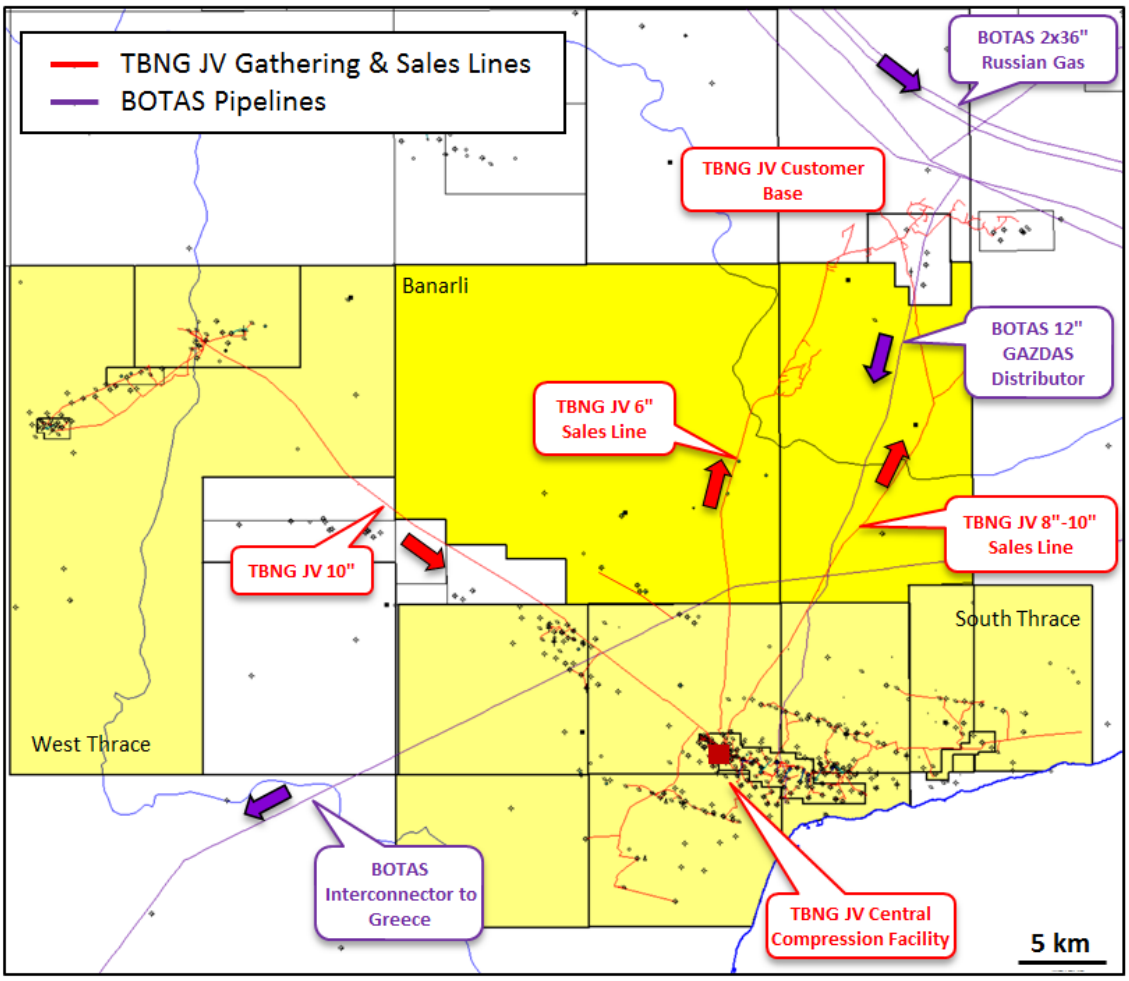
| Valeura Working Interest Lands | Block | Operated | Working Interest | | Gross Acres | Phase | Expiry of Current Phase |
|---|---|---|---|---|---|---|---|
| | | | Shallow | Deep | | | |
| **South Thrace Production Leases** | 3860 | Yes | 81.5% | | 3,457 | Initial Production | 02-Dec-21 |
| | 3861 | 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,d2 | 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 |

**Petroleum Sales**

The Company has 81.5% ownership of, and operates, its own natural gas gathering grid and export lines. Natural gas is delivered directly to more than 55 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%, but in Q4 2018 the Company's realised price was approximately 1% less than 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 Opet 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 underutilised 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.




**Operations**

***Shallow Conventional Gas***

Gas sales from the TBNG JV Lands in 2018 averaged 4.3 MMcf/d. Oil and natural gas liquids sales totaled 8 bbl/d. Average realised prices for Valeura's gas sales from the South Thrace and West Thrace were $7.56/Mcf in 2018. All the production from the Company'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 Production Leases. 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 Company's reserves are associated with undeveloped reserves 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. Management believes that shallow gas wells and high-pressure stimulated tight gas wells will exhibit relatively high decline rates of 50% and 75%, 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, if required.

***BCGA Play***

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 Hayrabolu-10 and Yayli-1 wells which were deepened and provided more evidence supporting the BCGA play.

After 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 Teslimkoy 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%.

In Q4 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 programme 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 programme 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.

In September 2018, Valeura recompleted the Yamalik-1 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 stabilised 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.

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 prove that 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 4,885 metres. Based on drilling and wireline logging data, the well is interpreted to have intersected over-pressured tight gas below 3,270 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 Company's potential upside 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 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, 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 deep wells were not completed with modern high pressure stimulation technologies 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.

## STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

### Reserves in Turkey

The Company engaged D&M to prepare a report relating to the Company's reserves in Turkey as at December 31, 2018. The reserves on the properties described herein are estimates only. Actual reserves on these properties may be greater or less than those estimated.

All of the Company's crude oil and natural gas reserves in Turkey are located in the Thrace Basin. Set out below is a summary of the crude oil and natural gas reserves and the value of future net revenue of the Company as at December 31, 2018 as evaluated by D&M in the D&M Reserves Report. The reserves evaluated by D&M in the D&M Reserves Report are summarised in Appendix A-1. The report on the reserves data by D&M (in Form 51-101F2) and the report of the Company's management and Board on such reserves data (in Form 51-101F3) are included in this Annual Information Form as Appendices A-3 and A-5, respectively.

The following is a summary of the D&M Reserves Report which is qualified in its entirety by the Company's Statement of Reserves Data and Other Oil and Gas Information attached as Appendix A-1 hereto.

**Oil and Gas Reserves**
**Based on Forecast Prices and Costs[1]**

| | Light and Medium Crude Oil | | Heavy Crude Oil | | Conventional Natural Gas | | Natural Gas Liquids | | Total Oil Equivalent[10] | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Gross[1] (Mbbl) | Net[1] (Mbbl) | Gross[1] (Mbbl) | Net[1] (Mbbl) | Gross[1] (MMcf) | Net[1] (MMcf) | Gross[1] (Mbbl) | Net[1] (Mbbl) | Gross[1] (Mboe) | Net[1] (Mboe) |
| Proved Developed Producing[2][5][6] | 14 | 13 | - | - | 2,927 | 2,533 | - | - | 502 | 435 |
| Proved Developed Non-Producing[2][5][7] | 1 | 1 | - | - | 1,217 | 1,053 | - | - | 204 | 177 |
| Proved Undeveloped[2][8] | - | - | - | - | 7,533 | 6,516 | - | - | 1,256 | 1,086 |
| Total Proved[2] | 15 | 14 | - | - | 11,677 | 10,102 | - | - | 1,962 | 1,698 |
| Total Probable[3] | 6 | 5 | - | - | 32,289 | 27,943 | - | - | 5,388 | 4,662 |
| Total Proved Plus Probable[2][3] | 21 | 19 | - | - | 43,966 | 38,045 | - | - | 7,350 | 6,360 |
| Total Possible[4] | 10 | 9 | - | - | 25,217 | 21,833 | - | - | 4,213 | 3,648 |

| | Light and Medium Crude Oil | | Heavy Crude Oil | | Conventional Natural Gas | | Natural Gas Liquids | | Total Oil Equivalent[10] | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Gross[1] (Mbbl) | Net[1] (Mbbl) | Gross[1] (Mbbl) | Net[1] (Mbbl) | Gross[1] (MMcf) | Net[1] (MMcf) | Gross[1] (Mbbl) | Net[1] (Mbbl) | Gross[1] (Mboe) | Net[1] (Mboe) |
| Total Proved Plus Probable Plus Possible[2][3][4] | 31 | 28 | - | - | 69,183 | 59,878 | - | - | 11,563 | 10,008 |

**Net Present Values of Future Net Revenue**
**Based on Forecast Prices and Costs[1][2]**

| | Before Deducting Income Taxes Discounted At | | | | | After Deducting Income Taxes[15] Discounted At | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 0% (M US$) | 5% (M US$) | 10% (M US$) | 15% (M US$) | 20% (M US$) | 0% (M US$) | 5% (M US$) | 10% (M US$) | 15% (M US$) | 20% (M US$) |
| Proved Developed Producing[2][5][6] | 8,153 | 7,548 | 7,041 | 6,607 | 6,228 | 6,285 | 5,799 | 5,534 | 5,049 | 4,752 |
| Proved Developed Non-Producing[2][5][7] | 4,305 | 3,587 | 2,995 | 2,517 | 2,133 | 3,334 | 2,807 | 2,340 | 1,997 | 1,701 |
| Proved Undeveloped[2][8] | 17,656 | 12,861 | 9,258 | 6,537 | 4,473 | 13,494 | 9,760 | 6,857 | 4,898 | 3,338 |
| Total Proved[2] | 30,114 | 23,996 | 19,294 | 15,661 | 12,834 | 23,113 | 18,366 | 14,731 | 11,944 | 9,791 |
| Total Probable[3] | 101,590 | 67,108 | 44,813 | 30,263 | 20,687 | 78,469 | 51,367 | 34,144 | 22,686 | 15,322 |
| Total Proved Plus Probable[2][3] | 131,704 | 91,104 | 64,107 | 45,924 | 33,521 | 101,582 | 69,733 | 48,875 | 34,630 | 25,113 |
| Total Possible[4] | 108,443 | 68,200 | 44,730 | 30,618 | 21,854 | 84,706 | 53,055 | 34,566 | 23,787 | 17,036 |
| Total Proved Plus Probable Plus Possible[2][3][4] | 240,147 | 159,304 | 108,837 | 76,542 | 55,375 | 186,288 | 122,788 | 83,441 | 58,417 | 42,149 |

**Note:**

See Notes that follow the table titled "*Reconciliation of the Company's Gross Reserves by Principal Product Type Based on Forecast Prices and Costs*" in Appendix A-1.

## PROSPECTIVE RESOURCES

The prospective resources evaluated by D&M in the D&M Resources Report are summarised in APPENDIX A-2. The report on the prospective resources data by D&M (in Form 51-101F2) and the report from the Company's management and the Board on such prospective resources data (in Form 51-101F3) are included in this Annual Information form as Appendices A-4 and A-5, respectively.

## DESCRIPTION OF CAPITAL STRUCTURE

Valeura is authorised to issue an unlimited number of Common Shares and an unlimited number of preferred shares (the "**Preferred Shares**").

As at December 31, 2018, there were 86,232,988 Common Shares and nil Preferred Shares outstanding. As of the date hereof, there were 86,584,989 Common Shares outstanding as a result of the exercise of Options. In addition, as of the date hereof, there were 5,821,666 Options outstanding.

**Common Shares**

The Company is authorised to issue an unlimited number of Common Shares. The holders of the Common Shares are entitled to dividends, if, as and when declared by the Board, to one vote per share at meetings of the Shareholders and, upon liquidation, to receive such assets of the Company as are distributable to the holders of the Common Shares.

**Preferred Shares**

The Company is authorised to issue an unlimited number of Preferred Shares, issuable in series. 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. 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.

## DIVIDENDS

Valeura has not declared or paid any dividends on the Common Shares since incorporation. It is not currently expected that dividends will be paid in respect of the Common Shares during the current phase of development of Valeura'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.

## PRIOR SALES

Valeura has not issued or sold any securities convertible into Common Shares during the year ended December 31, 2018, except as set forth below.

| Date of Issue/Grant | Number and Designation of Securities | Issue/Exercise Price |
|---|---|---|
| March 1, 2018 | 10,527,000 Common Shares | $5.70 |
| March 23, 2018 | 927,500 Options | $4.62 |
| May 30, 2017 | 150,000 Options | $4.60 |

## MARKET FOR COMMON SHARES

The Common Shares are listed and posted for trading on the TSX under the symbol VLE. The following table sets forth the price ranges and traded volume of Common Shares in 2018 as reported by the TSX.

| Period | High ($) | Low ($) | Volume |
|---|---|---|---|
| January | 5.89 | 3.30 | 13,489,800 |
| February | 8.27 | 5.22 | 18,197,300 |
| March | 6.25 | 3.80 | 14,516,700 |
| April | 5.82 | 4.06 | 11,564,000 |
| May | 5.70 | 4.13 | 9,566,900 |
| June | 4.92 | 3.97 | 7,479,200 |
| July | 4.85 | 3.63 | 4,871,300 |

| Period | High ($) | Low ($) | Volume |
|---|---|---|---|
| August | 4.25 | 2.58 | 8,459,800 |
| September | 4.67 | 2.94 | 7,183,800 |
| October | 4.81 | 3.62 | 4,858,100 |
| November | 4.48 | 2.34 | 11,140,200 |
| December | 3.89 | 2.69 | 5,436,200 |

## DIRECTORS AND EXECUTIVE OFFICERS

### Directors and Executive Officers

The following table sets forth the names, province or state and country of residence, present positions with Valeura and principal occupations during the past five years of the directors and executive officers of Valeura. The term of office for each director is from the date of the annual meeting at which they are elected until the next annual meeting or until their successor is elected or appointed.

| Name and Residence | Position(s) with Valeura | Principal Occupation(s) During the Past Five Years |
|---|---|---|
| Dr. Timothy R. Marchant(1)(2)(3)<br>Calgary, Alberta, Canada | Chairman since 2018<br>Director since 2015 | Adjunct Professor of Strategy and Energy Geopolitics, Haskayne School of Business, University of Calgary<br>Director of Vermilion Energy Inc. since 2010.<br>Director of Cub Energy Inc. since 2013. |
| Russell Hiscock(1)(2)<br>Montreal, Quebec, Canada | Director since 2018 | President and Chief Executive Officer of the CN Investment Division from 2008 until 2018. |
| James D. McFarland(3)<br>Calgary, Alberta, Canada | Director since 2010 | President and Chief Executive Officer of Valeura from April 2010 to October 2017 and Chief Executive Officer from October 2017 to December 2017.<br>Director of Pengrowth Energy Corporation and MEG Energy Corp since 2010.<br>Director of Arrow Exploration Corp. since 2018 |
| Ronald W. Royal(2)(3)<br>Abbotsford, British Columbia, Canada | Director since 2010 | Private Businessman since April 2007.<br>Director of Gran Tierra Energy Inc. since 2015.<br>Director of Caracal Energy Inc. from 2011 to 2014.<br>Director of Oando Energy Resources Inc. from 2015 to 2016. |
| W. Sean Guest<br>Calgary, Alberta, Canada | President and Chief Executive Officer<br>Director since 2018 | President of Valeura since October 2017 and Chief Executive Officer of Valeura since January 2018.<br>Chief Operating Officer of Valeura May 2017 to December 2017.<br>Chief Executive Officer of Bukit Energy from February 2014 to May 2017. |
| Stephen E. Bjornson<br>Calgary, Alberta, Canada | Chief Financial Officer | Chief Financial Officer of Valeura since April, 2010. |
| Lyle A. Martinson<br>Calgary, Alberta, Canada | Chief Operating Officer | Vice President, Operations of Valeura since April, 2010.<br>Chief Operating Officer of Valeura since May 2018. |
| Gordon Begg<br>Calgary, Alberta, Canada | Vice President, Commercial | Vice President, Commercial of Valeura since May 2018.<br>Chief Operating Officer of Bukka Energy Inc June 2011 to April 2018 |

**Notes:**

(1) Member of the Governance and Compensation Committee.

(2) Member of the Audit Committee.
(3) Member of the Reserves & Health, Safety, Security and Community Relations Committee.

As of the date hereof, the directors and executive officers of Valeura, as a group, beneficially own, directly or indirectly, 1,565,509 Common Shares representing approximately 1.8% of the issued and outstanding Common Shares.

As of the date hereof, the directors and executive officers of Valeura, as a group, beneficially own, directly or indirectly 4,559,000 Options. If all such Options were exercised, the directors and executive officers of Valeura, as a group, would hold approximately 6.7% of the then issued and outstanding Common Shares (on a fully diluted basis).

**Corporate Cease Trade Orders or Bankruptcies**

To the knowledge of management, no director or executive officer of Valeura is, or has been, within the past 10 years before the date hereof, a director or executive officer of any issuer that, while that person was acting in that capacity: (i) was the subject of a cease trade or similar order or an order that denied the issuer access to any exemption under securities legislation for a period of more than 30 consecutive days; or (ii) was subject to an event that resulted, after the person ceased to be a director or executive officer, in the issuer being the subject of a cease trade or similar order or an order that denied the issuer access to any exemption under securities legislation for a period of more than 30 consecutive days.

To the knowledge of management, no director or executive officer of Valeura is, or has been, within the past 10 years before the date hereof, a director or executive officer of any issuer that, while that person was acting in that capacity or within a year of that issuer ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

**Personal Bankruptcies**

To the knowledge of management, no director or executive officer of Valeura has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or became subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold such person's assets.

**Penalties or Sanctions**

To the knowledge of management, no director or executive officer of Valeura has been subject to: (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, other than penalties for late filing of insider reports; or (ii) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

**Conflicts of Interest**

Circumstances may arise where Board members are directors or officers of companies which are in competition to the interests of Valeura. No assurances can be given that opportunities identified by such Board members will be provided to Valeura. Pursuant to the ABCA, directors who have an interest in a proposed transaction upon which the Board is voting are required to disclose their interests and refrain from voting on the transaction.

## AUDIT COMMITTEE

### Composition of the Audit Committee

The Audit Committee of the Board operates under written terms of reference that set out its responsibilities and composition requirements. A copy of the terms of reference is attached to this Annual Information Form as Appendix B. 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 consists of Messrs. Hiscock (Chair), Marchant and Royal. All members of the Audit Committee are independent and financially literate as such terms are defined by National Instrument 52 110 – Audit Committees.

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. 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 following sets out the education and experience of each director relevant to the performance of his duties as a member of the Audit Committee. The chair of the Audit Committee, Mr. Russell Hiscock, holds a Chartered Financial Analyst designation as well as a Certified Management Accountant designation and has accounting and financial experience as a result of his role as President and Chief Executive Officer CN Investment Division. Dr. Tim Marchant has a Ph.D. in Geology from Trinity College, University of Dublin, Ireland. Dr. Marchant completed the Executive

Programme at the Ivey School of Business, University of Western Ontario in 1994 and the Institute of Corporate Directors Education Programme in 2011. In a career that spanned 29 years with Amoco and BP, Dr. Marchant held senior executive positions in Canada and a number of countries in the Middle East including Egypt, Saudi Arabia, Abu Dhabi and Kuwait. Mr. Ronald W. Royal holds a Bachelor of Applied Science degree in Mechanical Engineering from the University of British Columbia and has obtained financial experience and exposure to accounting and financial issues through his involvement as an executive officer of international affiliates of ExxonMobil Corporation.

**Auditors' Fees**

KPMG LLP, Chartered Professional Accountants, became Valeura's auditors on April 9, 2010. Fees paid to Valeura's auditors for the years ended December 31, 2018 and 2017 are detailed below.

| Fee | For the year ended December 31, 2018 | For the year ended December 31, 2017 |
|---|---|---|
| Audit Fees(1) | $342,600 | $301,700 |
| Tax Fees(2) | - | - |
| All Other Fees | $65,000 | $36,500 |
| Total | $407,600 | $338,200 |

**Notes:**

(1) "Audit Fees" include the aggregate professional fees paid to the external auditors for the audit of the annual consolidated financial statements and other annual regulatory audits and filings. It also includes the aggregate fees paid to the external auditors for services related to the audit services, including reviewing quarterly financial statements and management's discussion thereon and consulting with the Board and Audit Committee regarding financial reporting and accounting standards.

(2) "Tax Fees" include the aggregate fees paid to external auditors for tax compliance, tax advice, tax planning and advisory services, including preparation of tax returns.

All permissible categories of non-audit services require pre-approval by the Audit Committee, subject to certain statutory exemptions.

## RISK FACTORS

### RISKS RELATING TO THE COMPANY'S BUSINESS

***The Company 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 Company's sole source of near-term revenue earnings. A significant portion of the Company's reserves are associated with undeveloped reserves in tight formations. Whilst the Company has drilled and stimulated normally-pressured, tight formations in many shallow wells, experience in drilling and stimulating over-pressured, tight formations in deep wells is very limited. There is uncertainty regarding the sustainability of initial production rates and decline rates thereafter. Management believes that shallow gas wells and high-pressure stimulated tight gas wells will exhibit relatively high decline rates of 50% and 75%, 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 Company'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 commercial producibility of these hydrocarbons. 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 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. Yamalik-1 was subjected to high-pressure stimulation on a 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 are planned for Inanli-1, but this will not be commenced until Q2 2019.

In the longer term the Company will be dependent on the development of its other Thrace Basin assets in Turkey. 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 Company's business, results of operations, financial condition and the price of the Common Shares, as the Company 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 has a 50% interest in the deep formations on the Banarli Exploration Licences. Valeura is currently the operator of the deep exploration programme during Equinor's earning phase of the Banarli Farm-in, but once Equinor has fully earned its 50% interest, Equinor has the option to request operatorship of the deep programme. At that point, Equinor could propose a more significant drilling programme than currently envisaged. If such a programme resulted in a more significant capital commitment than anticipated, the Company may not have the resources to fund its share of the programme 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.

***Reliance on Turkish infrastructure***

The Company currently owns and operates its entire 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 is not available to the Company on commercially acceptable terms the Company's ability to commercially exploit its assets would be limited.

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 reserves to pipelines and processing facilities and related to operational problems with such pipelines

and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, land access, 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 or costs associated with any take or pay obligations. 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 Company is dependent on its directors, senior management team and employees with relevant experience***

The Company is reliant on a number of key personnel. International exploration and development activities such as those the Company is engaged in require specialised 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 Company. Furthermore, it may be particularly difficult for the Company to attract and retain suitably qualified and experienced people, given the competition from other industry participants and the relative size of the Company.

There is no assurance that the Company 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 Company's business plan, which will be particularly important as the Company expands. Competition for such personnel is 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 organisations 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.

***Estimates of resources***

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.

***Estimates of reserves***

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 D&M Reserves Report 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.

***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 and oil and gas sales. In Turkey, the wet weather in the winter months of the year can require delays in operations.

***Substantial capital requirements***

Valeura anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas 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. 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 programmes. From time to time, Valeura may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. 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, 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 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 Company 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 Company is not aware of any specific matters, the Company'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 Company 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 Company may not be able to find adequate replacement services on commercially acceptable terms, on a timely basis, or at all.

Should the Company 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 and completion 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 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 U.S. 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 unauthorised 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 management has 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 Company may affect the Company's ability to pay dividends or make distributions***

The Company 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.

***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 THE COMPANY'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 Company'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 Company'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 Company 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, 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; (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 Company'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, 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 and 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 Company's operations may be harmful to the environment and the Company 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 of the Thrace Basin are designated as prime agricultural land requiring land use approvals from both Agricultural and Energy and Natural Resources Ministries in Turkey. Currently, there are no restrictions on the hydraulic stimulation of wells in Turkey. However, a number of jurisdictions in Europe have temporarily or permanently banned hydraulic fracturing, a form of high-pressure stimulation, of wells and there is a risk that these restrictions may spread to other jurisdictions in the region, including Turkey. High pressure stimulation of tight gas formations is critical to achieving commercial production. Any future restrictions could have a material adverse effect on Valeura's business. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach 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 and land use 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 and in accordance with all applicable laws.

***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.

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 materials, 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 Company's exploration, processing or logistics operations, a loss of the Company'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 Company 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 Company'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 Company 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 Company'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, production leases and other licences, leases and permits (together "**Licences**") and working interests in such Licences. 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 oil and natural gas 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 continue 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 minimise 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 nationalisation, 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, certain corporate transactions 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 centred 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, President Erdogan 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% 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 Common Shares.

To date, the above events have not impacted the Company's ability to conduct operated and non-operated 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 operated and non-operated 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 Company 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 management believes 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 Company 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 Company's reputation, business, results of operations, financial condition and the price of the Common Shares.

The Company has and will engage a number of consultants and contractors in Turkey in connection with its projects and, although the Company 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 the high standards in line with the Company's policies, there is a risk that agents or other persons or

representatives acting on behalf of the Company may engage in corrupt activities without the knowledge of the Company.

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 COMMON SHARES**

***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 Company's control, including the following: (i) actual or anticipated fluctuations in the Company'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 Company or its competitors; (viii) changes in laws, rules and regulations applicable to the Company and its operations; (ix) general economic, political and other conditions; (x) the Company'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 Company'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 Company'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 Company'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 Company'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 Company'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 Company may incur in the future, including the terms of any credit facilities the Company 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.

***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.

## INDUSTRY CONDITIONS

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 June 30, 2013. The most significant changes as described below relate to land tenure regulations.

*Commercial Terms*

Turkey's fiscal regime for oil and gas operations is presently comprised of royalties and income tax. Royalties are at 12.5% and the corporate income tax rate is 22%. Under the New Petroleum Law, the government royalty rate remained unchanged at 12.5%. Also, there are no changes in taxation regulations with respect to the petroleum industry.

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

*Land Tenure Regime*

All of the Company's licences and leases in Turkey are regulated under the New Petroleum Law, described in more detail under the heading "*Turkish Petroluem Law Regime*". The regulator imposed a change to mapping coordinates country wide and the result for the Company was a commencement date for the licences as June 27, 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 GDMPA 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 programme obligation for each year of an exploration licence and the annual work programme 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% of the work programme 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.

*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.

*Pipeline Infrastructure*

Valeura through its interests in the TBNG JV has 81.5% ownership and operates its own gas gathering grid and export lines to its 55 customers regional customers. The TBNG JV network is not currently connected to the national gas grid.

BOTAS owns and operates the national crude oil pipeline grid and the national natural gas pipeline grid in Turkey.

With regard to major natural gas pipelines, BOTAS owns and operates the national gas grid which connects essentially all the major population centres and is within easy access to the Company's existing and planned operations in the Thrace Basin of northwest Turkey. At the end of 2010, the BOTAS natural gas pipeline network consisted of 11,593 kilometres of various pipelines sizes from 10-inch to 48-inch diameter.

With regard to major crude oil pipelines, BOTAS owns and operates the following infrastructure: the 18-inch Batman to Dortyol crude oil pipeline, which services the prevalent crude oil producing areas of the southeast Anatolia region;

the 24-inch Ceyhan to Kirikkale crude oil pipeline, which supplies mainly imported crude oil to the Kirikkale refinery east of Ankara; and the Turkey portion of the twin 40-inch and 46-inch Kirkuk to Ceyhan oil pipeline delivering Iraqi crude oil to the port city of Ceyhan for export. It also operates the Turkish portion of the Baku to Tbilisi to Ceyhan crude oil pipeline delivering Azeri crude oil to Ceyhan for export.

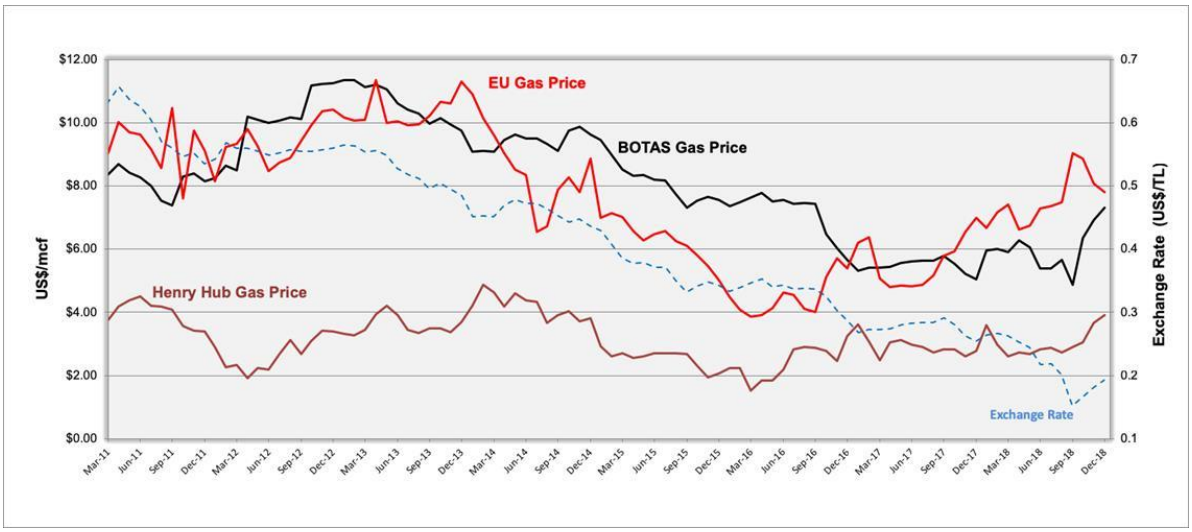
*Pricing and Marketing*

Turkey imports more than 99% of its natural gas and 92% 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 year. In Turkey in 2017 consumption increased almost 20%, 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.

***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% of Turkey's natural gas imports. Given the very small domestic production of approximately 0.04 Bcf/d (<1% 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% of Turkey's natural gas imports followed by Iran at 17%, Azerbaijan at 14%, LNG from Algeria and Nigeria at 12% and other at 4%. 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 Valeura and its subsidiary's gas sales contracts are referenced to the BOTAS Reference Price and denominated in TL. The figure above 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% to 15% 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% 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% as a partner in the TBNG JV), resulting in a net discount of approximately 4% from the BOTAS Reference Price.

*Turkish Petroleum Law Regime*

***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 licences and leases. Offshore licences and leases are not discussed within the scope of this section as Valeura and its subsidiaries do not hold any offshore licences or leases in Turkey as of the date hereof.

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

***Exploration Licences***

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 authorised 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% 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% 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 licence 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 authorised representative resident in Turkey;

b) a 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% of the crude oil and natural gas produced from onshore fields discovered after January 1, 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.

***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 programme 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 programme 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.

***Marketing***

The marketing of natural gas in Turkey is subject to Natural Gas Market Law No. 4646 adopted as of April 18, 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 Energy Market Regulatory Authority ("**EMRA**") 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 December 4, 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.

## LEGAL AND REGULATORY PROCEEDINGS

Valeura is not a party to any legal proceeding nor was it a party to, nor is or was any of its property the subject of, any legal proceeding during the year ended December 31, 2018, nor is Valeura aware of any such contemplated legal proceedings, which involve a claim for damages, exclusive of interest and costs, that may exceed 10 percent of the current assets of Valeura.

During the year ended December 31, 2018, there were no: (i) penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority; (ii) penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements the Company entered into before a court relating to securities legislation or with a securities regulatory authority.

## INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director, officer or principal Shareholder, nor any affiliate or associate of such a person, has or has had any material interest in any transaction or any proposed transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect Valeura.

## TRANSFER AGENT AND REGISTRAR

Computershare Trust Company of Canada, at its principal office in Calgary, Alberta, is the transfer agent and registrar for the Common Shares.

## MATERIAL CONTRACTS

The Company entered into the following material contracts within the most recently completed financial year:

- the underwriting agreement dated February 8, 2018 among the Company, GMP Securities L.P. and Cormark Securities Inc. in respect of the 2018 Offering.

See "*General Development of the Business*".

## INTERESTS OF EXPERTS

Reserve and resource estimates contained in this Annual Information Form have been prepared by D&M. As at December 31, 2018, the effective date of those estimates, and as of the date hereof, the principals, directors, officers and associates of D&M, as a group, owned, directly or indirectly, less than one percent of the outstanding Common Shares.

The auditors of the Company, KPMG LLP, are independent with respect to the Company, in accordance with the Rules of Professional Conduct of the Institute of Chartered Professional Accountants of Alberta.

## ADDITIONAL INFORMATION

Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorised for issuance under equity compensation plans is contained in the Proxy Statement and Information Circular of the Company prepared in connection with the most recent annual meeting of Shareholders that involved the election of directors. Additional financial information is provided in the Company's financial statements and management discussion and analysis for the year ended December 31, 2018.

Copies of this Annual Information Form, any interim financial statements of the Company subsequent to the annual financial statements, the Company's Proxy Statement and Information Circular and other additional information relating to the Company are available on SEDAR at www.sedar.com.

**APPENDIX A-1 – FORM 51-101F1 – STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION**

**FORM 51-101F1 STATEMENT OF RESERVES DATA**
**AND OTHER OIL AND NATURAL GAS INFORMATION**

*(Capitalised terms not specifically defined in this Appendix A-1 have the meaning ascribed to them in the Annual Information Form to which this Appendix A-1 is attached)*

The Company engaged D&M to prepare a report relating to the Company's reserves in Turkey as at December 31, 2018. The reserves on the properties in Turkey described herein are estimates only. Actual reserves on these properties may be greater or less than those estimated.

The Company's crude oil and conventional natural gas reserves in Turkey are located in the Thrace Basin area of Turkey, which is west of Istanbul. Set out below is a summary of the crude oil and conventional natural gas reserves and the value of future net revenue of the Company as at December 31, 2018 as evaluated by D&M in its report with a preparation date of March 13, 2019 (the "**D&M Reserves Report**"). The pricing used in the forecast price evaluations is set forth in the notes to the tables.

The D&M Reserves Report was prepared using assumptions and methodology guidelines outlined in the COGE Handbook and in accordance with NI 51-101.

**The estimated future net revenues contained in the following tables do not necessarily represent the fair market value of the Company's reserves. There is no assurance that the forecast price and cost assumptions contained in the D&M Reserves Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the D&M Reserves Report. The recovery and reserves estimates on the Company's properties described herein are estimates only.**

**OIL AND GAS RESERVES**
**BASED ON FORECAST PRICES AND COSTS[9]**

| | Light and Medium Crude Oil | | Heavy Crude Oil | | Conventional Natural Gas | | Natural Gas Liquids | | Total Oil Equivalent[10] | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Gross[1] (Mbbl) | Net[1] (Mbbl) | Gross[1] (Mbbl) | Net[1] (Mbbl) | Gross[1] (MMcf) | Net[1] (MMcf) | Gross[1] (Mbbl) | Net[1] (Mbbl) | Gross[1] (Mboe) | Net[1] (Mboe) |
| Proved Developed Producing[2][5][6] | 14 | 13 | - | - | 2,927 | 2,533 | - | - | 502 | 435 |
| Proved Developed Non-Producing[2][5][7] | 1 | 1 | - | - | 1,217 | 1,053 | - | - | 204 | 177 |
| Proved Undeveloped[2][8] | - | - | - | - | 7,533 | 6,516 | - | - | 1,256 | 1,086 |
| Total Proved[2] | 15 | 14 | - | - | 11,677 | 10,102 | - | - | 1,962 | 1,698 |
| Total Probable[3] | 6 | 5 | - | - | 32,289 | 27,943 | - | - | 5,388 | 4,662 |
| Total Proved Plus Probable[2][3] | 21 | 19 | - | - | 43,966 | 38,045 | - | - | 7,350 | 6,360 |
| Total Possible[4] | 10 | 9 | - | - | 25,217 | 21,833 | - | - | 4,213 | 3,648 |
| Total Proved Plus Probable Plus Possible[2][3][4] | 31 | 28 | - | - | 69,183 | 59,878 | - | - | 11,563 | 10,008 |

## NET PRESENT VALUES OF FUTURE NET REVENUE BASED ON FORECAST PRICES AND COSTS[9][15]

| | Before Deducting Income Taxes Discounted At | | | | | After Deducting Income Taxes[15] Discounted At | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 0% (M US$) | 5% (M US$) | 10% (M US$) | 15% (M US$) | 20% (M US$) | 0% (M US$) | 5% (M US$) | 10% (M US$) | 15% (M US$) | 20% (M US$) |
| Proved Developed Producing[2][5][6] | 8,153 | 7,548 | 7,041 | 6,607 | 6,228 | 6,285 | 5,799 | 5,534 | 5,049 | 4,752 |
| Proved Developed Non-Producing[2][5][7] | 4,305 | 3,587 | 2,995 | 2,517 | 2,133 | 3,334 | 2,807 | 2,340 | 1,997 | 1,701 |
| Proved Undeveloped[2][8] | 17,656 | 12,861 | 9,258 | 6,537 | 4,473 | 13,494 | 9,760 | 6,857 | 4,898 | 3,338 |
| Total Proved[2] | 30,114 | 23,996 | 19,294 | 15,661 | 12,834 | 23,113 | 18,366 | 14,731 | 11,944 | 9,791 |
| Total Probable[3] | 101,590 | 67,108 | 44,813 | 30,263 | 20,687 | 78,469 | 51,367 | 34,144 | 22,686 | 15,322 |
| Total Proved Plus Probable[2][3] | 131,704 | 91,104 | 64,107 | 45,924 | 33,521 | 101,582 | 69,733 | 48,875 | 34,630 | 25,113 |
| Total Possible[4] | 108,443 | 68,200 | 44,730 | 30,618 | 21,854 | 84,706 | 53,055 | 34,566 | 23,787 | 17,036 |
| Total Proved Plus Probable Plus Possible[2][3][4] | 240,147 | 159,304 | 108,837 | 76,542 | 55,375 | 186,288 | 122,788 | 83,441 | 58,417 | 42,149 |

## TOTAL FUTURE NET REVENUE (UNDISCOUNTED) BASED ON FORECAST PRICES AND COSTS[9]

| | Revenue (M US$) | Royalties (M US$) | Operating Costs (M US$) | Development Costs (M US$) | Abandonment and Reclamation Costs (M US$) | Future Net Revenue Before Income Taxes (M US$) | Income Taxes[15] (M US$) | Future Net Revenue After Income Taxes[15] (M US$) |
|---|---|---|---|---|---|---|---|---|
| Total Proved[2] | 76,380 | 11,906 | 14,378 | 26,281 | 5,608 | 30,113 | 7,000 | 23,113 |
| Total Proved Plus Probable[2][3] | 295,888 | 46,054 | 43,016 | 113,787 | 7,383 | 131,702 | 30,120 | 101,582 |
| Total Proved Plus Probable Plus Possible[2][3][4] | 475,529 | 73,917 | 70,011 | 156,803 | 8,570 | 240,145 | 53,857 | 186,288 |

**FUTURE NET REVENUE BY PRODUCT TYPE**
**BASED ON FORECAST PRICES AND COSTS[9]**

| | | Future Net Revenue Before Income Taxes (Discounted at 10%/Year) | | |
|---|---|---|---|---|
| | **Production Group** | **(M US$)** | **US$/boe[10]** | **US$/Mcfe[11]** |
| Total Proved[2] | Light and medium crude oil[12] | 319 | 33.79 | 5.63 |
| | Heavy crude oil[12] | - | - | - |
| | Conventional natural gas[13][16] | 18,975 | 11.18 | 1.86 |
| **Total Proved[2]** | | **19,294** | **11.37** | **1.90** |
| Probable[3] | Light and medium crude oil[12] | 70 | 30.28 | 5.05 |
| | Heavy crude oil[12] | - | - | - |
| | Conventional natural gas[13][16] | 44,743 | 9.60 | 1.60 |
| **Total Probable[3]** | | **44,813** | **9.61** | **1.60** |
| Total Proved Plus Probable[2][3] | Light and medium crude oil[12] | 389 | 33.10 | 5.52 |
| | Heavy crude oil[12] | - | - | - |
| | Conventional natural gas[13][16] | 63,718 | 10.02 | 1.67 |
| **Total Proved Plus Probable[2][3]** | | **64,107** | **10.08** | **1.68** |
| Possible[4] | Light and medium crude oil[12] | 98 | 28.34 | 4.72 |
| | Heavy crude oil[12] | - | - | - |
| | Conventional natural gas[13][16] | 44,632 | 12.24 | 2.04 |
| **Total Possible[4]** | | **44,730** | **12.26** | **2.04** |
| Total Proved Plus Probable Plus Possible[2][3][4] | Light and medium crude oil[12] | 487 | 32.01 | 5.34 |
| | Heavy crude oil[12] | - | - | - |
| | Conventional natural gas[13][16] | 108,350 | 10.83 | 1.81 |
| **Total Proved Plus Probable Plus Possible[2][3][4]** | | **108,837** | **10.88** | **1.81** |

The pricing assumptions used in the D&M Reserves Report with respect to net present values of future net revenue (forecast) as well as the cost escalation rates used for operating and capital costs are set forth below.

**FORECAST PRICES & COST ESCALATION RATES USED IN D&M RESERVES REPORT[9]**

| | Conventional Natural Gas | | Light and Medium Crude Oil | | Cost Escalation |
|---|---|---|---|---|---|
| Year | TBNG (US$/Mcf) | Banarli (US$/Mcf) | TBNG (US$/bbl) | Banarli (US$/bbl) | %/year |
| 2019 | 7.24 | 7.04 | 57.35 | 57.35 | 0.0 |
| 2020 | 7.33 | 7.13 | 58.08 | 58.08 | 2.0 |
| 2021 | 7.39 | 7.18 | 58.52 | 58.52 | 2.0 |
| 2022 | 7.44 | 7.23 | 58.88 | 58.88 | 2.0 |
| 2023 | 7.46 | 7.25 | 59.07 | 59.07 | 2.0 |
| 2024 | 7.61 | 7.40 | 60.25 | 60.25 | 2.0 |
| 2025 | 7.76 | 7.54 | 61.46 | 61.46 | 2.0 |
| 2026 | 7.92 | 7.69 | 62.69 | 62.69 | 2.0 |
| 2027 | 8.07 | 7.85 | 63.94 | 63.94 | 2.0 |
| 2028 | 8.24 | 8.00 | 65.22 | 65.22 | 2.0 |
| 2029 | 8.40 | 8.16 | 66.52 | 66.52 | 2.0 |
| 2030 | 8.57 | 8.33 | 67.85 | 67.85 | 2.0 |
| 2031+ | +2.0%/yr thereafter | +2.0%/yr thereafter | +2.0%/yr thereafter | +2.0%/yr thereafter | +2.0%/yr thereafter |

The TBNG and Banarli conventional natural gas price forecast is based on gas sales from TBNG JV Lands and Banarli Licences realizing a price equivalent to 98.4% and 95.6% of the BOTAS Reference Price, respectively. The light and medium crude oil price forecast is based on liquid sales from TBNG JV Lands and Banarli Licences realizing a price equivalent to Brent pricing.

The Company's weighted average historical prices Canadian Dollars in Turkey for the year ended December 31, 2018 were:

| Conventional Natural Gas ($/Mcf) | Light and Medium Crude Oil ($/bbl) | Natural Gas Liquids ($/bbl) |
|---|---|---|
| 7.54 | 91.85 | Not Applicable |

## RECONCILIATION OF THE COMPANY'S GROSS RESERVES BY PRINCIPAL PRODUCT TYPE BASED ON FORECAST PRICES AND COSTS [9]

The following table sets forth a reconciliation of the changes in the Company's working interest, before royalties, of light and medium crude oil, heavy crude oil, conventional natural gas, natural gas liquids and oil equivalent reserves as at December 31, 2018 against such reserves as at December 31, 2017 based on the forecast price and cost assumptions set forth in Note 9:

| | Light and Medium Crude Oil | | | | | Heavy Crude Oil | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Gross Proved (Mbbl) | Gross Probable (Mbbl) | Gross Proved Plus Probable (Mbbl) | Gross Possible (Mbbl) | Gross Proved Plus Probable Plus Possible (Mbbl) | Gross Proved (Mbbl) | Gross Probable (Mbbl) | Gross Proved Plus Probable (Mbbl) | Gross Possible (Mbbl) | Gross Proved Plus Probable Plus Possible (Mbbl) |
| At December 31, 2017 | 5 | 3 | 8 | 5 | 13 | 0 | 0 | 0 | 0 | 0 |
| Extensions | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Technical Revisions | 9 | 0 | 9 | 0 | 9 | 0 | 0 | 0 | 0 | 0 |
| Discoveries | 5 | 3 | 8 | 5 | 13 | 0 | 0 | 0 | 0 | 0 |
| Acquisitions | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Dispositions | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Economic Factors | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Production | 4 | 0 | 4 | 0 | 4 | 0 | 0 | 0 | 0 | 0 |
| At December 31, 2018 | 15 | 6 | 21 | 10 | 31 | 0 | 0 | 0 | 0 | 0 |

| | Conventional Natural Gas | | | | | Natural Gas Liquids | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Gross Proved (MMcf) | Gross Probable (MMcf) | Gross Proved Plus Probable (MMcf) | Gross Possible (MMcf) | Gross Proved Plus Probable Plus Possible (MMcf) | Gross Proved (Mbbl) | Gross Probable (Mbbl) | Gross Proved Plus Probable (Mbbl) | Gross Possible (Mbbl) | Gross Proved Plus Probable Plus Possible (Mbbl) |
| At December 31, 2017 | 13,236 | 33,611 | 46,847 | 26,565 | 73,412 | 0 | 0 | 0 | 0 | 0 |
| Extensions | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Technical Revisions | -130 | -1,386 | -1,516 | -1,472 | -2,988 | 0 | 0 | 0 | 0 | 0 |
| Discoveries | 134 | 64 | 198 | 124 | 322 | 0 | 0 | 0 | 0 | 0 |
| Acquisitions | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Dispositions | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Economic Factors | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Production | 1,563 | 0 | 1,563 | 0 | 1,563 | 0 | 0 | 0 | 0 | 0 |
| At December 31, 2018 | 11,677 | 32,289 | 43,966 | 25,217 | 69,183 | 0 | 0 | 0 | 0 | 0 |

| | Oil Equivalent[10][17] | | | | |
|---|---|---|---|---|---|
| | **Gross Proved (Mboe)** | **Gross Probable (Mboe)** | **Gross Proved Plus Probable (Mboe)** | **Gross Possible (Mboe)** | **Gross Proved Plus Probable Plus Possible (Mboe)** |
| At December 31, 2017 | 2,211 | 5,605 | 7,816 | 4,433 | 12,249 |
| Extensions | 0 | 0 | 0 | 0 | 0 |
| Technical Revisions | -12 | -231 | -243 | -246 | -489 |
| Discoveries | 27 | 14 | 41 | 26 | 67 |
| Acquisitions | 0 | 0 | 0 | 0 | 0 |
| Dispositions | 0 | 0 | 0 | 0 | 0 |
| Economic Factors | 0 | 0 | 0 | 0 | 0 |
| Production | 265 | 0 | 265 | 0 | 265 |
| At December 31, 2018 | 1,961 | 5,388 | 7,349 | 4,213 | 11,562 |

**Notes:**

(1) "**Gross Reserves**" are the Company's working interest (operating or non-operating) share before deducting royalties and without including any royalty interests of the Company. "**Net Reserves**" are the Company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalty interests in reserves.

(2) "**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.

(3) "**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.

(4) "**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.

(5) "**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 a well) to put the reserves on production.

(6) "**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.

(7) "**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.

(8) "**Undeveloped**" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

(9) The pricing assumptions used in the D&M Reserves Report with respect to net values of future net revenue (forecast) as well as the cost escalation rates used for operating and capital costs are set forth in the preceding table titled "Forecast Prices & Cost Escalation Rates Used in D&M Reserves Report". The Forecast Prices & Cost Escalation rates were developed by D&M as at December 31, 2018 and reflect the then current year forecast prices and cost escalation rates. D&M is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

(10) "**boe**" means barrel of oil equivalent, derived by converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(11) "**Mcfe**" means thousand cubic feet of sales gas equivalent derived by converting oil to gas in the ratio of one barrel of oil to six thousand cubic feet of gas. Mcfes may be misleading, particularly if used in isolation. A Mcfe conversion ratio of 1 bbl to 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(12) Including solution gas and other by-products associated with oil production.

(13) Including non-associated gas by-products but excluding solution gas.

(14) Reference to M US$, US$/bbl, US$/Mcf, US$/boe and US$/Mcfe are stated in United States dollars. Reference to M$, $/bbl, $/Mcf, $/boe and $/Mcfe are stated in Canadian dollars.

(15) Income taxes are Turkey income taxes.

(16) The D&M Reserves Report categorises all production as natural gas as the primary phase.

(17) Values may not add due to rounding.

***Proved Undeveloped Reserves***

The following table sets forth the volumes of proved undeveloped reserves that were first attributed for each of the Company's product types in each of the three most recent financial years:

| | Light and Medium Crude Oil (Mbbl) | Heavy Crude Oil (Mbbl) | Conventional Natural Gas (MMcf) | Natural Gas Liquids (Mbbl) | Oil Equivalent[(1)] (Mboe) |
|---|---|---|---|---|---|
| December 31, 2016 | 0 | 0 | 0 | 0 | 0 |
| December 31, 2017 | 0 | 0 | 0 | 0 | 0 |
| December 31, 2018 | 0 | 0 | 0 | 0 | 0 |

**Note:**

(1) "**boe**" means barrel of oil equivalent, derived by converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil. Barrels of oil equivalent may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

In the D&M Reserves Report as of December 31, 2018 there are no assigned proved undeveloped reserves first attributed in 2018.

In the D&M Reserves Report as of December 31, 2018 there are a total of 16 drilling locations assigned proved undeveloped reserves. The Company expects to develop the majority (15 of the 16 drilling locations) of these reserves over the next three years. The Company anticipates utilizing a portion of a one rig programme over the next three years (2019 to 2021) in the development of these proved undeveloped reserves. The pace of development of these reserves can be influenced by many factors, including but not limited to, changing technical conditions, partner and regulatory approval, changes in product pricing, capital allocation priorities and the results of yearly drilling and reservoir evaluations. As new information becomes available these reserves are reviewed and drilling plans are revised accordingly.

***Probable Undeveloped Reserves***

The following table sets forth the volumes of probable undeveloped reserves that were first attributed for each of the Company's product types in each of the three most recent financial years:

| | Light and Medium Crude Oil (Mbbl) | Heavy Crude Oil (Mbbl) | Conventional Natural Gas (MMcf) | Natural Gas Liquids (Mbbl) | Oil Equivalent[(1)] (Mboe) |
|---|---|---|---|---|---|
| December 31, 2016 | 0 | 0 | 0 | 0 | 0 |
| December 31, 2017 | 0 | 0 | 0 | 0 | 0 |
| December 31, 2018 | 0 | 0 | 0 | 0 | 0 |

**Note:**

(1) "boe" means barrel of oil equivalent, derived by converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil. Barrels of oil equivalent may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

In the D&M Reserves Report as of December 31, 2018 there are no assigned probable undeveloped reserves first attributed in 2018.

In the D&M Reserves Report as of December 31, 2018 there are a total of 50 drilling locations assigned probable undeveloped reserves. The Company expects to develop the majority (48 of the 50 drilling locations) of these

reserves over the next six years. The Company anticipates utilizing a portion of a one rig programme over the next three years (2019 to 2021); scaling up to a one rig programme in 2022; a two rig programme in 2023; and scaling back to a partial one rig programme in 2024. The pace of development of these reserves can be influenced by many factors, including but not limited to, changing technical conditions, partner and regulatory approval, changes in product pricing, capital allocation priorities and the results of yearly drilling and reservoir evaluations. As new information becomes available these reserves are reviewed and drilling plans are revised accordingly.

**Significant Factors or Uncertainties Affecting Reserves Data**

There are a number of factors that could result in delayed or cancelled development of the Company's proved and probable undeveloped reserves, including the following: (i) partner and regulatory approvals; (ii) availability of equipment; (iii) product pricing; (iv) currency exchange rates; (v) well performance; and (vi) availability of financing in the future. Approximately 88% of the drilling locations (14 locations) assigned proved undeveloped reserves and 96% of the drilling locations (48 locations) assigned probable undeveloped reserves are in tight gas reservoirs located below the conventional shallow gas reservoirs in the Tekirdag field, which is located immediately adjacent to the growing city of Tekirdag. The Company expects that the process to achieve routine drilling location approvals from the Ministry of Energy and Natural Resources, the Ministry of Agriculture and the local landowners could take longer than experienced in the past and may require pad drilling operations, all of which could extend the current contemplated timelines of approximately three years and approximately six years for development of the proved undeveloped reserves and the probable undeveloped reserves, respectively.

Further to the timing of the development of proved undeveloped reserves, the Company envisages initially utilizing a portion of a one drilling rig programme over the next three years (2019 to 2021) to develop the assigned proved undeveloped reserves over an approximate three-year timeline. Further to the timing of the development of probable undeveloped reserves, the Company envisages initially utilizing a portion of a one drilling rig programme over the next three years (2019 to 2021); scaling up to a one drilling rig programme in 2022; further scaling up to a two drilling rig programme in the fifth year (2023); and scaling back to a one drilling rig programme in the sixth year (2024) to develop the assigned probable undeveloped reserves over an approximate six-year timeline. This was felt to be a reasonable development pace given the large scale of the drilling programme. Also the pace reflects some extension to normal timelines for routine approvals of well locations by the Turkish authorities, recognizing that 88% of the drilling locations assigned proved undeveloped reserves and 96% of the drilling locations assigned probable undeveloped reserves (total of 62 drilling locations) are accessing unconventional tight gas reservoirs in the Tekirdag field, which is located immediately adjacent to the growing city of Tekirdag. The development timeline also enables learning and fine-tuning of well design and fracture stimulation design during the course of the programme so as to improve cost efficiency and overall effectiveness.

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices, currency exchange rates and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of future net revenue there from. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effect of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, currency exchange rates, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in forecast prices, currency exchange rates, reservoir performance and geological conditions or production. These revisions can be either positive or negative. While the Company does not anticipate any significant economic factors or significant uncertainties will affect any particular component of the reserve data, the reserves can be affected significantly by fluctuations in product

pricing, currency exchange rates, capital expenditures, operating costs, royalty regimes and well performance that are beyond the Company's control.

**Future Development Costs**

The following table sets forth the development costs deducted in the estimation of future net revenue attributable to each of the following reserves categories contained in the D&M Reserves Report:

| | **Total Proved[1] Estimated Using Forecast Prices and Costs (M US$)** | **Total Proved[1] Plus Probable[2] Estimated Using Forecast Prices and Costs (M US$)** |
|---|---|---|
| 2019 | 3,444 | 6,181 |
| 2020 | 10,150 | 10,150 |
| 2021 | 10,175 | 10,175 |
| 2022 | 1,863 | 22,620 |
| 2023 | 648 | 39,464 |
| Remainder | 0 | 25,195 |
| Total for all years undiscounted | 26,280 | 113,785 |

**Notes:**

(1) "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.

(2) "**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.

The Company's primary source of liquidity to fund its estimated future development costs, as outlined in the above table, is derived from one of or a combination of the Company's internally-generated cash flow, cash on hand, debt financing when deemed appropriate and new equity issues if made on favourable terms.

**Oil and Gas Properties and Wells**

The Company's major properties are the TBNG JV Lands and Banarli Licences both situated in the Thrace Basin. The Company also holds interests in three production leases at Edirne in the Thrace Basin which is considered a minor property. In total the Company's land holdings as of December 31, 2018 comprised an onshore area of approximately 456,470 gross acres (approximately 373,588 net acres from surface to 2,500 metres and approximately 255,662 net acres below 2,500 metres) all in Turkey. These areas assume Equinor completes its earning of a 50% interest in the deep rights (below 2,500 metres) on the two Banarli Licences. All of the Company's 2018 production was from the Thrace Basin.

As of December 31, 2018, the TBNG JV Lands entailed 14 production leases and one exploration licence comprising an onshore area of approximately 272,747 gross acres (approximately 222,289 net acres from surface to 2,500 metres and approximately 171,283 net acres below 2500 metres). All development is onshore and a small percentage of the acreage is developed. Nine of the 14 production leases and both of the exploration licences on the TBNG JV Lands are new production leases and exploration licences that were converted under the New Petroleum Law.

As of December 31, 2018, the Banarli Licences entailed two exploration licences comprising an onshore area of approximately 133,840 gross acres (approximately 133,840 net acres from surface to 2,500 metres and approximately 66,920 net acres below 2,500 metres). These areas assume Equinor completes its earning of a 50% interest in the deep rights (below 2,500 metres) on the two Banarli Licences. The Banarli Licences are new exploration licences that were converted under the New Petroleum Law.

As of December 31, 2018, the Edirne Lands entailed three production leases comprising an onshore area of approximately 49,883 gross acres (approximately 17,459 net acres). The Edirne production leases are new production leases that were converted under the New Petroleum Law.

The natural gas produced in the Thrace Basin has a high methane content and is relatively dry with a low water to gas ratio which currently only requires dehydration and compression to meet sales requirements. The Company has an extensive gas gathering network which gathers all the production to a central dehydration and compression facility. Processed natural gas is delivered through a TBNG JV owned distribution network to 55 customers within a 50 kilometres distance of TBNG JV's central processing facility.

A listing of the Company's wells in Turkey as of December 31, 2018 is shown below:

| | Oil Wells | | Natural Gas Wells | | Standing & Other Wells | |
|---|---|---|---|---|---|---|
| | Gross(1) | Net(2) | Gross(1) | Net(2) | Gross(1) | Net(2) |
| Producing | 1 | 0.82 | 86 | 70.28 | 0 | 0.00 |
| Non-producing | 0 | 0.00 | 122 | 94.34 | 21 | 16.99 |
| Total | 1 | 0.82 | 208 | 164.61 | 21 | 16.99 |

**Notes:**

(1) )"**Gross Wells**" are the total number of wells in which the Company has an interest.

(2) "**Net Wells**" are the number of wells obtained by aggregating the Company's working interest in each of its gross wells.

**Properties with No Attributed Reserves**

The following table sets out the Company's undeveloped land position in Turkey effective December 31, 2018:

| | Undeveloped Acreage | | | |
|---|---|---|---|---|
| | Shallow Acreage (surface to a depth of 2,500 metres) | | Deep Acreage (a depth of 2,500 metres and deeper) | |
| | Gross(1) | Net(2) | Gross(1) | Net(2) |
| Thrace Basin | 456,470 | 373,588 | 456,470 | 255,662 |
| Total | 456,470 | 373,588 | 456,470 | 255,662 |

**Notes:**

(1) "**Gross**" means the total number of acres in which the Company has a working interest.

(2) "**Net**" means the number of acres obtained by aggregating the Company's working interest in each of its acreage positions.

The above table assumes Equinor completes its earning of a 50% working interest in the deep rights on Banarli Licences.

No net undeveloped acreage is expected to expire in 2019.

**Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves**

At this time the Company has not completed an independent evaluation of its undeveloped acreage in Turkey. However, the Company has completed an independent assessment of its prospective resources on the TBNG JV Lands and the Banarli Licences effective December 31, 2018 which identified significant undiscovered prospective resources potential. See "*Appendix A-2 – Prospective Resources Data*" for a summary of the prospective resources evaluated by D&M in the D&M Resources Report and for details regarding risked estimates.

**Forward Contracts**

Currently there are no material forward contracts or commitments.

**Abandonment and Reclamation Costs**

All wells assigned reserves as well as unabandoned wells that have not been assigned reserves are included in the D&M Reserves Report and are assigned abandonment and reclamation costs.

Abandonment and reclamation costs are estimated on an area by area basis. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment and reclamation requirements. The Company has 182.4 net wells as of December 31, 2018 for which abandonment and reclamation costs are expected to be incurred.

In the D&M Reserves Report the total well abandonment cost in respect of proved reserves using Forecast Prices and Costs are US$5.6 million (undiscounted). All of this amount was deducted as abandonment and reclamation costs in estimating the Company's future net revenue as disclosed above.

In the D&M Reserves Report well abandonment and reclamation costs for all wells with reserves as well as unabandoned wells that have not been assigned reserves have been included at the property level. Additional abandonment and reclamation costs associated with suspended wells and facility abandonment and reclamation expenses have not been included in this analysis.

**Tax Horizon**

The Company paid cash income taxes in Turkey for the period ended December 31, 2018, mostly due to tax on farm-in proceeds received. Based on current estimates of the Company's future taxable income and expected future capital expenditures, management believes that the Company will not be required to pay cash income taxes in Turkey in 2018.

**Costs Incurred**

The following table summarises the capital expenditures made by the Company on oil and natural gas properties in Turkey for the year ended December 31, 2018.

| | Property Acquisition (Disposition) Costs[14] (M$) | | | |
|---|---|---|---|---|
| | **Proved Properties** | **Unproved Properties** | **Exploration Costs[14] (M$)** | **Development Costs[14] (M$)** |
| TBNG JV Lands | - | - | 857 | (74) |
| Banarli Licences | - | - | 7,240 | - |
| Other | - | - | - | - |
| Total Turkey | - | - | 8,097 | (74) |

**Note:**

See Notes that follow the table titled "R*econciliation of the Company's Gross Reserves by Principal Product Type Based on Forecast Prices and Costs*".

**Exploration and Development Activities**

The following table sets forth the number of wells the Company drilled for the year ended December 31, 2018 in Turkey (the Company did not drill any service wells or stratigraphic test wells):

| | Exploratory Wells | | Development Wells | |
|---|---|---|---|---|
| | **Gross(1)(2)(3)** | **Net(1)(2)(3)** | **Gross(1)(2)(3)** | **Net(1)(2)(3)** |
| Oil Wells | 0 | 0.00 | 0 | 0.00 |
| Gas Wells | 1 | 0.50 | 1 | 0.82 |
| Standing & Other Wells | 0 | 0.00 | 0 | 0.00 |
| Dry Holes | 0 | 0.00 | 0 | 0.00 |
| Total Wells | 1 | 0.50 | 1 | 0.82 |

**Notes:**

(1) "**Gross Wells**" are the total number of wells in which the Company has an interest.

(2) "**Net Wells**" are the number of wells obtained by aggregating the Company's working interest in each of its gross wells.

(3) Spud date is the criteria the Company uses to categorise drilled wells by year.

See "*Description of the Business and Operations*" in the Annual Information Form for a general description of Valeura's most important current and likely exploration and development activities.

**Production Estimates**

The following table sets forth the volume of working interest daily production, before royalties, estimated for 2019 which is reflected in the estimate of future net revenue disclosed in the tables of reserve information in respect of gross proved and probable reserves in Turkey:

| | Light and Medium Crude Oil (bbl/d) | Heavy Crude Oil (bbl/d) | Conventional Natural Gas (Mcf/d) | Natural Gas Liquids (bbl/d) |
|---|---|---|---|---|
| Proved Developed Producing[(2)(6)] | | | | |
| TBNG JV Lands | 10 | 0 | 3,117 | 0 |
| Banarli Licences | 3 | 0 | 131 | 0 |
| Total Proved Developed Producing | 13 | 0 | 3,428 | 0 |
| Proved Developed Non-Producing[(2)(7)] | | | | |
| TBNG JV Lands | 0 | 0 | 394 | 0 |
| Banarli Licences | 0 | 0 | 0 | 0 |
| Total Proved Developed Non-Producing | 0 | 0 | 394 | 0 |
| Proved Undeveloped[(2)(8)] | | | | |
| TBNG JV Lands | 0 | 0 | 877 | 0 |
| Banarli Licences | 0 | 0 | 0 | 0 |
| Total Proved Undeveloped | 0 | 0 | 877 | 0 |
| Total Proved[(2)] | | | | |
| TBNG JV Lands | 10 | 0 | 4,388 | 0 |
| Banarli Licences | 3 | 0 | 131 | 0 |
| Total Proved | 13 | 0 | 4,519 | 0 |
| Total Probable[(3)] | | | | |
| TBNG JV lands | 0 | 0 | 783 | 0 |
| Banarli Licences | 1 | 0 | 248 | 0 |
| Total Probable | 1 | 0 | 1,031 | 0 |
| Total Proved Plus Probable[(2)(3)] | | | | |
| TBNG JV Lands | 10 | 0 | 5,171 | 0 |
| Banarli Licences | 4 | 0 | 379 | 0 |
| Total Proved Plus Probable | 14 | 0 | 5,550 | 0 |

**Note:**

See Notes that follow the table titled "Reconciliation of the Company's Gross Reserves by Principal Product Type Based on Forecast Prices and Costs".

**Production History**

The following table sets forth certain information in respect of production, product prices received, royalties, production costs and netbacks received by the Company for each quarter of its most recently completed financial year for properties in Turkey:

| | Three Months Ended March 31, 2018 | Three Months Ended June 30, 2018 | Three Months Ended September 30, 2018 | Three Months Ended December 31, 2018 |
|---|---|---|---|---|
| Average Daily Production | | | | |
| Light and Medium Crude Oil (bbl/d) | 15 | 9 | - | 8 |
| Conventional Natural Gas (Mcf/d) | 5,066 | 4,360 | 3,931 | 3,689 |
| boes (boe/d) | 859 | 736 | 655 | 623 |
| Average Prices Received | | | | |
| Light and Medium Crude Oil ($/bbl)(14) | 82.61 | 95.77 | - | 104.41 |
| Conventional Natural Gas ($/Mcf)(14) | 7.37 | 7.24 | 6.65 | 9.06 |
| boes ($/boe)(14) | 44.87 | 44.06 | 39.83 | 55.00 |
| Royalties | | | | |
| Light and Medium Crude Oil ($/bbl)(14) | 8.48 | 13.06 | - | 14.20 |
| Conventional Natural Gas ($/Mcf)(14) | 0.99 | 0.97 | 0.89 | 1.24 |
| boes ($/boe)(14) | 5.96 | 5.91 | 5.36 | 7.54 |
| Production Costs | | | | |
| Light and Medium Crude Oil ($/bbl)(14) | 8.63 | 11.94 | - | 10.88 |
| Conventional Natural Gas ($/Mcf)(14) | 2.28 | 2.61 | 1.81 | 2.50 |
| boes ($/boe)(14) | 13.57 | 15.62 | 10.84 | 14.98 |
| Netback Received | | | | |
| Light and Medium Crude Oil ($/bbl)(14) | 65.50 | 70.76 | - | 79.33 |
| Conventional Natural Gas ($/Mcf)(14) | 4.11 | 3.66 | 3.94 | 5.31 |
| boes ($/boe)(14) | 25.35 | 22.53 | 23.63 | 32.48 |

**Note:**

See Notes that follow the table titled "R*econciliation of the Company's Gross Reserves by Principal Product Type Based on Forecast Prices and Costs*".

The following table sets forth certain information in respect of production that is included in the preceding table and is attributable to TBNG JV Lands:

| | Three Months Ended March 31, 2018 | Three Months Ended June 30, 2018 | Three Months Ended September 30, 2018 | Three Months Ended December 31, 2018 |
|---|---|---|---|---|
| Average Daily Production | | | | |
| Light and Medium Crude Oil (bbl/d) | 15 | 9 | - | 8 |
| Conventional Natural Gas (Mcf/d) | 4,884 | 4,208 | 3,798 | 3,628 |
| boes (boe/d) | 829 | 710 | 633 | 613 |

## APPENDIX A-2 – PROSPECTIVE RESOURCES DATA

## PROSPECTIVE RESOURCES DATA

*(Capitalised terms not specifically defined in this Appendix A-2 have the meaning ascribed to them in the Annual Information Form to which this Appendix A-2 is attached)*

The Company engaged D&M to prepare a report relating to the Company's prospective resources in Turkey as at December 31, 2018. The prospective resources on the properties described herein are estimates only. Actual prospective resources on these properties may be greater or less than those estimated.

The D&M Resources Report was prepared using the guidelines outlined in the COGE Handbook and in accordance with NI 51-101.

**Teslimkoy/Kesan Basin-Centered Gas Prospect**

D&M evaluated the unconventional prospective resources attributable to the Teslimkoy/Kesan basin-centered gas prospect on the Company's lands in the Thrace Basin of Turkey. The working interest lands included comprise the deep formations (generally below 2,500 metres depth) on the Banarli Licences (50% working interest), West Thrace Lands (31.5% working interest) and South Thrace Lands (81.5% working interest).

The D&M evaluation benefited from the Yamalik-1 natural gas-condensate discovery, which was drilled and flow tested on the Banarli Licecses in 2017 and from the Inanli-1 appraisal well, which was drilling at a depth of approximately 4,559 metres at yearend and subsequently reached a total depth of 4,855 metres on January 28, 2019.

The Yamalik-1 well discovered an approximate 1,300 metres column of natural gas and condensate in over-pressured reservoirs below 2,900 metres in the Teslimkoy and Kesan Formations. The well was drilled to 4,196 metres, fracture stimulated and production tested in Q4 2017. As announced on December 27, 2018, four production tests from eight frac stages in the Kesan Formation yielded a 24-hour aggregate test rate of 2.9 MMcf/d. Extensive coring and wireline logging information was also captured in the well. As announced on November 13, 2018, the Yamalik-1 well was recompleted and tied into Valeura's gas production infrastructure for longer term testing.

Yamalik-1 was the first well to be extensively facture stimulated in the basin-centered gas prospect in the Thrace Basin. However, well data from seven other legacy wells drilled in the prospective area to depths up to 4,050 metres also indicate over-pressured natural gas below approximately 2,500 metres and were available for D&M's evaluation. Only one of these legacy wells (Yayli-1) was fracture stimulated with a small two-stage frack at a depth of approximately 2,800 metres. As announced on January 28, 2018, the Inanli-1 well was drilled to a total depth of 4,855 metres and is currently undergoing evaluation.

**COMPANY WORKING INTEREST**
**NATURAL GAS PROSPECTIVE RESOURCES[6][7][8][9][10]**

The following table summarises D&M's estimates of the Company's working interest prospective natural gas resources (defined as "conventional natural gas" under NI 51-101) as at December 31, 2018. These numbers as reported by D&M are for the complete gas stream and explicitly include condensate resources (defined as "natural gas liquids" under NI 51-101) which are entrained in the natural gas. Sales gas volumes would be nominally lower than those presented below. The table shown in the section below titled "Company Working Interest Natural Gas Liquids Prospective Resources" summarises the amount of condensate as at December 31, 2018 that would be recovered in association with the production of the natural gas volumes shown below.

| Conventional Natural Gas [13][15] | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Company Working Interest Lands [1] | Unrisked | | | | | | | | Chance of Commerciality % [11] | Risked Mean Estimate [12] | |
| | Low Estimate [2] | | Best Estimate [3] | | High Estimate [4] | | Mean Estimate [5] | | | | |
| | Gross (Bcf) | Net (Bcf) | Gross (Bcf) | Net (Bcf) | Gross (Bcf) | Net (Bcf) | Gross (Bcf) | Net (Bcf) | | Gross (Bcf) | Net (Bcf) |
| Total | 3,229 | 2,813 | 7,652 | 6,666 | 20,077 | 17,485 | 10,137 | 8,829 | 51.1 | 5,182 | 4,514 |

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 utilised their experience in analogous basins. The prospective resources in above and below tables assume a low, best, high and mean estimate recovery factor of approximately 25%, 40%, 55% and 40% 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.

**COMPANY WORKING INTEREST**
**NATURAL GAS LIQUIDS PROSPECTIVE RESOURCES[6][7][8][9][10]**

The following table summarises the amount of condensate as at December 31, 2018 that would be recovered in association with the production of the natural gas volumes summarised in the table shown above in the section titled "Company Working Interest Natural Gas Prospective Resources".

| Condensate (Natural Gas Liquids) [14][15] | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Company Working Interest Lands [1] | Unrisked | | | | | | | |
| | Low Estimate [2] | | Best Estimate [3] | | High Estimate [4] | | Mean Estimate [5] | |
| | Gross (MMbbl) | Net (MMbbl) | Gross (MMbbl) | Net (MMbbl) | Gross (MMbbl) | Net (MMbbl) | Gross (MMbbl) | Net (MMbbl) |
| Total | 45 | 39 | 155 | 135 | 504 | 439 | 236 | 206 |

**Chance of Commerciality**

D&M has assigned a chance of discovery of 70%. 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%, 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% 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 CAD$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% 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 basin-centered gas prospect 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 basin-centered prospect 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 basin-centered gas prospect 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.

Readers should also review the "*Risk Factors*" section in the Annual Information Form for a broader discussion of the risks and uncertainties facing the Company.

**Notes:**

(1) The Company's working interest in the lands (exploration licences and production leases) that are encompassed (all or a portion thereof) in the basin-centered gas prospect in the Teslimkoy/Kesan Formation is as follows: Banarli Licences 50%, West Thrace Lands 31.5% and South Thrace Lands 81.5%.

(2) The low estimate is the $P_{90}$ quantity. $P_{90}$ means there is a 90% chance that the estimated quantity will be equaled or exceeded.

(3) The best estimate is the $P_{50}$ quantity. $P_{50}$ means there is a 50% chance that the estimated quantity will be equaled or exceeded.

(4) The high estimate is the $P_{10}$ quantity. $P_{10}$ means there is a 10% chance that the estimated quantity will be equaled or exceeded.

(5) The mean estimate is the probability-weighted average (expected value).

(6) The totals are the arithmetic summation of probabilistic estimates. Arithmetic summation may produce invalid results except for the mean.

(7) Unconventional prospective resources, as prepared by D&M, are those quantities of petroleum that are estimated, at a given date, to be potentially recoverable from undiscovered unconventional accumulations by application of future development projects. Unconventional prospective resources may exist in petroleum accumulations that are pervasive throughout a large potential production area and would not be significantly affected by hydrodynamic influences (also called continuous-type deposits). Typically such accumulations (once discovered) require specialised extraction technology (e.g. massive fracturing programmes for tight gas). Tight gas occurs within low permeability reservoir rocks, which are rocks with matrix porosity of 10 percent or less and permeability of 0.1 millidarcies or less, exclusive of fractures. Tight gas can be regionally distributed (e.g. the basin-centered gas prospect in the Thrace Basin evaluated herein), rather than accumulated in a readily producible reservoir in a discrete structural closure as in a conventional gas field.

(8) Prospective resources have both an associated *chance of discovery* and a *chance of development*. 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 unconventional prospective resources should be regarded only as estimates that may change as additional information becomes available. Not only are such unconventional prospective resources estimates based on that information which is currently available, but such estimates are also subject to uncertainties inherent in the application of judgmental factors in interpreting such information. Unconventional prospective resources should not be confused with those quantities that are associated with contingent resources or reserves due to the additional risks involved. 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 quantities that might actually be recovered, should they be discovered and developed, may differ significantly from the estimates herein.

(9) The unconventional prospective resources estimates contained in the D&M Resources Report are expressed as gross and working interest unconventional prospective resources. The above tables summarise Valeura's working interest unconventional prospective resources, which incorporate the fraction of potential hydrocarbon pore volume owned or partially owned by the Company and the Company's working interest ownership, before deduction of any associated royalty burdens. Recovery efficiency is applied to unconventional prospective resources in the above tables.

(10) The estimation of resources quantities for a prospect 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. Estimates of petroleum resources herein are expressed using the terms low estimate, best estimate, high estimate and mean estimate (unrisked and risked) to reflect the range of uncertainty.

(11) The chance of commerciality is defined as the product of the *chance of discovery* and the *chance of development*. *Chance of discovery* is defined in COGE Handbook as the estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum. *Chance of development* is the estimated probability that, once discovered, a known accumulation will be commercially developed.

*Chance of discovery* in the D&M Resources Report is referred to as the probability of geologic success ($P_g$), which is defined as the probability of discovering reservoirs that flow hydrocarbons at a measureable rate. The $P_g$ is estimated by quantifying with a probability, each of the following 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 distributions.

In the D&M Resources Report, two factors have been considered in determining the *chance of development* as follows:

*Chance of development* = $P_{tefs}$ (probability of threshold economic field size) x $P_d$ (probability of development)

D&M defines $P_{tefs}$ 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 threshold economic field size (TEFS). 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% equal to zero using the most likely price scenario.

D&M defines $P_d$ as the probability that a given discovery will be a viable development project. It 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.

(12) The risked mean estimate of conventional natural gas prospective resources = the unrisked mean estimate x *chance of discovery* x *chance of development*.

(13) The conventional natural gas (raw gas in the D&M Resources Report) is the total gas produced from the reservoir prior to processing or separation and includes all non hydrocarbon components as well as any gas equivalent of condensate.

(14) The natural gas liquids prospective resources are included in the conventional natural gas prospective resources.

(15) "**Gross Prospective Resources**" are the Company's working interest (operating or non-operating) share before deducting royalties and without including any royalty interests of the Company. "**Net Prospective Resources**" are the Company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalty interests in prospective resources.

## APPENDIX A-3 – FORM 51-101F2 – REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

## APPENDIX A-4 – FORM 51-101F2 – REPORT ON PROSPECTIVE RESOURCES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

**APPENDIX A-5 – FORM 51-101F3 - REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE**

**FORM 51-101F3**

**REPORT OF**
**MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE**

Management of Valeura Energy Inc., (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data and includes other information such as prospective resources data.

An independent qualified reserves evaluator has evaluated the Company's reserves data and prospective resources data. The reports of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;
(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
(c) reviewed the reserves data and prospective resources data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data, prospective resources data and other oil and gas information;
(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data or the prospective resources data; and
(c) the content and filing of this report.

Because the reserves data and the prospective resources data are based on judgements regarding future events, actual results will vary and the variations may be material.

March 13, 2019

(signed) "*Sean Guest*"
Sean Guest
President and Chief Executive Officer

(signed) "Gordon Begg"
Gordon Begg
Vice President, Commercial

(signed) "*Ronald Royal*"
Ronald Royal
Director and Chairman of Reserves Committee

(signed) "*Timothy Marchant*"
Timothy Marchant
Director and Member of Reserves Committee

## APPENDIX B – TERMS OF REFERENCE FOR THE AUDIT COMMITTEE

## APPENDIX B

## TERMS OF REFERENCE FOR THE AUDIT COMMITTEE

### I. PURPOSE

The primary function of the Audit Committee (the "**Committee**") is to assist the Board in fulfilling its oversight responsibilities by reviewing:

**A.** the financial information that will be provided to the shareholders and others;

**B.** the systems of internal controls, management and the Board of Directors have established; and

**C.** all audit processes.

Primary responsibility for the financial reporting, information systems, risk management and internal controls of Corporation is vested in management and is overseen by the Board.

### II. COMPOSITION AND OPERATIONS

**A.** The Committee shall be composed of not fewer than three directors and not more than five directors, all of whom are independent[1] directors of the Corporation.

**B.** All Committee members shall be "financially literate"[2] and at least one member shall have "accounting or related financial expertise". The Committee may include a member who is not financially literate, provided he or she attains this status within a reasonable period of time following his or her appointment and providing the Board has determined that including such member will not materially adversely affect the ability of the Committee to act independently.

**C.** The Committee shall operate in a manner that is consistent with the Committee Guidelines outlined in Tab 7 of the Board Manual.

**D.** The Corporation's auditors shall be advised of the names of the committee members and will receive notice of and be invited to attend meetings of the Audit Committee, and to be heard at those meetings on matters relating to the Auditor's duties.

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

**F.** The Committee shall meet at least four times each year.

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1 Independence requirements are described in the Appendix to Tab 5, Board Operating Guidelines.

2 The Board has adopted the NI 52-110 definition of "financial literacy", which is an individual is financially literate if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the issuer's financial statements.

## III. Duties and Responsibilities

Subject to the powers and duties of the Board, the Committee will perform the following duties:

### A. *Financial Statements and Other Financial Information*

The Committee will review and recommend for approval to the Board financial information that will be made publicly available. This includes:

i) review and recommend approval of the Corporation's annual financial statements and MD&A and report to the Board of Directors before the statements are approved by the Board of Directors;

ii) review and approve for release the Corporation's quarterly financial statements and press release;

iii) satisfy itself that adequate procedures are in place for the review of the public disclosure of financial information extracted or derived from the Corporation's financial statements, other than the public disclosure referred to in items (i) and (ii) above, and periodically assess the adequacy of those procedures; and

iv) review the Annual Information Form and any Prospectus/Private Placement Memorandums.

Review and discuss:

v) the appropriateness of accounting policies and financial reporting practices used by the Corporation;

vi) any significant proposed changes in financial reporting and accounting policies and practices to be adopted by the Corporation;

vii) any new or pending developments in accounting and reporting standards that may affect the Corporation;

viii) review 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 Corporation, and the manner in which these matters may be, or have been, disclosed in the financial statements; and

ix) review accounting, tax and financial aspects of the operations of the Corporation as the Committee considers appropriate.

### B. *Risk Management, Internal Control and Information Systems*

The Audit Committee will review and obtain reasonable assurance that the risk management, internal control and information systems are operating effectively to produce accurate, appropriate and timely management and financial information. This includes:

i) review the Corporation's risk management controls and policies;

ii) obtain reasonable assurance that the information systems are reliable and the systems of internal controls are properly designed and effectively implemented through discussions with and reports from management, the internal auditor and external auditor; and

iii) review management steps to implement and maintain appropriate internal control procedures including a review of policies.

**C.** ***External Audit***

The External Auditor is required to report directly to the Committee, which will review the planning and results of external audit activities and the ongoing relationship with the external auditor. This includes:

i) review and recommend to the Board, for shareholder approval, engagement and compensation of the external auditor;

ii) review and approve the annual external audit plan, including but not limited to the following:

a) engagement letter;

b) objectives and scope of the external audit work;

c) procedures for quarterly review of financial statements;

d) materiality limit;

e) areas of audit risk;

f) staffing;

g) timetable; and

h) approve fees;

iii) meet with the external auditor to discuss the Corporation's quarterly and annual financial statements and the auditor's report including the appropriateness of accounting policies and underlying estimates;

iv) maintain oversight of the External Auditor's work and advise the Board, including but not limited to:

a) the resolution of any disagreements between management and the External Auditor regarding financial reporting;

b) any significant accounting or financial reporting issue;

c) the auditors' evaluation of the Corporation's system of internal controls, procedures and documentation;

d) the post audit or management letter containing any findings or recommendation of the external auditor, including management's response thereto and the subsequent follow-up to any identified internal control weaknesses;

e) any other matters the external auditor brings to the Committee's attention; and

f) assess the performance and consider the annual appointment or re-appointment of external auditors for recommendation to the Board ensuring that such auditors are participants in good standing pursuant to applicable regulatory laws;

v) review the auditor's report on all material subsidiaries;

vi) review and discuss with the external auditors all significant relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the external auditors' independence, including, without limitation:

a) requesting, receiving and reviewing, on a periodic basis, a formal written statement from the external auditors delineating all relationships that may reasonably be thought to bear on the independence of the external auditors with respect to the Corporation;

b) discussing with the external auditors any disclosed relationships or services that the external auditors believe may affect the objectivity and independence of the external auditors; and

c) recommending that the Board take appropriate action in response to the external auditors' report to satisfy itself of the external auditors' independence;

vii) review and pre-approve any non-audit services to be provided by the external auditor's firm or its affiliates (including estimated fees), and consider the impact on the independence of the external audit; and

viii) meet periodically, and at least annually, with the external auditor without management present.

**D.** ***Compliance***

The Committee shall:

i) ensure that the External Auditor's fees are disclosed by category in the Annual Information Form in compliance with regulatory requirements;

ii) disclose any specific policies or procedures the Corporation has adopted for pre-approving non-audit services by the External Auditor including affirmation that they meet regulatory requirements;

iii) assist the Governance and Compensation Committee with preparing the Corporation's governance disclosure by ensuring it has current and accurate information on:

a) the independence of each Committee member relative to regulatory requirements for audit committees;

b) the state of financial literacy of each Committee member, including the name of any member(s) currently in the process of acquiring financial literacy and when they are expected to attain this status; and

c) the education and experience of each Committee member relevant to his or her responsibilities as Committee member;

iv) disclose if the Corporation has relied upon any exemptions to the requirements for Audit Committees under regulatory requirements.

**E.** ***Other***

The Committee shall:

i) establish and periodically review implementation of procedures for:

a) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls, or auditing matters; and

b) the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters;

ii) review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former External Auditor;

iii) review insurance coverage of significant business risks and uncertainties;

iv) review material litigation and its impact on financial reporting;

v) review policies and procedures for the review and approval of officers' expenses and perquisites;

vi) review policies and practices concerning the expenses and perquisites of the Chairman, including the use of the assets of the Corporation;

vii) review with external auditors any corporate transactions in which directors or officers of the Corporation have a personal interest;

viii) review the terms of reference for the Committee annually and make recommendations to the Board as required;

ix) review list of gifts and entertainment expenses and other matters contemplated under the Anti-Corruption Policy; and

x) review the adequacy of the Anti-Corruption Policy and report on its implementation and matters arising thereunder to the Board.

## IV. ACCOUNTABILITY

**A.** The Committee Chair has the responsibility to make periodic reports to the Board, as requested, on financial matters relative to the Corporation.

**B.** The Committee shall report its discussions to the Board by maintaining minutes of its meetings and providing an oral report at the next Board meeting.