valeura energy inc.

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2013

Dated March 11, 2014

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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

bbl	barrel
Mbbl	thousand barrels
bbl/d	barrel per day
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMBtu	million British Thermal Units
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day

Other

AECO	a natural gas storage facility located at Suffield, Alberta.
API	American Petroleum Institute.
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28°API or higher is generally referred to as light crude oil.
boe	barrel of oil equivalent on the basis of one boe to six thousand cubic feet of gas. Barrels of oil equivalent may be misleading, particularly if used in isolation. A boe conversion ratio of 1 boe 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.
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.
Mcfe	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.
NYMEX	New York Mercantile Exchange.
TL/m^3	Turkish Lira per cubic metre.
$	Canadian dollars.
US$	U.S. dollars.
WTI	West Texas Intermediate, is a type of crude oil used as a benchmark in oil pricing, and is the underlying commodity of futures contracts on the New York Mercantile Exchange (NYMEX).

Conversions

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units)

To convert from	To	Multiply by
Mcf	1,000 cubic metres of gas	0.028
1,000 cubic metres of gas	Mcf	35.493
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.

"**ABCA**" means the *Business Corporations Act* (Alberta), R.S.A. 2000, c. B-9, together with any or all regulations promulgated thereunder, as amended from time to time.

"**AME**" means Aladdin Middle East Ltd.

"**AME-GYP Farm-in Agreement**" means the farm-in agreement executed on September 1, 2010 between Valeura and AME and GYP, two affiliated oil and gas companies operating in Turkey. Valeura earned a 27.5% participating interest in two exploration licences (2674 and 2677) in the Karakilise area of southeast Turkey pursuant to a binding letter agreement executed by Valeura, AME and GYP on November 15, 2011, which completed the earning under the farm-in agreement.

"**Arrangement**" means the arrangement of PanWestern and Northern Hunter under the provisions of Section 193 of the ABCA, completed on April 9, 2010.

"**Arrangement Agreement**" means the amended and restated arrangement and reorganization agreement dated February 18, 2010 between PanWestern and Northern Hunter.

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

''BOTAS'' means Boru Hatlari ile Petrol Tasima Anonim Sirketi, which owns and operates the national crude oil pipeline grid and the national gas pipeline grid in Turkey.

"**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., a Company incorporated pursuant to the laws of the Province of Alberta (previously PanWestern Energy Inc.).

"**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 of Dallas, Texas.

"**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 in its report with a preparation date of March 11, 2014 and effective December 31, 2013.

"**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 Acquisition Agreement**" means the acquisition agreement executed on December 14, 2010 whereby Valeura agreed to purchase certain non-operated producing natural gas assets in the Thrace Basin in Turkey owned by a wholly-owned affiliate of Australia-based Otto Energy Ltd., which closed on March 24, 2011.

"**Exile**" means Exile Resources Inc.

"**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.

"**frac**" 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.

"**Financing Warrants**" means the common share purchase warrants issued as part of the Subscription Receipts Offering which closed on February 28, 2011. On a post-Share Consolidation basis, the holder of Financing Warrants is entitled to exchange 10 warrants to acquire one Common Share at a price of $5.50 per Common Share for a period of 60 months from the closing date of the Subscription Receipts Offering. The Company will have the right to accelerate the expiry date of the Financing Warrants to 30 days from the date of notice once the 20 day volume weighted average price of the Company's Common Shares on the TSX has become equal to, or greater than, $11.00 per Common Share.

"**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).

"**future net revenue**" means the estimated net amount after costs to be received with respect to the development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using forecast prices.

"**GDPA**" means the Republic of Turkey's General Directorate of Petroleum Affairs.

"**GLJ**" means GLJ Petroleum Consultants Ltd. based in Calgary, Alberta.

"**GLJ Reserves Report**" means the independent engineering evaluation of the oil and natural gas reserves attributable to the properties of Valeura in Canada prepared by GLJ in its report dated February 26, 2014 and effective December 31, 2013. The preparation date of the GLJ Reserves Report is February 25, 2014.

"**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.

"**GYP**" means Guney Yildizi Petrol Uretim Sondaj, Muteahhitlik ve Ticaret A.S.

"**Marhat**" means Marhat Insaat Enerji Madencilik Taahhut Sanayi Ticaret Ltd. Sti.

"**MENA**" means the Middle East and North Africa.

"**Multi Party Agreement**" means an agreement executed on June 6, 2011 between affiliates of Valeura, TransAtlantic and PTI Holdings for the acquisition of jointly acquired participating interests in certain producing natural gas assets and lands in the Thrace Basin of northwest Turkey and interests in exploration lands in the Anatolian Basin in southeast Turkey held by TBNG and PTI. The agreement was effected through the purchase of all of the shares of TBNG and PTI held by Mustafa Mehmet.

"**Mustafa Mehmet**" means Mustafa Mehmet Corporation, a corporation organized pursuant to the laws of the United States Virgin Islands.

"**natural gas**" as described in the COGE Handbook means a mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds.

"**natural gas liquids**" or "**NGLs**" as described in the COGE Handbook means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

"**NEB**" means the National Energy Board.

"**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 the Petroleum Law No. 6491 adopted by the Turkish Government dated May 30, 2013 replacing the longstanding predecessor Petroleum Law No. 6326 adopted in 1954.

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

"**non-associated gas**" means an accumulation of natural gas in a reservoir where there is no crude oil.

"**Northern Hunter**" means Northern Hunter Energy Inc., a Company amalgamated pursuant to the laws of the Province of Alberta.

"**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.

"**Oando**" means Oando Energy Resources Inc.

"**Old Petroleum Law**" means Turkey's Petroleum Law No. 6326 which has been replaced by the New Petroleum Law.

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

"**Otto**" means Otto Energy Ltd.

"**PanWestern**" means PanWestern Energy Inc. (now Valeura Energy Inc.), a Company incorporated pursuant to the laws of the Province of Alberta.

"**Performance Warrants**" means warrants to acquire Common Shares at a price of $2.00 per Common Share (post-Share Consolidation basis) and exercisable upon reaching certain thresholds relating to Common Share trading price and time.

"**PKK**" means the Kurdistan Workers' Party, which is a Kurdish organization listed as a terrorist organization by the UN and NATO, fighting an armed struggle with the Turkish state for an autonomous Kurdistan and cultural and political rights for the Kurds in Turkey.

"**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., a corporation organized pursuant to the laws of the British Virgin Islands and having a branch in Turkey.

"**PTI Holdings**" means Pinnacle Turkey Holding Company, LLC, a Delaware limited liability company.

"**Recapitalization Private Placement**" means the issuance of 30,000,000 Common Shares at a price of $0.20 per Common Share (on a pre-Share Consolidation basis) for aggregate gross proceeds of $6.00 million that occurred on April 9, 2010 just prior to the completion of the Arrangement.

"**reservoir**" means a porous and permeable subsurface rock formation that contains a separate accumulation of petroleum that is confined by impermeable rock or water barriers and is characterized by a single pressure system.

"**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.

"**Share Consolidation**" means the consolidation of the Company's common shares on a 10 for 1 basis which occurred on September 15, 2011.

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

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

"**Special Warrants**" means the special warrants issued pursuant to the Special Warrant Offering.

"**Special Warrant Offering**" means the private placement of 51,100,000 Special Warrants at a price of $0.47 per Special Warrant (pre-Share Consolidation basis) for aggregate gross proceeds of $24.017 million, which closed on April 16, 2010, and which Special Warrants converted to Common Shares on May 21, 2010 upon the filing of a final prospectus.

"**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".

"**Subscription Receipt Agreement**" means the subscription receipt agreement dated February 28, 2011 among the Company, Valiant Trust Company, Canaccord Genuity Corp. and Cormark Securities Inc. with respect to the issuance and sale of the Subscription Receipts pursuant to the Subscription Receipts Offering.

"**Subscription Receipts**" means the 265,384,350 subscription receipts of the Company, issued at a price of $0.325 per Subscription Receipt (pre-Share Consolidation basis) on February 28, 2011 under the Subscription Receipts Offering, for total gross proceeds of $86.25 million. Each Subscription Receipt entitled the holder thereof, upon the satisfaction of certain escrow release conditions related to the closing of the TBNG-PTI acquisition, to automatically receive one Common Share and one-half of one Financing Warrant.

"**Subscription Receipts Offering**" means the issuance and sale, via private placement, of 265,384,350 (pre-Share Consolidation basis) Subscription Receipts of the Company which closed on February 28, 2011.

"**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.

"**TBNG-PTI Offer**" means the conditional offer executed on February 9, 2011 with an affiliate of TransAtlantic Petroleum Ltd. to jointly acquire certain non-operated producing natural gas assets and lands in the Thrace Basin of Turkey and other interests in exploration lands in the Anatolian Basin of Turkey from TBNG and PTI.

"**TL**" means the Turkish Lira.

"**TransAtlantic**" means TransAtlantic Petroleum Ltd., a corporation incorporated pursuant to the laws of Bermuda.

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

"**TSXV**" means the TSX Venture Exchange.

"**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.

"**Warrant Indenture**" means the warrant indenture dated February 28, 2011 between the Company and Valiant Trust Company governing the terms of the Financing Warrants issued upon conversion of the Subscription Receipts into Common Shares and Financing Warrants, upon the closing of the TBNG-PTI acquisition.

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

RESERVES AND RESOURCES DEFINITIONS

Reserves

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

"**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.

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

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

"**possible**" reserves are those additional reserves that are less certain to be recovered than probable reserves. 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.

"**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.

"**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.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Resources

In addition to the reserves definitions provided in the preceding sections, the following definitions from the COGE Handbook were used to prepare the disclosure of contingent resources.

"**contingent**" resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent resources have an associated chance of development (economic, regulatory, market and facility, corporate commitment or political risks). The estimates herein have not been risked for the chance of development. There is no certainty that the contingent resources will be developed and, if they are 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 contingent resources.

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.

FORWARD-LOOKING STATEMENTS

Certain information contained in this Annual Information Form constitutes forward-looking information under applicable securities legislation. Such forward-looking information is 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 information may not be appropriate for other purposes, such as making investment decisions. Forward-looking information typically contains statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "target", "goal", "propose", "project" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information in this Annual Information Form may include, but is not limited to, information with respect to:

- the Company's growth strategy;
- anticipated work programs, budgets and operational plans, including targeted seismic, drilling, workovers, fracs and completions, the program to manage water production, the tight gas delineation and development program in the Tekirdag field and adjacent structures and future potential vertical and horizontal wells, and the timing associated with each of the foregoing;
- continued political stability in the areas in which the Company is operating, particularly in southeast Turkey where the Company has a non-operating interest in an exploration licence in the Gaziantep area, given the unrest in neighboring Syria and ongoing terrorist activity by the PKK;
- the ability of the Company to obtain GDPA approvals for pending new exploration licence awards in the Thrace Basin and the timing thereof;
- continued operations of and approvals forthcoming from the GDPA in a manner consistent with past conduct;
- results of future seismic programs;
- future vertical and horizontal drilling and multi-stage fracking activity, including the extent and pace of tight gas delineation and development drilling in the Tekirdag field and adjacent areas and funding thereof;
- the ability to manage water production to maximize oil and gas recovery;
- the ability to reduce costs, achieve capital efficiencies and increase production and the associated corporate sales outlook;
- the availability of operating cash flow and the ability to finance development;
- the continued drilling of horizontal wells with multi-stage frac completions and the expected impact thereof;
- future production rates and associated cash flow;
- future capital and other expenditures, including the amount and nature thereof;
- the ability of the Company to obtain financing on acceptable terms;
- the plans to attract a joint venture partner and drill an exploration well on the Banarli Licence 5104 and the costs, timing, funding and potential upside thereof;
- future economic conditions;

- future currency and exchange rates;
- the Company's continued ability to obtain and retain qualified staff and equipment in a timely and cost efficient manner;
- technical decision making;
- the ability to execute and agree with partners on work programs (and the nature and extent of such work programs) and budgets in respect of all of the majority of the Company's assets, 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 necessary government and stock exchange approvals;
- statements related to "reserves" or "resources" are deemed forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources can be profitably produced in the future. Specifically, forward-looking information contained herein regarding "reserves" and "resources" may include:
    - volumes and estimated value of Valeura's oil and gas reserves; and
    - the life of Valeura's reserves.
- the ability to convert resources to reserves in the future;
- volume and product mix of Valeura's oil and gas production;
- the amount and timing of future asset retirement obligations;
- future liquidity, creditworthiness and financial capacity;
- future interest rates;
- future results from operations and operating metrics;
- future exploration, development and other expenditures;
- future costs, expenses and royalty rates; and
- future transaction and operational plans and the timing associated therewith.

Forward-looking information is based on a number of factors and assumptions which have been used to develop such information but which may prove to be incorrect. Although the Company believes that the expectations reflected in such forward-looking information are reasonable, undue reliance should not be placed on forward-looking information 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;
- the ability of the Company to satisfy the drilling and other requirements under its licences and leases, including meeting spudding deadlines under the Banarli Licence 5104 and Copkoy Licence 5147;
- the ability to attract partners and negotiate farm-out arrangements, in particular on the Banarli Licence 5104;
- the impact of the New Petroleum Law adopted by the Republic of Turkey on May 30, 2013 and the associated regulations dated January 21, 2014;
- the ability of the Company to replace and expand oil and natural gas reserves through exploitation, development, step-out exploration and acquisition;
- 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 foreign countries;
- 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 programs;
- the Company's ability to operate the properties in a safe, 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.

Forward-looking information is based on management's current expectations regarding future growth, results of operations, production, future commodity prices and foreign exchange rates, future capital and other expenditures (including the amount, nature and sources of funding thereof), plans for and results of drilling activity, environmental matters, business prospects and opportunities and future economic conditions. Forward-looking information with respect to the Company's assets in Turkey is also based on management's assumptions that the oil and gas regulatory framework and political situation in Turkey will continue to be stable and operate in its current state, and that the Company will obtain all necessary government and regulatory approvals to complete the activities described herein.

Forward-looking information involves significant known and unknown risks and uncertainties. Exploration, appraisal, and development of oil and natural gas reserves are speculative activities and involve a significant degree of risk. A number of factors could cause actual results to differ materially from those anticipated by the Company including, but not limited to: 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 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 (including the spudding deadlines under the Banarli Licence 5104 and Copkoy Licence 5147); 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 (particularly in the southeastern part of Turkey); the risks of increased costs and delays in timing related to protecting the safety and security of Valeura's personnel and property; the risk of commodity and BOTAS pricing and foreign exchange rate fluctuations; the uncertainty associated with negotiating with third parties in countries other than Canada; the risk of partners having different views on work programs and potential disputes among partners; the uncertainty regarding government and other approvals (potential changes in laws and regulations); risks associated with weather delays and natural disasters; and, the risk associated with international activity.

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

VALEURA ENERGY INC.

General

Valeura Energy Inc. ("**Valeura**" or "**the Company**") is a Canada-based public company engaged in the exploration, development and production of petroleum and natural gas in Turkey and Western Canada. The Company's shares are traded on the Toronto Stock Exchange ("**TSX**") in Canada under the trading symbol VLE.

Valeura evolved from two predecessor companies operating in Canada: PanWestern Energy Inc. ("**PanWestern**"), a public company that was listed on the TSX Venture Exchange ("**TSXV**"), and Northern Hunter Energy Inc. ("**Northern Hunter**"), a private oil and gas company. PanWestern was originally incorporated under the ABCA on June 7, 2000 under the name "Sasha Corp". Northern Hunter was incorporated under the ABCA on September 1, 2006.

On April 9, 2010, PanWestern and Northern Hunter completed a Plan of Arrangement (the "**Arrangement**") under the ABCA whereby PanWestern acquired all of the assets and liabilities of Northern Hunter. Because the shareholders of Northern Hunter acquired more than 50% of the shares in the merged entity, the transaction was accounted for as a reverse take-over whereby Northern Hunter was considered the acquirer for accounting purposes. As part of the Arrangement, the board of directors of PanWestern was reconstituted with members from Northern Hunter's board of directors and the management team became that of Northern Hunter. Subsequent to completion of the Arrangement, PanWestern filed articles of amendment on June 29, 2010 to change its name to Valeura Energy Inc., as approved at PanWestern's annual and special meeting of Shareholders on June 29, 2010.

After pursuing a number of acquisition opportunities in several target countries familiar to the management of the Company, Valeura executed its first international transaction in Turkey in September 2010. Under terms of this first AME-GYP Farm-in Agreement, Valeura agreed to fund an exploration program to earn beneficial interests in a number of exploration licences in the Anatolian Basin of southeast Turkey. In December 2010, Valeura executed a second transaction in Turkey, the Edirne Acquisition Agreement, to purchase certain non-operated natural gas producing assets in the Thrace Basin of northwest Turkey.

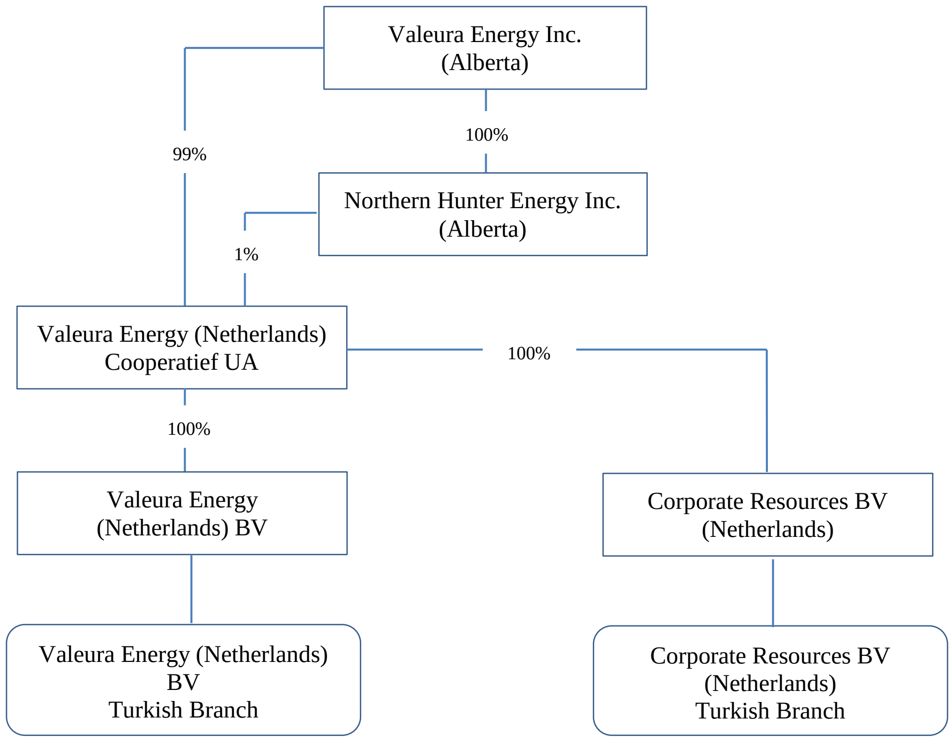
The Company has since grown this initial platform in Turkey through subsequent acquisitions, farm-ins and new licence awards as described below and, as at the date hereof, held interests in 14 production leases and exploration licences encompassing approximately 1.0 million gross acres (gross) (0.43 million net acres). In 2013 the Company produced an average of 980 boe/d, more than 95% of which was natural gas from the Thrace Basin of Turkey.

In addition to information in respect of Valeura contained herein, further details concerning the Company are provided in the financial statements and related management discussion and analysis of Valeura, which have been filed under the profile of the Company at www.sedar.com.

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.

Organizational Structure of the Company

The following diagram describes: the inter-corporate relationships among the Company and each of its material subsidiaries as at December 31, 2013; where each principal subsidiary was incorporated; and, the percentage of votes attaching to all voting securities of each subsidiary beneficially owned by Valeura and held by such subsidiaries.



GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

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

2011

As announced on February 9, 2011, Valeura executed the TBNG-PTI Offer with an affiliate of TransAtlantic Petroleum Ltd. ("**TransAtlantic**") to jointly acquire non-operated producing natural gas assets and lands in the Thrace Basin of Turkey and other interests in exploration lands in the Anatolian Basin of Turkey from TBNG and Pinnacle Turkey, Inc. ("**PTI**"), effective October 1, 2010 (the "TBNG-PTI Joint Venture"). The transaction closed on June 8, 2011, at a final purchase price, after adjustments, of approximately $53.7 million (Valeura's 40% share), following the execution of definitive agreements including the Multi Party Agreement.

To finance the TBNG-PTI Offer, Valeura completed the Subscription Receipts Offering on February 28, 2011 for total gross proceeds of $86.25 million. Valeura issued a total of 265,384,350 Subscription Receipts (pre-Share Consolidation basis) at a price of $0.325 per Subscription Receipt. Each Subscription Receipt entitled the holder thereof to receive one Common Share and one-half of one Financing Warrant. The terms of the Financing Warrants are further described in this Annual Information Form under "*Description of Capital Structure*".

Valeura also executed two farm-in agreements in the Thrace Basin in May and June 2011. The first was with Marhat, whereby Valeura acquired a 100% working interest and operatorship of Licence 4201, subject to an overriding royalty to Marhat. In the second farm-in, Valeura negotiated the right to earn a 50% working interest in two licences (4094 and 4532) held by TransAtlantic by funding seismic and two exploration wells. These three licences are contiguous with the TBNG-PTI Joint Venture licences in the Thrace Basin described above.

At Valeura's annual and special meeting of shareholders held on June 15, 2011, shareholders approved the Share Consolidation. The Share Consolidation was subsequently approved by the TSXV and occurred contemporaneously with the Company's graduation from the TSXV to the TSX.

In November 2011, Valeura drilled the first well, Evrenbey-1, under the farm-in agreement with TransAtlantic on Licences 4094 and 4532. The well was cased and suspended.

Under a binding letter agreement executed on November 14, 2011, Valeura also acquired a 24% participating interest from GYP in three exploration licences (3998, 3999 and 4187) in the western reaches of the Thrace Basin, contiguous with Valeura's existing acreage and extending to the Greece border. The acquisition was negotiated concurrently with finalizing the AME-GYP Farm-in Agreement in southeast Turkey, in which Valeura earned a final 27.5% participating interest in two exploration licences (2674 and 2677) in the Karakilise area.

2012

In February 2012, Valeura drilled the Dagdere-1 well under the farm-in agreement with Marhat on Licence 4201. The well was cased and suspended.

In June 2012, Valeura was awarded two new exploration licences by the GDPA in the Anatolian Basin in southeast Turkey, including Licence 5052 (Valeura 100%) in the Karakilise area contiguous with Licences 2674 and 2677 (Valeura 27.5%), and Licence 4985 (Valeura 100%) in the Bostanci area at the juncture of the Syrian and northern Iraq borders. Under a pre-bidding arrangement, Oando (formerly Exile) had a right to a 50% participating interest in Licence 4985.

On October 10, 2012, Valeura closed a bought-deal financing for gross proceeds of $14.95 million. Valeura issued 11,500,000 Common Shares at a price of $1.30 per Common Share.

In October 2012, the Company and its partners agreed to let Licences 3998, 3999 and 4187 in the Thrace Basin expire over the October 2012 to January 2013 period, at no further cost, after Valeura drilled an unsuccessful shallow gas exploration well in the third quarter of 2012 (Kavacik-1), which was abandoned.

2013

In March 2013, Valeura relinquished the Marhat farm-in Licence 4201 in advance of the next district drilling requirement, at no further cost, given its assessment of non-commercial reserves in the Dagdere-1 well and limited resulting prospectivity on the licence.

In April 2013, the Company was awarded the Banarli Licence 5104 (Valeura 100%) by the GDPA. This exploration licence has a four-year initial term and covers an area of 118,598 gross acres located near the centre and deepest part of the Thrace Basin.

In May 2013, the TBNG-PTI Joint Venture was successful in acquiring exploration Licence 5151 (Valeura 40%) (120,728 gross acres; 48,291 net acres), which encompasses lands in expired Licence 3734 previously held by the TBNG-PTI Joint Venture.

In June 2013, Valeura chose to relinquish its rights at no further cost under the TransAtlantic farm-in agreement on Licences 4094 and 4532 in the Thrace Basin, given its assessment of non-commercial reserves in the Evrenbey-1 well and resulting limited prospectivity on the licence.

In June 2013, Oando relinquished its right to a 50% participating interest in the Bostanci Licence 4985. The Company subsequently acquired, on a 100% cost basis, an additional 20 kilometres of new seismic on the Bostanci Licence in July 2013 along the borders with Syria and northern Iraq. After interpreting the new seismic and carrying out a process to seek a new farm-in partner, the Company made the decision to relinquish the licence in

October 2013, at no further cost, in advance of the spudding deadline under the licence terms, given the assessed exploration risk, projected well cost of more than $10 million and inability to attract a farm-in partner.

In July 2013, the Company was awarded the Copkoy Licence 5147 (Valeura 100%) (20,668 gross acres) in the Thrace Basin, which encompasses lands in the expired Licence 4187.

In October 2013, the Company and its partners relinquished three of the four Gaziantep licences (Valeura 26%), at no further cost, in advance of the next district drilling commitment. Licence 4076 was retained, in which the horizontal well Alibey-1 was drilled in July 2012. The well tested oil but is currently suspended pending a potential workover to minimize water production.

In October 2013, Valeura also relinquished Karakilise Licence 5052 (Valeura 100%) after an extensive review and re-processing of additional seismic data acquired from the government after the licence award, and an unsuccessful process to attract a farm-in partner.

The Company is pursuing other opportunities in Turkey, and as of the date hereof, applications for two exploration licences in the Thrace Basin submitted in the second quarter of 2013 are pending a decision from the GDPA. These have the potential to further expand the Company's acreage position. However, there is no certainty that these applications will be successful and the timing of a GDPA decision is uncertain.

Subsequent Developments

In February 2014, the Company sold its 27.5% interest in the two Karakilise Licences 2674 and 2677, which included two marginal oil wells producing in aggregate less than 10 bopd (net). Both licences were near expiry at the end of their 11-year term, requiring applications for production leases and relinquishment of the residual exploration areas by May 2014. The Company assessed that there was limited upside potential in retaining these licences.

DESCRIPTION OF THE BUSINESS AND OPERATIONS

Valeura is a Canada-based public company engaged in the exploration, development and production of petroleum and natural gas in Turkey and Western Canada. The Company is focused on continuing to grow internationally in Turkey and other selected countries in the Mediterranean Basin, Central Europe, and the Middle East and North Africa ("**MENA**") region. The Canadian operations include small, non-strategic legacy assets that may be sold as market conditions permit.

Corporate Strategy

At its founding, Valeura adopted a longer-term international growth strategy with the following key elements:

- Target the creation of a large global exploration and production ("**E&P**") company in five to seven years
- Build an E&P portfolio in one or two regions of the world
    - Mediterranean Basin / Central Europe / MENA regions are of prime interest currently, but may pursue opportunities in other regions that meet screening criteria
    - Focus on countries with world-class hydrocarbon basins, attractive fiscal regimes, limited political and contract risk, established infrastructure and significant deal flow
    - Target under-explored and under-exploited assets, and under-capitalized companies
    - High-grade portfolio with operated, high working interest, onshore producing assets with material exploitation, development, and step-out exploration upside
    - Establish critical mass by acquiring large reservoirs or large land positions with a high density of repeatable opportunities (conventional and unconventional oil and premium gas)
    - Apply modern technologies and strong execution oversight

In the near-term, and recognizing the current state of capital markets, Valeura is focused on growing its established business in Turkey, particularly its natural gas operations in the Thrace Basin, and achieving the following key objectives:

- Develop the tight gas play in the Thrace Basin with modern multi-stage frac technology in vertical and horizontal wells, building on an extensive proof-of-concept program since mid-2011 to de-risk the play;
- Optimize the long-standing conventional shallow gas business in the Thrace Basin, including exploration on new 3D seismic acquired in the Osmanli area in late 2013;
- Pursue the foregoing in the near term with a paced capital expenditure program funded from operating cash flow and cash on hand; and
- Fulfill exploration-focussed commitment programs on high potential licences, including pursuing a potential basin-centered gas play in the deeper horizons below 3,000 metres on the Banarli Licence 5104 and seeking partners to share the associated costs and exploration risk.

Personnel

As at December 31, 2013, Valeura had 13 full-time employees in its head office in Calgary, as well as three full-time employees in its branch in Ankara, Turkey.

Operations of the Company

The following paragraphs describe the Company's principal properties and operations by country.

TURKEY

The extent of Valeura's land holdings, as at the date hereof, in the Thrace Basin in northwest Turkey and the Anatolian Basin in southeast Turkey acquired through various transactions, including asset purchases, farm-ins and new licence awards, is set forth in the table below.

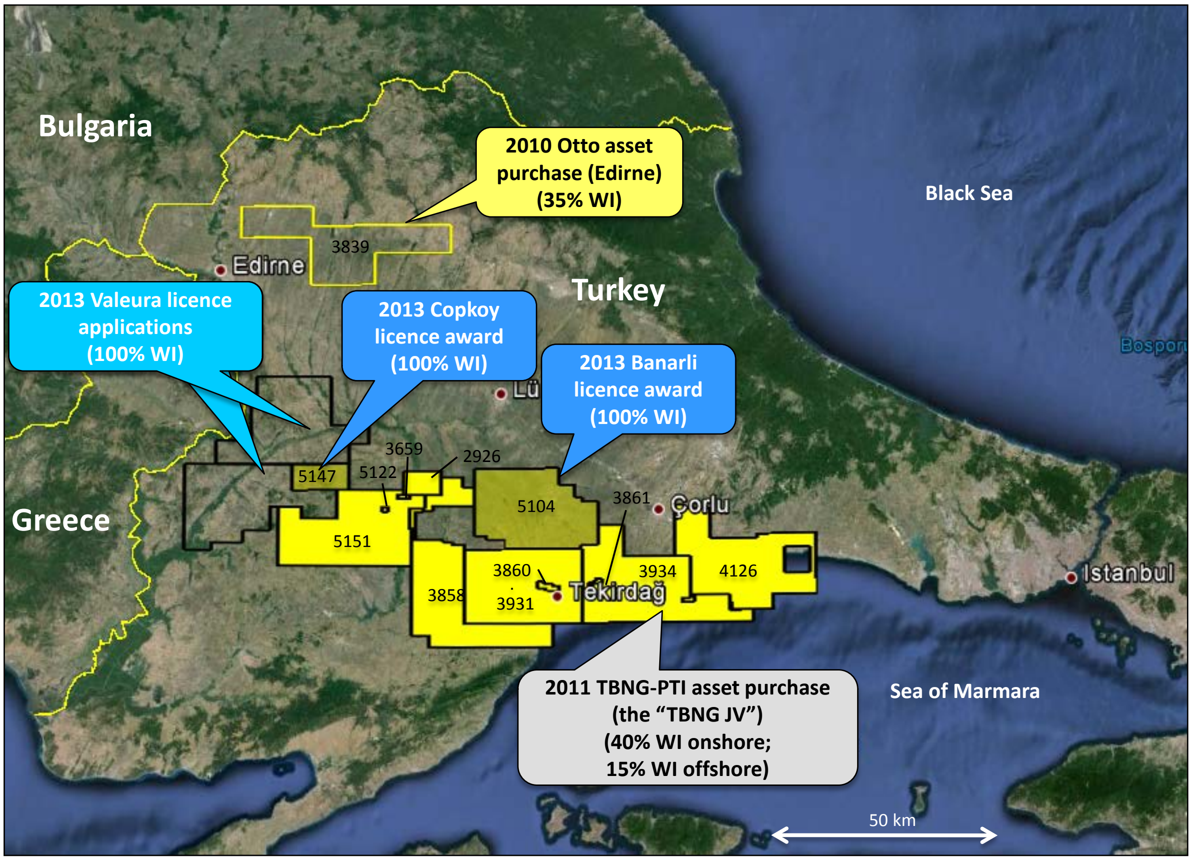
TRANSACTION	PETROLEUM DISTRICT(1)	LEASES & LICENCES (#)	GROSS AREA (acres)	VALEURA NET AREA (acres)
THRACE BASIN				
TBNG-PTI – Onshore	I (MARMARA)	10	507,853	203,141
TBNG-PTI – Offshore	I (MARMARA)	-	116,508	17,476
Licence 5104 Award (Banarli) (2)	I (MARMARA)	1	118,598	118,598
Licence 5147 Award (Copkoy) (3)	I (MARMARA)	1	20,668	20,668
Otto-Edirne (Licence 3839)	I (MARMARA)	1	119,125	41,694
SUB TOTAL		**13**	**882,752**	**401,577**
ANATOLIAN BASIN				
TBNG-PTI (Licence 4607)	XII (GAZIANTEP)	1	123,372	32,077
TOTAL		**14**	**1,006,124**	**433,654**

Notes:

(1) Under the New Petroleum Law, Turkey's 18 onshore petroleum districts have been replaced by a single onshore district.
(2) Exploration Licence 5104 (Valeura 100%) requires that a well be spudded by early July 2014 to hold the licence.
(3) Exploration Licence 5147 (Valeura 100%) requires that a well be spudded by early October 2014 to hold the licence.

THRACE BASIN

Valeura's production in Turkey is dominated by natural gas, all of which is produced in the Thrace Basin located in an area west of Istanbul and extending to the borders of Greece and Bulgaria. The map below depicts Valeura's assets in the Thrace Basin as at the date hereof and the two pending exploration licence applications.



TBNG-PTI Joint Venture Producing Assets

The TBNG-PTI Joint Venture lands (Valeura 40%) acquired in in 2011 are located in the Thrace Basin and included four production leases and 10 exploration licences, of which two licences were entirely on land, three licences had a portion in the shallow waters of the Sea of Marmara (up to 200 metre water depth), and five licences were in deeper water (200 to 1,200 metre water depth). The five deep offshore licences were subsequently relinquished in 2011. One onshore exploration licence also expired in 2012, after the carve-out of a new production lease, and the relinquished lands were subsequently re-acquired through a successful application process in 2013. As of the date hereof, Valeura has net acreage in the onshore areas of the TBNG-PTI Joint Venture of 203,141 acres (40% interest) and 17,476 acres (15% interest) in the shallow offshore (five production leases and five exploration licences).

Natural gas is currently produced from both conventional and unconventional (tight gas) sandstone reservoirs in onshore leases and licences on the TBNG-PTI Joint Venture lands. Gas sales from these lands in 2013 averaged 12.9 MMcf/d (gross) or 5.2 MMcf/d (net 40%).

Average realized prices for Valeura's gas sales from the TBNG-PTI Joint Venture lands were approximately $10.30 per Mcf in 2013.

Conventional Gas

Approximately 50% of the natural gas produced from the TBNG-PTI Joint Venture lands is shallow gas produced from approximately 65 wells, all located onshore. Shallow gas is produced from Tertiary-aged stacked sands in the Danismen and Osmancik formations at relatively shallow depths of 500 to 1,500 metres. The gas, which is composed primarily of methane, is gathered, dehydrated and compressed in owned facilities and distributed on an owned sales line network directly to more than 50 commercial and end-user customers. TransAtlantic manages the marketing arrangements on behalf of the parties under the joint venture operating agreement.

In 2012 the Company completed 32 well workovers (gross) and drilled nine new shallow exploration and development wells (gross) on the TBNG-PTI Joint Venture lands. In 2013 an additional 14 well workovers (gross) were completed and one new shallow gas development well (gross) was drilled.

Opportunities exist to further optimize the shallow gas business in 2014 and future years through exploration and development drilling, well workovers, and additional wellhead compression to mitigate natural declines. When the assets were acquired, approximately 3,500 kilometres of legacy 2D seismic was available on the onshore lands in the Thrace Basin but no 3D seismic had been shot. The initial acquisition of 413 square kilometres of new 3D seismic in the Tekirdag and Hayrabolu areas was completed in mid-October 2011. All of the 3D seismic was processed by the end of December 2011 and fully interpreted by April 2012 to position a ramp-up of deeper, tight gas drilling and selected shallow gas drilling in the second quarter of 2012. In the third and fourth quarters of 2013, an additional 232 square kilometers of 3D seismic was acquired in the Osmanli area and, as of the date hereof, is being processed and interpreted. It is expected that this new 3D seismic will provide drilling opportunities for both conventional shallow gas and deeper tight gas in 2014 and future years.

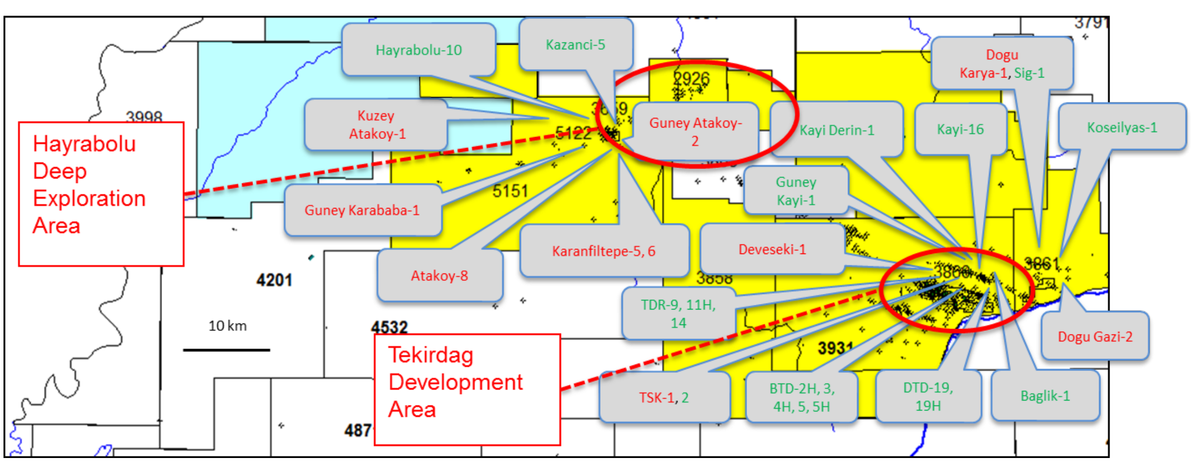
Unconventional Gas

Valeura acquired its position in the Thrace Basin with the belief that there was significant upside potential associated with applying modern multi-stage frac completion technology to exploit deeper tight gas sands in the Mezardere, Teslimkoy, and Kesan formations in structures that underlie the shallow gas reservoirs. Producing analogies in the Thrace Basin and selective deep drilling in the past on the TBNG-PTI Joint Venture lands indicated the presence of relatively low porosity (6 to 15%), stacked sandstone reservoirs in these formations that tested gas, but this tight gas was generally not producible at commercial rates in the absence of fracture stimulation.

There are many other analogies of tight gas reservoirs around the world in similar basins that have benefited from the application of modern drilling and completion technologies and robust capital investment. In parts of the Thrace Basin, there are up to 5,000 metres of sediments with a number of tight gas targets that are expected to benefit from multi-stage fracs in vertical wells, given the relatively large gross thickness of the target interval, or in horizontal wells in selected horizons as geological understanding and frac experience grow.

Unlocking the potential in the deeper tight gas play in the Thrace Basin has been a top priority for the Company since mid-2011. The Company has carried out an extensive proof-of-concept program since that time to de-risk the tight gas play. To the end of 2013, the Company had fracked 56 wells (43 well re-entry fracs in vertical wells, 10 fracs on new deep vertical wells and three multi-stage fracs in three new horizontal wells) in tight gas reservoirs on the TBNG-PTI Joint Venture lands with encouraging results. In 2012 the Company spudded 11 deep wells drilled on new 3D seismic to depths up to 3,755 metres in the Mezardere, Teslimkoy, and Kesan formations. In 2013, the Company spudded two medium depth wells, one deep vertical well (4,054 metres) and three horizontal wells in tight gas reservoirs. To the end of 2013, 13 of these 17 new wells had been fracked.

The Company's conventional shallow gas (red) and unconventional tight gas (green) drilling program in 2012, 2013 and 2014 year-to-date on the TBNG-PTI Joint Venture lands is illustrated in the figure and table below.



TIME	WELLS SPUDDED	PRODUCING	EVALUATING/ COMPLETING	CASED & STANDING	PLUGGED & ABANDONED	DRILLING
UNCONVENTIONAL						
2012 SUB-TOTAL	11	8	3	-	-	-
2013 SUB-TOTAL	6	5	1	-	-	-
2014 YTD SUB TOTAL	2	1	-	1	-	-
CONVENTIONAL						
2012 SUB-TOTAL	9	6	1	-	2	-
2013 SUB-TOTAL	1	-	1	-	-	-
2014 YTD SUB TOTAL	-	-	-	-	-	-
TOTAL 2012 – 2014 YTD	**29**	**20**	**6**	**1**	**2**	**-**

In 2012, TransAtlantic, the operator of the TBNG-PTI Joint Venture lands, announced a potential vertical well development program of up to 88 wells that could extend over several years in the Tekirdag field area targeting tight gas. This formed the basis of a development program for purposes of assessing reserves at year-end 2012. This potential development program was subsequently modified as at year-end 2013 to reflect a slower pace of development with a program in 2014 essentially fully-funded from expected cash flow. This potential development program is subject to a number of contingencies including approvals from partners and regulatory authorities, availability of equipment and additional financing in the future.

Opportunities exist to also ramp up the tight gas program on other discovered fields on the TBNG-PTI Joint Venture lands. Also, results from the initial three horizontal wells drilled in 2013 and two horizontal wells drilled to date in 2014 in the Tekirdag field could shape the ultimate development program in 2014 and future years in terms of determining the optimum mix of horizontal and vertical wells.

Otto Producing Asset Purchase

The assets acquired from Otto under the Edirne Acquisition Agreement consist of a 35% interest in the Edirne Exploration Licence 3839 (the "**Edirne Licence**") in the Thrace Basin. The Edirne Licence covers an area of 119,125 gross acres (41,694 net acres) in the Thrace Basin, approximately 200 kilometres northwest of Istanbul, near the borders with Greece and Bulgaria. An affiliate of TransAtlantic operates the Edirne Licence.

Gas sales from the Edirne Licence in 2013 averaged 0.9 MMcf/d (gross) or 0.3 MMcf/d (net 35%). Average realized prices for Valeura's gas sales from the Edirne Licence were approximately $9.16 per Mcf in 2013.

Natural gas is currently produced from eight to nine wells that are completed in Tertiary-aged sands in the Osmancik formation at a depth of approximately 300 metres. The gas is relatively lean and requires only dehydration and compression to meet sales specifications. The gas is processed on a fee basis in a third-party owned facility and is tied into the pipeline system operated by BOTAS located nine kilometres from the plant, which carries imported Russian gas to the Istanbul area and other cities in Turkey. The gas is sold to one of Turkey's largest gas and power wholesalers. Sales from the Edirne Licence began in April 2010.

In 2013 the Company completed two successful workovers. The operator drilled five shallow gas wells in 2013 in which Valeura did not participate given the Company's view that these were marginal opportunities.

Banarli Exploration Licence

In April 2013, Valeura was awarded the Banarli Licence 5104 (Valeura 100%). The licence has a four-year initial term and covers an area of 118,598 gross acres (185 square miles) located near the centre and deepest part of the Thrace Basin. In June 2013, Valeura completed a 93 kilometre 2D seismic program to complement the existing 2D seismic coverage on the licence of more than 200 kilometres. The licence is unexplored with only two relatively shallow wells drilled to date, of which the latest, Karaca-1, was plugged and abandoned at a depth of 1,026 metres in November 2010.

Valeura believes the licence is ideally located to test for a potential basin-centered gas play and to explore for over-pressured gas below a depth of approximately 3,000 metres. Based on the extensive 2D seismic control, the Teslimkoy and Mezardere Formations are interpreted to be deeper than 3,000 metres on essentially all of the licence. At this depth and associated temperature, the source rock shales and reservoir sands could be in an active hydrocarbon-generating "kitchen" forming a basin-centered gas accumulation, with regionally pervasive, low permeability, gas-saturated sandstone reservoirs exhibiting abnormally high pressures. The Company expects that a 4,000 to 5,000 metre vertical exploration well would be required as an initial step to test the concept at an estimated cost of at least $10 million (gross) to drill and complete the well with a multi-stage frac.

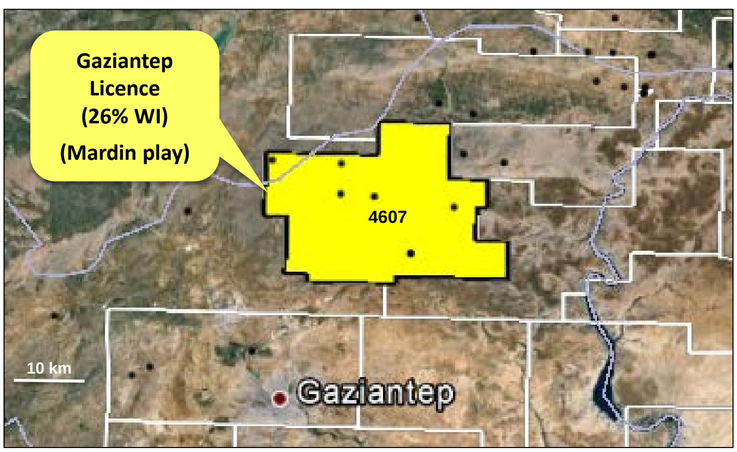
Valeura has an active process underway to seek a joint venture partner to participate in funding this potentially high impact exploration program at Banarli and has engaged Moyes & Co. to assist in this process. Under the Banarli Licence terms, a well must be spudded by early July 2014, which includes a normal extension of up to 90 days to comply with a notice to drill. There is no minimum depth requirement for this well.

Other Areas

Valeura has applied for two exploration licences northwest and contiguous with the TBNG-PTI Joint Venture lands, shown in the map on page 18 above. There is no certainty that these applications will be successful, and the timing of the GDPA decision is uncertain.

ANATOLIAN BASIN

The map below depicts Valeura's assets, as at the date hereof, in the Anatolian Basin in southeast Turkey, which consist of one non-operated exploration licence in the Gaziantep area (Valeura 26%).



Gaziantep Licences

In June 2011 as part of the TBNG-PTI acquisition, Valeura acquired a 26% non-operated interest in five exploration licences in the Anatolian Basin located around the city of Gaziantep. One of these licences (4638) was subsequently relinquished in November 2011 and an additional three licences (4648, 4649 and 4656) were relinquished in October 2013.

In July 2012, a 414 metre horizontal sidetrack was drilled in the Alibey-1 well on Licence 4607, aimed at improving productivity from a Mardin Group heavy oil discovery in the original well. Approximately 80 metres of horizontal porous section was identified on logs, with extensive natural fracturing throughout the horizontal section. The sidetrack, which is at a true vertical depth of approximately 1,868 metres, was cased with a 4.5-inch liner. In Q2 2013, all of the indicated pay in the well was perforated and acidized. However, initial testing indicated oil rates of 10 to 15 bopd at a high water cut. Further evaluation is underway to assess the merits of a recompletion program to potentially reduce water production from the well.

CANADA

Valeura and its predecessor companies have operated oil and gas fields in Canada for approximately 10 years. Valeura operates nine oil and gas properties in Alberta, which produced approximately 48 boe/d (net) in 2013. The principal areas are shown in the map below.

Grand Forks / Hays

Valeura has an interest in 10 wells in the area, of which four are operated, with an average working interest of 69.6%. Net production from the area in 2013 averaged 46 Mcf/d of natural gas and 24 bbl/d of oil or a total of approximately 32 boe/d.

Other Properties

Valeura holds working interests ranging from 10.0% to 84.4% in various other properties in Alberta. Net production from these other properties in 2013 averaged 49 Mcf/d of natural gas and 8 bbl/d of liquids, or a total of approximately 16 boe/d.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Reserves in Turkey

The Company engaged DeGolyer and MacNaughton ("**D&M**") to prepare a report relating to the Company's reserves in Turkey as at December 31, 2013. The reserves on the properties described herein are estimates only. Actual reserves on these properties may be greater or less than those estimated.

The Company's crude oil and 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 natural gas reserves and the value of future net revenue of the Company as at December 31, 2013 as evaluated by D&M in its report with a preparation date of March 11, 2014, (the "**D&M Reserves Report**"). A summary of the D&M Reserves Report and accompanying narrative (in Form 51-101F1), as well as the report on the reserves data by D&M (in Form 51-101F2) and the report of the Company's management on such reserves data (in Form 51-101F3) are included in this Annual Information Form as Appendices A-1, A-2 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 Natural Gas Information (Turkey) attached as Appendix A-1 hereto.

Oil and Gas Reserves in Turkey
Based on Forecast Prices and Costs(9)

	Light and Medium Oil		Heavy Oil		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)(6)	4	3	-	-	4,449	3,849	-	-	746	645
Proved Developed Non-Producing(2)(7)	36	31	-	-	1,691	1,463	-	-	318	275
Proved Undeveloped(2)(8)	46	40	-	-	3,229	2,794	-	-	584	506
Total Proved(2)	86	74	-	-	9,369	8,106	-	-	1,648	1,426
Total Probable(3)	50	43	-	-	21,780	18,841	-	-	3,680	3,183
Total Proved Plus Probable(2)(3)	136	117	-	-	31,149	26,947	-	-	5,328	4,609
Total Possible(4)	78	68	-	-	29,356	25,393	-	-	4,971	4,300
Total Proved Plus Probable Plus Possible(2)(3)(4)	214	185	-	-	60,505	52,340	-	-	10,299	8,909

Net Present Values of Future Net Revenue in Turkey Based on Forecast Prices and Costs (9)(11)

	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes(11) 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)(6)	32,840	30,333	28,230	26,436	24,883	32,840	30,333	28,230	26,436	24,883
Proved Developed Non-Producing(2)(7)	12,157	9,824	8,245	7,125	6,295	10,393	8,283	6,962	5,885	5,155
Proved Undeveloped(2)(8)	9,295	7,441	5,897	4,606	3,523	7,219	5,843	4,620	3,787	3,016
Total Proved(2)	54,292	47,598	42,372	38,167	34,701	50,452	44,459	39,812	36,108	33,054
Total Probable(3)	148,649	103,891	75,324	56,313	43,216	119,094	83,127	60,289	45,141	34,751
Total Proved Plus Probable(2)(3)	202,941	151,489	117,696	94,480	77,917	169,546	127,586	100,101	81,249	67,805
Total Possible(4)	254,297	161,242	110,114	79,398	59,666	203,362	129,749	88,428	63,543	47,633
Total Proved Plus Probable Plus Possible(2)(3)(4)	457,238	312,731	227,810	173,878	137,583	372,908	257,335	188,529	144,792	115,438

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. 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.

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 Appendix A-1 in a 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, 2013 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. Income taxes are Turkey income taxes.

Reserves in Canada

The Company engaged GLJ Petroleum Consultants ("**GLJ**") to prepare a report relating to the Company's reserves in Canada as at December 31, 2013. The reserves on the properties described herein are estimates only. Actual reserves on these properties may be greater or less than those estimated.

As at December 31, 2013, the Company's crude oil and natural gas reserves are located in Alberta, Canada. Set out below is a summary of the crude oil and natural gas reserves and the net present value of future net revenues of the Company as at December 31, 2013, as evaluated by GLJ in its report dated February 26, 2014 and with a preparation date of February 25, 2014 (the "**GLJ Reserves Report**"). A summary of the GLJ Reserves Report and accompanying narrative (in Form 51-101F1), as well as the report on the reserves data by GLJ (in Form 51-101F2) and the report of the Company's management on such reserves data (in Form 51-101F3) are included in this Annual Information Form as Appendices A-3, A-4 and A-5 respectively.

The following is a summary of the GLJ Reserves Report which is qualified in its entirety by the Company's Statement of Reserves Data and Other Oil and Natural Gas Information (Canada) attached as Appendix A-4 hereto.

Oil and Gas Reserves in Canada
Based on Forecast Prices and Costs(8)(10)

	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Total Oil Equivalent(9)	
	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)	35	33	6	5	70	87	3	2	55	55
Proved Developed Non-Producing(2)(6)	22	19	0	0	281	248	11	8	80	68
Proved Undeveloped(2)(7)	0	0	0	0	0	0	0	0	0	0
Total Proved(2)	57	52	6	5	351	335	14	10	135	123
Total Probable(3)	109	97	4	3	936	860	54	40	323	283
Total Proved Plus Probable(2)(3)	166	149	10	8	1,287	1,195	68	50	458	406

Net Present Values of Future Net Revenue in Canada
Based on Forecast Prices and Costs(8)(10)

	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes Discounted At				
	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved Developed Producing(2)(5)	1,344	1,172	1,051	959	884	1,344	1,172	1,051	959	884
Proved Developed Non-Producing(2)(6)	569	477	403	342	292	569	477	403	342	292
Proved Undeveloped(2)(7)	0	0	0	0	0	0	0	0	0	0
Total Proved(2)	1,913	1,650	1,454	1,301	1,176	1,913	1,650	1,454	1,301	1,176
Total Probable(3)	5,798	4,236	3,222	2,521	2,016	5,798	4,236	3,222	2,521	2,016
Total Proved Plus Probable(2)(3)	7,711	5,886	4,676	3,822	3,192	7,711	5,886	4,676	3,822	3,192

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. "**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.
5. "**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.
6. "**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.
7. "**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.
8. The pricing assumptions used in the GLJ Reserves Report with respect to net values of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth in Appendix A-3 in a table titled "Forecast Prices, Inflation & Exchange Rates Used in GLJ Reserves Report". The Forecast Prices, Inflation & Exchange rates were developed by GLJ as at January 1, 2014 and reflect the then current year forecast prices, inflation and exchange rates. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.
9. "**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.
10. Values may not add due to rounding.

Resources in Turkey

The Company has not updated the contingent resources assessment for the Thrace Basin carried out by D&M as at December 31, 2012, which was summarized in Valeura's Annual Information Form for the year ended December 31, 2012. Any decision to update D&M's contingent resources assessment will be dependent on further results from horizontal drilling on the TBNG-PTI Joint Venture lands and potential exploration drilling on the Banarli Licence 5104 in 2014.

DESCRIPTION OF CAPITAL STRUCTURE

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

At Valeura's annual and special meeting of shareholders held on June 15, 2011, shareholders approved the Share Consolidation. The Share Consolidation was subsequently approved by the TSXV and occurred contemporaneously with the Company's graduation from the TSXV to the TSX.

As at December 31, 2013, there were 57,906,135 Common Shares (post-Share Consolidation basis) and nil Preferred Shares outstanding. As of the date hereof, 57,906,135 Common Shares and nil Preferred Shares were issued and outstanding. The following is a summary of the rights, privileges, restrictions and conditions attaching to the Common Shares and Preferred Shares.

Common Shares

The Company is authorized 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 authorized 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 rateably 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 rateably with holders of each other series of Preferred Shares the amount, if any, specified as being payable preferentially to holders of such series.

Subscription Receipts

On February 28, 2011 the Company completed a bought deal private placement of Subscription Receipts, issuing 265,384,350 Subscription Receipts (pre-Share Consolidation basis) at a price of $0.325 per Subscription Receipt for total gross proceeds of $86.25 million. Each Subscription Receipt entitled the holder thereof, upon the satisfaction of certain escrow release conditions related to the closing of TBNG-PTI acquisition, to automatically receive one Common Share and one-half of one Financing Warrant of the Company. On a post-Share Consolidation basis, the holder of Financing Warrants was entitled to exchange 10 Financing Warrants to acquire one Common Share at a price of $5.50 per Common Share for a period of 60 months from the closing date of the Subscription Receipts Offering. The Company will have the right to accelerate the expiry date of the Financing Warrants to 30 days from the date of notice once the 20 day volume weighted average price of the Company's Common Shares on the TSX has become equal to, or greater than, $11.00 per Common Share.

The Subscription Receipts Offering was completed in conjunction with the closing of the TBNG-PTI acquisition and the Common Shares were free-trading as of June 29, 2011.

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

During the financial year ended December 31, 2013, Valeura issued Options to acquire an aggregate of 1,673,750 Common Shares (post-Share Consolidation basis) at an exercise price of $1.00, and redeemed and cancelled 3,174,000 options with exercise prices ranging from $1.46 to $3.65 and having a weighted average exercise price of $2.44.

As of the date hereof, there were: Options issued and outstanding to purchase 1,847,250 Common Shares; Performance Warrants issued and outstanding to purchase 2,796,750 Common Shares; and, Financial Warrants issued and outstanding to purchase 13,269,217 Common Shares. These Options, Performance Warrants and Financial Warrants are the only unlisted securities of Valeura.

MARKET FOR SECURITIES

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 2013 as reported by the TSX.

2013	High	Low	Volume
January	1.15	0.87	7,726,996
February	1.14	0.96	3,185,139
March	1.07	0.86	1,490,877
April	0.93	0.73	1,252,237
May	0.90	0.49	1,296,028
June	0.55	0.40	764,232
July	0.50	0.31	1,139,798
August	0.50	0.38	930,904
September	0.50	0.375	975,483
October	0.43	0.35	1,219,076
November	0.38	0.31	2,128,946
December	0.34	0.27	2,527,029

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 officers and directors 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
Abdel F. Badwi(2) Calgary, Alberta, Canada	Director since 2010	Vice Chairman of Bankers Petroleum Ltd. (a publicly traded oil and gas company) since April 2013. President and Chief Executive Officer of Bankers Petroleum Ltd. from February 2008 to April 2013.
Stephen E. Bjornson (4) Calgary, Alberta, Canada	Chief Financial Officer	Chief Financial Officer of Valeura since April 9, 2010. Chief Executive Officer of Northern Hunter from November 1, 2008 to April 9, 2010.
William T. Fanagan (1)(2) Vancouver, British Columbia, Canada	Director since 2010	Private Businessman since August 2001.
Claudio A. Ghersinich (1)(3)(4) Calgary, Alberta, Canada	Director since 2010	President and Chief Executive Officer of Carrera Investments Corp. since May 2005. Director of Vermilion Energy Inc. since 1994. Chairman of the Board, ArPetrol Ltd. since March 2011 and prior to that, a director of ArPetrol Inc. (private) since 2004 and Chairman since 2007.
Lyle A. Martinson Calgary, Alberta, Canada	Vice President, Operations	Vice President, Operations of Valeura since April 9, 2010. Operations and Drilling Manager - Libya of Verenex

Name and Residence	Position(s) with Valeura	Principal Occupation(s) During the Past Five Years
		Energy Inc. (an oil and gas company) from August 2006 to December 2009.
James D. McFarland Calgary, Alberta, Canada	President and Chief Executive Officer, Director since 2010	President and Chief Executive Officer of Valeura since April 9, 2010. President and Chief Executive Officer of Verenex Energy Inc. (an oil and gas company) from March 1, 2004 to December, 2009.
Kenneth D. McKay (2)(3)(4) Calgary, Alberta, Canada	Director since 2010	Private Businessman since August 2012. Executive Chairman, Bulldog Oil & Gas Inc. (an oil and gas company) from October 2008 to July 2012.
Ronald W. Royal(1)(3) Abbotsford, British Columbia, Canada	Director since 2010	Private Businessman since April, 2007. Director of Caracal Energy Inc. (a publicly traded oil and gas company) since July 2011.
Donald W. Shepherd Calgary, Alberta, Canada	Vice President, Engineering	Vice President, Engineering of Valeura since April 9, 2010. General Manager - Libya of Verenex Energy Inc. (an oil and gas company) from January 2006 to December 2009.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Governance and Compensation Committee.
(3) Member of the Reserves & Health, Safety and Environment Committee.
(4) Messrs. Bjornson, Ghersinich and McKay were directors since 2006 of Northern Hunter Inc., a predecessor private oil and gas company.

As of the date hereof, the directors and executive officers of Valeura, as a group, beneficially own, directly or indirectly, 3,439,728 Common Shares representing approximately 5.9% of the issued and outstanding Common Shares of Valeura.

As of the date hereof, the directors and executive officers of Valeura, as a group, beneficially own, directly or indirectly: (a) 960,000 Options to purchase Common Shares issuable pursuant to the Company's stock option plan (the "**Option Plan**"); (b) 2,607,750 Performance Warrants to purchase this same number of Common Shares; and (c) Financing Warrants to purchase 137,479 Common Shares. If all such Options, Performance Warrants and Financing Warrants were exercised, the directors and executive officers of Valeura, as a group, would hold approximately 9.4% of the then issued and outstanding Common Shares (on a fully diluted basis).

Corporate Cease Trade Orders or Bankruptcies

Except as disclosed below, to the knowledge of management, no director, executive officer or Shareholder holding a sufficient number of securities of Valeura to affect materially the control of Valeura:

(a) is, as at the date hereof, or has been, within 10 years before the date hereof, a director or chief executive officer or chief financial officer of any Company (including Valeura) 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 relevant Company access to any exemption under securities legislation, for a period of more than 30 consecutive days;

(ii) was subject to an event that resulted, after the director or officer ceased to be a director or officer, in the Company being the subject of a cease trade or similar order or an order that denied the relevant Company access to any exemption under securities legislation, for a period of more than 30 consecutive days; or

(iii) is, as the date hereof, or has been within 10 years from the date hereof, a director or executive officer of any company (including Valeura) that, while that person was acting in such capacity, or within a year of that person 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, executive officer or Shareholder holding a sufficient number of securities of Valeura to affect materially the control of Valeura has: (i) been subject to 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) been subject to 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 Audit Committee consists of Messrs. Fanagan (Chairman), Ghersinich and Royal. All members of the Audit Committee are independent and financially literate (as determined by National Instrument 52-110 - *Audit Committees*).

In considering criteria for the determination of financial literacy, the Board looked at the ability to read and understand a balance sheet, an income statement and cash flow statement of a public company as well as the director's past experience in reviewing or overseeing the preparation of financial statements. 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, William T. Fanagan, holds a chartered accountant designation from the Institute of Chartered Accountants in Ireland and has accounting and financial expertise as a result of his experience as the President and Chief Executive Officer of a publicly traded international oil and gas company. Mr. Claudio A. Ghersinich holds a B.Sc. Civil Engineering degree from the University of Manitoba and has obtained financial experience and exposure to accounting and financial issues in a role as a founder of a publicly traded oil and gas company in 1994 and as an audit committee member of other public companies. 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 Accountants, became Valeura's auditors on April 9, 2010 concurrently with the completion of the Arrangement in order to fill the vacancy created by the resignation of DNTW Chartered Accountants LLP who had served as PanWestern's auditors since March 4, 2008 and resigned at the request of the Company. Fees paid to Valeura's auditors for the years ended December 31, 2013 and 2012 are detailed below:

Fee	For the year ended December 31, 2013	For the year ended December 31, 2012
Audit Fees(1)	$161,695	$140,000
Tax Fees(2)	-	-
All Other Fees(3)	-	$57,500
Total	$161,695	$197,500

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.
(3) "Other Fees" include fees and services related to underwriter's due diligence and the review of the short-form prospectus for the October 2012 bought-deal financing.

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

RISK FACTORS

Foreign Operations

Valeura currently has, and will continue to have, the majority of its operations outside of Canada in Turkey. 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 operations or result in a requirement for greater expenditure.

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

Acts of Violence, Terrorist Attacks or Civil Unrest in Turkey

During Q2 2013 Turkey experienced a period of political unrest and civil disobedience which had diminished in its intensity during the second half of 2013. However, in late 2013 and early 2014, further political unrest has occurred. This has resulted in a sharp devaluation of the Turkish Lira, which has negatively impacted the Company's revenues from Turkey. These events have not impacted the Company's ability to conduct drilling and production operations and no delays or security issues have been experienced.

Some of Valeura's operations are in the Gaziantep area of southeastern Turkey. Historically, the southeastern area of Turkey has experienced political, social or economic problems, terrorist attacks, insurgencies or civil unrest associated with activities of the PKK terrorist organization. More recently, unrest in neighboring Syria has resulted in a large number of Syrian refugees crossing the border into southeast Turkey and periodic shelling between Turkish and Syrian military forces near the border. If any of these events or conditions occurs in the vicinity of Valeura's operations, access to operating locations may be precluded and the operators (including Valeura) may incur substantial costs to maintain the safety of personnel and operations. Despite these precautions, the safety of operator personnel or Valeura personnel and operations in these locations may continue to 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.

Specialized Skill and Knowledge

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Company makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of Valeura. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. In the case where the acquired businesses are non-operated, the Company will need to rely on the operator to achieve the foregoing benefits and the Company's ability to influence the operator's activities in this regard. Management continually assesses the value and contribution of services provided and assets required to provide such services. Accordingly, non-core assets are periodically disposed of, so that the Company can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Company, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Company.

Government Rules and Regulations

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

Existing laws and regulations include matters relating to land tenure, drilling, production practices including hydraulic fracturing of wells, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, foreign trade and investment and government approval of lease and licence transfers and other regulatory approvals that are subject to change from time to time. Current legislation is generally a matter of public record and Valeura cannot predict what additional legislation or amendments may be proposed that will affect Valeura's operations or when any such proposals, if enacted, might become effective. There is no certainty regarding obtaining government approvals. Changes in government policy or laws and regulations could adversely affect Valeura's results of operations and financial condition. In particular, the Company is reviewing the impact of the New Petroleum Law with respect to land tenure regulations. 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.

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 decline over time as such existing reserves are exploited. 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 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. There is uncertainty regarding the sustainability of initial production rates and decline rates thereafter, and management believes that new shallow gas wells and new fracked tight gas wells will exhibit relatively high decline rates at 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 manage water production. Losses resulting from the occurrence of any of these risks could have a material adverse effect on future results of operations, liquidity and financial condition.

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. 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 prospects for exploratory drilling. 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.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations in Canada and foreign jurisdictions where Valeura operates. 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. Currently, there are no restrictions on the hydraulic fracturing of wells in Turkey. However a number of jurisdictions in Europe have temporarily or permanently banned hydraulic fracturing of wells and there is a risk that these restrictions may spread to other jurisdictions in the region including Turkey. 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 regulations, no assurance can be given that environmental laws 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.

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 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, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

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, 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. Any substantial and extended decline in the price of oil and gas would have an adverse effect on Valeura's carrying value of its proved reserves, borrowing capacity, revenues, profitability and cash flows from operations. The exchange rate between the Canadian dollar, US dollar and Turkish Lira 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.

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. If its revenues or reserves decline, it may have limited ability to acquire or expend the capital necessary to undertake or complete future drilling programs. 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.

Additional Funding Requirements

Valeura's cash flow from its reserves, once developed, may not be sufficient to fund its ongoing activities at all times. 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 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. 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.

Issuance of Debt

From time to time Valeura may enter into transactions to acquire assets or the shares of other entities. In the early stages of growth, 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.

Hedging

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. Similarly, from time to time Valeura may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, Valeura will not benefit from the fluctuating exchange rate. Valeura may similarly seek to fix the exchange rate between the Turkish Lira and the Canadian or US dollar.

Availability of Drilling, Hydraulic Fracturing and Other Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling, hydraulic fracturing and other related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Valeura and may delay exploration and development activities. To the extent it 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 and will be largely unable to direct or control the activities of the operators.

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.

Reserves Are Estimates Only

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 Turkish and Canadian properties have been independently evaluated by D&M and GLJ, respectively, and are contained in the D&M Reserves Report and GLJ Reserves Report as at December 31, 2013. Both reports 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 GLJ 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.

Depletion of Reserves and Production Declines

Valeura's oil and natural gas reserves and production, and therefore its cash flows and earnings, will be highly dependent upon Valeura developing and increasing its current reserve base and discovering or acquiring additional reserves. Without the addition of reserves through exploration and development activities or acquisition, Valeura's reserves and production will naturally decline over time as reserves are depleted. To the extent that cash flow from operations is insufficient and external sources of capital become limited or unavailable, Valeura's ability to make the necessary capital investments to maintain and expand its oil and natural gas reserves will be impaired. There can be no assurance that Valeura will be able to find and develop or acquire additional reserves to replace production at commercially feasible costs, or that Valeura will be able to convert its contingent resources to reserves.

Insurance

Valeura's involvement in the exploration for and development of oil and natural gas properties may result in it becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although prior to drilling Valeura will obtain 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.

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 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.

Expiration of Permits, Licences and Leases

Valeura's properties will be held in the form of permits, licences and leases and working interests in permits, licences and leases. If Valeura or the holder of the permit, licence or lease fails to meet the specific requirement of a permit, licence or lease, the permit, licence or lease may terminate or expire (excluding those which may be voluntarily relinquished by the Company). While Valeura monitors the status and expiry of all of its current licences and leases, there can be no assurance that any of the obligations required to maintain such licences or leases will be met. The termination or expiration of any of its licences or leases or the working interests relating to a licence or lease may have a material adverse effect on Valeura's results of operations and business. To the extent such permits, licences and leases 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.

Internal Controls Over Financial Reporting

Valeura has established internal controls over financial reporting ("**ICFR**") which include policies and procedures that pertain to the maintenance of financial records, the preparation of accurate financial statements, controls over bank accounts and the prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets or funds. Valeura has delegation of authority policies approved by the respective boards of directors of the parent company and each subsidiary, which policies delineate how various corporate and financial matters must be approved and the authority levels of management and employees (including in-country managers in Turkey). Valeura has the right and periodically conducts audits of the records and expenditures of its operating partners. While 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.

Internal Controls and Procedures Over Anti-Corruption Requirements

Valeura has established a Code of Business Conduct and Ethics which includes policies and procedures covering anti-bribery and anti-corruption of public foreign 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. 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.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of Western Canada. Valeura is not aware of any claims that have been made in respect of its property and assets; however, if a claim arose and was successful this could have an adverse effect on Valeura and its operations.

Seasonality

The level of activity in the oil and gas industry is influenced by seasonal weather patterns. Also, certain oil and gas producing areas are located in areas that may be inaccessible during certain seasons, particularly in Western Canada. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in demand for the goods and services of Valeura. In Turkey, the wet weather in certain times of the year can require delays in operations.

Third Party Credit Risk

Valeura may be exposed to third party credit risk through its contractual arrangements with current or future joint venture 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.

Conflicts of Interest

The directors or officers of Valeura may also be directors or officers of other oil and gas companies or otherwise involved in natural resource exploration and development and situations may arise where they are in a conflict of interest with Valeura. Conflicts of interest, if any, which arise will be subject to and governed by procedures prescribed by the ABCA which require a director or officer of a company who is a party to, or is a director or an officer of, or has some material interest in any person who is a party to, a material contract or proposed material contract with Valeura to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

Reliance on Key Personnel

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, is 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.

Valeura's shareholders must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of Valeura.

Management of Key Relationships in Turkey

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

Transportation Costs

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

Disruptions in Production

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 leases, permits or licences, 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.

Canadian Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil, sulphur, natural gas and natural gas liquids production.

Risk Management

Oil and gas exploration and development companies face many and varied kinds of risks. While risk management cannot eliminate the impact of all potential risks, it is anticipated that Valeura will strive to manage such risks to the extent possible and practical.

Valeura's geological focus is on areas in which the prospects are well understood by management. Technological tools are regularly used to reduce risk and increase the probability of success. Maintaining a highly motivated and talented staff of petroleum and natural gas professionals further minimizes the business risk.

Reliance on Industry Partners

Other companies currently do and it is expected that additional companies will operate some of the assets in which Valeura has an interest. In Turkey, Valeura is a non-operator on almost all of its assets. As a result, Valeura has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect Valeura's financial performance. Valeura's return on assets operated by others therefore depends upon a number of factors that may be outside of Valeura's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

To the extent 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.

Dilution

Valeura may make future acquisitions or enter into financings or other transactions involving the issuance of securities of Valeura which may be dilutive.

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/United States dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar had increased materially in value against the United States dollar although the Canadian dollar has recently decreased from such levels. The Company's drilling operations in Turkey and related contracts are based in US Dollars. Material increases in the value of the US dollar will negatively impact the Company's costs of drilling and completions activity. Future Canadian/United States and Canadian/Turkish Lira 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 the Turkish Lira. The revenue stream in Turkey is based on Turkish Lira revenue for natural gas and US dollar based revenue for crude oil translated into Turkish Lira. The majority of costs will be incurred in US Dollars and Turkish Lira. Decreases in the value of the Turkish Lira could result in decreases in revenue. Increases in the value of the Turkish Lira and US Dollars 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. The Company is in the process of specifically assessing its exposure to the Turkish Lira and any possibilities that may exist to mitigate such exposure. Recent volatility and weakness in the value of the Turkish Lira may impair the ability of the Company to manage this exposure. Continued devaluation of the Turkish Lira without a corresponding increase in the natural gas reference price will result in continued decreases in funds flow from operations and will affect the ability of the Company to meet its financial obligations.

Income Taxes

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.

INDUSTRY CONDITIONS

Turkey

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

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

Commercial Terms

Turkey's fiscal regime for oil and gas licences is presently comprised of royalties and income tax. Royalties are at 12.5% and the corporate income tax rate is 20%. Additionally, 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.

Licensing Regime

All of the Company's current licences and leases were awarded under the Old Petroleum Law. Under the Old Petroleum Law, the following regulations applied. Petroleum exploration licences had an initial four-year term. Licences could be extended in certain circumstances for two additional two-year terms for a total licence term of eight years. If, at the end of the eighth year, a producible discovery was confirmed or an exploration well was spudded by that time which ultimately resulted in a discovery, the term of the licence could be extended for a further three years (discovery extension) for a total term up to 11 years to explore and appraise the licence prior to applying for a lease(s) on discovered reserves at the end of the 11th year at the latest. The GDPA, the agency responsible for the regulation of oil and gas activities in Turkey, awarded a licence after it approved the applicant's work program, which could include obligations such as geological and geophysical work, seismic acquisition and drilling of wells.

The Old Petroleum Law stipulated the statutory drilling obligation. Before the end of the third year of the oldest licence in any district, the first well would need to be spudded. This obligation could be extended for one year upon a bank guarantee. Following the rig release of the first well, the licence holder would need to spud a well every six months (could be extended for another six months) from rig release of the previous well or from rig release of the completion of the previous well in any licence in the same district. In the case where a company held more than one licence in a district, the company could group the licences. In this case one well would satisfy the district drilling obligation for all the grouped licences.

A licence grants exclusive rights over an area for the exploration for petroleum. Under the Old Petroleum Law, a company could own up to eight licences (on the basis of a 100% working interest) or up to 400,000 hectares of net land within a designated petroleum district, whichever was applicable. Rentals were due annually based on the hectares under the licence.

Leases

Under the Old Petroleum Law, if a discovery was made the licence holder could produce oil and gas during the remaining term in the licence, and at any time up to the end of the eighth year of the licence, could apply to extend the land tenure in the form of a production lease at a reduced areal extent, not to exceed the greater of one-half of the licence or 25,000 hectares. Under a lease, the lessee could continue to develop the lease area and produce oil and gas. Leases were generally granted for an initial term of 20 years and could be renewed upon application for two additional 10-year periods. Annual rentals were due based on the number of hectares comprising the lease. The 20-

year lease period was calculated from the start of any discovery extension (i.e. the end of the eighth year at the latest).

New Petroleum Law

Under the New Petroleum Law, the government royalty rate remains unchanged at 12.5%. Also, there are no changes in taxation regulations with respect to the petroleum industry. However, there are a number of changes to the land tenure system.

Restrictions on the maximum area that can be held under exploration licences within each petroleum district have been eliminated coincident with the consolidation of 18 onshore districts into a single district. This could facilitate consolidation of landholdings in certain areas such as the Thrace Basin.

Future exploration licence awards will require the posting of a bond of up to 2% of the work program for the initial term or any subsequent extensions (no bonds were required under the Old Petroleum Law). The initial term of new licences will be five years (four years under the Old Petroleum Law). Exploration licences can be extended up to 11 years (two, two-year extensions plus a two-year discovery extension) prior to carving-out one or more production leases and relinquishing other land (total of 11 years, unchanged from the Old Petroleum Law), provided a discovery is made by the end of the ninth year (eighth year under the Old Petroleum Law). The restriction with respect to the size of a production lease under the Old Petroleum Law has been eliminated. There is no change to the term of production leases which are granted with a 20-year initial term, extendable up to 40 years. However, under the Old Petroleum Law, the three year discovery period of the exploration licence was defined as three years of the initial production lease term. Under the New Petroleum Law, the 20-year lease period is calculated from the end of the discovery period (i.e. at the end of the 11th year, which is effectively an additional three years relative to the term under the Old Petroleum Law).

The GDPA has also adopted a new international grid system and has indicated its intent to realign all exploration licence and production lease boundaries to the new grid system. Future licence awards will presumably fit the new grid system. Voluntary conversion of "old" licences to "new" licences is possible and encouraged in certain circumstances depending on the age of the licence (within its first six years), which would also require realignment of the licence boundaries to the new international grid system. Typically, any such realignment would require negotiation between adjacent licence holders and such negotiations may not be attainable in the required timeframe. The GDPA is targeting to complete any such conversions by early June 2014.

"Old" licences can be retained in their current configuration but the maximum possible term of these licences has been reduced from 11 years to eight years (i.e. four-year initial term, one two-year extension and a final two-year discovery extension if a discovery is made before the end of the sixth year).

The Company is currently reviewing the impact of the new regulations issued on January 21, 2014 designed to implement all aspects of the New Petroleum Law, and the Company is in discussions with the GDPA and its joint venture partners to determine the feasibility of converting some of its licence holdings to the New Petroleum Law, including the potential conversion of the 100% owned Banarli Licence 5104.

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

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 approximately 98% of its natural gas and 92% of its crude oil energy needs and as such any new 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 demand in Turkey in 2013 was approximately 4.60 Bcf/d. BOTAS is the major distributor of natural gas in Turkey with sales in 2013 totalling 3.67 Bcf/d, including 3.60 Bcf/d to domestic customers and 0.07 Bcf/d of exports to Greece. Given the very small domestic production of approximately 0.07 Bcf/d, 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. BOTAS imports close to 98% of the natural gas distributed in Turkey. Russia supplies approximately 58% of these imports followed by Iran at 18%, Azerbaijan at 7%, Algerian and Nigerian LNG at 10% and spot and other at 7%. Accordingly the BOTAS cost tracks world reference pricing and in turn sets the price available to domestic producers translated into Turkish Lira, at some discount. BOTAS regularly posts prices in Turkish Lira ("TL") and its Industrial Interruptible Tariff benchmark price ("BOTAS Reference Price") for March 2014 is 0.714194 TL/m^3, which is equivalent to approximately $10.06 per Mcf (at the current exchange rate of approximately $1 = 2.0 TL). BOTAS along with a number of other privately owned natural gas distributors in Turkey are expected to be the main potential purchasers of any new domestic natural gas production. The Company expects future pricing achievable for new gas supplies to be at a modest 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-PTI Joint Venture lands are purchased by more than 50 local customers directly tied in to the Company's sales gas distribution system at an average discount of approximately 4% to the BOTAS Reference Price. The Company's natural gas production from the Edirne Licence is purchased by a privately held natural gas distributor at a price equal to a 15% discount to the BOTAS Reference Price. The Edirne gas is tied into and distributed through the BOTAS gas grid. The Company expects the BOTAS price to continue to track world market pricing.

Canada

The oil and natural gas industry in Canada is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. 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. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in Canada.

Pricing and Marketing

In Canada, oil producers negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The price depends in part on oil quality, prices of competing fuels, distance to market, and the value of refined products. Oil exports may be made under export contracts having terms not exceeding one year in the case of light oil, and not exceeding two years in the case of heavy oil, provided that an order approving any such export has been approved by the National Energy Board (“NEB”). Any oil export to be made pursuant to a contract of longer duration requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Government of Canada.

In Canada, the price of natural gas sold is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that export contracts in excess of two years must continue to meet certain criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years must be made pursuant to a NEB order, or, in the case of exports for a longer duration, pursuant to an NEB licence and Government of Canada approval.

The provincial government of Alberta also regulates the removal of gas from their jurisdictions for consumption elsewhere based upon such factors as reserve availability, transportation arrangements and market considerations.

Royalties

In addition to federal regulations, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other related matters. The royalty regime is a significant factor in the profitability of oil and gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the royalty rate payable generally depends in part on the prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced.

Production from lands other than Crown lands is subject to certain provincial taxes and royalties. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Competitive Conditions

The oil and natural gas industry is intensely competitive in all its phases. Valeura competes with a substantial number of other companies that may have greater technical or financial resources. Many of such companies not only explore for and produce oil and natural gas, but also carry on refining operations and market oil and other products on a worldwide basis. Generally there is intense competition for the acquisition of undeveloped or producing resource properties considered to have commercial potential. Prices paid for oil and natural gas properties are subject to market fluctuations and will directly affect the profitability of producing any oil or natural gas reserves that may be acquired or developed by the Company.

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 financial year ended December 31, 2013, 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, 2013, 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, except as set forth below.

Directors and executive officers of the Company and their associates participated in the Recapitalization Private Placement in April 2010 as to 1,316,250 Common Shares (post-Share Consolidation basis) ($2,632,500). The

Recapitalization Private Placement was approved by shareholders of Valeura. Directors and one other executive officer participated in the Subscription Receipts Offering in February 2011 as to 267,884 Common Shares (post-Share Consolidation basis) ($870,624). One director and one executive officer participated in the October 2012 bought-deal financing as to 85,000 Common Shares ($110,500).

TRANSFER AGENT AND REGISTRAR

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

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Company has not entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year that are still in effect other than the Warrant Indenture.

INTERESTS OF EXPERTS

Reserve estimates contained in this Annual Information Form have been prepared by D&M and GLJ. As at December 31, 2013, the effective date of those estimates, respectively, and as of the date hereof, the principals, directors, officers and associates of each of D&M and GLJ, 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 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 authorized 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, 2013.

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 NATURAL GAS INFORMATION (TURKEY)

FORM 51-101F1

STATEMENT OF RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION (TURKEY)

Valeura Energy Inc. (the "**Company**") engaged DeGolyer and MacNaughton ("**D&M**") to prepare a report relating to the Company's reserves in Turkey as at December 31, 2013. 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 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 natural gas reserves and the value of future net revenue of the Company as at December 31, 2013 as evaluated by D&M in its report with a preparation date of March 11, 2014 (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 Canadian Oil and Gas Evaluation Handbook and in accordance with National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**").

All evaluations of future revenue are after the deduction of future income tax expenses, unless otherwise noted in the tables, royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does 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. The actual reserves on the Company's properties may be greater or less than those calculated.

OIL AND GAS RESERVES IN TURKEY BASED ON FORECAST PRICES AND COSTS(9)(15)

	Light and Medium Oil		Heavy Oil		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)(6)	4	3	-	-	4,449	3,849	-	-	746	645
Proved Developed Non-Producing(2)(7)	36	31	-	-	1,691	1,463	-	-	318	275
Proved Undeveloped(2)(8)	46	40	-	-	3,229	2,794	-	-	584	506
Total Proved(2)	86	74	-	-	9,369	8,106	-	-	1,648	1,426
Total Probable(3)	50	43	-	-	21,780	18,841	-	-	3,680	3,183
Total Proved Plus Probable(2)(3)	136	117	-	-	31,149	26,947	-	-	5,328	4,609
Total Possible(4)	78	68	-	-	29,356	25,393	-	-	4,971	4,300
Total Proved Plus Probable Plus Possible(2)(3)(4)	214	185	-	-	60,505	52,340	-	-	10,299	8,909

NET PRESENT VALUES OF FUTURE NET REVENUE IN TURKEY BASED ON FORECAST PRICES AND COSTS[9][14][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][6]	32,840	30,333	28,230	26,436	24,883	32,840	30,333	28,230	26,436	24,883
Proved Developed Non-Producing[2][7]	12,157	9,824	8,245	7,125	6,295	10,393	8,283	6,962	5,885	5,155
Proved Undeveloped[2][8]	9,295	7,441	5,897	4,606	3,523	7,219	5,843	4,620	3,787	3,016
Total Proved[2]	54,292	47,598	42,372	38,167	34,701	50,452	44,459	39,812	36,108	33,054
Total Probable[3]	148,649	103,891	75,324	56,313	43,216	119,094	83,127	60,289	45,141	34,751
Total Proved Plus Probable[2][3]	202,941	151,489	117,696	94,480	77,917	169,546	127,586	100,101	81,249	67,805
Total Possible[4]	254,297	161,242	110,114	79,398	59,666	203,362	129,749	88,428	63,543	47,633
Total Proved Plus Probable Plus Possible[2][3][4]	457,238	312,731	227,810	173,878	137,583	372,908	257,335	188,529	144,792	115,438

TOTAL FUTURE NET REVENUE IN TURKEY (UNDISCOUNTED) BASED ON FORECAST PRICES AND COSTS[9][14]

	Revenue (M US$)	Royalties (M US$)	Operating Costs (M US$)	Development Costs (M US$)	Abandonment 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]	106,193	14,288	12,848	22,861	1,904	54,292	3,840	50,452
Total Proved Plus Probable[2][3]	364,532	49,127	41,992	68,076	2,396	202,941	33,395	169,546
Total Proved Plus Probable Plus Possible[2][3][4]	734,436	99,023	82,463	92,928	2,784	457,238	84,330	372,908

FUTURE NET REVENUE BY PRODUCTION GROUP IN TURKEY
BASED ON FORECAST PRICES AND COSTS[9][14]

		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]	-	-	-
	Heavy oil[12]	-	-	-
	Natural gas[13][16]	42,372	29.71	4.95
Total Proved[2]		42,372	29.71	4.95
Probable[3]	Light and medium crude oil[12]	-	-	-
	Heavy oil[12]	-	-	-
	Natural gas[13][16]	75,324	23.66	3.94
Total Probable[3]		75,324	23.66	3.94
Total Proved Plus Probable[2][3]	Light and medium crude oil[12]	-	-	-
	Heavy oil[12]	-	-	-
	Natural gas[13][16]	117,696	25.54	4.26
Total Proved Plus Probable[2][3]		117,696	25.54	4.26
Possible[4]	Light and medium crude oil[12]	-	-	-
	Heavy oil[12]	-	-	-
	Natural gas[13][16]	110,114	25.61	4.27
Total Possible[4]		110,114	25.61	4.27
Total Proved Plus Probable Plus Possible[2][3][4]	Light and medium crude oil[12]	-	-	-
	Heavy oil[12]	-	-	-
	Natural gas[13][16]	227,810	25.57	4.26
Total Proved Plus Probable Plus Possible[2][3][4]		227,810	25.57	4.26

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. D&M is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

FORECAST PRICES & COST ESCALATION RATES USED IN D&M RESERVES REPORT

Year	Natural Gas: TBNG Gas Price (US$/Mcf)	Natural Gas: Edirne Gas Price (US$/Mcf)	Crude Oil: Alibey Oil Price (US$/bbl)	Crude Oil: Kazanci Oil Price (US$/bbl)	Cost Escalation %/year
2014	9.52	8.56	100.96	78.23	0.0
2015	10.56	9.49	96.96	75.13	2.0
2016	10.77	9.68	96.81	75.01	2.0
2017	10.98	9.87	96.68	74.92	2.0
2018	11.20	10.07	96.60	74.85	2.0
2019	11.43	10.27	96.75	74.97	2.0
2020	11.66	10.47	98.68	76.47	2.0
2021	11.89	10.68	100.66	77.99	2.0
2022	12.13	10.90	102.66	79.55	2.0
2023	12.37	11.11	104.72	81.15	2.0
2024	12.62	11.34	106.82	82.77	2.0
2025	12.87	11.56	108.95	84.42	2.0
2026+	+2.0%/yr thereafter	+2.0%/yr thereafter	+2.0%/yr thereafter	+2.0%/yr thereafter	2.0

The Company's weighted average historical prices in Turkey for the year ended December 31, 2013 were:

Natural Gas ($/Mcf)	Light and Medium Oil ($/bbl)	Natural Gas Liquids ($/bbl)
10.23	97.36	Not Applicable

RECONCILIATION OF THE COMPANY'S GROSS RESERVES IN TURKEY 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 oil, natural gas, natural gas liquids and oil equivalent reserves as at December 31, 2013 against such reserves as at December 31, 2012 based on the forecast price and cost assumptions set forth in Note 9:

	Light and Medium Oil					Heavy 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, 2012	53	27	80	42	122	0	0	0	0	0
Extensions	0	0	0	0	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0	0	0	0	0
Technical Revisions	36	23	59	36	95	0	0	0	0	0
Discoveries	0	0	0	0	0	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	3	0	3	0	3	0	0	0	0	0
At December 31, 2013	86	50	136	78	214	0	0	0	0	0

	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, 2012	5,709	20,715	26,424	27,977	54,401	0	0	0	0	0
Extensions	0	0	0	0	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0	0	0	0	0
Technical Revisions	5,666	1,065	6,731	1,379	8,110	0	0	0	0	0
Discoveries	0	0	0	0	0	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	2,005	0	2,005	0	2,005	0	0	0	0	0
At December 31, 2013	9,370	21,780	31,150	29,356	60,506	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, 2012	1,005	3,480	4,485	4,705	9,190
Extensions	0	0	0	0	0
Improved Recovery	0	0	0	0	0
Technical Revisions	980	200	1,180	266	1,446
Discoveries	0	0	0	0	0
Acquisitions	0	0	0	0	0
Dispositions	0	0	0	0	0
Economic Factors	0	0	0	0	0
Production	337	0	337	0	337
At December 31, 2013	1,648	3,680	5,328	4,971	10,299

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. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of 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, 2013 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. 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.
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 categorizes all production as natural gas as the primary phase.
17. Values may not add due to rounding.

Proved Undeveloped Reserves in Turkey

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 and in the aggregate before that time:

	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)	Oil Equivalent[10] (Mboe)
Aggregate prior to 2011	--[1]	--[1]	--[1]	--[1]	--[1]
December 31, 2011	0	0	696	0	116
December 31, 2012	11	0	2,068	0	356
December 31, 2013	36	-	1,522	-	290

Notes:
1. Proved Undeveloped Reserves for the years prior to 2011 are not applicable as all the Company's reserves in Turkey were acquired after December 31, 2010.

The total Proved Undeveloped Reserves first attributed in 2013 partially consists of proved reserves of 1,522 MMcf (88% of the total Proved Undeveloped Reserves first attributed in 2013 based on oil equivalent) assigned to nine new drill gas wells on the TBNG-PTI joint venture lands (Valeura 40%). The remainder of the Proved Undeveloped Reserves first attributed in 2013 are comprised of proved oil reserves of 36 Mbbl (12% of total Proved Undeveloped Reserves first attributed in 2013 based on oil equivalent) assigned to one new drill oil well at Alibey on the Gaziantep Licence 4607 (Valeura 26%).

In the D&M Reserve Report as of December 31, 2013 there are a total of 26 Proved Undeveloped locations assigned reserves (including the aforementioned 10 new drill wells that have first attributed Proved Undeveloped Reserves in 2013). The Company continually evaluates its capital program to maximize its opportunities and any well that ultimately is drilled may or may not correspond exactly to the well location quoted in the D&M Reserves Report as each actual drilled well is dependent on new information and ongoing technical and economic review. The Company has budgeted 10 to 12 wells in 2014 on lands associated with and in close proximity to the 26 wells assigned Proved Undeveloped Reserves, and while the Company has not set budgets for the year 2015 and beyond, if similar levels of yearly drilling activity continued beyond 2014, development of the assigned Proved Undeveloped Reserves, in the majority of cases, can be expected to occur within the next three years.

Probable Undeveloped Reserves in Turkey

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 and in the aggregate before such time:

	Light and Medium Oil (Mbbl)	**Heavy Oil (Mbbl)**	**Natural Gas (MMcf)**	**Natural Gas Liquids (Mbbl)**	**Oil Equivalent[10] (Mboe)**
Aggregate prior to 2011	--[1]	--[1]	--[1]	--[1]	--[1]
December 31, 2011	0	0	1,543	0	257
December 31, 2012	2	0	18,744	0	3,126
December 31, 2013	23	-	1,024	-	194

Notes:

1. Probable Undeveloped Reserves for the years prior to 2011 are not applicable as all the Company's reserves in Turkey were acquired after December 31, 2010.

The total Probable Undeveloped Reserves first attributed in 2013 consists of probable reserves of 1,024 MMcf and 23 Mbbl (100% of the total Probable Undeveloped Reserves first attributed in 2013 based on oil equivalent) associated with the aforementioned 10 Proved Undeveloped new drill wells.

In the D&M Reserve Report as of December 31, 2013 there are a total of 54 drilling locations assigned Probable Undeveloped Reserves. There were no new drill locations assigned as Probable Undeveloped locations in 2013. The Company continually evaluates its capital program to maximize its opportunities and any well that ultimately is drilled may or may not correspond exactly to the well location quoted in the D&M Reserves Report as each actual drilled well is dependent on new information and ongoing technical and economic review. The Company has budgeted 10 to 12 wells in 2014 on lands associated with and in close proximity to the 54 wells assigned Probable Undeveloped Reserves, and while the Company has not set budgets for the year 2015 and beyond, if yearly drilling activity increased to 15 to 20 wells per year in the years beyond 2014, development of the assigned Probable Undeveloped Reserves, in the majority of cases, can be expected to occur within the next five to six years.

Significant Factors or Uncertainties

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 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, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in forecast prices, 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, capital expenditures, operating costs, royalty regimes and well performance that are beyond the Company's control.

Future Development Costs in Turkey

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$)	**Total Proved[(1)] Plus Probable[(2)] Estimated Using Forecast Prices and Costs** (M US$)
2014	8,517	9,257
2015	8,600	13,446
2016	4,307	15,910
2017	123	12,000
2018	174	12,661
Remainder	1,140	4,803
Total for all years undiscounted	22,861	68,077

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 the Company's internally-generated cash flow, debt financing when deemed appropriate and new equity issues if made on favourable terms.

Oil and Gas Properties and Wells in Turkey

The Company's major property is the TBNG-PTI joint venture natural gas property in the Thrace Basin in Turkey located west of Istanbul. The property entails ten onshore licences and leases comprising an onshore area of approximately 794 gross sections (317 net sections) and an offshore area of approximately 182 gross sections (27 net sections). All development is onshore and a small percentage of the acreage is developed. The natural gas 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 the joint venture's own distribution network to more than 50 customers within a 50 kilometre distance of the Company's central facility. All of the Company's production in Turkey is onshore and located in the Thrace Basin area west of Istanbul.

A listing of the Company's wells in Turkey 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	0.40	100	39.70	0	0.00
Non-producing	1	0.26	111	44.15	34	13.60
Total	2	0.66	211	83.85	34	13.60

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.

The above wells in Turkey does not include two gross Oil Wells (0.55 net Oil Wells) held effective December 31, 2013, associated with Licences 2674 and 2677 in the Anatolian Basin. The Company sold its interests in these wells and lands in February 2014.

Properties with No Attributed Reserves in Turkey

The following table sets out the Company's undeveloped land position in Turkey effective December 31, 2013:

	Undeveloped Acreage	
	Gross(1)	**Net(1)**
Thrace Basin	874,410	398,278
Anatolian Basin	123,214	32,036
Total	997,624	430,314

Note:

1. "**Gross**" means the total number of acres in which the Company has a working interest. "**Net**" means the number of acres obtained by aggregating the Company's working interest in each of its acreage positions.

The above undeveloped acreage in Turkey does not include 241,946 undeveloped gross acres (66,535 undeveloped net acres) held effective December 31, 2013, associated with Licences 2674 and 2677 in the Anatolian Basin. The Company sold its interest in these lands in February 2014.

The Company expects its rights to explore, develop and exploit approximately 118,373 gross acres (41,431 net acres) associated with Licence 3839 (Edirne) to expire within one year due to the ending of the exploration licence term.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves in Turkey

At this time the Company has not completed an independent evaluation of its undeveloped acreage in Turkey. However, in 2012 the Company completed an independent assessment of its contingent resources on the TBNG-PTI joint venture lands in the Thrace Basin effective December 31, 2012 which identified significant resource potential. The Company has not updated the contingent resources assessment for the Thrace Basin carried out by D&M as at December 31, 2012, which was summarized in Valeura's 2012 Annual Information Form. Any decision to update D&M's contingent resources assessment will be dependent on further results from horizontal drilling on the TBNG JV lands and potential exploration drilling on the Banarli Licence 5104 in 2014.

Through its 2014 drilling program the Company expects that its budgeted drilling program of approximately 10 to 12 wells on the TBNG-PTI joint venture lands will include several wells that could assist in converting a portion of contingent resources to reserves.

Forward Contracts

Currently there are no material forward contracts or commitments.

Abandonment and Reclamation Costs in Turkey

All wells assigned reserves are included in the D&M Reserves Report and are assigned abandonment costs.

Abandonment 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 requirements. The Company has 98.1 net wells as of December 31, 2013 for which abandonment and reclamation costs are expected to be incurred.

In the D&M Reserves Report the total abandonment cost in respect of proved reserves using forecast costs are US$1.9 million (undiscounted) and US$0.8 million (discounted at 10%). 100% of such amounts were deducted as abandonment costs in estimating the Company's future net revenue as disclosed above.

In the D&M Reserves Report well abandonment costs for all wells with reserves have been included at the property level. Additional abandonment costs associated with non-reserves wells, lease reclamation costs and facility abandonment and reclamation expenses have not been included in this analysis.

Tax Horizon in Turkey

The Company was not required to pay any cash income taxes in Turkey for the period ended December 31, 2013. Based on current estimates of the Company's future taxable income and expected future capital expenditures, management does not expect to be cash taxable for the foreseeable future.

Costs Incurred in Turkey

The following table summarizes the capital expenditures made by the Company on oil and natural gas properties in Turkey for the year ended December 31, 2013.

	Property Acquisition Costs[14] (M$)		**Exploration Costs[14] (M$)**	**Development Costs[14] (M$)**
	Proved Properties	**Unproved Properties**		
TBNG	-	-	18,369	5,028
Edirne	-	-	-	38
Other	-	-	3,443	-
Total Turkey	0	0	21,812	5,066

Exploration and Development Activities in Turkey

The following table sets forth the number of wells the Company drilled for the year ended December 31, 2013 in Turkey:

	Exploratory Wells		**Development Wells**	
	Gross[1][2]	**Net[1][2]**	**Gross[1][2]**	**Net[1][2]**
Oil Wells	0	0.00	0	0.00
Gas Wells	0	0.00	4	1.60
Standing & Other Wells	3	1.20	0	0.00
Dry Holes	0	0.00	0	0.00
Total Wells	3	1.20	4	1.60

Note:

1. "**Gross Wells**" are the total number of wells in which the Company has an interest. "**Net Wells**" are the number of wells obtained by aggregating the Company's working interest in each of its gross wells.

2. Spud date is the criteria the Company uses to categorize drilled wells by year.

Production Estimates in Turkey

The following table sets forth the volume of working interest daily production, before royalties, estimated for 2014 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 Oil (bbl/d)	Heavy Oil (bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbl/d)
Proved Developed Producing(2)(6)				
TBNG	5	0	6,275	0
Edirne	0	0	131	0
Total Proved Developed Producing	5	0	6,406	0
Proved Developed Non-Producing(2)(7)				
TBNG	60	0	1,335	0
Edirne	0	0	62	0
Total Proved Developed Non-Producing	60	0	1,397	0
Proved Undeveloped(2)(8)				
TBNG	0	0	1,510	0
Edirne	0	0	0	0
Total Proved Undeveloped	0	0	1,510	0
Total Proved(2)				
TBNG	65	0	9,120	0
Edirne	0	0	193	0
Total Proved	65	0	9,313	0
Total Probable(3)				
TBNG	31	0	1,797	0
Edirne	0	0	31	0
Total Probable	31	0	1,828	0
Total Proved Plus \ Probable(2)(3)				
TBNG	96	0	10,917	0
Edirne	0	0	224	0
Total Proved Plus Probable	96	0	11,141	0

Note:

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

Production History in Turkey

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, 2013	**Three Months Ended June 30, 2013**	**Three Months Ended September 30, 2013**	**Three Months Ended December 31, 2013**
Average Daily Production				
Light and Medium Oil (bbl/d)	17	17	16	14
Natural Gas (Mcf/d)	4,645	4,784	5,708	6,812
BOEs (boe/d)	791	815	967	1,149
Average Net Prices Received				
Light and Medium Oil ($/bbl)(14)	98.84	93.86	99.26	97.64
Natural Gas ($/Mcf)(14)	10.66	10.37	10.13	9.93
BOEs ($/boe)(14)	64.70	62.92	61.41	60.04
Royalties				
Light and Medium Oil ($/bbl)(14)	13.93	13.60	14.81	17.25
Natural Gas ($/Mcf)(14)	1.43	1.39	1.36	1.34
BOEs ($/boe)(14)	8.68	8.47	8.28	8.14
Production Costs				
Light and Medium Oil ($/bbl)(14)	37.25	33.95	37.42	70.69
Natural Gas ($/Mcf)(14)	2.30	1.86	1.16	1.24
BOEs ($/boe)(14)	14.31	11.63	7.44	8.19
Netback Received				
Light and Medium Oil ($/bbl)(14)	47.66	46.31	47.03	9.70
Natural Gas ($/Mcf)(14)	6.93	7.12	7.61	7.35
BOEs ($/boe)(14)	41.71	42.82	45.69	43.71

The following table sets forth certain information in respect of production that is included in the preceding table and is attributable to TBNG-PTI joint venture properties:

	Three Months Ended March 31, 2013	**Three Months Ended June 30, 2013**	**Three Months Ended September 30, 2013**	**Three Months Ended December 31, 2013**
Average Daily Production				
Light and Medium Oil (bbl/d)	9	8	8	8
Natural Gas (Mcf/d)	4,250	4,406	5,395	6,586
BOEs (boe/d)	717	742	907	1,105

APPENDIX A-2 – FORM 51-101F2 - REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR (TURKEY)

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

CANADIAN NATIONAL INSTRUMENT 51-101
FORM 51-101F2
REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR

To the board of directors of Valeura Energy Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2013. The reserves data are estimates of the proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) in thousands of United States dollars (M U.S.$) attributed to proved-plus-probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2013, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation	Location of Reserves	Net Present Value of Future Net Revenue (before Income Taxes, Discounted at 10 Percent)			
			Audited (M U.S.$)	Evaluated (M U.S.$)	Reviewed (M U.S.$)	Total (M U.S.$)
DeGolyer and MacNaughton	Appraisal Report as of December 31, 2013 on Reserves attributable to Valeura Energy Inc. for Certain Properties in Turkey with a preparation date of March 11, 2014	Turkey	Not Applicable	117,696	Not Applicable	117,696

5. In our opinion, the reserves and revenue evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after the preparation date.

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

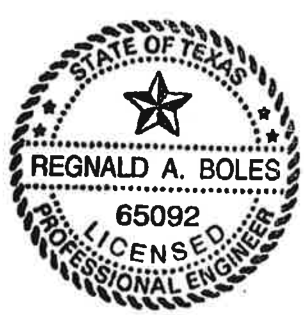
Executed as to our report referred to above:

DeGolyer and MacNaughton, Dallas, Texas USA, dated March 11, 2014.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716



Regnald A. Boles

Regnald A. Boles, P.E.
Senior Vice President
DeGolyer and MacNaughton

APPENDIX A-3 – FORM 51-101F1 - STATEMENT OF RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION (CANADA)

FORM 51-101F1

STATEMENT OF RESERVES DATA
AND OTHER OIL AND NATURAL GAS INFORMATION (CANADA)

Valeura Energy Inc. (the "**Company**") engaged GLJ Petroleum Consultants Ltd. ("**GLJ**") to prepare a report relating to the Company's reserves in Canada as at December 31, 2013. The reserves on the properties in Canada described herein are estimates only. Actual reserves on these properties may be greater or less than those estimated.

The Company's crude oil and natural gas reserves in Canada are located in the province of Alberta. Set out below are a summary of the crude oil and natural gas reserves and the value of future net revenue of the Company as at December 31, 2013 as evaluated by GLJ in its report dated February 26, 2014 (the "**GLJ Reserves Report**"). The preparation date of the GLJ Reserves Report is February 25, 2014. The pricing used in the forecast price evaluations is set forth in the notes to the tables.

The GLJ Reserves Report was prepared using assumptions and methodology guidelines outlined in the Canadian Oil and Gas Evaluation Handbook and in accordance with National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**").

All evaluations of future revenue are after the deduction of future income tax expenses, unless otherwise noted in the tables, royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does 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 GLJ Reserves Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the GLJ Reserves Report. The recovery and reserves estimates on the Company's properties described herein are estimates only. The actual reserves on the Company's properties may be greater or less than those calculated.

OIL AND GAS RESERVES IN CANADA
BASED ON FORECAST PRICES AND COSTS (9)(14)(16)

	Light and Medium Oil		Heavy Oil		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)(6)	35	33	6	5	70	87	3	2	55	55
Proved Developed Non-Producing(2)(7)	22	19	0	0	281	248	11	8	80	68
Proved Undeveloped(2)(8)	0	0	0	0	0	0	0	0	0	0
Total Proved(2)	57	52	6	5	351	335	14	10	135	123
Total Probable(3)	109	97	4	3	936	860	54	40	323	283
Total Proved Plus Probable(2)(3)	166	149	10	8	1,287	1,195	68	50	458	406

NET PRESENT VALUES OF FUTURE NET REVENUE IN CANADA BASED ON FORECAST PRICES AND COSTS [9][14][16]

	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes Discounted At				
	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved Developed Producing[2][6]	1,344	1,172	1,051	959	884	1,344	1,172	1,051	959	884
Proved Developed Non-Producing[2][7]	569	477	403	342	292	569	477	403	342	292
Proved Undeveloped[2][8]	0	0	0	0	0	0	0	0	0	0
Total Proved[2]	1,913	1,650	1,454	1,301	1,176	1,913	1,650	1,454	1,301	1,176
Total Probable[3]	5,798	4,236	3,222	2,521	2,016	5,798	4,236	3,222	2,521	2,016
Total Proved Plus Probable[2][3]	7,711	5,886	4,676	3,822	3,192	7,711	5,886	4,676	3,822	3,192

TOTAL FUTURE NET REVENUE IN CANADA (UNDISCOUNTED) BASED ON FORECAST PRICES AND COSTS [9][14]

	Revenue (M$)	Royalties [15] (M$)	Operating Costs (M$)	Development Costs (M$)	Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Total Proved[2]	7,412	720	3,967	605	207	1,913	0	1,913
Total Proved Plus Probable[2][3]	24,188	2,456	10,808	2,881	332	7,711	0	7,711

FUTURE NET REVENUE BY PRODUCTION GROUP IN CANADA BASED ON FORECAST PRICES AND COSTS (9)(16)

	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) M$	$/boe(10)	$/Mcfe(11)
Total Proved(2)	Light and medium crude oil(12)	945	15.86	2.64
	Heavy oil(12)	129	19.38	3.23
	Natural gas(13)	380	6.71	1.12
Total Proved(2)		**1454**	**11.83**	**1.97**
Total Probable(3)		**3,222**	**11.38**	**1.90**
Total Proved Plus Probable(2)(3)	Light and medium crude oil(12)	3,460	13.20	2.20
	Heavy oil(12)	193	17.98	3.00
	Natural gas(13)	1,023	7.68	1.28
Total Proved Plus Probable(2)(3)		**4,676**	**11.52**	**1.92**

The pricing assumptions used in the GLJ Reserves Report with respect to net present values of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

FORECAST PRICES, INFLATION & EXCHANGE RATES USED IN GLJ RESERVES REPORT

	Natural Gas		Natural Gas Liquids Edmonton						Inflation Rate	Exchange Rate
Year	**AECO Gas Price ($/MMbtu)**	**Henry Hub NYMEX Near Month Contract (US$/MMbtu)**	**Edmonton Propane ($/bbl)**	**Edmonton Butane ($/bbl)**	**Edmonton Pentanes Plus ($/bbl)**	**Spec Ethane ($/bbl)**	**Light Sweet Crude Oil (40 API, 0.3%S) at Edmonton**	**NYMEX WTI Near Month Futures Contract Crude Oil at Cushing Oklahoma (US$/bbl)**	**%/year**	**US$/$**
2014	4.03	4.25	57.83	73.22	105.20	13.26	92.76	97.50	2.0	0.95
2015	4.26	4.50	58.42	75.95	107.11	14.08	97.37	97.50	2.0	0.95
2016	4.50	4.75	60.00	78.00	107.00	14.89	100.00	97.50	2.0	0.95
2017	4.74	5.00	60.00	78.00	107.00	15.71	100.00	97.50	2.0	0.95
2018	4.97	5.25	60.00	78.00	107.00	16.53	100.00	97.50	2.0	0.95
2019	5.21	5.50	60.00	78.00	107.00	17.34	100.00	97.50	2.0	0.95
2020	5.33	5.63	60.46	78.60	107.82	17.77	100.77	98.54	2.0	0.95
2021	5.44	5.74	61.67	80.17	109.97	18.13	102.78	100.51	2.0	0.95
2022	5.55	5.86	62.90	81.77	112.17	18.52	104.83	102.52	2.0	0.95
2023	5.66	5.97	64.16	83.40	114.41	18.88	106.93	104.57	2.0	0.95
2024+	+2.0%/yr thereafter	+2.0%/yr thereafter	+2.0%/yr thereafter	+2.0%/yr thereafter	+2.0%/yr thereafter	+2.0%/yr thereafter	+2.0%/yr thereafter	+2.0%/yr thereafter	2.0	0.95

The Company's weighted average historical prices in Canada for the year ended December 31, 2013 were:

Natural Gas ($/Mcf)	Light and Medium Oil ($/bbl)	Natural Gas Liquids ($/bbl)
3.02	73.79	65.93

RECONCILIATION OF THE COMPANY'S GROSS RESERVES IN CANADA BY PRINCIPAL PRODUCT TYPE BASED ON FORECAST PRICES AND COSTS (9)(16)

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 oil, natural gas, natural gas liquids and oil equivalent reserves as at December 31, 2013 against such reserves as at December 31, 2012 based on the forecast price and cost assumptions set forth in Note 9:

	Light and Medium Oil			**Heavy Oil**			**Natural Gas**		
	Gross Proved (Mbbl)	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved Plus Probable (MMcf)**
At December 31, 2012	62	131	192	8	5	13	355	1,040	1,395
Extensions	0	0	0	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0	0	0	0
Technical Revisions	5	(21)	(15)	(1)	(1)	(2)	27	(88)	(61)
Discoveries	0	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0
Economic Factors	(1)	(1)	(2)	0	0	0	0	(16)	(16)
Production	9	0	9	2	0	2	31	0	31
At December 31, 2013	57	109	166	6	4	10	351	936	1,287

	Natural Gas Liquids			**Oil Equivalent[10]**		
	Gross Proved (Mbbl)	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**	**Gross Proved (Mboe)**	**Gross Probable (Mboe)**	**Gross Proved Plus Probable (Mboe)**
At December 31, 2012	13	49	63	143	358	501
Extensions	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0
Technical Revisions	1	6	7	11	(31)	(21)
Discoveries	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0
Economic Factors	0	(1)	(1)	(1)	(5)	(6)
Production	1	0	1	17	0	17
At December 31, 2013	14	54	68	135	323	458

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. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of 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 GLJ Reserves Report with respect to net values of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth in the preceding table titled "**Forecast Prices, Inflation & Exchange Rates Used in GLJ Reserves Report**". The Forecast Prices, Inflation & Exchange rates were developed by GLJ as at January 1, 2014 and reflect the then current year forecast prices, inflation and exchange rates. GLJ 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. 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.

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$, $/boe and $/Mcfe are stated in Canadian dollars unless otherwise noted.

15. Royalties include Mineral Tax.

16. Values may not add due to rounding.

Proved Undeveloped Reserves in Canada

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 and in the aggregate before that time:

	Light and Medium Oil (Mbbl)	**Heavy Oil (Mbbl)**	**Natural Gas (MMcf)**	**Natural Gas Liquids (Mbbl)**	**Oil Equivalent[(10)] (Mboe)**
Aggregate prior to 2011	26[(1)(2)]	0 [(1)(2)]	10[(1)(2)]	0 [(1)(2)]	28[(1)(2)]
December 31, 2011	0	0	0	0	0
December 31, 2012	0	0	0	0	0
December 31, 2013	0	0	0	0	0

Notes:

1. Prior to December 31, 2009, Northern Hunter did not request its reserve evaluator to prepare attribution information as Northern Hunter was a private company; thus, no attribution information is available for the Northern Hunter portion of the Company's reserves for the years prior to 2008. For the year ended December 31, 2009, the Company (formerly PanWestern Energy Inc. ("**PWE**") and managed by a previous management team) filed its Statement of Reserves Data on SEDAR (www.sedar.com), which listed no attributions of Proved Undeveloped Reserves for the years prior to 2008.

2. As evaluated by Sproule Associates Limited in a report dated April 9, 2010 with an effective date of December 31, 2009.

The Company has no Proved Undeveloped Reserves assigned in Canada.

Probable Undeveloped Reserves in Canada

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 and in the aggregate before such time:

	Light and Medium Oil (Mbbl)	**Heavy Oil (Mbbl)**	**Natural Gas (MMcf)**	**Natural Gas Liquids (Mbbl)**	**Oil Equivalent(10) (Mboe)**
Aggregate prior to 2011	91(1)(2)	0	627(1)(2)	14	209(1)(2)
December 31, 2011	0	0	0	0	0
December 31, 2012	0	0	0	0	0
December 31, 2013	0	0	0	0	0

Notes:

1. Prior to December 31, 2009, Northern Hunter did not request its reserve evaluator to prepare attribution information as Northern Hunter was a private company; thus, no attribution information is available for the Northern Hunter portion of the Company's reserves for the years prior to 2008. For the year ended December 31, 2009, the Company (formerly PanWestern Energy Inc. ("**PWE**")) filed its Statement of Reserves Data on SEDAR (www.sedar.com), which listed no attributions of Proved Undeveloped Reserves for the years prior to 2008.
2. Included in Aggregate prior to 2010 is 9 Mbbl of Light and Medium Oil and 3 MMcf of Natural Gas which is equivalent to 9 Mboe of Oil Equivalent as evaluated by Sproule Associates Limited in a report dated April 9, 2010 with an effective date of December 31, 2009.

All of the Company's Probable Undeveloped Reserves in Canada of 191 boes are assigned in the Grand Forks/Hays area and are related to three offset probable well locations immediately adjacent to producing wells. These offset well locations are undergoing technical and economic review for development and if the Company, based on such review, decides to develop such Probable Undeveloped Reserves, such development is expected to occur within the next two to three years dependent on gas price recovery.

Significant Factors or Uncertainties

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 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, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in forecasted prices, reservoir performance and geological conditions or production. These revisions can be either positive or negative.

While we do 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, capital expenditures, operating costs, royalty regimes and well performance that are beyond the Company's control.

Future Development Costs in Canada

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 GLJ Reserves Report:

	Total Proved Estimated Using Forecast Prices and Costs (M$)	**Total Proved Plus Probable Estimated Using Forecast Prices and Costs** (M$)
2014	0	0
2015	605	2,851
2016	0	0
2017	0	0
2018	0	0
Remainder	0	30
Total for all years undiscounted	605	2,881

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

Oil and Gas Properties and Wells in Canada

The Company's major property is Grand Forks/Hays located in the province of Alberta and its production is oil, gas and natural gas liquids. Oil is trucked for processing and sold to a third party marketer. Raw gas is pipelined to a third party facility for processing. Processed natural gas and natural gas liquids are sold to a third party from the processing facility. All other properties of the Company are considered minor with raw production either trucked or pipelined for processing and sales via third party marketing contracts. All of the Company's production is onshore and located in the province of Alberta.

All of Company's oil and gas wells are in the province of Alberta. The Company has two wells that are owned 100% on a helium prospect in Saskatchewan. The helium lease has been farmed-out, however, the physical earning did not occur until January 2014. Hence the two non-producing wells associated with those lands are still treated as working interest wells as of this report date. A listing of producing and non producing wells including the two Saskatchewan helium wells (two Gross and two Net Non-Producing Natural Gas Wells) are listed below:

	Oil Wells		**Natural Gas Wells**	
	Gross[(1)]	**Net[(2)]**	**Gross[(1)]**	**Net[(2)]**
Producing	12	3.88	7	0.56
Non-producing	11	3.46	16	8.94
Total	23	7.34	23	9.50

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 in Canada

The following table sets out the Company's undeveloped land position effective December 31, 2013:

	Undeveloped Acreage	
	Gross[(1)]	**Net[(1)]**
Saskatchewan	23,452	23,452
Alberta	17,200	8,789
Total	40,652	32,241

Note:

1. "**Gross**" means the total number of acres in which the Company has a working interest. "**Net**" means the number of acres obtained by aggregating the Company's working interest in each of its acreage positions.

The Company relinquished 103,294 acres of Saskatchewan undeveloped acreage associated with a helium gas prospect. The Company farmed out the remaining 19,537 acres of undeveloped helium acreage to Canadian Helium Corp. retaining a non-convertible 6.0% gross over-riding royalty. The physical earning provisions of the farm out were not executed until late January 2014, hence the acreage under farm out is still carried as 100% working interest land in this report.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves in Canada

At this time the Company has no material value expectations for any of its Canadian properties that have no attributed reserves.

Forward Contracts

Currently there are no material forward contracts or commitments.

Abandonment and Reclamation Costs in Canada

All producing or wells assigned reserves are included in the GLJ Reserves Report and are assigned abandonment costs.

Abandonment costs are estimated on an area by area basis by GLJ. 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 requirements. The Company currently has 16.84 net wells for which abandonment and reclamation costs are expected to be incurred.

The total abandonment cost in the GLJ Reserves Report in respect of proved reserves using forecast prices is $0.2 million (undiscounted) and $0.1 million (discounted at 10%). 100% of such amounts were deducted as abandonment costs in estimating the Company's future net revenue as disclosed above.

Well abandonment costs for all wells with reserves have been included at the property level. Additional abandonment costs associated with non-reserves wells, lease reclamation costs and facility abandonment and reclamation expenses have not been included in this analysis.

Tax Horizon in Canada

In Canada the Company was not required to pay any cash income taxes for the period ended December 31, 2013. Based on current estimates of the Company's future taxable income and levels of tax deductible expenditures in Canada, management believes that the Company will not be required to pay cash income taxes for the life of the Total Proved Reserves in Canada.

Costs Incurred in Canada

The following table summarizes the capital expenditures made by the Company on oil and natural gas properties in Canada for the year ended December 31, 2013:

	Property Acquisition Costs (M$)		Exploration Costs (M$)	Development Costs (M$)
	Proved Properties	Unproved Properties		
Canada	0	0	0	54
Total	0	0	0	54

Exploration and Development Activities in Canada

The following table sets forth the number of wells the Company drilled for the year ended December 31, 2013 in Canada:

	Exploratory Wells		Development Wells	
	Gross(1)	Net(1)	Gross(1)	Net(1)
Oil Wells	0	0	0	0
Gas Wells	0	0	0	0
Service Wells	0	0	0	0
Dry Holes	0	0	0	0
Total Wells	0	0	0	0

Note:

1. "**Gross Wells**" are the total number of wells in which the Company has an interest. "**Net Wells**" are the number of wells obtained by aggregating the Company's working interest in each of its gross wells.

The Company has interests in 10 gross wells in the Grand Forks/Hays area and holds a 50% to 100% working interest position in 20.8 sections of land in the Grand Forks/Hays area. The main producing intervals are the Nisku-Arcs and Sawtooth formations.

Production Estimates in Canada

The following table sets forth the volume of working interest production, before royalties, estimated for 2014 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 Canada:

	Light and Medium Oil (bbl/d)	Heavy Oil (bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbl/d)
Proved Developed Producing(2)(6)				
Grand Forks/Hays	20	0	47	2
Other Properties	2	4	7	0
Valhalla	0	0	0	0
Total Proved Developed Producing	22	4	54	2
Proved Developed Non-Producing(2)(7)				
Grand Forks/Hays	0	0	0	0
Other Properties	0	0	0	0
Total Proved Developed Non-Producing	0	0	0	0
Proved Undeveloped(2)(8)				
Grand Forks/Hays	0	0	0	0
Other Properties	0	0	0	0
Total Proved Undeveloped	0	0	0	0
Total Proved(2)				
Grand Forks/Hays	20	0	47	2
Other Properties	2	4	7	0
				0
Total Proved	22	4	54	2
Total Probable(3)				
Grand Forks/Hays	1	0	1	0
Other Properties	0	0	0	0
				0
Total Probable	1	0	2	1
Total Proved Plus Probable(2)(3)				
Grand Forks/Hays	21	0	49	2
Other Properties	2	4	7	0
		0		0
Total Proved Plus Probable	23	4	55	2

Note:

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

Production History in Canada

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 Canada:

	Three Months Ended March 31, 2013	Three Months Ended June 30, 2013	Three Months Ended September 30, 2013	Three Months Ended December 31, 2013
Average Daily Production				
Light and Medium Oil (bbl/d)	33	29	30	27
Natural Gas (Mcf/d)	142	97	70	71
Natural Gas Liquids (/bbl/d)	3	2	2	3
BOEs (boe/d)	60	47	44	42
Average Net Prices Received				
Light and Medium Oil ($/bbl)	62.27	72.59	92.34	68.30
Natural Gas ($/Mcf)	2.97	3.39	2.39	3.25
Natural Gas Liquids ($/bbl)	66.75	66.65	68.44	62.42
BOEs ($/boe)	44.86	54.33	70.30	54.03
Royalties				
Light and Medium Oil ($/bbl)	4.63	2.62	9.81	8.86
Natural Gas ($/Mcf)	(0.42)	(0.34)	(0.67)	(3.40)
Natural Gas Liquids ($/bbl)	26.58	36.01	32.88	25.93
BOEs ($/boe)	2.87	2.60	7.27	1.68
Production Costs				
Light and Medium Oil ($/bbl)	31.61	46.55	29.03	56.10
Natural Gas ($/Mcf)	5.49	5.12	7.12	(8.83)
Natural Gas Liquids ($/bbl)	14.35	11.10	6.00	6.35
BOEs ($/boe)	31.30	39.43	31.54	21.76
Netback Received				
Light and Medium Oil ($/bbl)	26.02	23.41	53.50	3.34
Natural Gas ($/Mcf)	(2.10)	(1.39)	(4.06)	15.49
Natural Gas Liquids ($/bbl)	25.82	19.54	29.56	30.14
BOEs ($/boe)	10.69	12.30	31.49	30.60

The following table sets forth certain information in respect of production that is included in the preceding table and is attributable to Grand Forks/Hays property:

	Three Months Ended March 31, 2013	Three Months Ended June 30, 2013	Three Months Ended September 30, 2013	Three Months Ended December 31, 2013
Average Daily Production				
Light and Medium Oil (bbl/d)	23	23	22	20
Natural Gas (Mcf/d)	53	50	32	48
Natural Gas Liquids (/bbl/d)	2	2	2	2
BOEs (boe/d)	34	33	29	30

APPENDIX A-4 – FORM 51-101F2 - REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR (CANADA)

FORM 51-101F2
REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR OR AUDITOR

To the board of directors of Valeura Energy Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2013, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - M$)			
			Audited	Evaluated	Reviewed	**Total**
GLJ Petroleum Consultants	Corporate Summary February 25, 2014	CANADA	-	4,676	-	**4,676**

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.
7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 26, 2014

"Originally Signed by"
John E. Keith, P. Eng.
Vice President

APPENDIX A-5 – REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER OIL AND GAS INFORMATION - FORM 51-101F3

REPORT OF
MANAGEMENT AND DIRECTORS ON RESERVES DATA
AND OTHER OIL AND GAS INFORMATION

Report of Management and Directors on Reserve Data and Other Information (51-101F3)

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 which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013 estimated using forecast prices and costs.

GLJ Petroleum Consultants Ltd. and DeGolyer and MacNaughton, each an independent qualified reserves evaluator have evaluated the Company's reserves data. The reports of the independent qualified reserves evaluators 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 evaluators;

(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

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 approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

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

March 11, 2014

(signed) "*James D. McFarland*"
James D. McFarland
President and Chief Executive Officer

(signed) "*Donald W. Shepherd*"
Donald W. Shepherd
Vice President, Engineering

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

(signed) "*Claudio Ghersinich*"
Claudio Ghersinich
Director and Member of Reserves 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.