FOR THE YEAR ENDED DECEMBER 31, 2017

ANNUAL INFORMATION FORM

EXCELLENCE. TRUST. RESPECT. RESPONSIBILITY.

DATED FEBRUARY 28, 2018

VERMILION ENERGY

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GLOSSARY OF TERMS

In addition to terms defined elsewhere in this annual information form, the following are defined terms used in this annual information form:

"2003 Arrangement" means the plan of arrangement under the ABCA involving the Trust, Vermilion Resources Ltd., Clear Energy Inc. and Vermilion Acquisition Ltd., which was completed on January 22, 2003;

"ABCA" means the *Business Corporations Act* (Alberta), R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder;

"AIF" means this Annual Information Form and the appendices attached hereto;

"Affiliate" when used to indicate a relationship with a person or company, has the same meaning as set forth in the *Securities Act* (Alberta);

"Board of Directors" or **"board"** means the board of directors of Vermilion;

"CGUs" means cash generating units and based on management's judgement, represents the lowest level at which there is identifiable cash inflows that are largely independent of the cash inflows of other groups of assets or properties;

"Common Shares" means a common share in the capital of the Company;

"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;

"Control" means, with respect to control of a body corporate by a person, the holding (other than by way of security) by or for the benefit of that person of securities of that body corporate to which are attached more than 50% of the votes that may be cast to elect directors of the body corporate (whether or not securities of any other class or classes shall or might be entitled to vote upon the happening of any event or contingency) provided that such votes, if exercised, are sufficient to elect a majority of the board of directors of the body corporate;

"Conversion Arrangement" means the plan of arrangement effected on September 1, 2010 under section 193 of the ABCA pursuant to which the Trust converted from an income trust to a corporate structure, and Unitholders exchanged their Trust Units for common shares of the Company on a one-for-one basis and holders of exchangeable shares of Vermilion Resources Ltd., previously a subsidiary of the company ("VRL"), received 1.89344 common shares for each exchangeable share held;

"Dividend" means a dividend paid by Vermilion in respect of the common shares, expressed as an amount per common share;

"Dividend Payment Date" means any date that Dividends are paid to Shareholders, generally being the 15th day of the calendar month following the determination of a Dividend Record Date;

"Dividend Record Date" means the the date on which a shareholder must hold the stock to receive the applicable dividend;

"GLJ" means GLJ Petroleum Consultants Ltd., independent petroleum engineering consultants of Calgary, Alberta;

"GLJ Report" means the independent engineering reserves evaluation of certain oil, NGL and natural gas interests of the Company prepared by GLJ dated February 1, 2018 and effective December 31, 2017;

"GLJ Resource Assessment" means the independent engineering resource evaluation prepared by GLJ to assess contingent and prospective resources across all of the Company's key operating regions with an effective date of December 31, 2017;

"IFRS" means International Financial Reporting Standards or, alternatively, "GAAP", as issued by the International Accounting Standards Board;

"Income Tax Act" or **"Tax Act"** means the *Income Tax Act* (Canada), R.S.C. 1985, c. 1. (5th Supp.), as amended, including the regulations promulgated thereunder;

"Meeting" means the annual meeting of Shareholders of the Company to be held on April 26, 2018 (or, if adjourned, such other date on which the meeting is held);

"NYSE" means New York Stock Exchange;

"PRRT" means Petroleum Resource Rent Tax, a profit based tax levied on petroleum projects in Australia;

“Plan” means the Premium Dividend™ and Dividend Reinvestment Plan of the Company dated effective February 27, 2015, as amended or supplemented from time to time;

“Prospective Resources” are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects;

“Rights Plan” means the Shareholder Rights Plan of the Company;

“Shareholders” means holders from time to time of the Company’s common shares;

“Shareholder Rights Plan Agreement” means the Shareholder Rights Plan Agreement dated September 1, 2010 between the Company and Computershare Trust Company of Canada establishing the Rights Plan, as amended and restated as of May 1, 2013 and as amended or supplemented from time to time;

“Subsidiary” means, in relation to any person, any body corporate, partnership, joint venture, association or other entity of which more than 50% of the total voting power of common shares or units of ownership or beneficial interest entitled to vote in the election of directors (or members of a comparable governing body) is owned or controlled, directly or indirectly, by such person;

“TSX” means the Toronto Stock Exchange;

“Trust” means Vermilion Energy Trust, an unincorporated open-ended investment trust governed by the laws of the Province of Alberta that was dissolved and ceased to exist pursuant to the Conversion Arrangement;

“Trust Unit” means units in the capital of the Trust;

“Unitholders” means former unitholders of the Trust;

“Vermilion” or the **“Company”** means Vermilion Energy Inc. and where context allows, its consolidated business enterprise, except that a reference to “Vermilion” prior to the date of the Conversion Arrangement means the consolidated business enterprise of the Trust, unless otherwise indicated.

Conventions

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. All financial information herein has been presented in Canadian dollars in accordance with IFRS.

Abbreviations

Oil and Natural Gas Liquids	
bbl	barrel
Mbbl	thousand barrels
bbl/d	barrels per day
NGLs	natural gas liquids
Natural Gas	
Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMBtu	million British Thermal Units
Other	
°API	An indication of the specific gravity of crude oil measured on the API (American Petroleum Institute) 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
M$	thousand dollars
MM$	million dollars
Mboe	1,000 barrels of oil equivalent
MMboe	million barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade.
TTF	the day-ahead price for natural gas in the Netherlands, quoted in MWh of natural gas, at the Title Transfer Facility Virtual Trading Point operated by Dutch TSO Gas Transport Services
NBP	the reference price paid for natural gas in the United Kingdom, quoted in pence per therm, at the National Balancing Point Virtual Trading Point operated by National Grid
AECO	the daily average benchmark price for natural gas at the AECO 'C' hub in southeast Alberta

Conversion

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

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
bbls	Cubic metres	0.159
Cubic metres	bbls oil	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

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

Certain statements included or incorporated by reference in this annual information form may constitute forward looking statements or financial outlooks under applicable securities legislation. Such forward looking statements or information typically contain statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", or similar words suggesting future outcomes or statements regarding an outlook. Forward looking statements or information in this annual information form may include, but are not limited to:

- capital expenditures;
- business strategies and objectives;
- estimated reserve quantities and the discounted present value of future net cash flows from such reserves;
- petroleum and natural gas sales;
- future production levels (including the timing thereof) and rates of average annual production growth, estimated contingent and prospective resources;
- exploration and development plans;
- acquisition and disposition plans and the timing thereof;
- operating and other expenses, including the payment of future dividends;
- royalty and income tax rates;
- the timing of regulatory proceedings and approvals; and
- the estimate of Vermilion's share of the expected natural gas production from the Corrib field.

Such forward-looking statements or information are based on a number of assumptions all or any of which may prove to be incorrect. In addition to any other assumptions identified in this document, assumptions have been made regarding, among other things:

- the ability of the Company to obtain equipment, services and supplies in a timely manner to carry out its activities in Canada and internationally;
- the ability of the Company to market crude oil, natural gas liquids and natural gas successfully to current and new customers;
- the timing and costs of pipeline and storage facility construction and expansion and the ability to secure adequate product transportation;
- the timely receipt of required regulatory approvals;
- the ability of the Company to obtain financing on acceptable terms;
- foreign currency exchange rates and interest rates;
- future crude oil, natural gas liquids and natural gas prices; and
- Management's expectations relating to the timing and results of development activities.

Although the Company believes that the expectations reflected in such forward looking statements or information are reasonable, undue reliance should not be placed on forward looking statements because the Company can give no assurance that such expectations will prove to be correct. Financial outlooks are provided for the purpose of understanding the Company's financial strength and business objectives and the information may not be appropriate for other purposes. Forward looking statements or information are based on current expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by the Company and described in the forward looking statements or information. These risks and uncertainties include but are not limited to:

- the ability of management to execute its business plan;
- the risks of the oil and gas industry, both domestically and internationally, such as operational risks in exploring for, developing and producing crude oil, natural gas liquids and natural gas;
- risks and uncertainties involving geology of crude oil, natural gas liquids and natural gas deposits;
- risks inherent in the Company's marketing operations, including credit risk;
- the uncertainty of reserves estimates and reserves life and estimates of contingent resources and estimates of prospective resources and associated expenditures;
- the uncertainty of estimates and projections relating to production, costs and expenses;
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- the Company's ability to enter into or renew leases on acceptable terms;
- fluctuations in crude oil, natural gas liquids and natural gas prices, foreign currency exchange rates and interest rates;
- health, safety and environmental risks;
- uncertainties as to the availability and cost of financing;
- the ability of the Company to add production and reserves through exploration and development activities;
- general economic and business conditions;
- the possibility that government policies or laws may change or governmental approvals may be delayed or withheld;
- uncertainty in amounts and timing of royalty payments;
- risks associated with existing and potential future law suits and regulatory actions against the Company; and
- other risks and uncertainties described elsewhere in this annual information form or in the Company's other filings with Canadian securities authorities.

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

PRESENTATION OF OIL AND GAS RESERVES AND PRODUCTION INFORMATION

All oil and natural gas reserve information contained in this annual information form is derived from the GLJ Report and has been prepared and presented in accordance with the *Canadian Oil and Gas Evaluation Handbook* (“COGEH”) and *National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). The actual oil and natural gas reserves and future production will be greater than or less than the estimates provided in this annual information form. The estimated future net revenue from the production of the disclosed oil and natural gas reserves does not represent the fair market value of these reserves.

Natural gas volumes have been converted on the basis of six thousand cubic feet of natural gas to one barrel of oil equivalent. Barrels of oil equivalent (“boe”) may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Contingent Resources

"Contingent resources" are not, and should not be confused with, petroleum and natural gas reserves. "Contingent resources" are defined in COGEH as 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. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resource the estimated discovered recoverable quantities associated with a project in the early evaluation stage.

The primary contingencies which currently prevent the classification of Vermilion’s contingent resource as reserves include but are not limited to:

- preparation of firm development plans, including determination of the specific scope and timing of projects;
- project sanction;
- access to capital markets;
- shareholder and regulatory approvals as applicable;
- access to required services and field development infrastructure;
- oil and natural gas prices in Canada and internationally in jurisdictions in which Vermilion operates;
- demonstration of economic viability;
- future drilling program and testing results;
- further reservoir delineation and studies;
- facility design work;
- corporate commitment;
- development timing;
- limitations to development based on adverse topography or other surface restrictions; and
- the uncertainty regarding marketing and transportation of petroleum from development areas.

There is no certainty that it will be commercially viable to produce any portion of the contingent resources or that Vermilion will produce any portion of the volumes currently classified as contingent resources. The estimates of contingent resources involve implied assessment, based on certain estimates and assumptions, that the contingent resources described exists in the quantities predicted or estimated and that the contingent resources can be profitably produced in the future. **The net present value of the future net revenue from the contingent resources does not necessarily represent the fair market value of the contingent resources.** Actual contingent resources (and any volumes that may be reclassified as reserves) and future production therefrom may be greater than or less than the estimates provided herein.

Prospective Resources

“Prospective resources" are not, and should not be confused with, petroleum and natural gas reserves. "Prospective resources" are defined in COGEH as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources or that Vermilion will produce any portion of the volumes currently classified as prospective resources. The estimates of prospective resources involve implied assessment, based on certain estimates and assumptions, that the resources described exists in the quantities predicted or estimated and that the resources can be profitably produced in the future. **The net present value of the future net revenue from the prospective resources does not necessarily represent the fair market value of the prospective resources.** The recovery and resources estimates provided herein are estimates only. Actual prospective resources (and any volumes that may be reclassified as reserves or contingent resources) and future production from such prospective resources may be greater than or less than the estimates provided herein.

NON-GAAP MEASURES

This annual information form includes non-GAAP measures as further described herein. Management of the Company believes these non-GAAP measures are a useful tool in analyzing operating performance. These measures do not have standardized meanings prescribed by GAAP and are not disclosed in Vermilion’s audited consolidated financial statements and, therefore, may not be comparable with the calculations of similar measures for other entities.

“Cash dividends per share” represents actual cash dividends paid per share by the Company during the relevant periods.

"Capital expenditures" represents the sum of drilling and development and exploration and evaluation. Vermilion considers capital expenditures to be a useful measure of our investment in our existing asset base. Capital expenditures are also referred to as E&D capital.

"Fund flows from operations" represents a measure of profit or loss in accordance with IFRS 8 “Operating Segments”. Vermilion analyzes fund flows from operations both on a consolidated basis and on a business unit basis in order to assess the contribution of each business unit to our ability to generate income necessary to pay dividends, repay debt, fund asset retirement obligations and make capital investments.

"Netbacks" represents a per boe and per mcf performance measures used in the analysis of operational activities. Vermilion assesses netbacks both on a consolidated basis and on a business unit basis in order to compare and assess the operational and financial performance of each business unit versus other business units and also versus third party crude oil and natural gas producers.

VERMILION ENERGY INC.

General

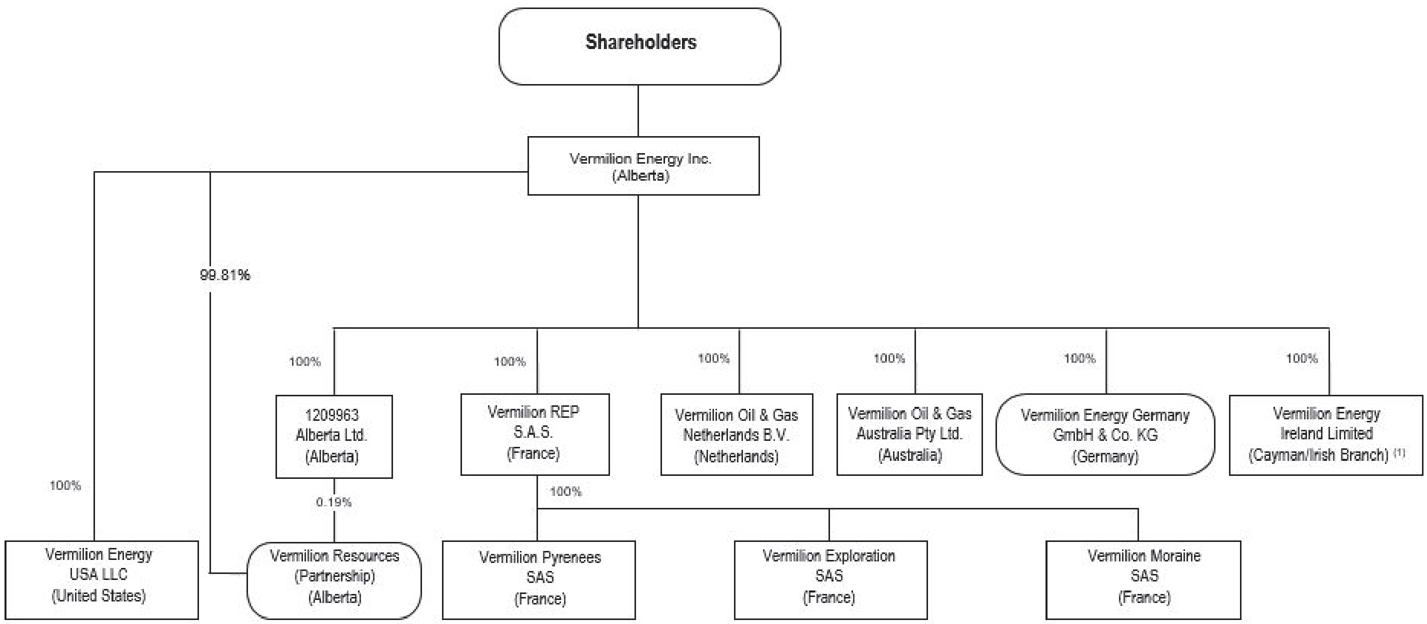
Vermilion Energy Inc. is the successor to the Trust, following the completion of the Conversion Arrangement whereby the Trust converted from an income trust to a corporate structure by way of a court approved plan of arrangement under the ABCA on September 1, 2010.

As at December 31, 2017, Vermilion had 505 full time employees of which 172 employees were located in its Calgary head office, 55 employees in its Canadian field offices, 149 employees in France, 59 employees in the Netherlands, 31 employees in Australia, 9 employees in the United States, 24 employees in Germany, 5 employees in Hungary and 1 employee in Croatia.

Vermilion was incorporated on July 21, 2010 pursuant to the provisions of the ABCA for the purpose of facilitating the Conversion Arrangement. The registered and head office of Vermilion Energy Inc. is located at Suite 3500, 520 – 3rd Avenue S.W., Calgary, Alberta, T2P 0R3.

Organizational Structure of the Company

The following diagram shows the intercorporate relationships among the Company and each of its material subsidiaries, where each material subsidiary was incorporated or formed and the percentage of votes attaching to all voting securities of each material subsidiary beneficially owned directly or indirectly by Vermilion. Reference should be made to the appropriate sections of this annual information form for a complete description of the structure of the Company.



Note:

(1) Vermilion Energy Ireland Limited is the Irish Branch of a Cayman Islands incorporated company.

DESCRIPTION OF THE BUSINESS

Vermilion is an international energy producer that seeks to create value through the acquisition, exploration, development and optimization of producing properties in North America, Europe and Australia. Vermilion focuses on the exploitation of light oil and liquids-rich natural gas conventional resource plays in Canada and the United States, the exploration and development of high impact natural gas opportunities in the Netherlands and Germany, and oil drilling and workover programs in France and Australia. Vermilion currently holds an 18.5% non-operated working interest in the Corrib gas field in Ireland.

Vermilion's priorities are health and safety, the environment, and profitability, in that order. Nothing is more important to us than the safety of the public and those who work with us, and the protection of our natural surroundings. Vermilion has been recognized as a top decile performer amongst Canadian publicly listed companies in governance practices, as a Climate Leadership Level performer by the CDP (formerly the Carbon Disclosure Project), and a Best Workplace in the Great Place to Work® Institute's annual rankings in Canada, France, the Netherlands and Germany. Vermilion emphasizes strategic community investment in each of our operating areas.

Operating Segments and Description of Properties[1]

Vermilion has operations in three core areas: North America, Europe and Australia. Vermilion's business within these regions is managed at the country level through business units which form the basis of the Company's operating segments. These operating segments, as well as a description of the material oil and natural gas properties, facilities and installations in which Vermilion has an interest, are discussed below. For a discussion of the competitive conditions affecting Vermilion's business, refer to "Competition" in the Risk Factors section of this AIF.

Canada Business Unit

Vermilion's Canadian production is primarily focused in three areas of Alberta: West Pembina, Slave Lake and Central Alberta and in the Northgate Region of southeast Saskatchewan. Vermilion's main liquids rich gas producing asset is the Mannville condensate play in the West Pembina area. The Cardium light crude oil play in West Pembina is the main oil producing area, along with the Northgate and Slave Lake oil producing areas. Vermilion's main natural gas producing areas are West Pembina and Central Alberta.

Vermilion holds an average 74% working interest in approximately 445,700 (330,900 net) acres of developed land, and an average 87% working interest in approximately 430,800 (376,400 net) acres of undeveloped land. Vermilion had 523 (375 net) producing natural gas wells and 639 (475 net) producing oil wells in Canada as at December 31, 2017.

Vermilion owns and operates three natural gas plants and has an ownership interest in six additional plants, resulting in combined gross natural gas processing capacity of over 80 MMcf/d. In addition, Vermilion has oil processing capacity of over 25,000 bbl/d through ten operated oil batteries including a 15,000 bbl/d oil battery in West Pembina.

For the year ended December 31, 2017, production in Canada averaged 97.9 MMcf/d of natural gas and 13,195 bbl/d of light crude oil, medium crude oil and NGLs. Sales of natural gas in 2017 were $83.5 million (2016 - $65.9 million) and sales from light crude oil, medium crude oil and NGLs were $247.3 million (2016 - $187.0 million).

During 2017, the majority of Vermilion's Canadian exploration and development expenditures were directed to our Mannville program with activity focused in the West Pembina and Ferrier areas of Alberta. During 2017 Vermilion drilled or participated in 24 (17.4 net) Mannville wells and production from the Mannville play increased by 42% as compared to 2016. Vermilion plans to drill 17 (13.8 net) Mannville wells in 2018. The Company also plans to drill or participate in five (4.2 net) Cardium wells and 21 (20.5 net) southeast Saskatchewan wells in 2018 as compared to seven (7.0 net) Cardium wells and 13 (11.1 net) southeast Saskatchewan wells in 2017. Vermilion expects that the Mannville, Cardium and southeast Saskatchewan assets will continue to support the Company's production growth.

The GLJ Report assigned 81,322 Mboe of total proved reserves and 139,209 Mboe of proved plus probable reserves to Vermilion's properties located in Canada as at December 31, 2017.

France Business Unit

Vermilion entered France in 1997 and has completed three subsequent acquisitions. The Company is the largest oil producer in the country and represents approximately three-quarters of domestic oil production. Vermilion predominately produces oil in France and the Company's oil is priced with reference to Dated Brent.

Vermilion's main producing areas in France are located in the Aquitaine Basin which is southwest of Bordeaux, France and in the Paris Basin, located just east of Paris. Vermilion also holds exploration lands in the Alsace-Lorraine region. The three major fields in the Paris Basin area are Champotran, Neocomian and Chaunoy, and the two major fields in the Aquitaine Basin are Parentis and Cazaux. Vermilion operates 19 oil batteries and 15 single well batteries in the country. Given the legacy nature of these assets, the throughput capability of these batteries exceeds any projected future requirements. Vermilion holds an average 96% working interest in 218,100 (208,900 net) acres of developed land and 99% working interest in 383,000 (379,800 net) acres of undeveloped land in the Aquitaine and Paris Basins. Vermilion had 338 (332 net) producing oil wells and three (3.0 net) producing gas wells in France as at December 31, 2017.

For the year ended December 31, 2017, production in France averaged 11,085 bbl/d of light crude oil and medium crude oil. Sales from light crude oil and medium crude oil in 2017 were $268.1 million (2016 - $246.6 million) with no sales of natural gas (2016 - $0.3 million). Natural gas sales in France have decreased significantly since 2013 following the closure of a third party processing facility.

In 2017, Vermilion drilled six (6.0 net) wells in the Neocomian fields in the Paris basin, four (4.0 net) wells in the Champotran field and one (1.0 net) horizontal sidetrack well in the Vulaines field. In 2018, Vermilion intends to drill two (2.0 net) Neocomian wells and three (3.0 net) Champotran wells. The Company also intends to continue its ongoing program of workovers and optimizations. By continuing to develop its inventory in France, while minimizing declines through workovers and optimizations, Vermilion seeks to deliver moderate production growth from its French assets.

The GLJ Report assigned 42,093 Mboe of total proved reserves and 64,188 Mboe of proved plus probable reserves to Vermilion's properties located in France as at December 31, 2017.

Netherlands Business Unit

Vermilion entered the Netherlands in 2004 and is the country's second largest onshore natural gas producer (excluding state-owned energy company EBN). Vermilion's natural gas production in the Netherlands is priced off of the TTF index.

Vermilion's Netherlands assets consist of 24 onshore concessions and two offshore concessions. Production consists primarily of natural gas with a small amount of related condensate. Vermilion’s total land position in the Netherlands covers 1,455,800 (826,000 net) acres at an average 56% working interest, of which 95% is undeveloped. Vermilion had 56 (39 net) producing natural gas wells as at December 31, 2017.

For the year ended December 31, 2017, Vermilion's production in the Netherlands averaged 40.5 MMcf/d of natural gas and 90 bbl/d of NGLs. Sales in 2017 of natural gas were $106.2 million (2016 - $99.3 million) and sales from NGLs were $1.9 million (2016 - $1.4 million).

Vermilion drilled two (1.0 net) exploration wells in the Netherlands during 2017 and the Company expects to drill three (1.5 net) exploration wells in 2018. Vermilion expects that its inventory of potentially high-impact exploration and development opportunities in the Netherlands will continue to support the Company's production growth in the country.

The GLJ Report assigned 10,347 Mboe of total proved reserves and 17,863 Mboe of proved plus probable reserves to Vermilion's properties located in the Netherlands as at December 31, 2017.

Germany Business Unit

Vermilion entered Germany in 2014 with the acquisition of a 25% non-operated interest in natural gas producing assets. In December 2016, Vermilion completed an acquisition of oil and gas producing properties that provided Vermilion with its first operated position in the country. Vermilion holds a significant undeveloped land position in Germany as a result of a farm-in agreement the Company entered into in 2015. Vermilion's natural gas production in Germany is priced with reference to TTF and oil production is priced with reference to Dated Brent.

Including the interests that were acquired in December 2016, Vermilion’s producing assets in Germany consist of operated and non-operated interests in seven natural gas fields and five oil fields. Prior to the December 2016 acquisition, Vermilion's producing assets in Germany consisted of a 25% non-operated interest in four natural gas fields. Vermilion had 135 (104 net) producing oil wells and 20 (7 net) producing natural gas wells as at December 31, 2017.

Vermilion holds a significant land position in northwest Germany comprised of 88,600 (32,600 net) developed acres and 2,787,000 (1,214,000 net) undeveloped acres. The Company also holds a 0.4% equity interest in Erdgas Munster GmbH ("EGM"), a joint venture created in 1959 to jointly transport, process, and market gas in northwest Germany. This transportation interest allows for our proportionate share of produced volumes to be processed, blended, and transported to designated gas consumers through the EGM network of approximately 2,000 kilometres of pipeline.

Furthermore, the Company holds a 50% equity interest in Hannoversche Erdölleitung GmbH ("HEG"), a joint venture company created in 1959 that collects and transports oil through a 185 km network of infrastructure from the Hannover region to rail loading facilities in Hannover.

For the year ended December 31, 2017, production in Germany averaged 19.4 MMcf/d of natural gas and 1,060 bbl/d of crude oil. Sales of natural gas in 2017 were $45.1 million (2016 - $29.0 million) and sales from crude oil were $23.6 million (2016 - nil).

During 2017, Vermilion focused on workover and optimization opportunities on the assets acquired in December 2016. In 2018, the Company plans to continue to invest in optimization and other well work on the assets the Company acquired in December 2016 as well as prepare for the drilling of one (0.25 net) well in the Dümmersee-Uchte area which is expected to be drilled in 2019. Vermilion will also advance permitting, studies and other activities associated with the farm-in agreement signed in mid-2015.

The GLJ Report assigned 12,640 Mboe of total proved reserves and 24,496 Mboe of proved plus probable reserves to Vermilion's properties located in Germany as at December 31, 2017.

Ireland Business Unit

Vermilion acquired an 18.5% non-operating interest in the offshore Corrib gas field located off the northwest coast of Ireland in 2009. The asset is comprised of six offshore wells, an onshore natural gas processing facility and offshore and onshore pipeline segments. At the time of the acquisition, most of the key components of the project, with the exception of the onshore pipeline, were either complete or in the latter stages of development. In 2011, approvals and permissions were granted for the onshore gas pipeline and tunneling commenced in December 2012. In May 2014, Vermilion announced the completion of tunnel boring operations. In September 2015, the project operator, Shell E&P Ireland Limited, declared the project operationally ready for service. With the final regulatory consent received on December 29, 2015, gas began to flow from the Corrib project on December 30, 2015.

Production volumes at Corrib reached full plant capacity of approximately 65 mmcf/d (10,900 boe/d) net to Vermilion at the end of Q2 2016 following recertification activities associated with a third party gas distribution pipeline network.

On July 12, 2017 Vermilion and Canada Pension Plan Investment Board ("CPPIB") announced a strategic partnership in Corrib, whereby CPPIB will acquire Shell E&P Ireland Limited’s 45% interest in Corrib for total cash consideration of €830 million, subject to customary closing adjustments and future contingent value payments based on performance and realized pricing. At closing, Vermilion expects to assume operatorship of Corrib. In addition to operatorship, CPPIB plans to transfer a 1.5% working interest to Vermilion for €19.4 million ($28.4 million), before closing adjustments. Vermilion’s incremental 1.5% ownership of Corrib represents production of approximately 850 boe/d (100% gas). The acquisition has an effective date of January 1, 2017 and is anticipated to close in the first half of 2018.

For the year ended December 31, 2017, production in Ireland averaged 58.4 MMcf/d of natural gas. Sales of natural gas in 2017 were $153.3 million (2016 - $109.2 million).

The GLJ Report assigned 13,634 Mboe of total proved reserves and 22,199 Mboe of proved plus probable reserves to Vermilion's property located in Ireland as at December 31, 2017.

Australia Business Unit

In 2005, Vermilion acquired a 60% operated interest in the Wandoo offshore oil field and related production assets, located on Western Australia's northwest shelf. In 2007, Vermilion acquired the remaining 40% interest in the asset. Production occurs from 18 well bores and five lateral sidetrack wells that are tied into two platforms, Wandoo 'A' and Wandoo 'B'. Wandoo 'B' is permanently manned, houses the required production facilities and incorporates 400,000 bbls of oil storage within the platform's concrete gravity structure. The Wandoo 'B' facilities are capable of processing 182,000 bbl/d of total fluid to separate the oil from produced water. Vermilion's land position in the Wandoo field is comprised of 59,600 acres (gross and net).

For the year ended December 31, 2017, Vermilion's production in Australia averaged 5,770 bbl/d of light crude oil and medium crude oil. Sales in 2017 from light crude oil and medium crude oil were $154.4 million (2016 - $136.8 million).

During 2015 and 2016, Vermilion drilled three wells in Australia and does not presently expect to drill any additional Australian wells until 2019. Vermilion expects to manage its Australian asset and related capital investment programs to maintain stable production levels of approximately 6,000 bbl/d.

The GLJ Report assigned 10,915 Mboe of total proved reserves and 15,565 Mboe of proved plus probable reserves to Vermilion's property located in Australia as at December 31, 2017.

United States Business Unit

Vermilion entered the United States in 2014. The Company's assets include 109,500 (97,200 net) acres of land in the Powder River basin of northeastern Wyoming, of which 95% is undeveloped. Vermilion had 13 (11 net) producing oil wells in the United States as at December 31, 2017.

For the year ended December 31, 2017, Vermilion's production in the United States averaged 716 bbl/d of light crude oil, medium crude oil and NGLs and 0.4 MMcf/d of natural gas. Sales from all commodities in 2017 were $15.4 million (2016 - $7.3 million).

During 2017, Vermilion continued work on its early stage Turner Sand development in the Powder River Basin, drilling and completing three (3.0 net) wells. In 2018, Vermilion expects to drill five (5.0 net) wells in this play.

The GLJ Report assigned 5,613 Mboe of total proved reserves and 14,970 Mboe of proved plus probable reserves to Vermilion's properties located in the United States.

Central and Eastern Europe ("CEE") Business Unit

Vermilion has established a CEE Business unit with a head office in Budapest, Hungary. The CEE business unit is responsible for business development in the CEE, including managing the exploration and development opportunities associated with the Company's land holdings in Hungary, Slovakia and Croatia.

At present, the CEE business unit does not have any production or revenues.

Vermilion's land position in the CEE consists of 652,800 (652,800 net) acres in Hungary, 184,600 (92,300 net) acres in Slovakia and 2.35 million (2.35 million net) acres in Croatia. Currently, Vermilion's entire land position in the CEE is undeveloped.

Vermilion plans to drill its first well (1.0 net) in the South Battonya license of Hungary in 2018.

(1) The production numbers stated refer to Vermilion's working interest share before deduction of Crown, freehold and other royalties. Reserve amounts are gross reserves, stated before deduction of royalties, as at December 31, 2017, based on forecast costs and price assumptions as evaluated in the GLJ Report.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History and Outlook

The following describes the development of Vermilion's business over the last three completed financial years. None of the acquisitions described below constituted a “significant acquisition” within the meaning of applicable securities laws.

2015

Vermilion achieved record annual production of 54,922 boe/d representing an increase of 11% as compared to 2014. Full-year average production was within 0.1% of guidance as strong production results from other business units largely offset the production shortfall related to regulatory delays at Corrib.

Vermilion maintained its dividend at $0.215 per month throughout 2015. In February 2015, Vermilion announced the implementation of a Premium Dividend™ Component of the Dividend Reinvestment Plan as a short term measure to maintain the Company’s financial strength. The Premium Dividend™ component allowed Vermilion to preserve financial flexibility by providing ongoing access to a modest amount of low-cost equity capital. Under the Premium Dividend™ component, shares were issued at 3.5% discount to average market price and participating shareholders received a premium cash payment equal to 101.5% of dividends.

In 2015, Vermilion entered into a farm-in agreement in northwest Germany. The farm-in provided Vermilion with participating interest in 18 onshore exploration licenses, comprising approximately 850,000 net undeveloped acres in the North German Basin, in exchange for carrying 50% of the farmor's costs associated with the drilling and testing of six net exploration wells over the following five years. The agreement also granted Vermilion operatorship during the exploration phase for 11 of the 18 licenses as well as access to key data spanning the farm-in assets.

On December 29, 2015 Vermilion announced that Shell E&P Ireland Limited, operator of the Corrib project, received the final remaining consent required for production from the office of Ireland's Minister for Communications, Energy and Natural Resources. Following this, natural gas began to flow from the Corrib gas project in Ireland on December 30, 2015.

Vermilion continued to prioritize preserving the strength of its balance sheet and increase its financial flexibility in response to the continued weak commodity price environment. Total exploration and development ("E&D") investment for 2015 totalled $487 million, representing a nearly 30% decrease from the prior year. Vermilion continued to focus on reducing costs through our company-wide Profitability Enhancement Program ("PEP"), and the Company increased its credit facility capacity by $500 million during the year to $2.0 billion while also extending the term to May 2019.

2016

Vermilion achieved record annual production of 63,526 boe/d representing an increase of 16% as compared to 2015. The increase was attributable to a full-year of Corrib production and organic growth in the Netherlands.

The commodity price environment continued to be extremely challenging during 2016. WTI averaged US$43.32/bbl for the year and reached an intra-year, monthly average low of US$30.62/bbl in February 2016. To support its balance sheet and dividend in the prevailing price environment, the Company continued to focus on further improving capital efficiencies as well as achieving cost reductions through PEP. Accordingly, in January 2016, Vermilion announced a $285 million E&D capital budget for 2016 representing a 42% decrease from 2015. As commodity prices continued to weaken during Q1 2016, in February 2016 Vermilion announced a further reduction in its 2016 E&D capital budget to $235 million. In August 2016, Vermilion modestly increased its E&D capital expenditure guidance for 2016 to $240 million. E&D capital expenditures for 2016 totaled $242.4 million, representing decreases from 2015 and 2014 of 50% and 65%, respectively.

Vermilion maintained its dividend at $0.215 per month throughout 2016. In addition, the Company began prorating the Premium Dividend™ Component of the Dividend Reinvestment Plan starting in 2016. The Premium Dividend™ Component of the Dividend Reinvestment Plan was implemented by Vermilion in 2015 as a short term measure to preserve the Company’s financial flexibility by providing access to a modest amount of low-cost equity capital. As a result of the continued strength in the Company's business associated with cost reductions, capital efficiency improvements and the expectation of a more stable commodity price environment, Vermilion began prorating the Premium Dividend™ Component of the Dividend Reinvestment Plan by 25% commencing with the October 2016 dividend.

Vermilion repaid the $225 million of 6.5% Senior Unsecured Notes that came due on February 10, 2016 with funds from its credit facility. While the Company assessed opportunities to diversify its debt structure, the credit facility represented the Company’s most cost-effective method of borrowing.

Effective March 1, 2016, Mr. Lorenzo Donadeo retired as Chief Executive Officer of Vermilion and became Chair of the Board of Directors. Mr. Anthony Marino, previously the Company's President and Chief Operating Officer, assumed the role of President and CEO. Mr. Larry Macdonald, previously the Board of Director's Chair, assumed the newly created role of Lead Independent Director.

In December 2016, Vermilion closed an acquisition of producing oil and gas properties in Germany from Engie E&P Deutschland GmbH (previously known as GDF Suez S.A.) for total consideration of $45.6 million, net of acquired product inventory. The acquisition comprised operated and non-operated interests in five oil and three natural gas producing fields, along with an operated interest in one exploration license. Vermilion assumed operatorship of six of the eight producing fields, with the other fields operated by ExxonMobil Production Deutschland ("EMPG") and Deutsche Erdoel AG ("DEA"). Production from the acquired assets was approximately 2,000 boe/d in 2016. The acquisition provided Vermilion with its first operated producing properties in Germany, and advanced the Company's objective of developing a material business unit in the country.

In June 2016, the Republic of Croatia ratified the grant of four exploration blocks to Vermilion. The exploration blocks consisted of approximately 2.35 million gross acres (100% working interest), with a substantial portion of the acreage located near existing crude oil and natural gas fields in northeast Croatia. The initial five-year exploration period consists of two phases with an option to relinquish the blocks following the initial three-year phase. In December 2016, Vermilion entered into a farm-in agreement in Slovakia with NAFTA, Slovakia's dominant exploration and production company. The farm-in agreement grants Vermilion a 50% working interest to jointly explore 183,000 gross acres on an existing license. The primary term of the farm-in agreement is five years.

Vermilion was awarded a position on CDP's 2016 Climate "A" List. CDP (formerly Carbon Disclosure Project) is a London-based not-for-profit organization that administers a global environmental disclosure system that assists in the measurement and management of corporate environmental impacts. Only 193 companies globally achieved Climate "A" List recognition in 2016 and Vermilion was one of only five oil and gas companies in the world, and the only North American energy company, on the 2016 Climate "A" List. Vermilion has voluntarily reported emissions data to CDP for each year since 2012, recognizing the importance of measuring and understanding the Company's environmental impact.

2017

Vermilion achieved record annual production of 68,021 boe/d representing an increase of 7% as compared to 2016. Production growth in Canada, the US, Ireland and Germany more than offset lower production in France, Netherlands and Australia. Permitting delays significantly reduced Netherlands production volumes in 2017, while an unplanned 31-day downtime period at Corrib late in Q3 and early Q4 2017 reduced annual production by approximately 900 boe/d.

Vermilion maintained its dividend at $0.215 per month throughout 2017. Additionally, as the Company's business continued its strong performance and with the prospect of a more stable commodity price environment, Vermilion continued the proration of the Premium Dividend™ Component of the Dividend Reinvestment Plan, which commenced in 2016, throughout the year. The Company discontinued the Premium Dividend™ Component beginning with the July 2017 dividend payment.

In March 2017, Vermilion issued US$300 million aggregate principal amount of eight-year senior unsecured notes bearing interest at a rate of 5.625% per annum. This issuance was completed by way of a private offering and represented Vermilion's first issuance in the US debt markets. The issuance of US dollar denominated debt provides a partial natural hedge against our largely US dollar denominated revenue streams.

In April 2017, Vermilion extended the term of its credit facility with its banking syndicate to May 2021. Following a review of the Company's projected liquidity requirements and the receipt of proceeds from the US debt issuance, Vermilion elected to request a reduction in the total facility amount to $1.4 billion from $2.0 billion.

In July 2017, Vermilion and Canada Pension Plan Investment Board ("CPPIB") announced a strategic partnership in Corrib, whereby CPPIB will acquire Shell E&P Ireland Limited's 45% interest in Corrib for total cash consideration of €830 million, subject to customary closing adjustments and future contingent value payments based on performance and realized pricing. At closing, Vermilion expects to assume operatorship of Corrib. In addition to operatorship, CPPIB plans to transfer a 1.5% working interest to Vermilion for €19.4 million ($28.4 million), before closing adjustments. Vermilion's incremental 1.5% ownership of Corrib represents production of approximately 850 boe/d (100% gas). The acquisition has an effective date of January 1, 2017 and is anticipated to close in the first half of 2018.

In December 2017, we were awarded a license for the Békéssámson concession for a 4-year term in Hungary. Located adjacent to our existing South Battonya concession in southeast Hungary, the Békéssámson concession covers 330,700 net acres (100% working interest) and more than doubles the size of our total land position in the country. We plan to drill our first well (1.0 net) in the South Battonya concession in Hungary in 2018.

Vermilion continued to be recognized for its commitment and leadership on environmental, social and governance matters in 2017. The Company received a top quartile ranking for our industry sector in RobecoSAM's annual Corporate Sustainability Assessment ("CSA"). The CSA analyzes sustainability performance across economic, environmental, governance and social criteria, and is the basis of the Dow Jones Sustainability Indices. The RobecoSAM assessment follows earlier recognition of Vermilion's sustainability performance, including being named to the CDP Climate Leadership Level (A-) as a global leader in environmental stewardship, and receipt of the French government's Circular Economy Award for Industrial and Regional Ecology for our geothermal energy partnership in Parentis. Vermilion was also ranked 13th by Corporate Knights on the Future 40 Responsible Corporate Leaders in Canada list. This marks the fourth year in a row that Vermilion has been recognized by Corporate Knights as one of Canada's top sustainability performers. Vermilion's MSCI ESG (Environment, Social and Governance) rating increased from BBB to A for 2017 and our Governance Metrics score ranked in the 90th percentile globally.

Outlook

Vermilion's business model continues to allow for flexibility in response to volatile commodity prices and regulatory changes, as demonstrated in 2017 through the Company's response to various permitting delays in the Netherlands to reallocate capital to other business units. Vermilion intends to maintain a low level of financial leverage and continue to fund dividends and E&D capital investment from internally generated fund flows from operations. Consistent with these objectives, in October 2017 Vermilion announced an E&D capital budget for 2018 of $315 million with corresponding production guidance of between 74,500-76,500 boe/d. In January 2018, after announcing an acquisition of a private southeast Saskatchewan light oil producer, Vermilion increased its 2018 E&D guidance to $325 million and production guidance to between 75,000-77,500 boe/d. Based on the current commodity price strip, Vermilion expects to fully fund 2018 E&D capital investment and cash dividends from fund flows from operations, with surplus cash generation primarily directed to debt reduction.

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STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Reserves and Future Net Revenue

The following is a summary of the oil and natural gas reserves and the value of future net revenue of Vermilion as evaluated by GLJ in a report dated February 1, 2018 with an effective date of December 31, 2017. Pricing used in the forecast price evaluations is set forth in the notes to the tables.

Reserves and other oil and gas information contained in this section is effective December 31, 2017 unless otherwise stated.

All evaluations of future net revenue set forth in the tables below are stated after overriding and lessor royalties, Crown royalties, freehold royalties, mineral taxes, direct lifting costs, normal allocated overhead and future capital investments, including abandonment and reclamation obligations. **Future net revenues estimated by the GLJ Report do not represent the fair market value of the reserves. Other assumptions relating to the costs, prices for future production and other matters are included in the GLJ Report. There is no assurance that the future price and cost assumptions used in the GLJ Report will prove accurate and variances could be material.**

Reserves for Australia, Canada, France, Germany, Ireland, the Netherlands and United States are established using deterministic methodology. Total proved reserves are established at the 90 percent probability (P90) level. There is a 90 percent probability that the actual reserves recovered will be equal to or greater than the P90 reserves. Total proved plus probable reserves are established at the 50 percent probability (P50) level. There is a 50 percent probability that the actual reserves recovered will be equal to or greater than the P50 reserves.

The Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are contained in Schedules "B" and "C", respectively.

The following tables provide reserves data and a breakdown of future net revenue by component and product type using forecast prices and costs. For Canada, the tables following include Alberta Gas Cost Allowance.

The following tables may not total due to rounding.

Oil and Gas Reserves - Based on Forecast Prices and Costs (1)

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (MMcf)	Net (2) (MMcf)
Proved Developed Producing (3) (5) (6)								
Australia	9,065	9,065	—	—	—	—	—	—
Canada	11,148	10,219	—	—	—	—	139,772	128,023
France	35,944	33,265	—	—	—	—	8,619	7,939
Germany	5,008	4,880	—	—	—	—	29,791	26,881
Ireland	—	—	—	—	—	—	81,803	81,803
Netherlands	—	—	—	—	—	—	37,296	24,721
United States	982	782	—	—	—	—	1,071	854
Total Proved Developed Producing	62,147	58,211	—	—	—	—	298,352	270,221

	Shale Gas		Coal Bed Methane		Natural Gas Liquids		BOE	
	Gross (2) (MMcf)	Net (2) (MMcf)	Gross (2) (MMcf)	Net (2) (MMcf)	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (Mboe)	Net (2) (Mboe)
Proved Developed Producing (3) (5) (6)								
Australia	—	—	—	—	—	—	9,065	9,065
Canada	60	56	2,330	2,153	11,215	9,102	46,057	41,026
France	—	—	—	—	—	—	37,381	34,588
Germany	—	—	—	—	—	—	9,973	9,360
Ireland	—	—	—	—	—	—	13,634	13,634
Netherlands	—	—	—	—	137	90	6,353	4,210
United States	—	—	—	—	147	117	1,308	1,041
Total Proved Developed Producing	60	56	2,330	2,153	11,499	9,309	123,771	112,924

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (MMcf)	Net (2) (MMcf)
Proved Developed Non-Producing (3) (5) (7)								
Australia	350	350	—	—	—	—		
Canada	878	768	—	—	—	—	9,420	8,489
France	562	492	—	—	—	—	—	—
Germany	539	521	—	—	—	—	8,959	8,156
Ireland	—	—	—	—	—	—	—	—
Netherlands	—	—	—	—	—	—	21,010	20,482
United States	—	—	—	—	—	—	—	—
Total Proved Developed Non-Producing	2,329	2,131	—	—	—	—	39,389	37,127

	Shale Gas		Coal Bed Methane		Natural Gas Liquids		BOE	
	Gross (2) (MMcf)	Net (2) (MMcf)	Gross (2) (MMcf)	Net (2) (MMcf)	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (Mboe)	Net (2) (Mboe)
Proved Developed Non-Producing (3) (5) (7)								
Australia	—	—	—	—	—	—	350	350
Canada	1,079	1,025	2,360	2,200	410	309	3,431	3,029
France	—	—	—	—	—	—	562	492
Germany	—	—	—	—	—	—	2,032	1,880
Ireland	—	—	—	—	—	—	—	—
Netherlands	—	—	—	—	56	54	3,558	3,468
United States	—	—	—	—	—	—	—	—
Total Proved Developed Non-Producing	1,079	1,025	2,360	2,200	466	363	9,933	9,219

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross [(2)] (Mbbl)	Net [(2)] (Mbbl)	Gross [(2)] (Mbbl)	Net [(2)] (Mbbl)	Gross [(2)] (Mbbl)	Net [(2)] (Mbbl)	Gross [(2)] (MMcf)	Net [(2)] (MMcf)
Proved Undeveloped [(3) (8)]								
Australia	1,500	1,500	—	—	—	—	—	—
Canada	7,634	6,929	—	—	—	—	91,104	83,603
France	4,140	3,767	—	—	—	—	64	64
Germany	241	235	—	—	—	—	2,361	1,939
Ireland	—	—	—	—	—	—	—	—
Netherlands	—	—	—	—	—	—	2,620	2,620
United States	3,300	2,693	—	—	—	—	3,309	2,700
Total Proved Undeveloped	16,815	15,124	—	—	—	—	99,458	90,926

	Shale Gas		Coal Bed Methane		Natural Gas Liquids		BOE	
	Gross [(2)] (MMcf)	Net [(2)] (MMcf)	Gross [(2)] (MMcf)	Net [(2)] (MMcf)	Gross [(2)] (Mbbl)	Net [(2)] (Mbbl)	Gross [(2)] (Mboe)	Net [(2)] (Mboe)
Proved Undeveloped [(3) (8)]								
Australia	—	—	—	—	—	—	1,500	1,500
Canada	—	—	2,023	1,849	8,679	7,689	31,834	28,860
France	—	—	—	—	—	—	4,151	3,778
Germany	—	—	—	—	—	—	635	558
Ireland	—	—	—	—	—	—	—	—
Netherlands	—	—	—	—	—	—	437	437
United States	—	—	—	—	454	370	4,306	3,513
Total Proved Undeveloped	—	—	2,023	1,849	9,133	8,059	42,863	38,646

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross [(2)] (Mbbl)	Net [(2)] (Mbbl)	Gross [(2)] (Mbbl)	Net [(2)] (Mbbl)	Gross [(2)] (Mbbl)	Net [(2)] (Mbbl)	Gross [(2)] (MMcf)	Net [(2)] (MMcf)
Proved [(3)]								
Australia	10,915	10,915	—	—	—	—	—	—
Canada	19,660	17,916	—	—	—	—	240,296	220,115
France	40,646	37,524	—	—	—	—	8,683	8,003
Germany	5,788	5,636	—	—	—	—	41,111	36,976
Ireland	—	—	—	—	—	—	81,803	81,803
Netherlands	—	—	—	—	—	—	60,926	47,823
United States	4,282	3,475	—	—	—	—	4,380	3,554
Total Proved	81,291	75,466	—	—	—	—	437,199	398,274

	Shale Gas		Coal Bed Methane		Natural Gas Liquids		BOE	
	Gross [(2)] (MMcf)	Net [(2)] (MMcf)	Gross [(2)] (MMcf)	Net [(2)] (MMcf)	Gross [(2)] (Mbbl)	Net [(2)] (Mbbl)	Gross [(2)] (Mboe)	Net [(2)] (Mboe)
Proved [(3)]								
Australia	—	—	—	—	—	—	10,915	10,915
Canada	1,139	1,081	6,713	6,202	20,304	17,100	81,322	72,916
France	—	—	—	—	—	—	42,093	38,858
Germany	—	—	—	—	—	—	12,640	11,799
Ireland	—	—	—	—	—	—	13,634	13,634
Netherlands	—	—	—	—	193	144	10,347	8,115
United States	—	—	—	—	601	487	5,613	4,554
Total Proved	1,139	1,081	6,713	6,202	21,098	17,731	176,564	160,791

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (MMcf)	Net (2) (MMcf)
Probable (4)								
Australia	4,650	4,650	—	—	—	—	—	—
Canada	12,885	11,417	—	—	—	—	181,055	164,336
France	21,786	20,115	—	—	—	—	1,854	1,769
Germany	3,000	2,931	—	—	—	—	53,134	47,092
Ireland	—	—	—	—	—	—	51,389	51,389
Netherlands	—	—	—	—	—	—	44,380	35,383
United States	7,073	5,827	—	—	—	—	7,520	6,194
Total Probable	49,394	44,940	—	—	—	—	339,332	306,163

	Shale Gas		Coal Bed Methane		Natural Gas Liquids		BOE	
	Gross (2) (MMcf)	Net (2) (MMcf)	Gross (2) (MMcf)	Net (2) (MMcf)	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (Mboe)	Net (2) (Mboe)
Probable (4)								
Australia	—	—	—	—	—	—	4,650	4,650
Canada	214	203	3,053	2,846	14,282	12,186	57,887	51,501
France	—	—	—	—	—	—	22,095	20,410
Germany	—	—	—	—	—	—	11,856	10,780
Ireland	—	—	—	—	—	—	8,565	8,565
Netherlands	—	—	—	—	119	90	7,516	5,987
United States	—	—	—	—	1,031	849	9,357	7,708
Total Probable	214	203	3,053	2,846	15,432	13,125	121,926	109,601

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (MMcf)	Net (2) (MMcf)
Proved Plus Probable (3) (4)								
Australia	15,565	15,565	—	—	—	—	—	—
Canada	32,545	29,333	—	—	—	—	421,351	384,451
France	62,432	57,639	—	—	—	—	10,537	9,772
Germany	8,788	8,567	—	—	—	—	94,245	84,068
Ireland	—	—	—	—	—	—	133,192	133,192
Netherlands	—	—	—	—	—	—	105,306	83,206
United States	11,355	9,302	—	—	—	—	11,900	9,748
Total Proved Plus Probable	130,685	120,406	—	—	—	—	776,531	704,437

	Shale Gas		Coal Bed Methane		Natural Gas Liquids		BOE	
	Gross (2) (MMcf)	Net (2) (MMcf)	Gross (2) (MMcf)	Net (2) (MMcf)	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (Mboe)	Net (2) (Mboe)
Proved Plus Probable (3) (4)								
Australia	—	—	—	—	—	—	15,565	15,565
Canada	1,353	1,284	9,766	9,048	34,586	29,286	139,209	124,416
France	—	—	—	—	—	—	64,188	59,268
Germany	—	—	—	—	—	—	24,496	22,578
Ireland	—	—	—	—	—	—	22,199	22,199
Netherlands	—	—	—	—	312	234	17,863	14,102
United States	—	—	—	—	1,632	1,336	14,970	12,263
Total Proved Plus Probable	1,353	1,284	9,766	9,048	36,530	30,856	298,490	270,391

Notes:

(1) The pricing assumptions used in the GLJ Report with respect to net present value of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below. See "Forecast Prices used in Estimates". The NGL price is an aggregate of the individual natural gas liquids prices used in the Total Proved plus Probable evaluation. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

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

(3) "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.

(4) "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.

(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.

Net Present Value of Future Net Revenue - Based on Forecast Prices and Costs [1]

	Before Deducting Future Income Taxes Discounted At					After Deducting Future Income Taxes Discounted At				
(M$)	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Proved Developed Producing [2] [4] [5]										
Australia	(17,017)	90,880	132,474	146,048	147,713	77,180	124,390	136,979	136,121	130,383
Canada	929,867	770,860	647,843	559,708	494,964	929,867	770,860	647,843	559,708	494,964
France	1,791,774	1,315,070	1,030,403	849,032	725,407	1,473,144	1,091,894	858,839	708,168	604,390
Germany	276,577	249,619	206,965	174,876	151,703	276,578	249,619	206,965	174,876	151,703
Ireland	389,204	376,115	346,327	316,408	290,143	389,204	376,115	346,327	316,408	290,143
Netherlands	48,794	60,781	66,245	68,260	68,404	48,793	60,781	66,245	68,260	68,404
United States	44,617	34,550	28,272	24,106	21,170	44,619	34,550	28,272	24,106	21,170
Total Proved Developed Producing	3,463,816	2,897,875	2,458,529	2,138,438	1,899,504	3,239,385	2,708,209	2,291,470	1,987,647	1,761,157
Proved Developed Non-Producing [2] [4] [6]										
Australia	28,079	24,122	20,869	18,180	15,942	28,079	24,122	20,869	18,180	15,942
Canada	60,804	42,405	32,416	26,238	22,048	60,804	42,405	32,417	26,238	22,048
France	10,082	8,113	6,095	4,559	3,438	6,848	5,499	3,953	2,763	1,896
Germany	49,825	37,600	27,510	20,411	15,501	32,059	29,369	23,502	18,374	14,426
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	70,140	70,244	67,599	63,916	59,989	53,099	54,167	52,375	49,452	46,205
United States	—	—	—	—	—	—	—	—	—	—
Total Proved Developed Non-Producing	218,930	182,484	154,489	133,304	116,918	180,889	155,562	133,116	115,007	100,517
Proved Undeveloped [2] [7]										
Australia	54,981	43,263	34,175	27,105	21,564	25,101	18,532	13,890	10,524	8,032
Canada	524,830	354,396	246,584	175,252	126,009	397,236	281,016	202,741	148,193	108,836
France	177,851	128,923	96,156	73,638	57,592	127,650	88,876	63,091	45,660	33,460
Germany	17,161	11,696	8,012	5,495	3,737	12,154	8,910	6,412	4,551	3,166
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	10,559	8,825	7,405	6,255	5,323	7,921	6,405	5,174	4,189	3,401
United States	110,911	64,500	39,231	24,394	15,111	105,425	62,306	38,295	23,973	14,912
Total Proved Undeveloped	896,293	611,603	431,563	312,139	229,336	675,487	466,045	329,603	237,090	171,807
Proved [2]										
Australia	66,043	158,265	187,518	191,333	185,219	130,360	167,044	171,738	164,825	154,357
Canada	1,515,501	1,167,661	926,843	761,198	643,021	1,387,907	1,094,281	883,001	734,139	625,848
France	1,979,707	1,452,106	1,132,654	927,229	786,437	1,607,642	1,186,269	925,883	756,591	639,746
Germany	343,563	298,915	242,487	200,782	170,941	320,791	287,898	236,879	197,801	169,295
Ireland	389,204	376,115	346,327	316,408	290,143	389,204	376,115	346,327	316,408	290,143
Netherlands	129,493	139,850	141,249	138,431	133,716	109,813	121,353	123,794	121,901	118,010
United States	155,528	99,050	67,503	48,500	36,281	150,044	96,856	66,567	48,079	36,082
Total Proved	4,579,039	3,691,962	3,044,581	2,583,881	2,245,758	4,095,761	3,329,816	2,754,189	2,339,744	2,033,481
Probable [3]										
Australia	154,459	149,732	125,619	102,719	84,652	93,591	88,478	72,912	58,670	47,633
Canada	1,363,584	814,347	539,091	384,014	288,722	1,003,602	592,655	390,429	278,355	210,521
France	1,200,008	673,205	431,159	299,927	219,972	879,913	477,377	292,831	193,985	134,663
Germany	414,585	244,149	151,416	100,767	70,641	293,314	172,157	104,603	68,306	47,063
Ireland	350,695	246,321	182,785	141,844	114,117	350,695	246,321	182,785	141,844	114,117
Netherlands	197,136	167,242	141,871	121,179	104,496	130,277	108,388	89,527	74,196	61,980
United States	353,649	198,078	124,603	84,897	61,103	278,493	157,846	100,547	69,404	50,591
Total Probable	4,034,116	2,493,074	1,696,544	1,235,347	943,703	3,029,885	1,843,222	1,233,634	884,760	666,568

	Before Deducting Future Income Taxes Discounted At					After Deducting Future Income Taxes Discounted At				
(M$)	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Proved Plus Probable (2) (3)										
Australia	220,502	307,997	313,137	294,052	269,871	223,951	255,522	244,650	223,495	201,990
Canada	2,879,085	1,982,008	1,465,934	1,145,212	931,743	2,391,509	1,686,936	1,273,430	1,012,494	836,369
France	3,179,715	2,125,311	1,563,813	1,227,156	1,006,409	2,487,555	1,663,646	1,218,714	950,576	774,409
Germany	758,148	543,064	393,903	301,549	241,582	614,105	460,055	341,482	266,107	216,358
Ireland	739,899	622,436	529,112	458,252	404,260	739,899	622,436	529,112	458,252	404,260
Netherlands	326,629	307,092	283,120	259,610	238,212	240,090	229,741	213,321	196,097	179,990
United States	509,177	297,128	192,106	133,397	97,384	428,537	254,702	167,114	117,483	86,673
Total Proved Plus Probable	8,613,155	6,185,036	4,741,125	3,819,228	3,189,461	7,125,646	5,173,038	3,987,823	3,224,504	2,700,049

Notes:

(1) The pricing assumptions used in the GLJ Report with respect to net present value of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below. See “Forecast Prices used in Estimates”. The NGL price is an aggregate of the individual natural gas liquids prices used in the Total Proved plus Probable evaluation. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

(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.

Total Future Net Revenue (Undiscounted) Based on Forecast Prices and Costs (1)

(M$)	Revenue	Royalties	Operating Costs	Capital Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Future Income Taxes	Future Net Revenue After Income Taxes
Proved (2)								
Australia	978,200	—	564,074	100,883	247,200	66,043	(64,317)	130,360
Canada	3,488,501	344,924	1,118,811	412,323	96,942	1,515,501	127,594	1,387,907
France	3,591,175	272,788	997,961	125,874	214,845	1,979,707	372,065	1,607,642
Germany	853,470	44,503	298,194	20,409	146,801	343,563	22,772	320,791
Ireland	643,435	—	170,325	18,907	64,999	389,204	—	389,204
Netherlands	546,125	104,158	203,425	28,166	80,883	129,493	19,680	109,813
United States	404,551	112,559	65,468	66,993	4,003	155,528	5,484	150,044
Total Proved	10,505,457	878,932	3,418,258	773,555	855,673	4,579,039	483,278	4,095,761
Proved Plus Probable (2) (3)								
Australia	1,432,958	—	775,932	166,801	269,723	220,502	(3,449)	223,951
Canada	6,224,592	647,349	1,828,575	744,672	124,911	2,879,085	487,576	2,391,509
France	5,718,238	433,546	1,481,349	346,196	277,432	3,179,715	692,160	2,487,555
Germany	1,672,382	105,662	507,204	104,899	196,469	758,148	144,043	614,105
Ireland	1,113,630	—	270,554	38,178	64,999	739,899	—	739,899
Netherlands	950,074	180,041	296,854	53,369	93,181	326,629	86,539	240,090
United States	1,137,518	308,001	166,074	145,966	8,300	509,177	80,640	428,537
Total Proved Plus Probable	18,249,392	1,674,599	5,326,542	1,600,081	1,035,015	8,613,155	1,487,509	7,125,646

Notes:

(1) The pricing assumptions used in the GLJ Report with respect to net present value of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below. See “Forecast Prices used in Estimates”. The NGL price is an aggregate of the individual natural gas liquids prices used in the Total Proved plus Probable evaluation. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

(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.

Future Net Revenue by Product Type Based on Forecast Prices and Costs (1)

	Future Net Revenue Before Income Taxes (2) (Discounted at 10% Per Year)	Unit Value
Proved Developed Producing	**(M$)**	**($/boe)**
Light Crude Oil & Medium Crude Oil (3)	1,764,235	27.51
Heavy Oil (3)	—	—
Conventional Natural Gas (4)	693,722	14.33
Shale Gas	122	8.56
Coal Bed Methane	450	1.25
Total Proved Developed Producing	2,458,529	21.77
Proved Developed Non-Producing		
Light Crude Oil & Medium Crude Oil (3)	43,821	18.44
Heavy Oil (3)	—	—
Conventional Natural Gas (4)	108,904	17.4
Shale Gas	984	4.54
Coal Bed Methane	780	2.13
Total Proved Developed Non-Producing	154,489	16.76
Proved Undeveloped		
Light Crude Oil & Medium Crude Oil (3)	273,008	14.16
Heavy Oil (3)	—	—
Conventional Natural Gas (4)	158,318	8.31
Shale Gas	—	—
Coal Bed Methane	237	0.77
Total Proved Undeveloped	431,563	12.04
Proved		
Light Crude Oil & Medium Crude Oil (3)	2,081,064	24.35
Heavy Oil (3)	—	—
Conventional Natural Gas (4)	960,944	12.92
Shale Gas	1,106	4.58
Coal Bed Methane	1,467	1.36
Total Proved	3,044,581	18.94
Probable		
Light Crude Oil & Medium Crude Oil (3)	1,031,625	19.21
Heavy Oil (3)	—	—
Conventional Natural Gas (4)	663,113	11.98
Shale Gas	238	5.49
Coal Bed Methane	1,568	3.31
Total Probable	1,696,544	15.48
Proved Plus Probable		
Light Crude Oil & Medium Crude Oil (3)	3,112,689	22.47
Heavy Oil (3)	—	—
Conventional Natural Gas (4)	1,624,057	12.42
Shale Gas	1,344	4.85
Coal Bed Methane	3,035	1.92
Total Proved Plus Probable	4,741,125	17.53

Notes:

(1) The pricing assumptions used in the GLJ Report with respect to net present value of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below. See "Forecast Prices used in Estimates". The NGL price is an aggregate of the individual natural gas liquids prices used in the Total Proved plus Probable evaluation. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

(2) Other Company revenue and costs not related to a specific product type have been allocated proportionately to the specified product types. Unit values are based on Company net reserves. Net present value of reserves categories are an approximation based on major products.

(3) Including solution gas and other by-products.

(4) Including by-products but excluding solution gas.

Forecast Prices used in Estimates (1)

	Light Crude Oil and & Medium Crude Oil			Crude Oil	Conventional Natural Gas Canada	Conventional Natural Gas Europe	Natural Gas Liquids	Inflation Rate	Exchange Rate	Exchange Rate
Year	**WTI Cushing Oklahoma ($US/bbl)**	**Edmonton Par Price 40˚ API ($Cdn/bbl)**	**Cromer Medium 29.3˚ API ($Cdn/bbl)**	**Brent Blend FOB North Sea ($US/bbl)**	**AECO Gas Price ($Cdn/MMBtu)**	**National Balancing Point (UK) ($US/MMBtu)**	**FOB Field Gate ($Cdn/bbl)**	**Percent Per Year**	**($US/$Cdn)**	**($Cdn/EUR)**
2017	50.88	62.78	59.90	54.16	2.16	5.63	46.67	1.60	0.77	1.46
Forecast										
2018	59.00	70.25	65.34	65.50	2.20	6.25	56.85	2.00	0.79	1.49
2019	59.00	70.25	65.34	63.50	2.54	6.50	53.46	2.00	0.79	1.46
2020	60.00	70.31	65.39	63.00	2.88	6.75	53.18	2.00	0.80	1.44
2021	66.00	72.84	67.74	66.00	3.24	7.00	54.74	2.00	0.81	1.42
2022	69.00	75.61	70.32	69.00	3.47	7.15	56.37	2.00	0.82	1.40
2023	72.00	78.31	72.83	72.00	3.58	7.30	58.31	2.00	0.83	1.39
2024	75.00	81.93	76.19	75.00	3.66	7.45	60.94	2.00	0.83	1.39
2025	78.00	85.54	79.55	78.00	3.73	7.60	63.57	2.00	0.83	1.39
2026	80.33	88.35	82.16	80.33	3.80	7.75	65.61	2.00	0.83	1.39
2027	81.88	90.22	83.90	81.88	3.88	7.90	66.96	2.00	0.83	1.39
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.83	1.39

Note:

(1) The pricing assumptions used in the GLJ Report with respect to net present value of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth above. The NGL price is an aggregate of the individual natural gas liquids prices used in the Total Proved plus Probable evaluation. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

All forecast prices in the tables above are provided by GLJ. For 2017, the price of crude oil in the United States is based on WTI. The benchmark price for Canadian crude oil is Edmonton Par and Canadian natural gas is priced against AECO. The benchmark price for Australia, France and Germany crude oil is Dated Brent. The price of our natural gas in Ireland is based on the NBP index. The price of Vermilion's natural gas in the Netherlands and Germany is based on the TTF day/month-ahead index, as determined on the Title Transfer Facility Virtual Trading Point. For the year ended December 31, 2017, the average realized sales prices before hedging were $57.64 per bbl (United States) for WTI, $51.36 per bbl for Canadian-based crude oil, condensate and NGLs and $2.34 per Mcf for Canadian natural gas, $73.99 per bbl (Australia), $67.08 per bbl (France) for Brent-based crude oil, $7.19 per Mcf (Ireland), $7.18 per Mcf (Netherlands), and $6.38 per Mcf (Germany).

Reconciliations of Changes in Reserves

The following tables set forth a reconciliation of the changes in Vermilion's gross light crude oil and medium crude oil, heavy oil, tight oil, conventional natural gas, coal bed methane, shale gas and NGLs reserves as at December 31, 2017 compared to such reserves as at December 31, 2016 based on the forecast price and cost assumptions set forth in note 3.

Reconciliation of Company Gross Reserves by Principal Product Type - Based on Forecast Prices and Costs

AUSTRALIA	Total Oil (4)			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P (1) (2)	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
At December 31, 2016	12,418	4,650	17,068	12,418	4,650	17,068	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	603	—	603	603	—	603	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	(2,106)	—	(2,106)	(2,106)	—	(2,106)	—	—	—	—	—	—
At December 31, 2017	10,915	4,650	15,565	10,915	4,650	15,565	—	—	—	—	—	—

	Total Gas (4)			Conventional Natural Gas			Coal Bed Methane (5)			Shale Gas (5)		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)
At December 31, 2016	—	—	—	—	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—	—	—	—	—
At December 31, 2017	—	—	—	—	—	—	—	—	—	—	—	—

	Natural Gas Liquids			BOE		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)	(Mboe)
At December 31, 2016	—	—	—	12,418	4,650	17,068
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—
Technical Revisions	—	—	—	603	—	603
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—
Production	—	—	—	(2,106)	—	(2,106)
At December 31, 2017	—	—	—	10,915	4,650	15,565

CANADA	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2]	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
At December 31, 2016	21,974	14,105	36,079	21,962	14,103	36,065	—	—	—	12	2	14
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	594	302	896	594	302	896	—	—	—	—	—	—
Technical Revisions	(681)	(1,542)	(2,223)	(670)	(1,540)	(2,210)	—	—	—	(11)	(2)	(13)
Acquisitions	16	4	20	16	4	20	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(48)	16	(32)	(48)	16	(32)	—	—	—	—	—	—
Production	(2,195)	—	(2,195)	(2,194)	—	(2,194)	—	—	—	(1)	—	(1)
At December 31, 2017	19,660	12,885	32,545	19,660	12,885	32,545	—	—	—	—	—	—

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)
At December 31, 2016	226,530	156,668	383,198	217,098	151,707	368,805	8,061	4,677	12,738	1,371	284	1,655
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	58,040	29,520	87,560	57,075	28,977	86,052	965	543	1,508	—	—	—
Technical Revisions	1,696	372	2,068	1,057	378	1,435	799	64	863	(160)	(70)	(230)
Acquisitions	3,452	1,113	4,565	2,686	872	3,558	766	241	1,007	—	—	—
Dispositions	(2,182)	(2,150)	(4,332)	(576)	(231)	(807)	(1,606)	(1,919)	(3,525)	—	—	—
Economic Factors	(3,658)	(1,201)	(4,859)	(2,497)	(648)	(3,145)	(1,161)	(553)	(1,714)	—	—	—
Production	(35,730)	—	(35,730)	(34,547)	—	(34,547)	(1,111)	—	(1,111)	(72)	—	(72)
At December 31, 2017	248,148	184,322	432,470	240,296	181,055	421,351	6,713	3,053	9,766	1,139	214	1,353

	Natural Gas Liquids			BOE		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)	(Mboe)
At December 31, 2016	17,363	12,907	30,270	77,092	53,123	130,215
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	5,669	1,235	6,904	15,936	6,457	22,393
Technical Revisions	(271)	95	(176)	(668)	(1,386)	(2,054)
Acquisitions	351	113	464	942	303	1,245
Dispositions	(3)	(1)	(4)	(367)	(359)	(726)
Economic Factors	(184)	(67)	(251)	(842)	(251)	(1,093)
Production	(2,621)	—	(2,621)	(10,771)	—	(10,771)
At December 31, 2017	20,304	14,282	34,586	81,322	57,887	139,209

FRANCE	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2]	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
At December 31, 2016	42,044	21,933	63,977	42,044	21,933	63,977	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	1,688	1,879	3,567	1,688	1,879	3,567	—	—	—	—	—	—
Technical Revisions	1,086	(1,912)	(826)	1,086	(1,912)	(826)	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(126)	(114)	(240)	(126)	(114)	(240)	—	—	—	—	—	—
Production	(4,046)	—	(4,046)	(4,046)	—	(4,046)	—	—	—	—	—	—
At December 31, 2017	40,646	21,786	62,432	40,646	21,786	62,432	—	—	—	—	—	—

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)
At December 31, 2016	5,482	892	6,374	5,482	892	6,374	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	3,239	968	4,207	3,239	968	4,207	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(37)	(6)	(43)	(37)	(6)	(43)	—	—	—	—	—	—
Production	(1)	—	(1)	(1)	—	(1)	—	—	—	—	—	—
At December 31, 2017	8,683	1,854	10,537	8,683	1,854	10,537	—	—	—	—	—	—

	Natural Gas Liquids			BOE		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)	(Mboe)
At December 31, 2016	—	—	—	42,958	22,082	65,040
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	1,688	1,879	3,567
Technical Revisions	—	—	—	1,625	(1,751)	(126)
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	(132)	(115)	(247)
Production	—	—	—	(4,046)	—	(4,046)
At December 31, 2017	—	—	—	42,093	22,095	64,188

GERMANY	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2]	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
At December 31, 2016	5,288	2,279	7,567	5,288	2,279	7,567	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	300	275	575	300	275	575	—	—	—	—	—	—
Technical Revisions	699	480	1,179	699	480	1,179	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(112)	(34)	(146)	(112)	(34)	(146)	—	—	—	—	—	—
Production	(387)	—	(387)	(387)	—	(387)	—	—	—	—	—	—
At December 31, 2017	5,788	3,000	8,788	5,788	3,000	8,788	—	—	—	—	—	—

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)
At December 31, 2016	41,481	54,284	95,765	41,481	54,284	95,765	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	117	108	225	117	108	225	—	—	—	—	—	—
Technical Revisions	6,590	(1,027)	5,563	6,590	(1,027)	5,563	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	(231)	(231)	—	(231)	(231)	—	—	—	—	—	—
Production	(7,077)	—	(7,077)	(7,077)	—	(7,077)	—	—	—	—	—	—
At December 31, 2017	41,111	53,134	94,245	41,111	53,134	94,245	—	—	—	—	—	—

	Natural Gas Liquids			BOE		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)	(Mboe)
At December 31, 2016	—	—	—	12,202	11,326	23,528
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	320	293	613
Technical Revisions	—	—	—	1,797	310	2,107
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	(112)	(73)	(185)
Production	—	—	—	(1,567)	—	(1,567)
At December 31, 2017	—	—	—	12,640	11,856	24,496

IRELAND	Total Oil (4)			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P (1) (2)	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
At December 31, 2016	—	—	—	—	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—	—	—	—	—
At December 31, 2017	—	—	—	—	—	—	—	—	—	—	—	—

	Total Gas (4)			Conventional Natural Gas			Coal Bed Methane (5)			Shale Gas (5)		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)
At December 31, 2016	99,575	50,787	150,362	99,575	50,787	150,362	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	3,553	602	4,155	3,553	602	4,155	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	(21,325)	—	(21,325)	(21,325)	—	(21,325)	—	—	—	—	—	—
At December 31, 2017	81,803	51,389	133,192	81,803	51,389	133,192	—	—	—	—	—	—

	Natural Gas Liquids			BOE		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)	(Mboe)
At December 31, 2016	—	—	—	16,596	8,465	25,061
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—
Technical Revisions	—	—	—	592	100	692
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—
Production	—	—	—	(3,554)	—	(3,554)
At December 31, 2017	—	—	—	13,634	8,565	22,199

NETHERLANDS	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2]	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
At December 31, 2016	—	—	—	—	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—	—	—	—	—
At December 31, 2017	—	—	—	—	—	—	—	—	—	—	—	—

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)
At December 31, 2016	62,350	43,184	105,534	62,350	43,184	105,534	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	8,163	7,807	15,970	8,163	7,807	15,970	—	—	—	—	—	—
Technical Revisions	5,232	(6,579)	(1,347)	5,232	(6,579)	(1,347)	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(22)	(32)	(54)	(22)	(32)	(54)	—	—	—	—	—	—
Production	(14,797)	—	(14,797)	(14,797)	—	(14,797)	—	—	—	—	—	—
At December 31, 2017	60,926	44,380	105,306	60,926	44,380	105,306	—	—	—	—	—	—

	Natural Gas Liquids			BOE		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)	(Mboe)
At December 31, 2016	81	63	144	10,473	7,260	17,733
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	30	21	51	1,391	1,322	2,713
Technical Revisions	115	35	150	986	(1,061)	(75)
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	(4)	(5)	(9)
Production	(33)	—	(33)	(2,499)	—	(2,499)
At December 31, 2017	193	119	312	10,347	7,516	17,863

UNITED STATES	Total Oil (4)			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P (1) (2)	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
At December 31, 2016	3,169	5,727	8,896	3,169	5,727	8,896	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	1,413	1,483	2,896	1,413	1,483	2,896	—	—	—	—	—	—
Technical Revisions	(49)	(133)	(182)	(49)	(133)	(182)	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(9)	(4)	(13)	(9)	(4)	(13)	—	—	—	—	—	—
Production	(242)	—	(242)	(242)	—	(242)	—	—	—	—	—	—
At December 31, 2017	4,282	7,073	11,355	4,282	7,073	11,355	—	—	—	—	—	—

	Total Gas (4)			Conventional Natural Gas			Coal Bed Methane (5)			Shale Gas (5)		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)
At December 31, 2016	2,969	5,481	8,450	2,969	5,481	8,450	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	1,328	1,554	2,882	1,328	1,554	2,882	—	—	—	—	—	—
Technical Revisions	231	489	720	231	489	720	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(5)	(4)	(9)	(5)	(4)	(9)	—	—	—	—	—	—
Production	(143)	—	(143)	(143)	—	(143)	—	—	—	—	—	—
At December 31, 2017	4,380	7,520	11,900	4,380	7,520	11,900	—	—	—	—	—	—

	Natural Gas Liquids			BOE		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)	(Mboe)
At December 31, 2016	412	760	1,172	4,076	7,401	11,477
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	182	213	395	1,816	1,955	3,771
Technical Revisions	28	59	87	18	7	25
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	(1)	(1)	(2)	(11)	(6)	(17)
Production	(20)	—	(20)	(286)	—	(286)
At December 31, 2017	601	1,031	1,632	5,613	9,357	14,970

TOTAL COMPANY	Total Oil (4)			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P (1) (2)	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
At December 31, 2016	84,893	48,694	133,587	84,881	48,692	133,573	—	—	—	12	2	14
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	3,995	3,939	7,934	3,995	3,939	7,934	—	—	—	—	—	—
Technical Revisions	1,657.51	(3,107)	(1,449.49)	1,668.51	(3,105)	(1,436.49)	—	—	—	(11)	(2)	(13)
Acquisitions	16	4	20	16	4	20	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(295)	(136)	(431)	(295)	(136)	(431)	—	—	—	—	—	—
Production	(8,976)	—	(8,976)	(8,975)	—	(8,975)	—	—	—	(1)	—	(1)
At December 31, 2017	81,291	49,394	130,685	81,291	49,394	130,685	—	—	—	—	—	—

	Total Gas (4)			Conventional Natural Gas			Coal Bed Methane (5)			Shale Gas (5)		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)
At December 31, 2016	438,387	311,296	749,683	428,955	306,335	735,290	8,061	4,677	12,738	1,371	284	1,655
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	67,648	38,989	106,637	66,683	38,446	105,129	965	543	1,508	—	—	—
Technical Revisions	20,541.45	(5,175)	15,366.45	19,902.45	(5,169)	14,733.45	799	64	863	(160)	(70)	(230)
Acquisitions	3,452	1,113	4,565	2,686	872	3,558	766	241	1,007	—	—	—
Dispositions	(2,182)	(2,150)	(4,332)	(576)	(231)	(807)	(1,606)	(1,919)	(3,525)	—	—	—
Economic Factors	(3,722)	(1,474)	(5,196)	(2,561)	(921)	(3,482)	(1,161)	(553)	(1,714)	—	—	—
Production	(79,073)	—	(79,073)	(77,890)	—	(77,890)	(1,111)	—	(1,111)	(72)	—	(72)
At December 31, 2017	445,051	342,599	787,650	437,199	339,332	776,531	6,713	3,053	9,766	1,139	214	1,353

	Natural Gas Liquids			BOE		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)	(Mboe)
At December 31, 2016	17,856	13,730	31,586	175,815	114,307	290,122
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	5,881	1,469	7,350	21,151	11,906	33,057
Technical Revisions	(128)	189	61	4,953	(3,781)	1,172
Acquisitions	351	113	464	942	303	1,245
Dispositions	(3)	(1)	(4)	(367)	(359)	(726)
Economic Factors	(185)	(68)	(253)	(1,101)	(450)	(1,551)
Production	(2,674)	—	(2,674)	(24,829)	—	(24,829)
At December 31, 2017	21,098	15,432	36,530	176,564	121,926	298,490

Notes:

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

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

(3) The pricing assumptions used in the GLJ Report with respect to net present value of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth above. See "Forecast Prices used in Estimates". The NGL price is an aggregate of the individual natural gas liquids prices used in the Total Proved plus Probable evaluation. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

(4) For reporting purposes, "Total Oil" is the sum of Light Crude oil and Medium Crude Oil, Heavy Oil and Tight Oil. For reporting purposes, "Total Gas" is the sum of Conventional Natural Gas, Coal Bed Methane and Shale Gas.

(5) "Coal Bed Methane" and "Shale Gas" were considered "Unconventional Natural Gas" in previous years. NI 51-101 no longer differentiates between conventional and unconventional activities.

Undeveloped Reserves

Proved 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. These reserves have a 90% probability of being recovered. Vermilion's current plan is to develop these reserves in the following three years. The pace of development of these reserves is influenced by many factors, including but not limited to, the outcomes of yearly drilling and reservoir evaluations, changes in commodity pricing, changes in capital allocations, changing technical conditions, regulatory changes and impact of future acquisitions and dispositions. As new information becomes available these reserves are reviewed and development plans are revised accordingly.

Probable 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. These reserves have a 50% probability of being recovered. Vermilion's current plan is to develop these reserves over the next five years. In general, development of these reserves requires additional evaluation data to increase the probability of success to a level that favourably ranks the project against other projects in Vermilion's inventory. This increases the timeline for the development of these reserves. This timetable may be altered depending on outside market forces, changes in capital allocations and impact of future acquisitions and dispositions.

Timing of Initial Undeveloped Reserves Assignment

Undeveloped Reserves Attributed in Current Year

	Light Crude Oil & Medium Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Coal Bed Methane (MMcf)		Natural Gas Liquids (Mbbl)		Total Oil Equivalent (Mboe	
	First Attributed (1)	Booked	First Attributed (1)	Booked	First Attributed (1)	Booked	First Attributed (1)	Booked	First Attributed (1)	Booked
Proved										
Prior to 2014	15,663	36,784	62,418	511,944	13,134	47,737	4,382	7,279	32,638	137,343
2014	5,614	15,434	26,111	170,763	—	11,610	2,175	7,942	12,140	53,772
2015	4,182	15,989	30,963	78,022	333	3,367	2,500	7,287	11,898	36,842
2016	1,411	16,140	25,023	90,934	—	3,043	1,737	7,546	7,318	39,348
2017	2,221	16,816	36,709	99,458	—	2,023	3,988	9,133	12,327	42,862
Probable										
Prior to 2014	23,890	63,484	81,938	276,407	7,773	29,252	4,724	7,784	43,567	122,212
2014	6,541	22,050	60,779	163,645	—	6,741	3,762	9,615	20,432	60,063
2015	6,118	25,126	50,125	122,802	57	2,949	5,708	10,965	20,190	57,050
2016	4,918	27,863	66,129	167,973	—	3,328	1,611	10,506	17,550	66,919
2017	4,336	28,646	38,537	197,647	—	1,055	2,802	11,455	13,561	73,217

Note:
(1) "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year

Future Development Costs (1)

The table below sets out the future development costs deducted in the estimation of future net revenue attributable to total proved reserves and total proved plus probable reserves (using forecast prices and costs).

(M$)	Total Proved Estimated Using Forecast Prices and Costs	Total Proved Plus Probable Estimated Using Forecast Prices and Costs
Australia		
2018	11,565	11,565
2019	70,052	70,052
2020	3,026	3,026
2021	3,140	58,821
2022	3,164	3,164
Remainder	9,936	20,173
Total for all years undiscounted	100,883	166,801
Canada		
2018	136,499	150,107
2019	142,540	155,186
2020	110,461	139,784
2021	20,828	119,929
2022	622	114,329
Remainder	1,373	65,337
Total for all years undiscounted	412,323	744,672
France		
2018	30,969	52,162
2019	34,118	84,258
2020	19,848	100,335
2021	26,017	59,875
2022	4,289	24,707
Remainder	10,633	24,859
Total for all years undiscounted	125,874	346,196
Germany		
2018	2,116	5,381
2019	11,172	17,742
2020	3,162	10,590
2021	3,185	29,808
2022	124	38,918
Remainder	650	2,460
Total for all years undiscounted	20,409	104,899
Ireland		
2018	—	—
2019	1,855	1,855
2020	—	19,271
2021	—	—
2022	—	—
Remainder	17,052	17,052
Total for all years undiscounted	18,907	38,178
Netherlands		
2018	3,205	9,569
2019	12,253	13,923
2020	6,181	14,170
2021	324	4,909
2022	326	4,921
Remainder	5,877	5,877
Total for all years undiscounted	28,166	53,369

(M$)	Total Proved Estimated Using Forecast Prices and Costs	Total Proved Plus Probable Estimated Using Forecast Prices and Costs
United States		
2018	3,797	11,392
2019	28,082	39,224
2020	35,114	46,818
2021	—	48,532
2022	—	—
Remainder	—	—
Total for all years undiscounted	66,993	145,966
Total Company		
2018	188,151	240,176
2019	300,072	382,240
2020	177,792	333,994
2021	53,494	321,874
2022	8,525	186,039
Remainder	45,521	135,758
Total for all years undiscounted	773,555	1,600,081

Note:
(1) The pricing assumptions used in the GLJ Report with respect to net present value of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth above. See "Forecast Prices used in Estimates". The NGL price is an aggregate of the individual natural gas liquids prices used in the Total Proved plus Probable evaluation. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

Vermilion expects to source its capital expenditure requirements from internally generated cash flow and, as appropriate, from Vermilion's existing credit facility or equity or debt financing. It is anticipated that costs of funding the future development costs will not impact development of its properties or Vermilion's reserves or future net revenue.

Oil and Gas Properties and Wells (1) (2)

The following table sets forth the number of wells in which Vermilion held a working interest as at December 31, 2017:

	Oil				Gas			
	Producing		Non-Producing (5)		Producing		Non-Producing (5)	
	Gross Wells (3)	Net Wells (4)	Gross Wells (3)	Net Wells (4)	Gross Wells (3)	Net Wells (4)	Gross Wells (3)	Net Wells (4)
Canada								
Alberta	480	338	161	99	523	375	339	231
Saskatchewan	159	137	28	23	—	—	2	2
Total Canada	639	475	189	123	523	375	341	233
Australia	18	18	1	1	—	—	—	—
France	338	332	95	93	—	—	3	3
Germany	135	104	38	31	20	7	5	3
Ireland	—	—	—	—	6	1	—	—
Netherlands	—	—	—	—	56	39	40	32
United States (Wyoming)	13	11	2	1	—	—	—	—
Total Vermilion	1,143	940	325	249	605	422	389	271

Notes:
(1) Well counts are based on wellbores.
(2) Wells for Australia and Ireland are located offshore.
(3) "Gross" refers to the total wells in which Vermilion has an interest, directly or indirectly.
(4) "Net" refers to the total wells in which Vermilion has an interest, directly or indirectly, multiplied by the percentage working interest owned by Vermilion, directly or indirectly, therein.
(5) Non-producing wells include wells which are capable of producing, but which are currently not producing, and are re-evaluated with respect to future commodity prices, proximity to facility infrastructure, design of future exploration and development programs and access to capital.

Costs Incurred

The following table summarizes the capital expenditures made by Vermilion on oil and gas properties for the year ended December 31, 2017:

	Acquisition Costs				
(M$)	Proved Properties	Unproved Properties	Exploration Costs	Development Costs	Total Costs
Australia	—	—	—	29,896	29,896
Canada	22,011	—	—	148,211	170,222
Croatia	—	—	2,764	—	2,764
France	—	—	2,294	69,026	71,320
Germany	—	—	3,366	5,710	9,076
Hungary	—	—	2,596	—	2,596
Ireland	—	—	—	544	544
Netherlands	—	—	16,468	14,956	31,424
United States	3,403	—	—	19,058	22,461
Total	25,414	—	32,103	287,401	344,918

Acreage

The following table summarizes the acreage for the year ended December 31, 2017:

	Developed (1)		Undeveloped		Total	Total
	Gross (2)	Net (3)	Gross (2)	Net (3)	Gross (2)(4)	Net (3)(4)
Australia	20,164	20,164	39,389	39,389	59,553	59,553
Canada	445,665	330,940	430,766	376,448	876,431	707,388
Croatia	—	—	2,348,984	2,348,984	2,348,984	2,348,984
France	218,110	208,858	383,050	379,813	601,160	588,671
Germany	88,603	32,662	2,787,722	1,214,962	2,876,325	1,247,624
Hungary	—	—	652,817	652,817	652,817	652,817
Ireland	7,200	1,300	—	—	7,200	1,300
Netherlands	81,328	48,848	1,374,458	777,189	1,455,786	826,037
Slovakia	—	—	184,591	92,295	184,591	92,295
United States	5,058	4,721	104,452	92,436	109,510	97,157
Total	866,128	647,493	8,306,229	5,974,333	9,172,357	6,621,826

Notes:

(1) "Developed" means the acreage assigned to productive wells based on applicable regulations.

(2) "Gross" means the total acreage in which Vermilion has a working interest, directly or indirectly.

(3) "Net" means the total acreage in which Vermilion has a working interest, directly or indirectly, multiplied by the percentage working interest of Vermilion.

(4) When determining gross and net acreage for two or more leases covering the same lands but different rights, the acreage is reported for each lease. Where there are multiple discontinuous rights in a single lease, the acreage is reported only once.

Exploration and Development Activities

The following table sets forth the number of development and exploration wells which Vermilion completed during its 2017 financial year:

	Exploration Wells		Development Wells	
	Gross (1)	Net (2)	Gross (1)	Net (2)
Australia				
Oil	—	—	—	—
Gas	—	—	—	—
Dry Holes	—	—	—	—
Total Completed	—	—	—	—
Canada				
Oil	—	—	20.0	18.1
Gas	—	—	24.0	17.4
Dry Holes	—	—	—	—
Total Completed	—	—	44.0	35.5
France				
Oil	—	—	7.0	7.0
Gas	—	—	—	—
Dry Holes	—	—	—	—
Total Completed	—	—	7.0	7.0
Germany				
Oil	—	—	—	—
Gas	—	—	—	—
Dry Holes	—	—	—	—
Total Completed	—	—	—	—
Ireland				
Oil	—	—	—	—
Gas	—	—	—	—
Dry Holes	—	—	—	—
Total Completed	—	—	—	—
Netherlands				
Oil	—	—	—	—
Gas	—	—	2.0	1.0
Dry Holes	—	—	—	—
Total Completed	—	—	2.0	1.0
United States				
Oil	—	—	3.0	3.0
Gas	—	—	—	—
Dry Holes	—	—	—	—
Total Completed	—	—	3.0	3.0
Total Company				
Oil	—	—	30.0	28.1
Gas	—	—	26.0	18.4
Dry Holes	—	—	—	—
Total Completed	—	—	56.0	46.5

Notes:
(1) "Gross" refers to the total wells in which Vermilion has an interest, directly or indirectly.
(2) "Net" refers to the total wells in which Vermilion has an interest, directly or indirectly, multiplied by the percentage working interest owned by Vermilion, directly or indirectly therein.

Please see "Description of the Business - Operating Segments and Description of Properties" for a general description of the Company's current and likely exploration and development activities.

Properties with No Attributed Reserves

The following table sets out Vermilion's properties with no attributed reserves as at December 31, 2017:

	Properties with No Attributed Reserves	
Country	**Gross Acres (1)**	**Net Acres**
Australia	39,389	39,389
Canada	161,208	140,880
Croatia	2,348,984	2,348,984
France	272,487	270,184
Germany	2,717,434	1,184,328
Hungary	652,817	652,817
Ireland	—	—
Netherlands	1,319,359	746,033
Slovakia	184,591	92,295
United States	95,556	84,564
Total	7,791,825	5,559,474

Notes:

(1) "Gross" refers to the total acres in which Vermilion has an interest, directly or indirectly.

(2) "Net" refers to the total acres in which Vermilion has an interest, directly or indirectly, multiplied by the percentage working interest owned by Vermilion, directly or indirectly therein.

Vermilion expects its rights to explore, develop and exploit approximately 31,540 (26,581 net) acres in Canada, 3,681 (3,116 net) acres in the United States, and 117,618 (117,618 net) acres in France to expire within one year, unless the Company initiates the capital activity necessary to retain the rights. Work commitments on these lands are categorized as seismic acquisition, geophysical studies or well commitments. No such rights are expected to expire within one year for Australia, Croatia, Germany, Hungary, Ireland and the Netherlands. Vermilion currently has no material work commitments in Australia, Canada and the United States. Vermilion's work commitments with respect to its European lands held are estimated to be $19.6 million in the next year.

Vermilion's properties with no attributed reserves do not have any significant abandonment and reclamation costs in any country other than Canada, which has a net estimated cost of $27.3 million. All properties with no attributed reserves do not have high expected development or operating costs or contractual sales obligations to produce and sell at substantially lower prices than could be realized.

Tax Information

Vermilion pays current taxes in France, the Netherlands and Australia. Current income taxes in France and the Netherlands apply to taxable income after eligible deductions. In France, legislation was approved in late December 2017 to reduce current income tax rates starting in 2019. The new France tax rates are 34.4% for 2017 and 2018, 32% for 2019, 28.9% for 2020, 27.4% for 2021 and 25.8% for 2022 forward. In the Netherlands, current income taxes are applied to taxable income, after eligible deductions and a 10% uplift deduction applied to operating expenses, eligible general and administration expenses and tax deductions for depletion and abandonment retirement obligations, at a tax rate of 50%. As a function of the impact of Vermilion's tax pools, the Company does not presently pay, or is expected to pay in the foreseeable future, current taxes in Canada, Germany, Ireland and the United States. The Canadian segment includes holding companies that pay current taxes in foreign jurisdictions.

In Australia, current taxes include both corporate income taxes and PRRT. Corporate income taxes are applied at a rate of approximately 30% on taxable income after eligible deductions, which include PRRT paid. PRRT is a profit based tax applied at a rate of 40% on sales less eligible expenditures, including operating expenses and capital expenditures.

The following table sets forth Vermilion's tax pools as at December 31, 2017:

(M$)	Oil and Gas Assets	Tax Losses	Other	Total
Australia	266,208 (1)	—	—	266,208
Canada	914,071 (1)	517,687 (4)	20,113	1,451,871
France	332,435 (2)	10,688 (5)	—	343,123
Germany	184,549 (3)	88,712 (6)	18,878	292,139
Ireland	—	1,327,743 (4)	—	1,327,743
Netherlands	78,417 (3)	7,078	—	85,495
United States	37,022 (1)	43,305 (4)	1,783	82,110
Total	1,812,702	1,995,213	40,774	3,848,689

Notes:

(1) Deduction calculated using various declining balance rates
(2) Deduction calculated using a combination of straight-line over the assets life and unit of production method
(3) Deduction calculated using a unit of production method
(4) Tax losses can be carried forward at 100% against taxable income
(5) Tax losses carried forward are available to offset the first €1 million of taxable income and 50% of taxable profits in excess each taxation year
(6) Tax losses carried forward are available to offset the first €1 million of taxable income and 60% of taxable profits in excess each taxation year

Production Estimates

The following table sets forth the volume of production estimated for the year ended December 31, 2017 as reflected in the estimates of gross proved reserves and gross proved plus probable reserves in the GLJ Report:

	Light Crude Oil & Medium Crude Oil (bbl/d)	Heavy Oil (bbl/d)	Tight Oil (bbl/d)	Conventional Natural Gas (Mcf/d)	Shale Natural Gas (Mcf/d)	Coal Bed Methane (Mcf/d)	Natural Gas Liquids (bbl/d)	BOE (boe/d)
Australia								
Proved	4,474	—	—	—	—	—	—	4,474
Probable	180	—	—	—	—	—	—	180
Proved Plus Probable	4,654	—	—	—	—	—	—	4,654
Canada								
Proved	6,170	—	—	99,301	404	2,139	8,521	31,665
Probable	506	—	—	11,252	9	111	1,097	3,498
Proved Plus Probable	6,676	—	—	110,553	413	2,250	9,618	35,163
France								
Proved	11,225	—	—	1,288	—	—	—	11,440
Probable	756	—	—	11	—	—	—	758
Proved Plus Probable	11,981	—	—	1,299	—	—	—	12,198
Germany								
Proved	1,112	—	—	16,584	—	—	—	3,876
Probable	37	—	—	691	—	—	—	152
Proved Plus Probable	1,149	—	—	17,275	—	—	—	4,028
Ireland								
Proved	—	—	—	52,211	—	—	—	8,702
Probable	—	—	—	4,612	—	—	—	769
Proved Plus Probable	—	—	—	56,823	—	—	—	9,471
Netherlands								
Proved	—	—	—	44,424	—	—	154	7,558
Probable	—	—	—	6,361	—	—	19	1,079
Proved Plus Probable	—	—	—	50,785	—	—	173	8,637
United States								
Proved	578	—	—	404	—	—	55	700
Probable	273	—	—	156	—	—	22	321
Proved Plus Probable	851	—	—	560	—	—	77	1,021
Total Proved	23,559	—	—	214,212	404	2,139	8,730	68,415
Probable	1,752	—	—	23,083	9	111	1,138	6,757
Total Proved Plus Probable	25,311	—	—	237,295	413	2,250	9,868	75,172

Production History

The following table sets forth certain information in respect of production, product prices received, royalties, production costs and netbacks received by Vermilion for each quarter of its most recently completed financial year. Light crude oil and medium crude oil average net prices received in the following table also includes immaterial amounts generated by the sale of heavy oil.

	Three Months Ended March 31, 2017	Three Months Ended June 31, 2017	Three Months Ended September 31, 2017	Three Months Ended December 31, 2017
Australia				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	6,581	6,054	5,473	4,993
Conventional Natural Gas (MMcf/d)	—	—	—	—
Natural Gas Liquids (bbl/d)	—	—	—	—
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	77.11	71.37	66.97	83.32
Conventional Natural Gas ($/Mcf)	—	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	—	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	22.12	23.22	23.35	28.11
Conventional Natural Gas ($/Mcf)	—	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	54.99	48.15	43.62	55.21
Conventional Natural Gas ($/Mcf)	—	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Canada				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	5,650	6,357	6,177	5,872
Conventional Natural Gas (MMcf/d)	85.74	93.68	103.92	107.91
Natural Gas Liquids (bbl/d)	5,007	6,593	8,001	9,066
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	66.71	64.35	56.97	74.27
Conventional Natural Gas ($/Mcf)	2.99	2.83	1.84	1.88
Natural Gas Liquids ($/bbl)	41.09	37.14	36.98	42.8
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	8.29	8.22	5.46	7.04
Conventional Natural Gas ($/Mcf)	0.21	0.09	0.03	0.07
Natural Gas Liquids ($/bbl)	5.9	5.48	4.47	5.75
Transportation				
Light Crude Oil and Medium Crude Oil ($/bbl)	3.11	2.59	3.25	3.88
Conventional Natural Gas ($/Mcf)	0.22	0.19	0.17	0.15
Natural Gas Liquids ($/bbl)	1.85	1.36	1.31	1.44
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	11.41	8.23	11.05	10.51
Conventional Natural Gas ($/Mcf)	1.16	1.31	1.22	1.19
Natural Gas Liquids ($/bbl)	4.3	5.65	6.18	6.49
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	43.9	45.31	37.21	52.84
Conventional Natural Gas ($/Mcf)	1.4	1.24	0.42	0.47
Natural Gas Liquids ($/bbl)	29.04	24.65	25.02	29.12

France				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	10,834	11,368	10,918	11,215
Conventional Natural Gas (MMcf/d)	0.01	—	—	—
Natural Gas Liquids (bbl/d)	—	—	—	—
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	67.86	62.09	63.24	75.13
Conventional Natural Gas ($/Mcf)	1.52	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	6.06	6.1	6.12	10.11
Conventional Natural Gas ($/Mcf)	0.44	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Transportation				
Light Crude Oil and Medium Crude Oil ($/bbl)	3.45	3.6	3.29	4.27
Conventional Natural Gas ($/Mcf)	—	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	12.94	11.86	12.58	13.67
Conventional Natural Gas ($/Mcf)	1.18	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	45.41	40.53	41.25	47.08
Conventional Natural Gas ($/Mcf)	(0.1)	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Germany				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	989	1,047	1,054	1,148
Conventional Natural Gas (MMcf/d)	19.39	19.86	20.12	18.19
Natural Gas Liquids (bbl/d)	—	—	—	—
Average Net Prices Received	—	—	—	—
Light Crude Oil and Medium Crude Oil ($/bbl)	65.62	61.34	55.95	72.58
Conventional Natural Gas ($/Mcf)	6.95	6.09	5.5	7.07
Natural Gas Liquids ($/bbl)	—	—	—	—
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	3.67	1.25	2.43	1.72
Conventional Natural Gas ($/Mcf)	0.6	0.74	1.09	0.97
Natural Gas Liquids ($/bbl)	—	—	—	—
Transportation	—	—	—	—
Light Crude Oil and Medium Crude Oil ($/bbl)	8.11	9.22	8.97	5.86
Conventional Natural Gas ($/Mcf)	0.44	0.65	0.39	0.35
Natural Gas Liquids ($/bbl)	—	—	—	—
Production Costs	—	—	—	—
Light Crude Oil and Medium Crude Oil ($/bbl)	16.53	20.99	12.75	30.31
Conventional Natural Gas ($/Mcf)	1.98	2.21	1.2	1.84
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received	—	—	—	—
Light Crude Oil and Medium Crude Oil ($/bbl)	37.31	29.88	31.8	34.69
Conventional Natural Gas ($/Mcf)	3.93	2.49	2.82	3.91
Natural Gas Liquids ($/bbl)	—	—	—	—

Ireland				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	—	—	—	—
Conventional Natural Gas (MMcf/d)	64.82	63.81	49.04	56.23
Natural Gas Liquids (bbl/d)	—	—	—	—
Average Net Prices Received	—	—	—	—
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	7.65	6.32	6.25	8.47
Natural Gas Liquids ($/bbl)	—	—	—	—
Royalties	—	—	—	—
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	—	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Transportation	—	—	—	—
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	0.21	0.22	0.28	0.29
Natural Gas Liquids ($/bbl)	—	—	—	—
Production Costs	—	—	—	—
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	0.69	0.84	1.27	0.58
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received	—	—	—	—
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	6.75	5.26	4.7	7.6
Natural Gas Liquids ($/bbl)	—	—	—	—
Netherlands				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	—	—	—	—
Conventional Natural Gas (MMcf/d)	39.92	31.58	34.9	55.66
Natural Gas Liquids (bbl/d)	76	104	74	105
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	7.34	6.49	6.51	7.87
Natural Gas Liquids ($/bbl)	58.33	49.59	52.1	66.38
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	0.12	0.1	0.11	0.13
Natural Gas Liquids ($/bbl)	—	—	—	—
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	1.35	1.7	1.4	1.36
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	5.87	4.69	5	6.38
Natural Gas Liquids ($/bbl)	58.33	49.59	52.1	66.38

United States				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	365	747	880	667
Conventional Natural Gas (MMcf/d)	0.2	0.44	0.64	0.29
Natural Gas Liquids (bbl/d)	24	76	56	43
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	61.68	58.05	56.41	67.1
Conventional Natural Gas ($/Mcf)	2.48	1.55	2.07	2.48
Natural Gas Liquids ($/bbl)	25.67	14.7	24.9	42.59
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	17.2	16.18	15.44	18.4
Conventional Natural Gas ($/Mcf)	1.03	0.66	0.78	0.88
Natural Gas Liquids ($/bbl)	1.03	0.66	0.78	0.88
Transportation				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	0.27	0.21
Conventional Natural Gas ($/Mcf)	—	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	8.68	5.69	7.92	6.48
Conventional Natural Gas ($/Mcf)	—	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	35.8	36.18	32.78	42.01
Conventional Natural Gas ($/Mcf)	1.45	0.89	1.29	1.6
Natural Gas Liquids ($/bbl)	24.64	14.04	24.12	41.71
Total				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	21,805	26,687	25,190	23,701
Conventional Natural Gas (MMcf/d)	210.07	209.36	208.62	238.28
Natural Gas Liquids (bbl/d)	5,107	6,772	8,147	9,216
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	69.5	65.06	62.01	76.21
Conventional Natural Gas ($/Mcf)	5.62	4.75	4.01	5.23
Natural Gas Liquids ($/bbl)	41.27	37.08	37.01	43.07
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	5.31	4.94	4.73	7.2
Conventional Natural Gas ($/Mcf)	0.16	0.13	0.14	0.14
Natural Gas Liquids ($/bbl)	5.82	5.38	4.45	5.71
Transportation Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	2.72	2.45	2.67	3.28
Conventional Natural Gas ($/Mcf)	0.19	0.21	0.19	0.17
Natural Gas Liquids ($/bbl)	1.81	1.32	1.29	1.42
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	14.76	14.29	14.7	18.13
Conventional Natural Gas ($/Mcf)	1.12	1.31	1.26	1.13
Natural Gas Liquids ($/bbl)	4.21	5.5	6.07	6.38
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	46.71	43.38	39.91	47.6
Conventional Natural Gas ($/Mcf)	4.15	3.1	2.42	3.79
Natural Gas Liquids ($/bbl)	29.43	24.88	25.2	29.56

Marketing

The nature of Vermilion's operations results in exposure to fluctuations in commodity prices, interest rates and foreign currency exchange rates. Vermilion monitors and, when appropriate, uses derivative financial instruments to manage its exposure to these fluctuations. All transactions of this nature entered into by Vermilion are related to an underlying financial position or to future crude oil and natural gas production. Vermilion does not use derivative financial instruments for speculative purposes. Vermilion has not obtained collateral or other security to support its financial derivatives as management reviews the creditworthiness of its counterparties prior to entering into derivative contracts.

During the normal course of business, Vermilion may also enter into fixed price arrangements to sell a portion of its production or purchase commodities for operational use.

Vermilion's outstanding risk management positions as at December 31, 2017 are summarized in Supplemental Table 2: Hedges, included in the Company's 2017 Management's Discussion and Analysis, dated February 28, 2018, available on SEDAR at www.sedar.com, under Vermilion's SEDAR profile.

DIRECTORS AND OFFICERS

As at January 31, 2018, the directors and officers of Vermilion, as a group, beneficially owned, or controlled or directed, directly or indirectly, 4,082,950 common shares representing approximately 3.3% of the issued and outstanding common shares.

Set forth below is certain information respecting the current directors and officers of Vermilion. References to Vermilion in the following tables for dates prior to the Conversion Arrangement refer to VRL and to the Company following the date of the Conversion Arrangement.

Directors

Vermilion's board of directors currently consists of eleven directors. The directors are nominated by the Company and elected annually by Shareholders and hold office until the next annual meeting of Shareholders, or until their successors are elected or appointed.

Name and Municipality of Residence	Committee(s)	Office Held	Year First Elected or Appointed as Director	Principal Occupation During the Past Five Years
Lorenzo Donadeo Calgary, Alberta Canada	(1)	Chairman of the Board	1994	Since March 1, 2016, Chairman of the Board of Vermilion March 2014 – March 1, 2016 Chief Executive Officer of Vermilion 2003 – March 2014, President and Chief Executive Officer of Vermilion Since January 2015, Managing Director of a group of private wealth management companies
Stephen Larke Calgary, Alberta Canada	(3) (4)	Director	2017	Since 2016, Operating Partner and Advisory Board Member, Azimuth Capital Management, a private equity fund 2005 to 2015, Managing Director and Principal, Institutional Sales, and Executive Committee Member, Peters & Co., a private investment dealer
Loren M. Leiker Houston, Texas USA	(6)	Director	2012	Since 2014, Director of Navitas Midstream Partners LLC Since 2012, Director of SM Energy, a public energy company 2012 to 2015, Director of Midstates Petroleum, a public exploration and production company
Larry J. Macdonald Okotoks, Alberta Canada	(2) (3) (4) (5)	Lead Director	2002	Since March 1, 2016, Lead Director of Vermilion 2003 to March 1, 2016, Chairman of the Board of Vermilion 2012 to 2016, Chairman Northpoint Resources, a private oil and gas company Since 2003, Chairman & Chief Executive Officer and Director of Point Energy Ltd., a private oil and gas company 2006 to 2013, Director of Sure Energy Inc.
William F. Madison Sugar Land, Texas USA	(5) (6)	Director	2004	Since 2007, Director of Canadian Oil Recovery and Remediation Enterprise, Inc., a public oil recovery and remediation company 2011 to 2017, Director of Montana Tech Foundation, an independent, non-profit organization
Timothy R. Marchant Calgary, Alberta Canada	(5) (6)	Director	2010	Since 2015, Director, Valeura Energy Inc., a public oil and gas company Since 2013, Non-Executive Director of Cub Energy Inc., a public oil and gas company Since 2009, Adjunct Professor of Strategy and Energy Geopolitics, Haskayne School of Business 2011 to 2013, Executive Chair of Anatolia Energy Corp., a public oil and gas company
Anthony W. Marino Calgary, Alberta Canada		President & Chief Executive Officer and Director	2016	Since March 1, 2016, President and Chief Executive Officer March 2014 – March 1, 2016, President and Chief Operating Officer of Vermilion June 2012 – March 2014, Executive Vice President and Chief Operating Officer of Vermilion 2009 to 2012, Director, President & CEO, Baytex Energy Corporation, a public oil and gas company

Robert Michaleski Calgary, Alberta Canada	(3) (4)	Director	2016	Since 2013, Director of United Way of Calgary and Area, a non-profit organization 2012 to 2013, Chief Executive Officer of Pembina Pipeline Corporation, a public energy transportation company 2000 to 2012, President and Chief Executive Officer of Pembina Pipeline Corporation Since 2012, Director of Essential Energy Services Ltd., a public oilfield services company Since 2003, Director of Coril Holdings Ltd., a private investment company Since 2000, Director of Pembina Pipeline Corporation
Sarah E. Raiss Calgary, Alberta Canada	(4) (5)	Director	2014	Since 2016, Director and Chair, Compensation of Ritchie Bros. Auctioneers, a public heavy equipment auction company Since 2014, Director, Loblaw Companies Limited, a public food distributor company Since 2011, Director, Commercial Metals Company, a public global, metals recycling, manufacturing, fabricating and trading company 2012 to 2015, Board Chair, Alberta Electric Systems Operator, a not-for-profit entity responsible for the planning and operation of the Alberta Interconnected Electric System 2012 to February 2016, Director, Canadian Oil Sands Limited, a public oil company 2009 to 2014, Director, Shoppers Drug Mart Corporation, a public pharmacy products and services company
William Roby Katy, Texas USA	(5) (6)	Director	2017	Since 2015, Chief Executive Officer, Shepherd Energy, LLC., a private energy efficiency services company 2013 to 2014, Chief Operating Officer, Sheridan Production Company, LLC., a private oil and gas company 2000 to 2013, Senior Vice President and other management positions, Occidental Petroleum Corporation, a public oil and gas company
Catherine L. Williams Calgary, Alberta Canada	(3) (4)	Director	2015	Since 2010, Chair of Human Resources and Compensation Committee, Enbridge Inc., a public energy transportation company Since 2007, Director of Enbridge Inc., a public energy transportation company Since 2007, Owner and Managing Director, Options Canada Ltd., a private investment company 2016 to 2017, Director of Enbridge Income Fund, an energy infrastructure asset investment vehicle 2015 to 2017, Director of Enbridge Pipelines Inc. and Enbridge Income Partners GP Inc., subsidiaries of Enbridge Inc., a public energy transportation company 2015 to 2017, Trustee of Enbridge Commercial Trust, a subsidiary of Enbridge Inc., a public energy transportation company 2009 to 2014, Director, Alberta Investment Management Corporation, an institutional investment fund manager

Committees:
(1) Chairman of the Board
(2) Lead Director
(3) Member of the Audit Committee
(4) Member of the Governance and Human Resources Committee
(5) Member of the Health, Safety and Environment Committee
(6) Member of the Independent Reserves Committee

Officers

Name and Municipality of Residence	Office Held	Principal Occupation During the Past Five Years
Anthony W. Marino Calgary, Alberta Canada	President & Chief Executive Officer	Since March 1, 2016, President and Chief Executive Officer of Vermilion March 2014 – March 1, 2016, President and Chief Operating Officer of Vermilion June 2012 – March 2014, Executive Vice President and Chief Operating Officer of Vermilion 2009 to 2012, Director, President & CEO, Baytex Energy Corporation, a public oil and gas company
Curtis W. Hicks Calgary, Alberta Canada	Executive Vice President & Chief Financial Officer	Since 2004, Executive Vice President and Chief Financial Officer of Vermilion
Mona Jasinski Calgary, Alberta Canada	Executive Vice President People & Culture	Since February 2015, Executive Vice President, People and Culture of Vermilion 2011 to 2015, Executive Vice President People of Vermilion
Michael Kaluza Calgary, Alberta Canada	Executive Vice President & Chief Operating Officer	Since March 1, 2016, Executive Vice President and Chief Operating Officer of Vermilion May 2014 – March 1, 2016, Vice President, Canada Business Unit of Vermilion 2013 to 2014, Director Canada Business Unit of Vermilion 2012 to 2013, Vice President, Corporate Development and Planning, Baytex Energy Corporation, a public oil and gas company 2011 to 2012, Vice President, Planning, Baytex Energy Corporation, a public oil and gas company
Anthony (Dion) Hatcher Calgary, Alberta Canada	Vice President Canada Business Unit	Since March 1, 2016, Vice President Canada Business Unit of Vermilion May 1, 2014 to March 1, 2016, Director Alberta Foothills – Canada Business Unit of Vermilion February 2013 to May 2014, Cardium / LRG Development Manager of Vermilion January 2010 to February 2013 – Cardium Development Manager of Vermilion
Terry Hergott Calgary, Alberta Canada	Vice President Marketing	Since April 2012, Vice President, Marketing of Vermilion 1998 to 2012, Canadian Supply and Trading Manager, Marathon Petroleum Corp.
Gerard Schut Den Haag The Netherlands	Vice President European Operations	Since July 2012, Vice President European Operations of Vermilion August 2006 to May 2012, General Manager, Chevron Exploration and Production Netherlands, a subsidiary of Chevron Corporation, a public oil and gas company
Jenson Tan Calgary, Alberta Canada	Vice President Business Development	Since October 2017, Vice President, Business Development of Vermilion July 2016 to October 2017, Director, Business Development of Vermilion July 2013 to July 2016, Director, New Ventures of Vermilion November 2010 to July 2013, Business Development Professional of Vermilion
Robert J. Engbloom, Q.C. Calgary, Alberta Canada	Corporate Secretary	Since January 2015, senior partner with Norton Rose Fulbright Canada LLP, a law firm 2012 to 2014, partner with and Deputy Chair of Norton Rose Fulbright Canada LLP, a law firm

DESCRIPTION OF CAPITAL STRUCTURE

Credit Ratings

The following information relating to the Company's credit ratings is provided as it relates to the Company's financing costs, liquidity and operations. Specifically, credit ratings affect the Company's ability to obtain short-term and long-term financing and the cost of such financing. Additionally, the ability of the Company to engage in certain collateralized business activities on a cost effective basis depends on the Company's credit ratings. A reduction in the current rating on the Company's debt by its rating agencies, particularly a downgrade below current ratings, or a negative change in the Company's ratings outlook could adversely affect the Company's cost of financing and its access to sources of liquidity and capital. In addition, changes in credit ratings may affect the Company's ability to, and the associated costs of, (i) entering into ordinary course derivative or hedging transactions and may require the Company to post additional collateral under certain of its contracts, and (ii) entering into and maintaining ordinary course contracts with customers and suppliers on acceptable terms.

Vermilion's Rating

Standard & Poor's Ratings Services, a division of the McGraw-Hill Companies (Canada) Corporation ("S&P") has assigned a corporate credit rating of Vermilion of “BB-” with a stable outlook. S&P rates long-term corporate credit ratings by rating categories ranging from a high of "AAA" to a low of "D". The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. In addition, S&P may add a rating outlook of “positive”, “negative” or “stable” which assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years). An obligor rated “BB” is characterized by S&P as less vulnerable in the near term than other lower-rated obligors. However, it faces major ongoing uncertainties and exposure to adverse business, financial or economic conditions, which could lead to the obligor’s inadequate capacity to meet its financial commitments.

Moody's Investors Service ("Moody's") has assigned a corporate family rating to Vermilion of "Ba3" with a stable outlook. Moody's corporate family ratings are on a rating scale that ranges from Aaa to C, which represents the highest to lowest opinions of creditworthiness. Moody’s appends numerical modifiers 1, 2, and 3 to each generic rating classification from Aa through Caa, 3 indicating a ranking in the lower end of the generic rating category. A rating of Ba3 by Moody’s is within the fifth highest of nine categories. Obligations rated Ba3 are considered non-investment grade speculative and are subject to substantial credit risk.

The following table sets forth the ratings issued by the rating agencies noted therein as of February 28, 2018:

Rating Agency	Company Rating	Outlook	Senior Unsecured Notes
S&P	BB-	Stable	BB-
Moody's	Ba3	Stable	B2

Senior Unsecured Notes Rating

S&P has assigned a long-term issue credit rating on the senior unsecured notes due March 2025 of BB-. S&P rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. An obligation rated "BB" is characterized as less vulnerable to nonpayment than other speculative issues. However, it faces major ongoing uncertainties or exposure to adverse business, financial, or economic conditions, which could lead to the obligor's inadequate capacity to meet its financial commitment on the obligation. The "BB" category is the fifth highest of the ten available categories.

Moody's has assigned a long-term obligations rating on the senior unsecured notes due March 2025 of Ba3. Moody’s long-term obligations ratings are on a rating scale that ranges from Aaa to C, which represents the highest to lowest opinions of creditworthiness. Moody’s appends numerical modifiers 1, 2, and 3 to each generic rating classification from Aa through Caa, with 2 indicating a mid-range ranking within the generic rating category. A rating of B2 by Moody’s is within the sixth highest of nine categories. Obligations rated B2 are considered non-investment grade speculative and are subject to substantial credit risk.

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issuer of securities. The credit ratings accorded to the Senior Unsecured Notes and the Company are not recommendations to purchase, hold or sell such securities and are not a comment upon the market price of the Company's securities or their suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant. A revision or withdrawal of a credit rating could have a material adverse effect on the pricing or liquidity of the Senior Unsecured Notes or the common shares in any secondary markets. Vermilion does not undertake any obligation to maintain the ratings or to advise holders of the Senior Unsecured Notes or the common shares of any change in ratings. Each agency's rating should be evaluated independently of any other agency's rating.

Common Shares

The Company is authorized to issue an unlimited number of common shares. Each common share entitles the holder to receive notice of and to attend all meetings of Shareholders and to one vote at any such meeting. The holders of common shares are, at the discretion of the board and subject to applicable legal restrictions, entitled to receive any dividends declared by the board on the common shares. The holders of common shares will be entitled to share equally in any distribution of the assets of the Company upon the liquidation, dissolution, bankruptcy or winding-up of the Company or other distribution of its assets among the Shareholders for the purpose of winding-up the Company's affairs.

Awards (entitling the holder thereof to receive Common Shares) have been issued under the Vermilion Incentive Plan. See note 2 regarding equity compensation plans in Vermilion's annual financial statements as at and for the year ended December 31, 2017 (a copy of which is available on SEDAR at www.sedar.com under Vermilion's SEDAR profile) for further details regarding the amount and value of such awards.

Cash Dividends

The Company currently pays dividends on a monthly basis. All decisions with respect to the declaration of dividends on the common shares will be made by the board on the basis of the Company's net earnings, financial requirements and other conditions existing at such future time, planned acquisitions, income tax payable by the Company, crude oil and natural gas prices and access to capital markets, as well as the satisfaction of solvency tests imposed by the ABCA on corporations for the declaration and payment of dividends. It is expected that the dividends will be "eligible dividends" for income tax purposes and thus qualify for the enhanced gross-up and tax credit regime for certain Shareholders.

Record of Cash Dividends

The following table sets forth the amount of cash distributions per Unit for the specified periods declared by the Trust since the completion of the 2003 Arrangement on January 22, 2003 and the cash dividends per common share for the specified periods declared by the Company since the completion of the Conversion Arrangement on September 1, 2010. Dividends are generally paid on the 15th day of the month following the month of declaration. Until the December 2007 distribution announcement, Vermilion had paid distributions of $0.17 per Trust Unit per month. From the January 2008 payment date and onwards, Vermilion paid distributions of $0.19 per Trust Unit and dividends of $0.19 per common share, in each case per month (as applicable). In January 2013, Vermilion increased its dividend to $0.20 per common share effective for the January 2013 dividend paid in February 2013. In November 2013, Vermilion announced that its board had approved a 7.5% increase in the monthly dividend to $0.215 per common share per month effective for the January 2014 dividend paid in February 2014. The monthly dividend has been maintained at $0.215 per common share per month since January 2014.

Period	Distribution Amount for Period per Trust Unit
As Vermilion Energy Trust	
2003 – January 22 to December 31	$1.87
2004 – January to December	$2.04
2005 – January to December	$2.04
2006 – January to December	$2.04
2007 – January to December	$2.06
2008 – January to December	$2.28
2009 – January to December	$2.28
2010 – January to December (1)	$1.71
Period	**Dividend Amount for Period per Common Share**
As Vermilion Energy Inc.	
2010 – January to December (1)	$0.57
2011 – January to December	$2.28
2012 – January to December	$2.28
2013 – January to December	$2.40
2014 – January to December	$2.58
2015 – January to December	$2.58
2016 – January to December	$2.58
2017 – January to December	$2.58
2018 – January to February	$0.43
Total cash dividends since January 22, 2003	$34.60

Note:
(1) Total cash dividends paid out in 2010 by Vermilion and the Trust to a holder of a common share who was a former holder of a Trust Unit equals $2.28.

Premium Dividend™ and Dividend Reinvestment Plan

Vermilion's Premium Dividend™ and Dividend Reinvestment Plan (the "Plan") is comprised of two different components: the Dividend Reinvestment Component and the Premium Dividend™ Component. The Premium Dividend™ Component was introduced in 2015 as a temporary measure and was discontinued beginning with the July 2017 dividend payment.

The Dividend Reinvestment Component allows eligible Shareholders who elect to participate in the Dividend Reinvestment Component to reinvest their dividends in common shares at a discount (currently 2%) to the Average Market Price (with no broker commissions or trading costs). The Plan is similar to our previous Dividend Reinvestment Plan (Vermilion's Amended and Restated Dividend Reinvestment Plan dated effective September 1, 2010 as amended effective February 27, 2014 (the "Previous DRIP").

Participation in the Plan, which is explained in greater detail in the complete Plan document available on Vermilion's corporate website at www.vermilionenergy.com (under the heading "Investor Relations" subheading "DRIP"), is subject to eligibility restrictions, applicable withholding taxes, prorating as provided for in the Plan, and other limitations on the availability of common shares to be issued or purchased in certain events. Participation in the Plan is available to Canadian residents and non-U.S. resident foreign Shareholders who meet certain eligibility criteria as set forth in the complete Plan. U.S. resident Shareholders are not currently permitted to participate in the Plan due to the requirement, under U.S. securities regulations, to maintain a continuous shelf registration for issuance of new equity to U.S. Shareholders. At this time, Vermilion has not put in place the required shelf registration due to the high cost of establishing and maintaining such a shelf registration.

™ denotes trademark of Canaccord Genuity Capital Corporation.

Shareholder Rights Plan

Vermilion has a shareholder rights plan (the "Shareholder Rights Plan") to ensure that, to the extent possible, all Shareholders are treated equally and fairly in connection with any takeover bid for the Company. The Shareholder Rights Plan discourages coercive hostile takeover bids by creating the potential that any Common Shares which may be acquired or held by such a bidder will be significantly diluted. Pursuant to the Shareholder Rights Plan, one right (a "Right") has been issued by the Company in respect of each Common Share that is outstanding prior to the time the Rights separate from the Common Shares (the "Separation Time"). The Separation Time would occur at the time of an unsolicited take-over bid whereby a person acquires or attempts to acquire 20% or more of the Company's Common Shares. Until the Separation Time, the rights are not exercisable or dilutive. The Rights do not change the manner in which Shareholders currently trade their Common Shares and no separate Rights certificates are issued. On or after the Separation Time, each Right would permit the holder, other than 20% acquirer, to purchase Common Shares at a substantial discount to the prevailing market price unless the application of the Rights Plan is waived by the Board of Directors.

Vermilion initially adopted a unitholder rights plan in 2003, which was subsequently renewed and approved by unitholders in 2006 and 2009. In conjunction with the conversion of the Trust to a corporation on September 1, 2010, the Shareholder Rights Plan was approved and subsequently reapproved by Shareholders in 2013 and 2016. The Shareholder Rights Plan must be reapproved at every third annual meeting of Shareholders.

The foregoing summary is qualified in its entirety by reference to the Shareholder Rights Plan Agreement, a copy of which is available on SEDAR at www.sedar.com under Vermilion's SEDAR profile.

MARKET FOR SECURITIES

The outstanding common shares of the Company are listed and posted for trading on the TSX and the NYSE under the symbol VET. The following table sets forth the closing price range and trading volume of the common shares on the TSX for the periods indicated:

2017	High	Low	Close	Volume
January	$ 57.98	$ 52.79	$53.68	5,456,428
February	$ 54.47	$ 50.32	$50.51	7,443,561
March	$ 52.48	$ 46.85	$49.87	8,581,629
April	$ 51.03	$ 46.62	$48.06	5,522,017
May	$ 50.00	$ 41.19	$42.27	9,858,101
June	$ 45.67	$ 40.80	$41.14	9,999,384
July	$ 42.77	$ 38.60	$41.06	8,023,621
August	$ 41.29	$ 38.33	$40.70	7,508,957
September	$ 46.35	$ 40.52	$44.35	8,522,774
October	$ 44.48	$ 41.74	$44.03	8,028,346
November	$ 48.47	$ 44.03	$45.50	7,973,483
December	$ 46.02	$ 41.38	$45.68	8,826,557
2018	**High**	**Low**	**Close**	**Volume**
January	$ 50.46	$ 45.74	$46.50	8,487,719

AUDIT COMMITTEE MATTERS

Audit Committee Charter

Vermilion has established an audit committee (the "Audit Committee") to assist the board of directors in carrying out its oversight responsibilities with respect to, among other things, financial reporting, internal controls and the external audit process of the Company. The Audit Committee Terms of Reference are set out in Schedule "D" to this annual information form.

Composition of the Audit Committee

The following table sets forth the name of each current member of the Audit Committee, whether pursuant to applicable securities legislation, such member is considered independent, whether pursuant to applicable securities legislation, such member is considered financially literate and the relevant education and experience of such member.

Name	Independent	Financially Literate	Relevant Education and Experience
Catherine L. Williams (Chair)	Yes	Yes	Ms. Williams has a Bachelor of Arts degree from University of Western Ontario and a Masters in Business Administration from Queen's University. Ms. Williams has 31 years of oil and gas industry experience, with an extensive background in finance, mergers and acquisitions, and business management. Ms. Williams is currently the Owner and Managing Director of Options Canada Ltd. (since 2007) and serves as a Board member of Enbridge Inc. (since 2010) and Chairs its Human Resources and Compensation Committee. She was a Board member of Alberta Investment Management Corporation from 2009 to 2014 and Tim Hortons Inc. from 2009 to 2012. From 2003 to 2007, Ms. Williams held the role of Chief Financial Officer for Shell Canada Ltd., prior to which she held various positions with Shell Canada Limited, Shell Europe Oil Products, Shell Canada Oil Products and Shell International (1984 to 2003).
Stephen Larke	Yes	Yes	Mr. Larke holds a Bachelor of Commerce (Distinction) degree from the University of Calgary and is a Chartered Financial Analyst. He has over 20 years of experience in energy capital markets, including research, sales, trading and equity finance. He is currently an Operating Partner and Advisory Board member with Azimuth Capital Management, an energy-focused private equity fund based in Calgary, Alberta. From 2005 to 2015, Mr. Larke was Managing Director and Executive Committee member with Peters & Co., an independent energy investment firm based in Calgary. From 1997 to 2005, he was Vice-President and Director with TD Newcrest, serving in the role of energy equity analyst.
Larry J. Macdonald	Yes	Yes	Mr. Macdonald holds a Bachelor of Science degree from the University of Alberta. He has more than 46 years of experience in the oil and gas industry, with an extensive background in leadership, strategy and growth, finance, exploration, corporate relations and marketing. Mr. Macdonald completed the Executive Management Program at the Wharton Business School at the University of Pennsylvania in 1993 and attended a Financial Literacy Course at the Rotman Business School at the University of Toronto in coordination with the Institute of Corporate Directors. Currently, he is the Chairman and Chief Executive Officer (since 2003) of Point Energy Ltd., a private oil and gas exploration company. From 2012 to 2016, he was Chairman of Northpoint Resources. From 2003 to 2006, he was a Managing Director of Northpoint Energy Ltd., and from 2006 to 2013 a director of Sure Energy Inc. Previously, he was the Chairman and Chief Executive Officer of Pointwest Energy Inc. and President and Chief Operating Officer of Anderson Exploration Ltd. He began his career with PanCanadian Petroleum Limited in 1969 (until 1977) and later worked for several exploration firms.
Robert Michaleski	Yes	Yes	Mr. Michaleski holds a Bachelor of Commerce (Honours) degree from the University of Manitoba and is a Chartered Accountant. He has over 30 years of experience in various senior management and executive capacities at Pembina Pipeline Corporation. He was Chief Executive Officer from 2000 to 2013 and also President from 2000 to 2012. He was Vice President and Chief Financial Officer from 1997 to 2000, Vice President of Finance from 1992 to 1997, Controller from 1980 to 1992, and Manager of Internal Audit from 1978 to 1980. He has been a Director of Pembina since 2000, a Director of Essential Energy Services Ltd. since 2012, and a Director of Coril Holdings Ltd. since 2003. He is a member of the Institute of Corporate Directors.

External Audit Service Fees

Prior to the commencement of any work, fees for all audit and non-audit services provided by the Company's auditors must be approved by the Audit Committee.

During the years ended December 31, 2017 and 2016, Deloitte LLP, the auditors of the Company, received the following fees from the Company:

Item	2017	2016
Audit fees (1)	$1,658,920	$1,545,495
Audit-related fees (2)	$123,000	$18,325
Tax fees (3)	$34,828	$57,614

Notes:

(1) Audit fees consisted of professional services rendered by Deloitte LLP for the audit of the Company's financial statements for the years ended December 31, 2017 and 2016.

(2) Audit-related fees billed by Deloitte LLP for assurance and related services that are reasonably related to the performance of the audit or review of Vermilion's financial statements, but which are not included in the audit fees. Audit related fees increased in 2017 as a result of fees billed by Deloitte LLP for assurance and related services associated with the issuance of Vermilion's Senior Unsecured Notes.

(3) Tax fees consist of fees for tax compliance services in various jurisdictions.

CONFLICTS OF INTEREST

The directors and officers of Vermilion are engaged in and will continue to engage in other activities in the oil and natural gas industry and, as a result of these and other activities, the directors and officers of Vermilion may become subject to conflicts of interest. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under the ABCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

As at the date hereof, Vermilion is not aware of any existing or potential material conflicts of interest between Vermilion and a director or officer of Vermilion.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director or officer of the Company, nor any other insider of the Company, nor their associates or affiliates has or has had, at any time within the three most recently completed financial years ending December 31, 2017, any material interest, direct or indirect, in any transaction or proposed transaction that has materially affected or would materially affect the Company.

LEGAL PROCEEDINGS

The Company is not party to any significant legal proceedings as of February 28, 2018.

MATERIAL CONTRACTS

The Company has not entered into any material contracts outside its normal course of business.

INTERESTS OF EXPERTS

As at the date hereof, principals of GLJ, the independent engineers for the Company, personally disclosed in certificates of qualification that they neither had nor expect to receive any common shares. The principals of GLJ and their employees (as a group) beneficially own less than one percent of any of the Company's securities.

Deloitte LLP is the auditor of the Company and is independent within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Company's common shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario.

RISK FACTORS

The following is a summary of certain risk factors relating to the business of the Company. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this annual information form. Additional risks and uncertainties not currently known to Vermilion that it currently views as immaterial may also materially and adversely affect its business, financial condition and/or results of operations. Shareholders and potential Shareholders should carefully consider the information contained herein and, in particular, the following risk factors.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of proved and probable reserves and future net revenues to be derived therefrom, including many factors beyond the Company's control. The reserve and future net revenue information set forth in this annual information form represents estimates only. The reserves and estimated future net cash flow from the Company's properties have been independently evaluated by GLJ with an effective date of December 31, 2017. These evaluations 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 and natural gas, operating costs, well 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 prices in use at the date the GLJ Report was prepared, and many of these assumptions are subject to change and are beyond the Company's control. Actual production and cash flow derived therefrom will vary from these evaluations, and such variations could be material.

Estimates with respect to reserves that may be developed and produced in the future are often based upon volumetric calculations, probabilistic methods and upon analogy to similar types of reserves, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves.

Reserve estimates may require revision based on actual production experience. Such figures have been determined based upon assumed commodity prices and operating costs.

The present value of estimated future net revenue referred to in this annual information form should not be construed as the fair market value of estimated crude oil and natural gas reserves attributable to the Company's properties. The estimated discounted future 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 and taxation.

Uncertainty of Contingent Resource Estimates

Information regarding quantities of contingent resources included in Appendix A to this Annual Information Form are estimates only. References to “contingent resources” do not constitute, and should be distinguished from, references to “reserves”. The same uncertainties inherent in estimating quantities of reserves apply to estimating quantities of contingent resources. In addition, there are contingencies that prevent resources from being classified as reserves. There is no certainty that it will be commercially viable to produce any portion of the contingent resources due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. Actual results may vary significantly from these estimates and such variances could be material.

Uncertainty of Prospective Resource Estimates

Information regarding quantities of prospective resources included in Appendix A to this Annual Information Form are estimates only. References to “prospective resources” do not constitute, and should be distinguished from, references to “reserves” and “contingent resources”. The same uncertainties inherent in estimating quantities of reserves apply to estimating quantities of prospective resources. In addition, there are contingencies that prevent resources from being classified as reserves. There is no certainty that it will be commercially viable to produce any portion of the prospective resources. Actual results may vary significantly from these estimates and such variances could be material.

Volatility of Oil and Natural Gas Prices

The Company's operational results and financial condition are dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated materially during recent years and are determined by supply and demand factors. Demand factors can be impacted by general economic conditions, supply chain requirements, environmental and other factors. Environmental and other factors include changes in weather, weather patterns, fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and gas, and technology advances in fuel economy and energy generation devices. A substantial and prolonged decline in oil and natural gas prices could have an adverse effect on Vermilion's cash flow and financial position, which could include the effect of decreasing dividends.

Reputational Risks Relating to Environmental Matters

Practices and disclosures relating to environmental matters, including climate change, are attracting increasing scrutiny by stakeholders. Vermilion's response to addressing environmental matters can impact the Company's reputation and affect our ability to hire and retain employees; to compete for reserve acquisitions, exploration leases, licenses and concessions; and to receive regulatory approvals required to execute our operating programs.

Changes in Tax, Royalty and Other Government Incentive Program Legislation

There can be no assurance that income tax laws and government incentive programs relating to the oil and gas industry in Canada and the foreign jurisdictions in which the Company operates, will not be changed in a manner which adversely affects the Company.

The Governments of Alberta and Saskatchewan receive royalties on production of natural resources from lands in which they own the mineral rights. A change in the royalty regime resulting in an increase in royalties would reduce Vermilion's net earnings and could make future capital expenditures or Vermilion's operations uneconomic and could, in the event of a material increase in royalties, make it more difficult to service and repay outstanding debt or impair Vermilion's ability to declare dividends. Any material increase in royalties would also significantly reduce the value of the Company's associated assets.

The Government of Alberta released its Royalty Review Advisory Panel Report on January 29, 2016 ("RRAP"). The RRAP recommendations were accepted, which outlined the implementation of a Modernized Royalty Framework ("MRF") that took effect on January 1, 2017. The MRF includes royalty incentives for the efficient development of conventional crude oil, natural gas, and NGL resources, and no changes to the royalty structure of wells drilled prior to 2017 for a 10-year period from the royalty program's implementation date as they will continue to be governed by the previous Alberta Royalty Framework ("ARF"). It also includes the replacement of royalty credits/holidays on conventional wells by a revenue minus cost framework with a post-payout royalty rate based on commodity prices, the reduction of royalty rates for mature wells, and a neutral internal rate of return for any given play compared to the ARF.

Government Regulations

Vermilion's operations are governed by many levels of government, including municipal, state, provincial and federal governments in Canada, France, Germany, the Netherlands, Australia, Ireland, Hungary, Croatia, Slovakia and the United States. Vermilion is subject to laws and regulations regarding environment, health and safety issues, lease interests, taxes and royalties, among others. Failure to comply with the applicable laws can result in significant increases in costs, penalties and even losses of operating licenses. The regulatory process involved in each of the countries in which Vermilion operates is not uniform and regulatory regimes vary as to complexity, timeliness of access to, and response from, regulatory bodies and other matters specific to each jurisdiction. If regulatory approvals or permits are delayed or not obtained, there can also be delays or abandonment of projects, decreases in production and increases in costs, and Vermilion may not be able to fully execute its strategy. Governments may also amend or create new legislation and regulatory bodies may also amend regulations or impose additional requirements which could result in increased capital, operating and compliance costs.

Political Events and Terrorist Attacks

Political events throughout the world that cause disruptions in the supply of oil continue to affect the marketability and price of oil and natural gas acquired or discovered by Vermilion. Political developments arising in the countries in which Vermilion operates have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction to the Company's revenue.

Vermilion's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. The long-term impact of previous terrorist attacks and the threat of future terrorist attacks on the oil and gas industry in general, and on facilities for the transportation and refinement of oil and gas in particular, is not known at this time. If any of Vermilion's properties, wells or facilities or any infrastructure on which the Company relies are the subject of a terrorist attack, such attack may have a material adverse effect on Vermilion's business, financial condition, results of operations and prospects.

Competition

Vermilion actively competes for reserve acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and gas companies, some of which have significantly greater financial resources than Vermilion. Vermilion's competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators.

Vermilion's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

International Operations and Future Geographical/Industry Expansion

The operations and expertise of our management are currently focused primarily on oil and natural gas production, exploration and development in three geographical regions; North America, Europe and Australia. In the future we may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase our exposure to one or more existing risk factors, which may in turn result in our future operational and financial conditions being adversely affected.

Operational Matters

The operation of oil and gas wells and facilities involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to Vermilion and possible liability to regulators and third parties. Vermilion maintains liability insurance, where available, in amounts consistent with industry standards. Business interruption insurance may also be purchased for selected operations, to the extent that such insurance is commercially viable. Vermilion may become liable for damages arising from such events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities may impair Vermilion's ability to satisfy its debt obligations or declare dividends.

Continuing production from a property, and to some extent the marketing of production, are largely dependent upon the ability of the operator of the property. To the extent the operator fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although satisfactory title reviews are generally conducted in accordance with industry standards, such reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of Vermilion or its subsidiaries to certain properties. Such circumstances could impair Vermilion's ability to satisfy its debt obligations or declare dividends.

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of the properties, and by the operator to Vermilion, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of the properties or the establishment by the operator of reserves for such expenses.

Risks and uncertainties associated with weather conditions can shorten the winter drilling season in Canada and can impact the spring and summer drilling programs, potentially resulting in increased costs or reduced production. Western Australia’s northwest shelf is subject to seasonal disruptions caused by cyclones. During cyclone season (December to March) the Company may have to reduce production rates as a result of the inability to offload to tankers due to bad weather. Cyclones may also cause production shut-ins due to the evacuation of staff or damage to equipment on the platform.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (oil and natural gas) production. Specifically, hydraulic fracturing is used to produce commercial quantities or oil and natural gas from reservoirs that were previously unproductive or uneconomic. Hydraulic fracturing has also featured prominently in recent political, media and activist commentary on the subject of water usage and environmental damage. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase our costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves as well as increase our costs.

With activists groups expressing concern about the impact of hydraulic fracturing on the environment and water supplies, our corporate reputation may be adversely affected by the negative public perception and public protests against hydraulic fracturing.

Concerns regarding hydraulic fracturing may result in changes in regulations that delay the development of oil and natural gas resources and adversely affect our costs of compliance and reputation. Changes in government may result in new or enhanced regulatory burdens in respect of hydraulic fracturing which could affect our business.

Reliance on Key Personnel, Management and Labour

Our success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on our business, financial condition, results of operations and prospects. We do not have any key person insurance in effect. The contributions of our existing management team to immediate and near term operations are likely to be of central importance. In addition, the labour force in certain areas in which we operate is limited and the competition for qualified personnel in the oil and natural gas industry is intense. Vermilion expects that similar projects or expansions will proceed in the same area during the same time frame as our projects. Our projects require experienced employees, and such competition may result in increases in compensation paid to such personnel or in a lack of qualified personnel. There can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business.

Environmental Legislation

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial, state and federal legislation. A breach of such legislation may result in the imposition of fines, the issuance of clean up orders in respect of Vermilion or its assets, or the loss or suspension of regulatory approvals. Such legislation may be changed to impose higher standards and potentially more costly obligations on Vermilion. There can be no assurance that the Company will be able to satisfy its actual future environmental and reclamation obligations.

Vermilion expects to incur abandonment and reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2017, expenditures beyond normal compliance with environmental regulations were considered to be in the ordinary course of business. Vermilion does not anticipate material expenditures beyond amounts paid in respect of normal compliance with environmental regulations in 2017.

Vermilion's exploration and production facilities and other operations and activities in North America, Europe and Australia will emit a small amount of greenhouse gasses which may subject Vermilion to legislation regulating emissions of greenhouse gases and which may include a requirement to reduce emissions or emissions intensity from Vermilion's operations and facilities. As such, Vermilion continues to evaluate and monitor regulatory initiatives and overall trends so that it is aware of potential developments that could affect its business and operations. It is possible that future international, national, provincial or state emissions reduction requirements in jurisdictions that Vermilion operates in may require further reductions of emissions or emissions intensity. The direct or indirect costs of complying with emissions regulations may adversely affect the business of Vermilion in North America, Europe and Australia.

In 2015, the Government of Alberta released its Climate Leadership Plan which impacts all consumers and businesses that contribute to carbon emissions in Alberta. The plan includes imposing carbon pricing that is applied on carbon emissions from heating and transportation fuels across all sectors, which started at $20 per tonne on January 1, 2017 and moved to $30 per tonne on January 1, 2018, the phase-out of coal-fired power generation by 2030, a cap on oil sands production emissions of 100 megatonnes, and a 45 per cent reduction in methane emissions by the oil and gas sector by 2025. Vermilion expects the Climate Leadership Plan to increase the cost of operating its properties located in Alberta, but does not currently anticipate material impacts on its results of operations.

In 2017, the Canadian federal government proposed a new *Greenhouse Gas Pollution Pricing Act* in response to the Paris Agreement that was ratified by Canada and other nations in October 2016. Under the new Act, the federal government is proposing a benchmark carbon pricing program that includes, at a minimum, a price on carbon emissions of $10 per tonne in 2019, rising by $10 per tonne each year to $50 per tonne in 2023. The federal government also proposes a federal backstop in the event that provincial jurisdictions fail to meet the benchmark. As mentioned above, Alberta has already established a carbon pricing system that was referenced in the federal announcement and therefore, currently, the proposed legislation is not anticipated to have a material impact on Vermilion’s results of operations.

In 2017, the Minister for the Ecological and Inclusive Transition presented the Government of France’s Climate Plan. As part of implementing the Climate Plan, France’s Parliament passed legislation in December 2017 impacting oil and gas exploration and production on French territories. The legislation prohibits the issuance of new oil and gas exploration concessions and places restrictions on oil and gas production starting in 2040. The impact of this legislation is not anticipated to have a material impact on Vermilion’s reserves in France.

Vermilion continued to be recognized for its environmental, social and governance ("ESG") initiatives in 2017. Vermilion received a top quartile ranking for 2017 for our industry sector in RobecoSAM’s annual Corporate Sustainability Assessment (“CSA”). The CSA analyzes sustainability performance across economic, environmental, governance and social criteria, and is the basis of the Dow Jones Sustainability Indices. The company was also named to the CDP (formerly Carbon Disclosure Project) Climate Leadership level (A-) in 2017. Vermilion is the only Canadian energy company and one of only two North American energy companies to receive this designation, ranking us in the top 4% of energy companies globally. For more information on our ESG initiatives and performance, please see our Sustainability Report at: http://sustainability.vermilionenergy.com

Discretionary Nature of Dividends

The declaration and payment (including the amount thereof) of future cash dividends, if any, is subject to the discretion of the board of directors of the Company and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests under the ABCA for the declaration and payment of dividends. Depending on these and other factors considered relevant to the declaration and payment of dividends by the board of directors and management of the Company (some or all of which may be beyond the control of the board of directors and management of the Company), the Company may change its dividend policy from time to time. Any reduction of dividends may adversely affect the market price or value of common shares.

Debt Service

Vermilion may, from time to time, finance a significant portion of its operations through debt. Amounts paid in respect of interest and principal on debt incurred by Vermilion may impair Vermilion's ability to satisfy its other obligations. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment by Vermilion of its debt obligations. Ultimately, this may result in lower levels of cash flow for the Company.

Lenders may be provided with security over substantially all of the assets of Vermilion and its Subsidiaries. If Vermilion becomes unable to pay its debt service charges or otherwise commits an event of default such as bankruptcy, a lender may be able to foreclose on or sell the assets of Vermilion and/or its Subsidiaries.

Depletion of Reserves

The Company has certain unique attributes which differentiate it from other oil and gas industry participants. Dividends paid from cash flow generated in respect of properties, absent commodity price increases or cost effective acquisition and development activities, may decline over time in a manner consistent with declining production from typical crude oil, natural gas and natural gas liquids reserves. Accordingly, absent capital expenditures or acquisitions of additional crude oil and natural gas properties, Vermilion's current production levels and reserves will decline.

Vermilion's future crude oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on Vermilion's success in exploiting its reserve base and acquiring additional reserves. Without reserve additions through acquisition or development activities, Vermilion's reserves and production will decline over time as reserves are exploited.

Net Asset Value

The net asset value of the assets of the Company from time to time will vary dependent upon a number of factors beyond the control of management, including crude oil and natural gas prices. The trading prices of the common shares from time to time is also determined by a number of factors which are beyond the control of management and such trading prices may be greater than the net asset value of the Company's assets.

Volatility of Market Price of Common Shares

The market price of the common shares may be volatile. The volatility may affect the ability of Shareholders to sell the common shares at an advantageous price. Market price fluctuations in the common shares may be due to the Company’s operating results failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts’ estimates, governmental regulatory action, adverse change in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by the Corporation or its competitors, along with a variety of additional factors, including, without limitation, those set forth under “Forward-Looking Statements” in this annual information form. In addition, the market price for securities in the stock markets, including the TSX and NYSE, has experienced significant price and trading fluctuations in recent years. These fluctuations have resulted in volatility in the market prices of securities that often has been unrelated or disproportionate to changes in operating performance. These broad market fluctuations may adversely affect the market price of the common shares.

Variations in Interest Rates and Foreign Exchange Rates

An increase in interest rates could result in a significant increase in the amount the Company pays to service debt, potentially impacting dividends to Shareholders.

In addition, an increase in the exchange rate for the Canadian dollar versus the U.S. dollar would result in the receipt by the Company of fewer Canadian dollars for its production which may affect future dividends. The Company monitors and, when appropriate, uses derivative financial instruments to manage its exposure to currency exchange rate risks. The increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates may impact future dividends and the future value of the Company's reserves as determined by independent evaluators.

Increase in Operating Costs or Decline in Production Level

An increase in operating costs or a decline in Vermilion’s production level could have an adverse effect on Vermilion’s cash flow and, therefore, could reduce dividends to Shareholders and affect the market price of the common shares. The level of production may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond Vermilion's control. A significant decline in production could result in materially lower revenues and cash flow and, therefore, could reduce dividends to Shareholders and affect the market price of the common shares.

Acquisition Assumptions

When making acquisitions, Vermilion estimates future performance of the assets to be acquired that may prove to be inaccurate.

Acquired assets are subject to inherent risks associated with predicting the future performance of those assets. Vermilion makes certain estimates and assumptions respecting the economic potential of the assets it acquires which may not be realized over time. As such, assets acquired may not possess the value Vermilion attributed to them, which could adversely impact cash flow.

Failure to Realize Anticipated Benefits of Prior Acquisitions

Vermilion may, from time to time, complete one or more acquisitions for various strategic reasons including to strengthen its position in the oil and natural gas industry and to create the opportunity to realize certain benefits, including, among other things, potential cost savings. In order to achieve the benefits of any future acquisitions, Vermilion will be dependent upon its ability to successfully consolidate functions and integrate operations, procedures and personnel in a timely and efficient manner and to realize the anticipated growth opportunities and synergies from combining the acquired assets and operations with those of the Company. The integration of acquired assets and operations requires the dedication of management effort, time and resources, which may divert management's focus and resources from other strategic opportunities and from operational matters during the process. The integration process may result in the disruption of ongoing business and customer relationships that may adversely affect Vermilion's ability to achieve the anticipated benefits of such prior acquisitions.

Additional Financing

Vermilion’s credit facility and any replacement credit facility may not provide sufficient liquidity. The amounts available under Vermilion's credit facility may not be sufficient for future operations, or Vermilion may not be able to obtain additional financing on attractive economic terms, if at all. Any failure to obtain financing may have a material adverse effect on Vermilion's business, and dividends to Shareholders may be reduced, suspended or eliminated.

To the extent that external sources of capital, including the issuance of additional common shares, become limited or unavailable, Vermilion's ability to make the necessary capital investments to maintain or expand its crude oil and natural gas reserves will be impaired. To the extent the Company is required to use cash flow to finance capital expenditures or property acquisitions, the level of cash available that may be declared payable as dividends will be reduced.

Potential Conflicts of Interest

Circumstances may arise where members of the board of directors or officers of Vermilion are directors or officers of companies which are in competition to the interests of Vermilion. No assurances can be given that opportunities identified by such persons will be provided to Vermilion.

Hedging Arrangements

From time to time, Vermilion may enter into agreements to receive fixed prices on the Company’s oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that Vermilion engages in price risk management activities to protect the Company from commodity price declines, the Company may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, Vermilion’s hedging arrangements may expose the Company to the risk of financial loss in certain circumstances, including instances in which: production falls short of the hedged volumes; there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangements; the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time Vermilion may enter into arrangements to fix the exchange rate of Canadian to U.S. dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the U.S. dollar. However, if the Company does so and the Canadian dollar declines in value compared to the U.S. dollar, Vermilion will not benefit from the fluctuating exchange rate below the level of the derivative instrument used to manage the risk.

To the extent that risk management activities and hedging strategies are employed to address commodity prices, exchange rates, interest rates or other risks, risks associated with such activities and strategies, including counterparty risk, settlement risk, basis risk, liquidity risk and market risk, could impact or negate such activities and strategies, which would have a negative impact on Vermilion’s results of operations, financial position, cash flows and prospects.

Accounting Adjustments

The presentation of financial information in accordance with IFRS requires that management apply certain accounting policies and make certain estimates and assumptions which affect reported amounts in Vermilion’s consolidated financial statements. The accounting policies may result in non-cash charges to net income and write-downs of net assets in the consolidated financial statements. Such non-cash charges and write-downs may be viewed unfavourably by the market and may result in an inability to borrow funds and/or may result in a decline in the common share price.

Lower crude oil and gas prices increase the risk of write-downs of Vermilion’s oil and gas property investments. Under IFRS, assets are aggregated into groups known as CGUs for impairment testing. CGUs are reviewed for indicators that the carrying value of the CGU may exceed its recoverable amount. If an indication of impairment exists, the CGU’s recoverable amount is then estimated. A CGU’s recoverable amount is defined as the higher of the fair value less costs to sell and its value in use. If the carrying amount exceeds its recoverable amount an impairment loss is recorded to net earnings in the period to reduce the carrying value of the CGU to its recoverable amount. While these impairment losses would not affect cash flow, the charge to net earnings could be viewed unfavourably in the market.

Ineffective Internal Controls

Effective internal controls are necessary for us to provide reliable financial reports and to help prevent fraud. Although we have undertaken and will undertake a number of procedures in order to help ensure the reliability of our financial reports, including those that may be imposed on us under Canadian Securities Laws and applicable U.S. federal and state securities laws, we cannot be certain that such measures will ensure that we will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm our results of operations or cause us to fail to meet our reporting obligations. Additionally, implementing and monitoring effective internal controls can be costly. If we or our independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in our consolidated financial statements.

Market Accessibility

A decline in Vermilion's ability to market crude oil and natural gas production could have a material adverse effect on its production levels or on the price that Vermilion receives for production which, in turn, could reduce dividends to its Shareholders and the trading price of the common shares.

Vermilion's business depends in part upon the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities. Canadian federal and provincial, as well as United States federal and state, regulation of crude oil and natural gas production, processing and transportation, tax and energy policies, general economic conditions, and changes in supply and demand could adversely affect Vermilion's ability to produce and market crude oil and natural gas. If market factors change and inhibit the marketing of Vermilion production, overall production or realized prices may decline, which could reduce dividends to Shareholders.

Cost of New Technology

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil and natural gas companies may have greater financial, technical and personnel resources that provide them with technological advantages and may in the future allow them to implement new technologies before us. There can be no assurance that we will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by us or implemented in the future may become obsolete. In such case, our business, financial condition and results of operations could be materially adversely affected. Our inability to utilize the most advanced commercially available technology could adversely affect our business, financial condition and results of operations.

Cyber Security

Vermilion manages cyber security risk by ensuring appropriate technologies, processes and practices are effectively designed and implemented to help prevent, detect and respond to threats as they emerge and evolve. The primary risks to Vermilion include, loss of data, destruction or corruption of data, compromising of confidential customer or employee information, leaked information, disruption of business, theft or extortion of funds, regulatory infractions, loss of competitive advantage and reputational damage. Vermilion relies upon a complete suite of advanced controls as protection from such attacks including, but not limited to the following:

a) Enterprise class firewall infrastructure, secure network architecture and anti-malware defense systems to protect against network intrusion, malware infection and data loss.
b) Regularly conducted comprehensive third party reviews and vulnerability assessments to ensure that information technology systems are up-to-date and properly configured, to reduce security risks arising from outdated or misconfigured systems and software.
c) Disaster recovery planning, ongoing monitoring of network traffic patterns to identify potential malicious activities or attacks.

Incident response processes are in place to isolate and control potential attacks. Data backup and recovery processes are in place to minimize risk of data loss and resulting disruption of business. Through ongoing vigilance and regular employee awareness, Vermilion has not experienced a cyber security event of a material nature. As it is difficult to quantify the significance of such events, cyber attacks such as, security breaches of company, customer, employee, and vendor information, as well as hardware or software corruption, failure or error, telecommunications system failure, service provider error, intentional or unintentional personnel actions, malicious software, attempts to gain unauthorized access to data and other electronic security breaches that could lead to disruptions in systems, unauthorized release of confidential or otherwise protected information and the corruption of data, may in certain circumstances be material and could have an adverse effect on Vermilion's business, financial condition and results of operations. As result of the unpredictability of the timing, nature and scope of disruptions from such attacks, Vermilion could potentially be subject to production downtimes, operational delays, the compromising of confidential or otherwise protected information, destruction or corruption of data, security breaches, other manipulation or improper use of its systems and networks or financial losses, any of which could have a material adverse effect on Vermilion's competitive position, financial condition or results of operations.

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR at www.sedar.com under Vermilion's SEDAR profile. Additional information related to the remuneration and indebtedness of the directors and officers of the Company, and the principal holders of common shares and Rights to purchase common shares and securities authorized for issuance under the Company's equity compensation plans, where applicable, are contained in the information circular of the Company in respect of its most recent annual meeting of Shareholders involving the election of directors. Additional financial information is provided in the Company's audited financial statements and management's discussion and analysis for the year ended December 31, 2017.

APPENDIX A
CONTINGENT RESOURCES

Summary information regarding contingent resources and net present value of future net revenues from contingent resources are set forth below and are derived, in each case, from the GLJ Resources Assessment. The GLJ Resources Assessment was prepared in accordance with COGEH and NI 51-101 by GLJ, an independent qualified reserve evaluator. All contingent resources evaluated in the GLJ Resources Assessment were deemed economic at the effective date of December 31, 2017. Contingent resources are in addition to reserves estimated in the GLJ Report.

A range of contingent resources estimates (low, best and high) were prepared by GLJ. See notes 6 to 8 of the tables below for a description of low estimate, best estimate and high estimate.

The GLJ Resources Assessment estimated gross risked contingent resources with a project maturity subclass of "Development Pending" of 107.3 million boe (low estimate) to 253.6 million boe (high estimate), with a best estimate of 176.7 million boe. Contingent resources are in addition to reserves estimated in the GLJ Report.

The GLJ Resources Assessment estimated gross risked contingent resources with a project maturity subclass of "Development Unclarified" of 7.7 million boe (low estimate) to 46.1 million boe (high estimate), with a best estimate of 32.8 million boe.

An estimate of risked net present value of future net revenue of contingent resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the company proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is uncertainty that the risked net present value of future net revenue will be realized.

Summary of Risked Oil and Gas Contingent Resources as at December 31, 2017 (1) (2) - Forecast Prices and Costs (3) (4)

Resources	Light Crude Oil & Medium Crude Oil		Conventional Natural Gas		Coal Bed Methane		Natural Gas Liquids		BOE			Unrisked BOE	
Project Maturity Sub-Class	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)	Chance of Dev. % (9)	Gross (Mboe)	Net (Mboe)
Contingent (1C) - Low Estimate													
Development Pending (10)													
Australia	—	—	—	—	—	—	—	—	—	—	—	—	—
Canada	11,918	10,818	217,576	200,317	2,081	1,977	17,879	15,803	66,407	60,337	82%	80,740	73,403
France	13,677	12,798	940	940	—	—	—	—	13,834	12,955	87%	15,923	14,908
Germany	—	—	19,342	16,795	—	—	—	—	3,224	2,799	77%	4,187	3,635
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	61	61	4,647	4,647	—	—	1	1	837	837	81%	1,038	1,038
USA	17,651	14,699	17,643	14,693	—	—	2,416	2,104	23,008	19,252	90%	25,567	21,391
Total	43,307	38,376	260,148	237,392	2,081	1,977	20,296	17,908	107,310	96,180	84%	127,453	114,375
Contingent (2C) - Best Estimate													
Development Pending (10)													
Australia (11)	2,440	2,440	—	—	—	—	—	—	2,440	2,440	80%	3,050	3,050
Canada (12)	19,312	17,209	352,291	322,162	2,520	2,394	27,354	23,739	105,801	95,041	81%	131,380	118,063
France (13)	27,054	25,229	1,245	1,245	—	—	—	—	27,262	25,437	85%	32,027	29,891
Germany (14)	—	—	33,721	29,267	—	—	—	—	5,620	4,878	77%	7,299	6,335
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands (15)	121	121	13,995	13,995	—	—	8	8	2,462	2,462	78%	3,170	3,169
USA (16)	25,289	21,060	25,924	21,589	—	—	3,554	2,960	33,164	27,618	90%	36,849	30,687
Total	74,216	66,059	427,176	388,258	2,520	2,394	30,916	26,707	176,749	157,876	83%	213,775	191,195
Contingent (3C) - High Estimate													
Development Pending (10)													
Australia	3,280	3,280							3,280	3,280	80%	4,100	4,100
Canada	24,079	21,133	488,328	443,399	2,943	2,796	37,617	31,953	143,575	127,452	80%	179,355	159,116
France	43,275	40,278	1,618	1,618	—	—	—	—	43,545	40,548	84%	51,613	48,043
Germany	—	—	62,480	54,212	—	—	—	—	10,413	9,035	77%	13,523	11,734
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	242	242	27,237	27,237	—	—	16	16	4,798	4,798	79%	6,100	6,097
USA	36,411	30,320	38,218	31,826	—	—	5,240	4,363	48,021	39,987	90%	53,356	44,430
Total	107,287	95,253	617,881	558,292	2,943	2,796	42,873	36,332	253,632	225,100	82%	308,047	273,520

Resources	Light Crude Oil & Medium Crude Oil		Conventional Natural Gas		Coal Bed Methane		Natural Gas Liquids		BOE			Unrisked BOE	
Project													
Maturity	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Chance of Dev.	Gross	Net
Sub-Class	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)	% [9]	(Mboe)	(Mboe)
Contingent (1C) - Low Estimate													
Development Unclarified [17]													
Australia	—	—	—	—	—	—	—	—	—	—	—	—	—
Canada	—	—	30,844	27,821	—	—	531	439	5,672	5,076	60%	9,463	8,474
France	1,302	1,235	—	—	—	—	—	—	1,302	1,235	41%	3,212	3,049
Germany	—	—	—	—	—	—	—	—	—	—	—	—	—
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	—	—	3,120	3,120	—	—	—	—	520	520	70%	743	743
USA	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	1,302	1,235	33,964	30,941	—	—	531	439	7,494	6,831	56%	13,418	12,266
Contingent (2C) - Best Estimate													
Development Unclarified [17]													
Australia	—	—	—	—	—	—	—	—	—	—	—	—	—
Canada [18]	—	—	60,273	53,873	60,886	57,652	6,641	5,995	26,834	24,583	46%	58,404	53,558
France [19]	2,539	2,410	—	—	—	—	—	—	2,539	2,410	45%	5,690	5,404
Germany	—	—	1,496	1,190	—	—	—	—	249	198	35%	711	566
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands [20]	—	—	18,678	18,104	—	—	32	16	3,145	3,033	51%	6,134	5,912
USA	—	—	—	—	—	—	—	—	—	—	—		—
Total	2,539	2,410	80,447	73,167	60,886	57,652	6,673	6,011	32,767	30,224	46%	70,939	65,440
Contingent (3C) - High Estimate													
Development Unclarified [17]													
Australia	—	—	—	—	—	—	—	—	—	—	—	—	—
Canada	—	—	78,561	69,281	77,410	72,283	10,104	8,744	36,099	32,338	46%	78,918	70,761
France	3,825	3,632	—	—	—	—	—	—	3,825	3,632	46%	8,250	7,828
Germany	—	—	2,327	1,850	—	—	—	—	388	308	35%	1,109	880
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	—	—	34,682	33,807	—	—	48	24	5,828	5,659	54%	10,743	10,441
USA	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	3,825	3,632	115,570	104,938	77,410	72,283	10,152	8,768	46,140	41,937	47%	99,020	89,910

Summary of Risked Net Present Value of Future Net Revenues as at December 31, 2017 - Forecast Prices and Costs [3]

Resources Project Maturity Sub-Class (M$)	**Before Income Taxes, Discounted at [5]**					**After Income Taxes, Discounted at [5]**				
	0%	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**
Contingent (1C) - Low Estimate [6]										
Development Pending [10]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada	1,324,088	692,454	384,479	223,327	133,827	968,246	491,682	261,417	143,098	78,999
France	646,356	356,990	207,518	125,059	77,334	475,460	249,755	136,639	76,160	42,380
Germany	25,368	15,606	8,171	2,911	(697)	15,012	7,957	2,377	(1,574)	(4,234)
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	30,463	22,364	16,718	12,743	9,886	18,249	13,309	9,784	7,297	5,522
USA	705,352	353,098	190,899	109,417	65,316	553,775	277,974	149,964	85,463	50,507
Total	2,731,627	1,440,512	807,785	473,457	285,666	2,030,742	1,040,677	560,181	310,444	173,174
Contingent (2C) - Best Estimate [7]										
Development Pending [10]										
Australia [11]	81,610	50,240	31,044	19,219	11,873	17,295	7,186	1,687	(1,167)	(2,534)
Canada [12]	2,286,705	1,179,969	662,147	394,654	245,475	1,674,927	844,557	458,109	261,348	153,799
France [13]	1,414,420	759,973	439,654	268,026	170,036	1,048,109	540,491	298,625	172,711	103,017
Germany [14]	116,948	83,758	60,390	44,003	32,395	80,292	56,601	39,643	27,741	19,370
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands [15]	81,618	57,215	41,025	29,997	22,252	43,748	28,728	18,805	12,189	7,679
USA [16]	1,275,912	623,677	342,983	205,348	130,725	1,004,012	492,135	270,653	161,886	102,881
Total	5,257,213	2,754,832	1,577,243	961,247	612,756	3,868,383	1,969,698	1,087,522	634,708	384,212
Contingent (3C) - High Estimate [8]										
Development Pending [10]										
Australia	162,700	104,204	67,988	45,184	30,555	54,329	31,507	18,140	10,277	5,629
Canada	3,312,383	1,649,632	923,352	557,850	354,901	2,402,861	1,167,883	630,702	364,282	219,347
France	2,463,627	1,310,231	760,541	468,396	301,212	1,827,017	934,100	520,513	306,268	186,763
Germany	302,880	217,383	159,970	120,614	92,931	212,387	151,748	110,557	82,278	62,446
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	205,065	142,394	103,727	78,262	60,611	110,555	74,368	52,017	37,485	27,588
USA	2,174,766	1,004,149	546,550	330,707	215,009	1,713,929	792,856	431,644	261,128	169,703
Total	8,621,421	4,427,993	2,562,128	1,601,013	1,055,219	6,321,078	3,152,462	1,763,573	1,061,718	671,476
Contingent (1C) - Low Estimate [6]										
Development Unclarified [17]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada	53,655	21,601	9,005	3,855	1,673	41,934	16,497	6,597	2,643	1,029
France	97,733	53,885	31,470	19,270	12,266	73,554	40,473	23,562	14,377	9,118
Germany	—	—	—	—	—	—	—	—	—	—
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	13,366	8,426	5,351	3,406	2,156	6,990	3,867	1,988	855	175
USA	—	—	—	—	—	—	—	—	—	—
Total	164,754	83,912	45,826	26,531	16,095	122,478	60,837	32,147	17,875	10,322
Contingent (2C) - Best Estimate [7]										
Development Unclarified [17]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada [18]	371,151	160,012	67,074	23,472	2,109	267,364	108,714	38,845	6,527	(8,792)
France [19]	180,756	91,957	50,625	29,643	18,218	134,726	67,893	36,941	21,367	12,973
Germany	472	736	724	616	487	(353)	41	132	107	45
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands [20]	101,333	60,727	37,612	23,937	15,510	58,291	33,549	19,395	11,127	6,149
USA	—	—	—	—	—	—	—	—	—	—
Total	653,712	313,432	156,035	77,668	36,324	460,028	210,197	95,313	39,128	10,375
Contingent (3C) - High Estimate [8]										
Development Unclarified [17]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada	685,972	314,515	159,130	85,452	47,007	547,002	261,869	138,799	78,569	46,086
France	292,883	138,555	73,474	42,171	25,626	217,128	101,766	53,321	30,222	18,141
Germany	4,579	4,019	3,344	2,727	2,210	2,638	2,450	2,054	1,651	1,300
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	244,742	135,716	82,312	53,187	35,980	141,378	76,237	44,453	27,335	17,400
USA	—	—	—	—	—	—	—	—	—	—
Total	1,228,176	592,805	318,260	183,537	110,823	908,146	442,322	238,627	137,777	82,927

Notes:

(1) Contingent resources are defined in the COGEH as 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. There is no certainty that it will be commercially viable to produce any portion of the contingent resources or that Vermilion will produce any portion of the volumes currently classified as contingent resources. The estimates of contingent resources involve implied assessment, based on certain estimates and assumptions, that the resources described exists in the quantities predicted or estimated, as at a given date, and that the resources can be profitably produced in the future. The risked net present value of the future net revenue from the contingent resources does not represent the fair market value of the contingent resources. Actual contingent resources (and any volumes that may be reclassified as reserves) and future production therefrom may be greater than or less than the estimates provided herein.

(2) GLJ prepared the estimates of contingent resources shown for each property using deterministic principles and methods. Probabilistic aggregation of the low and high property estimates shown in the table might produce different total volumes than the arithmetic sums shown in the table.

(3) The forecast price and cost assumptions utilized in the year-end 2017 reserves report were also utilized by GLJ in preparing the GLJ Resource Assessment. See "Forecast Prices Used in Estimates" in this AIF.

(4) "Gross" contingent resources are Vermilion's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of Vermilion. "Net" contingent resources are Vermilion's working interest (operating or non-operating) share after deduction of royalty obligations, plus Vermilion's royalty interests in contingent resources.

(5) The risked net present value of future net revenue attributable to the contingent resources does not represent the fair market value of the contingent resources. Estimated abandonment and reclamation costs have been included in the evaluation.

(6) This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

(7) This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

(8) This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

(9) The Chance of Development (CoDev) is the estimated probability that, once discovered, a known accumulation will be commercially developed. Five factors have been considered in determining the CoDev as follows:

- CoDev = Ps (Economic Factor) × Ps (Technology Factor) × Ps (Development Plan Factor) ×Ps (Development Timeframe Factor) × Ps (Other Contingency Factor) wherein
- Ps is the probability of success
- Economic Factor – For reserves to be assessed, a project must be economic. With respect to contingent resources, this factor captures uncertainty in the assessment of economic status principally due to uncertainty in cost estimates and marketing options. Economic viability uncertainty due to technology is more aptly captured with the Technology Factor. The Economic Factor will be 1 for reserves and will often be 1 for development pending projects and for projects with a development study or pre-development study with a robust rate of return. A robust rate of return means that the project retains economic status with variation in costs and/or marketing plans over the expected range of outcomes for these variables.
- Technology Factor - For reserves to be assessed, a project must utilize established technology. With respect to contingent resources, this factor captures the uncertainty in the viability of the proposed technology for the subject reservoir, namely, the uncertainty associated with technology under development. By definition, technology under development is a recovery process or process improvement that has been determined to be technically viable via field test and is being field tested further to determine its economic viability in the subject reservoir. The Technology Factor will be 1 for reserves and for established technology. For technology under development, this factor will consider different risks associated with technologies being developed at the scale of the well versus the scale of a project and technologies which are being modified or extended for the subject reservoir versus new emerging technologies which have not previously been applied in any commercial application. The risk assessment will also consider the quality and sufficiency of the test data available, the ability to reliably scale such data and the ability to extrapolate results in time.
- Development Plan Factor – For reserves to be assessed, a project must have a detailed development plan. With respect to contingent resources, this factor captures the uncertainty in the project evaluation scenario. The Development Plan Factor will be 1 for reserves and high, approaching 1, for development pending projects. This factor will consider development plan detail variations including the degree of delineation, reservoir specific development and operating strategy detail (technology decision, well layouts (spacing and pad locations), completion strategy, start-up strategy, water source and disposal, other infrastructure, facility design, marketing plans) and the quality of the cost estimates as provided by the developer.
- Development Timeframe Factor – In the case of major projects, for reserves to be assessed, first major capital spending must be initiated within 5 years of the effective date. The Development Timeframe Factor will be 1 for reserves and will often be 1 for development pending projects provided the project is planned on-stream based on the same criteria used in the assessment of reserves. With respect to contingent resources, the factor will approach 1 for projects planned on-stream with a timeframe slightly longer than the limiting reserves criteria.
- Other Contingency Factor – For reserves to be assessed, all contingencies must be eliminated. With respect to contingent resources, this factor captures major contingencies, usually beyond the control of the operator, other than those captured by economic status, technology status, project evaluation scenario status and the development timeframe. The Other Contingency Factor will be 1 for reserves and for development pending projects and less than 1 for on hold. Provided all contingencies have been identified and their resolution is reasonably certain, this factor would also be 1 for development unclarified projects.
- These factors may be inter-related (dependent) and care has been taken to ensure that risks are appropriately accounted.

(10) Project maturity subclass development pending is defined as contingent resources where resolution of the final conditions for development is being actively pursued (high chance of development).

(11) Risked development pending best estimate contingent resources for Australia have been estimated based on the continued drilling in our active core asset (see "Description of Properties" section of this AIF) using established recovery technologies. The risked estimated cost to bring these contingent resources on commercial production is $143 MM and the expected timeline is between 6 and 8 years. The specific contingencies for these resources are corporate commitment and development timing.

(12) Risked development pending best estimate contingent resources for Canada have been estimated based on the continued drilling in our active core assets (see "Description of Properties" section of this AIF) using established recovery technologies. The risked estimated cost to bring these contingent resources on commercial production is $1,066 MM and the expected timeline is between 3 and 12 years. The specific contingencies for these resources are corporate commitment and development timing.

(13) Risked development pending best estimate contingent resources for France have been estimated based on the continued drilling in our active core assets (see "Description of Properties" section of this AIF) using established recovery technologies. The risked estimated cost to bring these contingent resources on commercial production is $571 MM and the expected timeline is between 3 and 12 years. The specific contingencies for these resources are corporate commitment and development timing.

(14) Risked development pending best estimate contingent resources for Germany have been estimated based on the continued drilling in our active core assets (see "Description of Properties" section of this AIF) using established recovery technologies. The risked estimated cost to bring these contingent resources on commercial production is $75 MM and the expected timeline is between 2 and 4 years. The specific contingencies for these resources are corporate commitment and development timing.

(15) Risked development pending best estimate contingent resources for Netherlands have been estimated based on the continued drilling in our active core assets (see "Description of Properties" section of this AIF) using established recovery technologies. The risked estimated cost to bring these contingent resources on commercial production is $45 MM and the expected timeline is between 2 and 4 years. The specific contingencies for these resources are corporate commitment and development timing.

(16) Risked development pending best estimate contingent resources for USA have been estimated based on the continued drilling in our active core asset (see "Description of Properties" section of this AIF) using established recovery technologies. The risked estimated cost to bring these contingent resources on commercial production is $380 MM and the expected timeline is between 1 and 11 years. The specific contingencies for these resources are corporate commitment and development timing.

(17) Project maturity subclass development unclarified is defined as contingent resources when the evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties.

(18) In Canada, GLJ has estimated an aggregate of risked unclarified best estimate contingent resources of 26.8 mmboe for the projects outlined below. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of $323 MM with an expected timeline of 3 to 12 years.

Edson Duvernay	Based on contingencies related to corporate commitment and development timing, economic risks associated with lower liquid yields, and capital and operating cost uncertainty, GLJ has estimated risked unclarified best estimate contingent resources at 15.5 mmboe and the risked estimated cost to bring these resources on commercial production is $242.8 MM. The expected timeline is 3 to 7 years.
Ferrier Notikewin	Based on contingencies related to corporate commitment and development timing that is greater than 10 years, GLJ has estimated risked unclarified best estimate contingent resources at 4.7 mmboe and the risked estimated cost to bring these resources on commercial production is $31 MM. The expected timeline is 11 to 15 years.
Ferrier Falher	Based on contingencies related to corporate commitment and development timing that is greater than 10 years, GLJ has estimated risked unclarified best estimate contingent resources at 3.2 mmboe and the risked estimated cost to bring these resources on commercial production is $23 MM. The expected timeline is 11 to 15 years.
West Pembina Glauconite	Based on contingencies related to corporate commitment and development timing as well as economic risk related to capital and operating cost uncertainty due to limited horizontal development in proximity to interest lands, GLJ has estimated risked unclarified best estimate contingent resources at 3.3 mmboe and the risked estimated cost to bring these resources on commercial production is $26 MM. The expected timeline is 4 to 6 years.

(19) In France, GLJ has estimated an aggregate of risked unclarified best estimate contingent resources of 2.5 mmboe for the projects outlined below. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of $37 MM with an expected timeline of 7 to 8 years.

Charmottes	Based on contingencies related to corporate commitment and development timing, along with the project still being in the pre-development study/sourcing stage related to waterflood development, GLJ has estimated risked unclarified best estimate contingent resources at 1.3 mmboe and the risked estimated cost to bring these resources on commercial production is $29 MM. The expected timeline is 7 to 9 years.
Chaunoy	Based on contingencies related to corporate commitment and development timing, along with a CO2 pilot project still being in the conceptual study stage, GLJ has estimated risked unclarified best estimate contingent resources at 1.2 mmboe and the risked estimated cost to bring these resources on commercial production is $8 MM. The expected timeline is 8 to 10 years.

(20) In the Netherlands, GLJ has estimated an aggregate of risked unclarified best estimate contingent resources of 3.1 mmboe for the projects outlined below. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of $51 MM with an expected timeline of 8 to 10 years.

Netherlands East	Based on contingencies related to corporate commitment and development timing along with proof-of-concept utilizing directional drilling and unknown deliverability from Zechstein carbonates, GLJ has estimated risked unclarified best estimate contingent resources at 1.5 mmboe and the risked estimated cost to bring these resources on commercial production is $25 MM. The expected timeline is 3 to 7 years.
Netherlands West	Based on contingencies related to corporate commitment and development timing along with further study required regarding the deliverability of the Bunter sands, GLJ has estimated risked unclarified best estimate contingent resources at 1.6 mmboe and the risked estimated cost to bring these resources on commercial production is $26 MM. The expected timeline is 3 to 5 years.

PROSPECTIVE RESOURCES

Summary information regarding prospective resources and net present value of future net revenues from prospective resources are set forth below and are derived, in each case, from the GLJ Resources Assessment. The GLJ Resources Assessment was prepared in accordance with COGEH and NI 51-101 by GLJ, an independent qualified reserve evaluator. All prospective resources evaluated in the GLJ Resources Assessment were deemed economic at the effective date of December 31, 2017. Prospective resources are in addition to reserves estimated in the GLJ Report.

A range of prospective resources estimates (low, best and high) were prepared by GLJ. See notes 6 to 8 of the tables below for a description of low estimate, best estimate and high estimate.

The GLJ Resources Assessment estimated gross risked prospective resources of 51.5 million boe (low estimate) to 260.4 million boe (high estimate), with a best estimate of 153.4 million boe.

An estimate of risked net present value of future net revenue of prospective resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the company proceeding with the required investment. It includes prospective resources that are considered too uncertain with respect to the chance of development and chance of discovery to be classified as reserves. There is uncertainty that the risked net present value of future net revenue will be realized.

Summary of Risked Oil and Gas Prospective Resources as at December 31, 2017 (1) (2) - Forecast Prices and Costs (3) (4)

Resources	Light Crude Oil & Medium Crude Oil		Conventional Natural Gas		Coal Bed Methane		Natural Gas Liquids		BOE			Unrisked BOE	
Project													
Maturity	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Chance of Commerciality	Gross	Net
Sub-Class	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)	% (9)	(Mboe)	(Mboe)
Prospective - Low Estimate													
Prospect (10)													
Australia	—	—	—	—	—	—	—	—	—	—	—	—	—
Canada	185	168	66,480	61,570	—	—	4,522	3,982	15,787	14,412	34%	46,435	42,388
France	5,528	4,977	—	—	—	—	—	—	5,528	4,977	21%	25,904	23,366
Germany	—	—	136,066	116,769	—	—	—	—	22,678	19,462	29%	78,200	67,110
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	—	—	44,603	41,372	—	—	50	46	7,484	6,941	10%	73,823	68,723
USA	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	5,713	5,145	247,149	219,711	—	—	4,572	4,028	51,477	45,792	23%	224,362	201,587
Prospective - Best Estimate													
Prospect (10)													
Australia (11)	579	579	—	—	—	—	—	—	579	579	48%	1,206	1,206
Canada (12)	2,090	1,871	162,093	147,542	112,623	106,205	24,876	22,098	72,752	66,260	23%	309,610	281,957
France (13)	16,335	14,636	—	—	—	—	—	—	16,335	14,636	21%	76,358	68,393
Germany (14)	—	—	292,725	251,987	—	—	—	—	48,788	41,998	29%	168,235	144,821
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands (15)	—	—	89,366	82,029	—	—	96	89	14,990	13,761	10%	147,256	134,912
USA	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	19,004	17,086	544,184	481,558	112,623	106,205	24,972	22,187	153,444	137,234	22%	702,665	631,289
Prospective - High Estimate													
Prospect (10)													
Australia	1,462	1,462	—	—	—	—	—	—	1,462	1,462	48%	3,046	3,046
Canada	2,684	2,383	231,682	209,203	147,282	136,241	38,134	32,553	103,979	92,510	24%	436,843	388,697
France	35,640	32,301	—	—	—	—	—	—	35,640	32,301	23%	156,320	141,671
Germany	—	—	554,429	479,424	—	—	—	—	92,405	79,904	29%	318,638	275,531
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	—	—	160,271	148,815	—	—	171	159	26,883	24,962	11%	252,881	235,491
USA	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	39,786	36,146	946,382	837,442	147,282	136,241	38,305	32,712	260,369	231,139	22%	1,167,728	1,044,436

Summary of Risked Net Present Value of Future Net Revenues as at December 31, 2017 - Forecast Prices and Costs [3]

Resources Project Maturity Sub-Class (M$)	Before Income Taxes, Discounted at [5] 0%	5%	10%	15%	20%	After Income Taxes, Discounted at [5] 0%	5%	10%	15%	20%
Prospective (Pr1) -Low Estimate [6]										
Prospect [10]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada	207,770	95,938	44,659	19,798	7,252	169,908	75,170	32,207	11,777	1,780
France	238,004	131,320	76,140	46,216	29,224	187,762	102,964	59,117	35,418	22,032
Germany	368,323	169,166	74,634	29,008	6,565	252,131	112,397	44,221	11,701	(3,782)
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	274,447	125,347	68,782	42,725	28,862	145,575	61,601	29,728	15,701	8,716
USA	—	—	—	—	—	—	—	—	—	—
Total	1,088,544	521,771	264,215	137,747	71,903	755,376	352,132	165,273	74,597	28,746
Prospective (Pr2) -Best Estimate [7]										
Prospect [10]										
Australia [11]	41,338	23,669	14,015	8,555	5,365	16,344	8,905	4,999	2,884	1,705
Canada [12]	1,491,712	623,324	281,364	133,988	65,665	1,065,129	430,068	182,436	78,310	31,913
France [13]	722,008	401,287	237,931	149,181	98,046	533,938	289,739	167,209	101,849	64,935
Germany [14]	1,259,830	556,044	260,954	126,408	60,705	883,031	385,237	174,225	78,544	32,534
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands [15]	664,124	319,700	187,996	124,429	88,794	358,130	165,622	92,188	57,620	38,865
USA	—	—	—	—	—	—	—	—	—	—
Total	4,179,012	1,924,024	982,260	542,561	318,575	2,856,572	1,279,571	621,057	319,207	169,952
Prospective (Pr3) -High Estimate [8]										
Prospect [10]										
Australia	136,670	74,308	43,028	26,126	16,460	57,049	30,416	17,274	10,298	6,378
Canada	2,681,315	1,109,012	521,064	267,963	146,940	1,909,850	772,257	349,756	171,101	87,888
France	1,937,405	1,011,329	573,475	347,956	223,097	1,458,826	749,093	417,797	249,512	157,614
Germany	2,751,890	1,219,651	585,356	295,653	153,056	1,969,884	858,139	400,902	194,089	93,693
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	1,355,100	675,317	411,776	281,254	206,125	738,129	360,566	214,793	143,533	103,140
USA	—	—	—	—	—	—	—	—	—	—
Total	8,862,380	4,089,617	2,134,699	1,218,952	745,678	6,133,738	2,770,471	1,400,522	768,533	448,713

Notes:

(1) Prospective resources are defined in the COGEH as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from unknown accumulations by application of future development projects. Prospective resources have both an associated chance of discovery (CoDis) and a chance of development (CoDev). There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources or that Vermilion will produce any portion of the volumes currently classified as prospective resources. The estimates of prospective resources involve implied assessment, based on certain estimates and assumptions, that the resources described exists in the quantities predicted or estimated, as at a given date, and that the resources can be profitably produced in the future. The risked net present value of the future net revenue from the prospective resources does not represent the fair market value of the prospective resources. Actual prospective resources (and any volumes that may be reclassified as reserves) and future production therefrom may be greater than or less than the estimates provided herein.

(2) GLJ prepared the estimates of prospective resources shown for each property using deterministic principles and methods. Probabilistic aggregation of the low and high property estimates shown in the table might produce different total volumes than the arithmetic sums shown in the table.

(3) The forecast price and cost assumptions utilized in the year-end 2017 reserves report were also utilized by GLJ in preparing the GLJ Resource Assessment. See "GLJ December 31, 2017 Forecast Prices" in this AIF.

(4) "Gross" prospective resources are Vermilion's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of Vermilion. "Net" prospective resources are Vermilion's working interest (operating or non-operating) share after deduction of royalty obligations, plus Vermilion's royalty interests in prospective resources.

(5) The risked net present value of future net revenue attributable to the prospective resources does not represent the fair market value of the prospective resources. Estimated abandonment and reclamation costs have been included in the evaluation.

(6) This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

(7) This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

(8) This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

(9) The chance of commerciality is defined as the product of the CoDis and the CoDev. CoDis is defined in COGEH as the estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum. CoDev is defined as the estimated probability that, once discovered, a known accumulation will be commercially developed.

CoDev is the estimated probability that, once discovered, a known accumulation will be commercially developed. Five factors have been considered in determining the CoDev as follows:

- Ps is the probability of success
- Economic Factor – For reserves to be assessed, a project must be economic. With respect to prospective resources, this factor captures uncertainty in the assessment of economic status principally due to uncertainty in cost estimates and marketing options. Economic viability uncertainty due to technology is more aptly captured with the Technology Factor. The Economic Factor will be 1 for reserves and will often be 1 for development pending and for projects with a development study or pre-development study with a robust rate of return. A robust rate of return means that the project retains economic status with variation in costs and/or marketing plans over the expected range of outcomes for these variables.
- Technology Factor - For reserves to be assessed, a project must utilize established technology. With respect to prospective resources, this factor captures the uncertainty in the viability of the proposed technology for the subject reservoir, namely, the uncertainty associated with technology under development. By definition, technology under development is a recovery process or process improvement that has been determined to be technically viable via field test and is being field tested further to determine its economic viability in the subject reservoir. The Technology Factor will be 1 for reserves and for established technology. For technology under development, this factor will consider different risks associated with technologies being developed at the scale of the well versus the scale of a project and technologies which are being modified or extended for the subject reservoir versus new emerging technologies which have not previously been applied in any commercial application. The risk assessment will also consider the quality and sufficiency of the test data available, the ability to reliably scale such data and the ability to extrapolate results in time.
- Development Plan Factor – For reserves to be assessed, a project must have a detailed development plan. With respect to prospective resources, this factor captures the uncertainty in the project evaluation scenario. The Development Plan Factor will be 1 for reserves and high, approaching 1, for development pending projects. This factor will consider development plan detail variations including the degree of delineation, reservoir specific development and operating strategy detail (technology decision, well layouts (spacing and pad locations), completion strategy, start-up strategy, water source and disposal, other infrastructure, facility design, marketing plans etc.) and the quality of the cost estimates as provided by the developer.
- Development Timeframe Factor – In the case of major projects, for reserves to be assessed, first major capital spending must be initiated within 5 years of the effective date. The Development Timeframe Factor will be 1 for reserves and will often be 1 for development pending provided the project is planned on-stream based on the same criteria used in the assessment of reserves. With respect to prospective resources, the factor will approach 1 for projects planned on-stream with a timeframe slightly longer than the limiting reserves criteria.
- Other Contingency Factor – For reserves to be assessed, all contingencies must be eliminated. With respect to prospective resources, this factor captures major contingencies, usually beyond the control of the operator, other than those captured by economic status, technology status, project evaluation scenario status and the development timeframe. The Other Contingency Factor will be 1 for reserves and for development pending and less than 1 for on hold. Provided all contingencies have been identified and their resolution is reasonably certain, this factor would also be 1 for development unclarified.
- These factors may be inter-related (dependent) and care has been taken to ensure that risks are appropriately accounted.

CoDis is defined in COGEH as the estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum. Five factors have been considered in determining the CoDis as follows:

- CoDis = Ps (Source) × Ps (Timing and Migration) × Ps (Trap) ×Ps (Seal) × Ps (Reservoir) wherein
- Ps is the probability of success
- Source – For a significant accumulation of potentially recoverable petroleum, a viable source rock capable of generating hydrocarbons must exist. The probability of a source rock investigates stratigraphic presence and location, volumetric adequacy and organic richness of the proposed source rock. In proven hydrocarbon systems, this factor will be a 1. This factor becomes critical when looking at frontier basins.
- Timing and Migration - For a significant accumulation of potentially recoverable petroleum, the source rock must reach thermal maturity to generate the hydrocarbons and have a conduit with which to fill the closures that existed at the time of migration. The probability of timing and migration investigates the movement of hydrocarbons from the source rock to the trap. This factor evaluates the pathways and/or carrier beds, including fault systems, which can transport buoyant hydrocarbons from the source kitchen to the prospect area at a time that the trap existed. This factor is often 1 in producing trends, but there is a possibility of migration shadows where the conduits do not fill a viable trap, which would decrease this factor.
- Trap - For a significant accumulation of potentially recoverable petroleum, a reservoir must be present in a structural or stratigraphic closure. The trap factor looks at the definition of the geometry of the accumulation, which is determined using seismic, gravity and/or magnetic techniques and surrounding well logs to determine the probability of a significant accumulation. The risking of this includes examining data quality (e.g. 2D vs 3D seismic coverage) and potential depth conversion possibilities which give confidence in the mapped trap. Stratigraphic trap definition is used for volumetric calculations, but it is given a 1 for this chance factor as the stratigraphic risk will be captured in seal.
- Seal - For a significant accumulation of potentially recoverable petroleum, a reservoir must be sealed both on the top and laterally by a lithology that contains the hydrocarbon accumulation within the reservoir. It is also necessary that these accumulated hydrocarbons have been preserved from flushing or leakage. Factors that affect top, seat and lateral seals are fluid viscosity, bed thickness, natural continuity of sealing facies, differential permeability, fault history and reservoir pressures needed to maintain a hydrocarbon column. The probability that the accumulation is not able to be contained by the surrounding rocks is captured in this chance factor.
- Reservoir - For a significant accumulation of potentially recoverable petroleum, a reservoir rock must be present and have sufficient porosity and permeability and be of a sufficient thickness to produce quantities of mobile hydrocarbon. Under this approach, encountering wet, commercial quality and quantity sandstones would not be a failure in the reservoir category, but rather in one of the other factors. It is the reservoir along with the trap which determine the volumetrics of the accumulation.
- Serial multiplication of these five decimal fractions representing the five geologic chance factors can be done as they are considered independent of each other.

(10) GLJ has sub-classified the best estimate prospective resources by maturity status, consistent with the requirements of the COGE Handbook. These prospective resources have been sub-classified as "Prospect" which the COGE Handbook defines as a potential accumulation within a play that is sufficiently well defined to present a viable drilling target.

(11) Prospective resources for Australia have been estimated based on development timing and reservoir risk, GLJ has estimated the CoDev at 80% and the CoDis at 60%. The corresponding chance of commerciality is 48%. Risked best estimate prospective resources have been estimated at .06 mmboe. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is $17 MM. The expected development timeline is 8 years.

(12) Prospective resources for Canada have been estimated based on the individual prospects outlined below. GLJ has estimated the aggregate CoDev at 27% and the aggregate CoDis at 88%. The corresponding chance of commerciality is 23%. Risked best estimate prospective resources have been estimated at an aggregate of 72.8 mmboe. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of $1061 MM. The expected development timeline is 2 to 20 years.

Edson Duvernay	Based on reservoir risk, development timing and economic risk related to capital and operating cost uncertainty, GLJ has estimated the CoDev at 19% and the CoDis at 90%. The corresponding chance of commerciality is 17%. Risked best estimate prospective resources have been estimated at 33.6 mmboe and the risked estimated cost to bring these resources on commercial production is $638 MM with an expected timeline of 7 to 14 years.
Wilrich Prospect:	Based on reservoir risk, development timing and limited Wilrich development on the land base, GLJ has estimated the CoDev at 35% and the CoDis at 85%. The corresponding chance of commerciality is 30%. Risked best estimate prospective resources have been estimated at 22.2 mmboe and the risked estimated cost to bring these resources on commercial production is $218 MM with an expected timeline of 2 to 9 years.
West Pembina Glauconite Prospect:	Based on chance of discovery risk due to uncertainty regarding threshold for reservoir quality to support commercial development of resources with horizontal drilling, along with economic risk related to capital and operating cost uncertainty due to limited horizontal development in proximity to interest lands and chance of development risk related to corporate commitment and development timing. GLJ has estimated the CoDev at 34% and the CoDis at 90%. The corresponding chance of commerciality is 31%. Risked best estimate prospective resources have been estimated at 6.2 mmboe and the risked estimated cost to bring these resources on commercial production is $53 MM with an expected timeline of 6 to 12 years.
Drayton Valley Notikewin Prospect:	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 70% and the CoDis at 85%. The corresponding chance of commerciality is 60%. Risked best estimate prospective resources have been estimated at 4.6 mmboe and the risked estimated cost to bring these resources on commercial production is $66 MM. The expected development timeline is 9 to 11 years.
Saskatchewan Prospects	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 90% and the CoDis at 80%. The corresponding chance of commerciality is 72%. Risked best estimate prospective resources have been estimated at 3.3 mmboe and the risked estimated cost to bring these resources on commercial production is $60 MM with an expected timeline of 7 to 11 years
Ferrier Falher Prospect	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 60% and the CoDis at 90%. The corresponding chance of commerciality is 54%. Risked best estimate prospective resources have been estimated at 2.7 mmboe and the risked estimated cost to bring these resources on commercial production is $23 MM with an expected timeline of 15 to 20 years.
Utikuma Gilwood Prospect	Based on reservoir risk, development timing and limited Gilwood development in the area, GLJ has estimated the CoDev at 60% and the CoDis at 50%. The corresponding chance of commerciality is 30%. Risked best estimate prospective resources have been estimated at 0.2 mmboe and the risked estimated cost to bring these resources on commercial production is $3 MM with an expected timeline of 3 to 9 years.

(13) Prospective resources for France have been estimated based on the individual prospects outlined below. GLJ has estimated the aggregate CoDev at 74% and the aggregate CoDis at 28%. The corresponding chance of commerciality is 21%. Risked best estimate prospective resources have been estimated at an aggregate of 16.3. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of $380 MM. The expected development timeline is 1 to 13 years.

Seebach Prospect	Based on risks associated with seal, trap, reservoir and charge along with development timing, GLJ has estimated the CoDev at 75% and the CoDis at 18%. The corresponding chance of commerciality is 14%. Risked best estimate prospective resources have been estimated at 7.8 mmboe and the risked estimated cost to bring these resources on commercial production is $40 MM with an expected timeline of 5 to 7 years.
Rachee Prospect	Based on risk of closure and data quality along with development timing, GLJ has estimated the CoDev at 80% and the CoDis at 80%. The corresponding chance of commerciality is 64%. Risked best estimate prospective resources have been estimated at 3.4 mmboe and the risked estimated cost to bring these resources on commercial production is $233 MM with an expected timeline of 9 to 13 years.
Malnoue Prospect	Based on reservoir, structure and trap risk along with development timing, GLJ has estimated the CoDev at 70% and the CoDis at 38%. The corresponding chance of commerciality is 27%. Risked best estimate prospective resources have been estimated at 1.4 mmboe and the risked estimated cost to bring these resources on commercial production is $35 MM with an expected timeline of 8 to 12 years.
West Lavergne Prospect	Based on structure risk and development timing GLJ has estimated the CoDev at 80% and the CoDis at 70%. The corresponding chance of commerciality is 56%. Risked best estimate prospective resources have been estimated at 1.2 mmboe and the risked estimated cost to bring these resources on commercial production is $7 MM with an expected timeline of 4 years.
Champotran Prospect	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 80% and the CoDis at 67%. The corresponding chance of commerciality is 54%. Risked best estimate prospective resources have been estimated at 0.9 mmboe and the risked estimated cost to bring these resources on commercial production is $21 MM with an expected timeline of 1 to 11 years.
Vulaines Prospect	Based on reservoir and structure risk along with development timing, GLJ has estimated the CoDev at 80% and the CoDis at 40%. The corresponding chance of commerciality is 32%. Risked best estimate prospective resources have been estimated at 0.6 mmboe and the risked estimated cost to bring these resources on commercial production is $14 MM with an expected timeline of 7 to 9 years.
Charmottes Prospect	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 60% and the CoDis at 50%. The corresponding chance of commerciality is 30%. Risked best estimate prospective resources have been estimated at 0.5 mmboe and the risked estimated cost to bring these resources on commercial production is $19 MM with an expected timeline of 10 to 12 years.
Bernet Prospect	Based on risks associated with reservoir, seal and trap along with economic factors, and development timing, GLJ has estimated the CoDev at 50% and the CoDis at 65%. The corresponding chance of commerciality is 33%. Risked best estimate prospective resources have been estimated at 0.3 mmboe and the risked estimated cost to bring these resources on commercial production is $7 MM with an expected timeline of 4 to 5 years.
Vert Le Grand Prospect	Based on reservoir and structure risk along with development timing, GLJ has estimated the CoDev at 70% and the CoDis at 28%. The corresponding chance of commerciality is 20%. Risked best estimate prospective resources have been estimated at 0.2 mmboe and the risked estimated cost to bring these resources on commercial production is $4 MM with an expected timeline of 4 to 5 years.

Les Genets Prospect	Based on reservoir, seal and closure risk, along with economic factors and development timing, GLJ has estimated the CoDev at 60% and the CoDis at 16%. The corresponding chance of commerciality is 10%. Risked best estimate prospective resources have been estimated at 0.1 mmboe and the risked estimated cost to bring these resources on commercial production is $1 MM with an expected timeline of 8 years.
North Acacias Prospect	Based on reservoir, seal and trap risk, along with economic factors and development timing, GLJ has estimated the CoDev at 70% and the CoDis at 39%. The corresponding chance of commerciality is 27%. Risked best estimate prospective resources have been estimated at 0.07 mmboe and the risked estimated cost to bring these resources on commercial production is $1 MM with an expected timeline of 4 to 5 years.

(14) Prospective resources for Germany have been estimated based on the individual prospects outlined below. GLJ has estimated the aggregate CoDev at 70% and the aggregate CoDis at 42%. The corresponding chance of commerciality is 29%. Risked best estimate prospective resources have been estimated at an aggregate of 48.8 mmboe. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of 313.4 MM. The expected development timeline is 1 to 13 years.

Wisselshorst A Prospect	Based on seal and trap risk along with development timing , GLJ has estimated the CoDev at 90%, and the CoDisc at 58%. The corresponding chance of commerciality is 52%. Risked Best Estimate Prospective resources have been estimated at 13.5 mmboe and the risked estimated cost to bring these resources on commercial production is $85.5MM with an expected timeline of 2 to 9 years.
Ihlow Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 71%, and the CoDisc at 51%. The corresponding chance of commerciality is 36%. Risked Best Estimate Prospective resources have been estimated at 6.6 mmboe and the risked estimated cost to bring these resources on commercial production is $46.6MM with an expected timeline of 5 to 7 years.
Wisselshorst B Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 90%, and the CoDisc at 50%. The corresponding chance of commerciality is 45%. Risked Best Estimate Prospective resources have been estimated at 5.5 mmboe and the risked estimated cost to bring these resources on commercial production is $42.7MM with an expected timeline of 5 to 12 years.
Weissenmoor South	Based on reservoir and trap risk along with development timing, GLJ has estimated the CoDev at 90%, and the CoDisc at 36%. The corresponding chance of commerciality is 32%. Risked Best Estimate Prospective resources have been estimated at 4.2 mmboe and the risked estimated cost to bring these resources on commercial production is $15.9MM with an expected timeline of 3 to 8 years.
Simonswolde South Prospect	Based on reservoir, seal and trap risk along with development timing , GLJ has estimated the CoDev at 71%, and the CoDisc at 48%. The corresponding chance of commerciality is 34%. Risked Best Estimate Prospective resources have been estimated at 4.1 mmboe and the risked estimated cost to bring these resources on commercial production is $16MM with an expected timeline of 8 to 9 years.
Fallingbostel	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 90%, and the CoDisc at 29%. The corresponding chance of commerciality is 26%. Risked Best Estimate Prospective resources have been estimated at 3.4 mmboe and the risked estimated cost to bring these resources on commercial production is $29.5MM with an expected timeline of 3 to 9 years.
Hellwege	Based on reservoir and trap risk along with development timing, GLJ has estimated the CoDev at 90%, and the CoDisc at 40%. The corresponding chance of commerciality is 36%. Risked Best Estimate Prospective resources have been estimated at 2.9 mmboe and the risked estimated cost to bring these resources on commercial production is $16.1MM with an expected timeline of 3 to 8 years.
Jeddeloh Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 38%, and the CoDisc at 32%. The corresponding chance of commerciality is 12%. Risked Best Estimate Prospective resources have been estimated at 2.9 mmboe and the risked estimated cost to bring these resources on commercial production is $23.1MM with an expected timeline of 3 to 12 years.
Ohlendorf Prospect	Based on source and trap risk along with development timing, GLJ has estimated the CoDev at 58%, and the CoDisc at 30%. The corresponding chance of commerciality is 17%. Risked Best Estimate Prospective resources have been estimated at 2.4 mmboe and the risked estimated cost to bring these resources on commercial production is $11.1MM with an expected timeline of 9 to 13 years.
Uphuser Meer Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 47%, and the CoDisc at 51%. The corresponding chance of commerciality is 24%. Risked Best Estimate Prospective resources have been estimated at 1.7 mmboe and the risked estimated cost to bring these resources on commercial production is $8.3MM with an expected timeline of 6 to 7 years.
Simonswolde North Prospect	Based on reservoir, seal and trap risk along with development timing , GLJ has estimated the CoDev at 62%, and the CoDisc at 45%. The corresponding chance of commerciality is 28%. Risked Best Estimate Prospective resources have been estimated at 1.4 mmboe and the risked estimated cost to bring these resources on commercial production is $6.1MM with an expected timeline of 6 to 7 years.
Burgmoor Z5 Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 63%, and the CoDisc at 52%. The corresponding chance of commerciality is 33%. Risked Best Estimate Prospective resources have been estimated at 0.7mmboe and the risked estimated cost to bring these resources on commercial production is $1.1MM with an expected timeline of 1 year.
Widdernhausen East Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 32%, and the CoDisc at 44%. The corresponding chance of commerciality is 14%. Risked Best Estimate Prospective resources have been estimated at 0.4 mmboe and the risked estimated cost to bring these resources on commercial production is $2.7MM with an expected timeline of 7 to 12 years.
Wellie Prospect	Based on reservoir, seal and source risk along with development timing, GLJ has estimated the CoDev at 32%, and the CoDisc at 20%. The corresponding chance of commerciality is 6%. Risked Best Estimate Prospective resources have been estimated at 0.3 mmboe and the risked estimated cost to bring these resources on commercial production is $3.3MM with an expected timeline of 10 years.
Otterstedt Prospect	Based on reservoir, seal and trap risk along with development timing , GLJ has estimated the CoDev at 46%, and the CoDisc at 34%. The corresponding chance of commerciality is 16%. Risked Best Estimate Prospective resources have been estimated at 0.3 mmboe and the risked estimated cost to bring these resources on commercial production is $3.5MM with an expected timeline of 8 to 13 years.

Ostervesede Prospect	Based on reservoir and seal risk along with development timing, GLJ has estimated the CoDev at 23%, and the CoDisc at 25%. The corresponding chance of commerciality is 6%. Risked Best Estimate Prospective resources have been estimated at 0.1 mmboe and the risked estimated cost to bring these resources on commercial production is $0.7MM with an expected timeline of 7 to 10 years.

(15) Prospective resources for Netherlands have been estimated based on the factors outlined below. GLJ has estimated the aggregate CoDev at 28% and the aggregate CoDis at 39%. The corresponding chance of commerciality is 11%. Risked best estimate prospective resources have been estimated at an aggregate of 15.0 mmboe. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of 127 MM with an expected timeline of 2 to 15 years.

Prospective resources for Netherlands East have been estimated based on the individual areas outlined below. GLJ has estimated the aggregate CoDev at 25% and the aggregate CoDis at 41%. The corresponding chance of commerciality is 10%. Risked best estimate prospective resources have been estimated at an aggregate of 12.1 mmboe and the risked estimated cost to bring these resources on commercial production is an aggregate of 83 MM with an expected timeline of 2 to 15 years.

- Chance of discovery provided for 109 prospective reservoir targets across 91 prospective locations. Risk primarily associated with presence of reservoir and seal as region proven to have adequate source, migration and timing to charge target reservoirs.
- Chance of development risked to account for company commitment and development timing, anticipated timing for permitting in respective licenses and distance to export (i.e. pipeline/facility requirements to transport gas to sales point). Chance of development is also a function of prospect size.
- 65 prospects summed probabilistically across 13 development groups to appropriately allocate required infrastructure capital across multiple prospective targets within reasonable proximity. As probabilistic summation of the groups resulted in strong economic indicators, no further minimum economic field size calculations were applied as they were considered to have nominal impact.

Prospective resources for Netherlands West have been estimated based on the factors outlined below. GLJ has estimated the aggregate CoDev at 41% and the aggregate CoDis at 28%. The corresponding chance of commerciality is 12%. Risked best estimate prospective resources have been estimated at an aggregate of 2.9 mmboe and the risked estimated cost to bring these resources on commercial production is an aggregate of$ 43 MM with an expected timeline of 2 to 12 years.

- Chance of discovery provided for 25 prospective reservoir targets across 21 prospective locations. Risk primarily associated with presence of reservoir and seal as region proven to have adequate source, migration and timing to charge target reservoirs.
- Chance of development risked to account for company commitment and development timing, anticipated timing for permitting in respective licenses and distance to export (i.e. pipeline/facility requirements to transport gas to sales point). Chance of development is also a function of prospect size.
- 17 prospects summed probabilistically across 5 development groups to appropriately allocate required infrastructure capital across multiple prospective targets within reasonable proximity. As probabilistic summation of the groups resulted in strong economic indicators no further minimum economic field size calculations were applied as they were considered to have nominal impact.

APPENDIX B

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

To the Board of Directors of Vermilion Energy Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, 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.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. 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.

5. The following table shows the net present value of 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 for the year ended December 2017, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Effective 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	December 31, 2017	Australia	—	313,137	—	313,137
GLJ Petroleum Consultants	December 31, 2017	Canada	—	1,465,934	—	1,465,934
GLJ Petroleum Consultants	December 31, 2017	France	—	1,563,813	—	1,563,813
GLJ Petroleum Consultants	December 31, 2017	Germany	—	393,903	—	393,903
GLJ Petroleum Consultants	December 31, 2017	Ireland	—	529,112	—	529,112
GLJ Petroleum Consultants	December 31, 2017	Netherlands	—	283,120	—	283,120
GLJ Petroleum Consultants	December 31, 2017	USA	—	192,106	—	192,106
Total			—	4,741,125	—	4,741,125

6. In our opinion, the reserves data 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.

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

8. 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 reports referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 1, 2018

"Jodi L. Anhorn"

Jodi L. Anhorn, M.Sc., P.Eng.

Executive Vice President & COO

GLJ PETROLEUM CONSULTANTS

APPENDIX B - PART 2

REPORT ON CONTINGENT RESOURCES DATA AND PROSPECTIVE RESOURCES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR (FORM 51-101F2)

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

1. We have evaluated the Company's contingent resources data and prospective resources data as at December 31, 2017. The contingent resources data and prospective resources data are risked estimates of volume of contingent resources and prospective resources and related risked net present value of future net revenue as at December 31, 2017, estimated using forecast prices and costs.

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

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

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

5. The following tables set forth the risked volume and risked net present value of future net revenue of contingent resources and prospective resources (before deduction of income taxes) attributed to contingent resources and prospective resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Company's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data and prospective resources data that we have evaluated and reported on to the Company's board of directors:

Contingent Resources

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Resources Other than Reserves (Country or Foreign Geographic Area)	Risked Volume (Mboe)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - M$) Audited	Evaluated	Total
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	Australia	2,440	—	31,044	31,044
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	Canada	105,801	—	662,147	662,147
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	France	27,262	—	439,654	439,654
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	Germany	5,620	—	60,390	60,390
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	Ireland	—	—	—	—
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	Netherlands	2,462	—	41,025	41,025
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	USA	33,164	—	342,983	342,983
Total				**176,749**	**—**	**1,577,243**	**1,577,243**

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	(Country or Foreign Geographic Area)	Risked Volume (Mboe)
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	Australia	—
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	Canada	26,834
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	France	2,539
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	Germany	249
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	Ireland	—
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	Netherlands	3,145
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	USA	—
Total				**32,767**

Prospective Resources

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	(Country or Foreign Geographic Area)	Risked Volume (Mboe)
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2017	Australia	579
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2017	Canada	72,752
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2017	France	16,335
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2017	Germany	48,788
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2017	Ireland	—
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2017	Netherlands	14,990
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2017	USA	—
Total				**153,444**

6. In our opinion, the contingent resources data and prospective resources 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 contingent resources data and prospective resources that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

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

EXECUTED as to our reports referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 1, 2018

"Jodi L. Anhorn"

Jodi L. Anhorn, M.Sc., P.Eng.

Executive Vice President & COO

GLJ PETROLEUM CONSULTANTS

APPENDIX C

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION (FORM 51-101F3)

Terms to which a meaning is ascribed in National Instrument 51-101 have the same meaning herein.

Management of Vermilion Energy Inc. (the "Company") are responsible for the preparation and disclosure, or arranging for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, and includes contingent resources data and prospective resources data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated the Company's reserves data, contingent resources data and prospective resources data. The report of the independent qualified reserves evaluators is presented in Schedule A to the Annual Information Form of the Company for the year ended December 31, 2017.

The Independent 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, contingent resources data and prospective resources data with Management and the independent qualified reserves evaluators.

The Independent Reserves Committee of the Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with Management. The Board of Directors has, on the recommendation of the Audit and Independent Reserves Committees, approved:

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

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

(c) the content and filing of this report.

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

"Anthony Marino"
Anthony Marino, President & Chief Executive Officer

"Curtis Hicks"
Curtis W. Hicks, Executive Vice President and Chief Financial Officer

"Lorenzo Donadeo"
Lorenzo Donadeo, Director and Chairman of the Board

"William Roby"
William Roby, Director

February 28, 2018

APPENDIX D

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 with respect to the Company's accounting and financing reporting processes and the audit of the Company's financial statements, including oversight of:

A. the integrity of the Company's financial statements;

B. the Company's compliance with legal and regulatory requirements;

C. the independent auditors' qualifications and independence;

D. the financial information that will be provided to the Shareholders and others;

E. the Company's systems of disclosure controls and internal controls regarding finance, accounting, legal compliance and ethics, which management and the Board have established;

F. the performance of the Company's audit processes; and

G. such other matters required by applicable laws and rules of any stock exchange on which the Company's shares are listed for trading.

While the Committee has the responsibilities and powers set forth in its terms of reference, it is not the duty of the Committee to prepare financial statements, plan or conduct audits or to determine that the Company's financial statements and disclosures are complete and accurate and are in accordance with International Financial Reporting Standards and applicable rules and regulations. Primary responsibility for the financial reporting, information systems, risk management, and disclosure controls and internal controls of the Company is vested in management.

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] under the requirements or guidelines for audit committee service under applicable securities laws and rules of any stock exchange on which the Company's shares are listed for trading.

B. All Committee members shall be "financially literate,"[2] and at least one member shall have "accounting or related financial expertise" as such terms are interpreted by the Board in its business judgment in light of, and in accordance with, the requirements or guidelines for audit committee service under applicable securities laws and rules of any stock exchange on which the Company's shares are listed for trading. 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. No Committee member shall serve on the audit committees of more than two other public issuers without prior determination by the Board that such simultaneous service would not impair the ability of such member to serve effectively on the Committee.

D. The Committee shall operate in a manner that is consistent with the Committee Guidelines outlined in Tab 8 of the Board Manual.

E. The Company'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 Committee, and to be heard at those meetings on matters relating to the auditor's duties.

F. The Committee may request any officer or employee of the Company, or the Company's legal counsel, or any external or internal auditors to attend a meeting of the Committee to provide such pertinent information as the Committee requests or to meet with any members of, or consultants to the Committee. The Committee has the authority to communicate directly with the internal and 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.

G. The Committee shall have the authority to select, retain, terminate and approve the fees and other retention terms of special independent legal counsel and other consultants or advisers to advise the Committee, as it deems necessary or appropriate, at the Company's expense.

1 Committee members must be "independent", as defined in Sections 1.4 and 1.5 of National Instrument 52-110 and ''independent'' under the requirements of Rule 10A-3 of the Securities Exchange Act of 1934, as amended, and Section 303A.06 of the NYSE Listed Company Manual.

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.

APPENDIX D
TERMS OF REFERENCE FOR THE AUDIT COMMITTEE (CONTINUED)

H. The Company shall provide for appropriate funding, as determined by the Committee, for payment of (i) compensation to the independent auditors engaged for the purpose of preparing or issuing an audit report or performing other audit review or attest services for the Company, (ii) compensation to any advisers employed by the Committee and (iii) ordinary administrative expenses of the Committee that are necessary or appropriate for carrying out its duties.

I. The Committee shall meet at least four times each year.

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 the responsibility to:

i) review and recommend approval of the Company's annual financial statements, MD&A and earnings press release and report to the Board of Directors before the statements are approved by the Board of Directors;
ii) review and recommend approval for release the Company's quarterly financial statements, MD&A and press releases, as well as financial information and earnings guidance provided to analysts and rating agencies;
iii) satisfy itself that adequate procedures are in place for the review of the public disclosure of financial information extracted or derived from the Company'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 where appropriate, discuss:

v) the appropriateness of critical accounting policies and financial reporting practices used by the Company;
vi) major issues regarding accounting principles and financial statement presentations, including any significant proposed changes in financial reporting and accounting principles, policies and practices to be adopted by the Company and major issues as to the adequacy of the Company's internal controls and any special audit steps adopted in light of material control deficiencies;
vii) analyses prepared by management or the external auditor setting forth significant financial reporting issues and judgments made in connection with the preparation of the financial statements, including analyses of the effects of alternative International Financial Reporting Standards ("IFRS") methods on the financial statements of the Company and any other opinions sought by management from an independent or other audit firm or advisor with respect to the accounting treatment of a particular item;
viii) any management letter or schedule of unadjusted differences provided by the external auditor and the Company's response to that letter and other material written communication between the external auditor and management;
ix) any problems, difficulties or differences encountered in the course of the audit work including any disagreements with management or restrictions on the scope of the external auditor's activities or on access to requested information and management's response thereto;
x) any new or pending developments in accounting and reporting standards that may affect the Company;
xi) the effect of regulatory and accounting initiatives, as well as any off-balance sheet structures on the financial statements of the Company and other financial disclosures;
xii) any reserves, accruals, provisions or estimates that may have a significant effect upon the financial statements of the Company;
xiii) the use of special purpose entities and the business purpose and economic effect of off balance sheet transactions, arrangements, obligations, guarantees and other relationships of Company and their impact on the reported financial results of the Company;
xiv) the use of any "pro forma" or "adjusted" information not in accordance with generally accepted accounting principles;
xv) any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Company, and the manner in which these matters may be, or have been, disclosed in the financial statements; and
xvi) accounting, tax and financial aspects of the operations of the Company as the Committee considers appropriate.

APPENDIX D
TERMS OF REFERENCE FOR THE AUDIT COMMITTEE (CONTINUED)

B. Risk Management, Internal Control and Information Systems

The Committee will review and discuss with management, 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 the responsibility to:

i) review the Company's risk management controls and policies with specific responsibility for Credit & Counterparty, Market & Financial, Political and Strategic & Repatriation risks;
ii) obtain reasonable assurance that the information systems are reliable and the systems of internal controls are properly designed and effectively implemented through separate and periodic 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, the appointment of the external auditor;
ii) review and approve the annual external audit plan, including but not limited to the following:
   a) engagement letter between the external auditor and financial management of the Company;
   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) compensation and fees to be paid by the Company to the external auditor.
iii) meet with the external auditor to discuss the Company'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 Company's system of internal controls, procedures and documentation;
   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;
   d) any other matters the external auditor brings to the Committee's attention; and
   e) evaluate and assess the qualifications and performance of the external auditors for recommendation to the Board as to the appointment or reappointment of the external auditor to be proposed for approval by the Shareholders, and 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 Company 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, including a list of all relationships between the external auditor and the Company that may reasonably be thought to bear on the independence of the external auditors with respect to the Company;
   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

APPENDIX D
TERMS OF REFERENCE FOR THE AUDIT COMMITTEE (CONTINUED)

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

vii) annually request and review a report from the external auditor regarding (a) the external auditor’s quality-control procedures, (b) any material issues raised by the most recent quality-control review, or peer review, of the external auditor, or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out by the firm, and (c) any steps taken to deal with any such issues;

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

ix) review the disclosure with respect to its pre-approval of audit and non-audit services provided by the external auditors; and

x) 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 adopted for pre-approving non-audit services by the external auditor including affirmation that they meet regulatory requirements;

iii) Assist the Governance and Human Resources Committee with preparing the Company'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 required, if the Company has relied upon any exemptions to the requirements for committees under applicable securities laws and rules of any stock exchange on which the Company’s shares are listed for trading.

E. Other

The Committee shall:

i) establish and periodically review procedures for:

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

b) the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters or other matters that could negatively affect the Company, such as violations of the Code of Business Conduct and Ethics.

ii) review and approve the Company'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 the policies and practices concerning the expenses and perquisites of the Chairman, including the use of the assets of the Company;

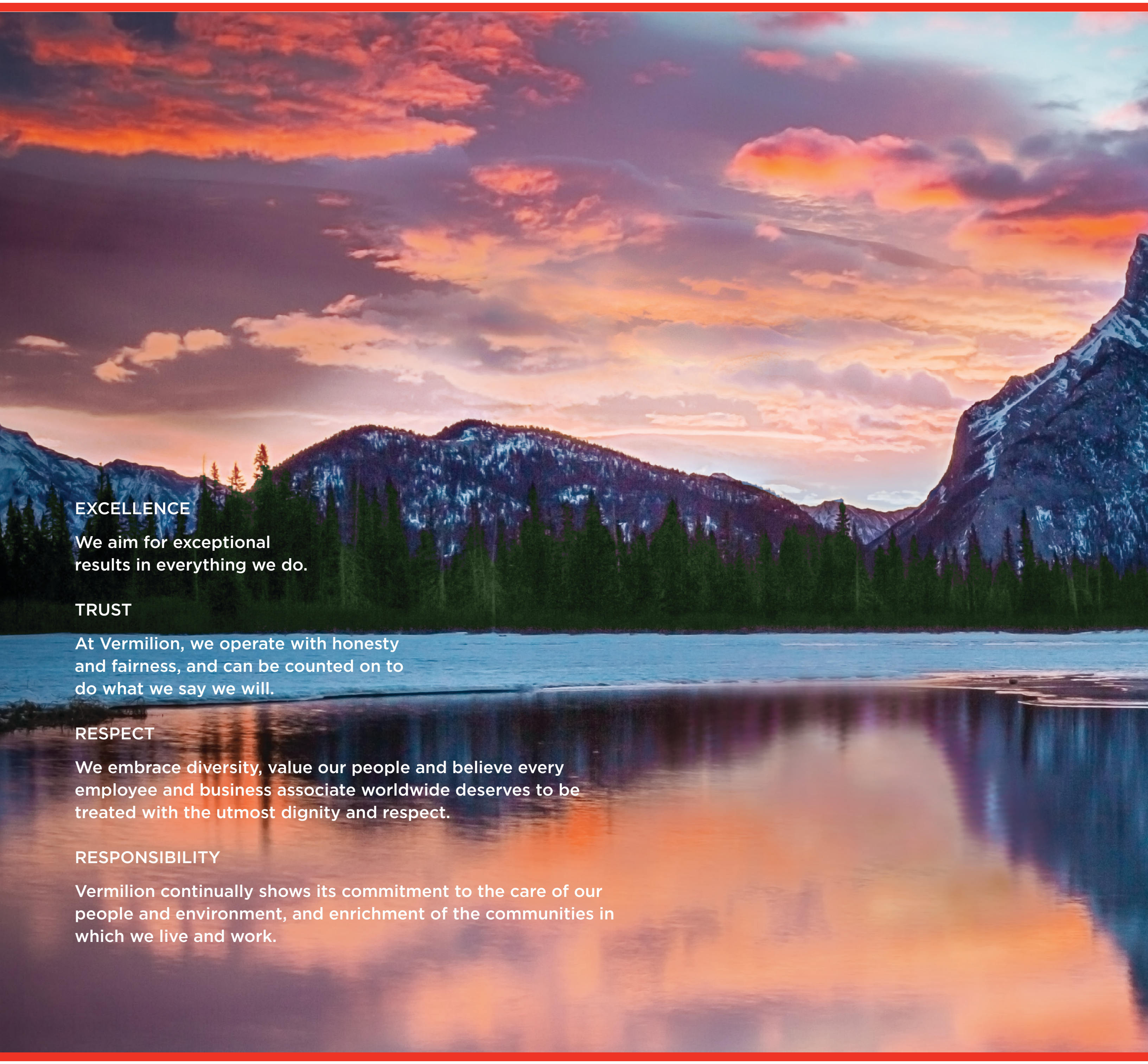
vii) review with external auditors any corporate transactions in which directors or officers of the Company have a personal interest; and

viii) review the terms of reference for the Committee at least annually and otherwise as it deems appropriate, and recommend changes to the Board as required. The Committee shall evaluate its performance with reference to the terms of reference annually.

IV. ACCOUNTABILITY

D. The Committee Chair has the responsibility to make periodic reports to the Board, as requested, on financial and other matters considered by the Committee relative to the Company.

E. 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.



EXCELLENCE

We aim for exceptional results in everything we do.

TRUST

At Vermilion, we operate with honesty and fairness, and can be counted on to do what we say we will.

RESPECT

We embrace diversity, value our people and believe every employee and business associate worldwide deserves to be treated with the utmost dignity and respect.

RESPONSIBILITY

Vermilion continually shows its commitment to the care of our people and environment, and enrichment of the communities in which we live and work.

VERMILION ENERGY

Vermilion Energy Inc.
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