UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549
Form 40-F

¨ Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934; or
þ Annual report pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended: December 31, 2019

Commission file number: No. 001-35829

Vermilion Energy Inc.

(Exact name of registrant as specified in its charter)

Alberta

(Province or other jurisdiction of incorporation or organization)

1311

(Primary standard industrial classification code number)

N/A

(I.R.S. employer identification number)

3500, 520 - 3rd Avenue S.W.

Calgary, Alberta T2P 0R3 Canada

(403) 269-4884

(Address and telephone number of registrant's principal executive office)

National Corporate Research, Ltd.

225 West 34th Street, Suite 910

New York, New York 10122 U.S.A.

(212) 947-7200

(Name, address and telephone number of agent for service in the United States)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class:	Trading Symbol:	Name of each exchange on which registered:
Common Shares	VET	New York Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act: **None**

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: **None**

For annual reports, indicate by check mark the information filed with this form:

þ **Annual Information Form** þ **Audited Annual Financial Statements**

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report: **156,289,575 shares**

Indicate by check mark whether the Registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports); and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No ¨

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit such files).

Yes þ No ¨

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act.
Emerging growth company ¨

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange Act. ¨

DOCUMENTS FILED PURSUANT TO GENERAL INSTRUCTIONS

In accordance with General Instruction B.(3) of Form 40-F, the Registrant has filed the following documents as part of this Annual Report on Form 40-F, as set forth in the Exhibit Index attached hereto:

Exhibit 99.1 - Annual Information Form for the fiscal year ended December 31, 2019
Exhibit 99.2 - Management's Discussion and Analysis for the fiscal year ended December 31, 2019; and
Exhibit 99.3 - Audited Annual Financial Statements for the fiscal year ended December 31, 2019

In accordance with General Instruction D.(9) of Form 40-F, the Registrant has filed the written consent of certain experts named in the foregoing Exhibits as Exhibit 99.5 and the written consent of its Independent Registered Public Accounting Firm as Exhibit 99.4, as set forth in the Exhibit Index attached hereto.

DISCLOSURE CONTROLS AND PROCEDURES

A. Evaluation of Disclosure Controls and Procedures

Vermilion Energy Inc. (the "Registrant") maintains disclosure controls and procedures designed to ensure that information required to be disclosed in the Registrant's filings under the Securities Exchange Act of 1934, as amended (the "Exchange Act") is recorded, processed, summarized and reported within the time period specified in the rules and forms of the Securities and Exchange Commission (the "Commission"). Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrant in the reports that it files or submits under the Exchange Act is accumulated and communicated to the issuer's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. The Registrant's Chief Executive Officer and Chief Financial Officer, after having evaluated the effectiveness of the Registrant's disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this report have concluded that, as of such date, the Registrant's disclosure controls and procedures are effective.

It should be noted that while the Registrant's Chief Executive Officer and the Chief Financial Officer believe that the Registrant's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the Registrant's disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

B. Management's Annual Report on Internal Control Over Financial Reporting

See page 3 of the 2019 Audited Consolidated Financial Statements included as Exhibit 99.3 to this report

C. Auditor Attestation

See page 5 of the 2019 Audited Consolidated Financial Statements included as Exhibit 99.3 to this report.

D. Changes in Internal Control Over Financial Reporting

There was no change in the Registrant's internal control over financial reporting that occurred during the period covered by this report that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

NOTICES REQUIRED BY RULE 104 OF REGULATION BTR

None

AUDIT COMMITTEE FINANCIAL EXPERT

The Registrant's Board of Directors has determined that it has at least one audit committee financial expert (as such term is defined in the rules and regulations of the Commission) serving on its Audit Committee. Catherine L. Williams has been determined to be such audit committee financial expert and is independent (as such term is defined by the New York Stock Exchange's corporate governance standards).

The Commission has indicated that the designation of Catherine L. Williams as an audit committee financial expert does not make her an "expert" for any purpose, impose on her any duties, obligations or liability that are greater than the duties, obligations or liability imposed on her as a member of the Audit Committee and the Board of Directors in absence of such designation, or affect the duties, obligations or liability of any other member of the Audit Committee or Board of Directors.

CODE OF ETHICS

The Registrant has adopted a written “code of ethics” (as that term is defined in Form 40-F) that applies to its directors, officers and employees, including its principal executive officer, principal financial officer, principal accounting officer or controller, and persons performing similar functions. A copy of such code of ethics is available upon request or on the Registrant’s website at www.vermilionenergy.com. In 2019, other than amendments to conform the code of ethics with the Registrant's approach to respecting human rights, there were no amendments to the code of ethics or waivers, including implicit waivers, from any provisions of the code of ethics.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

See page 58 of the Annual Information Form for the year ended December 31, 2019 included as Exhibit 99.1 to this report.

The Audit Committee pre-approves all audit related fees. The auditors present the estimate for the annual audit related services to the Audit Committee for approval prior to undertaking the annual audit of the financial statements.

All non-audit fees were pre-approved by the Audit Committee and none were approved on the basis of the de minimis exemption set forth in Rule 2-01(c)(7)(i)(C) of Regulation S-X .

OFF-BALANCE SHEET ARRANGEMENTS

The Registrant has not entered into any off balance sheet arrangements that have or are reasonably likely to have a current or future effect on its financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that are material to investors.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

Payments due by period as at December 31, 2019 (Cdn $000's)

($M)	Less than 1 year	1 - 3 years	3 - 5 years	After 5 years	Total
Long-term debt	63,948	127,896	1,577,713	399,179	2,168,736
Lease obligations	44,077	49,129	38,846	28,110	160,162
Processing and transportation agreements	30,529	47,688	12,774	3,004	93,995
Purchase obligations	27,220	9,856	557	—	37,633
Drilling and service agreements	16,071	58,398	21,207	—	95,676
Total contractual obligations and commitments	181,845	292,967	1,651,097	430,293	2,556,202

IDENTIFICATION OF THE AUDIT COMMITTEE

The Registrant's Board of Directors has a separately designated standing Audit Committee established in accordance with Section 3(a)(58)(A) of the Exchange Act which satisfies the requirements of Exchange Act Rule 10A-3. The Registrant's Audit Committee is comprised of Catherine L. Williams (Chair), Stephen P. Larke, Larry J. Macdonald, and Robert B. Michaleski, all of whom, in the opinion of the Registrant's Board of Directors are independent (as determined under Rule 10A-3 of the Exchange Act and the corporate governance standards of the NYSE) and are financially literate. Please refer to the Company's Annual Information Form attached as Exhibit 99.1 to this annual report on Form 40-F for details in connection with each of these members and their qualifications.

The members of the Audit Committee do not have fixed terms and are appointed from time to time by resolution of the directors.

The Audit Committee meets with the Registrant's Chief Executive Officer, Chief Financial Officer and the Company's independent auditors to review and inquire into matters affecting financial reporting, the system of internal accounting and financial controls, as well as audit procedures and audit plans. The Audit Committee also recommends to the Board of Directors which independent registered public auditing firm should be appointed by the Company, and reviews and recommends to the Board of Directors for approval the Registrant's audited annual financial statements and accompanying management's discussion and analysis.

The full text of the Audit Committee Terms of Reference is disclosed in the Company's Annual Information Form, attached hereto as Exhibit 99.1, and is incorporated by reference in this annual report on Form 40-F.

NYSE STATEMENT OF GOVERNANCE DIFFERENCES

As a Canadian corporation with securities listed on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE"), the Registrant is required to comply with all applicable Canadian requirements adopted by the Canadian Securities Administrators and the TSX, and applicable rules for foreign private issuers adopted by the Commission which give effect to the provisions of the Sarbanes-Oxley Act of 2002 ("Sarbanes-Oxley").

The Registrant's corporate governance practices meet or exceed all applicable Canadian and Sarbanes-Oxley requirements and also incorporate many "best practices" derived from those required to be followed by U.S. domestic companies under the NYSE listing standards. In accordance with Section 303A.11 of the NYSE Listed Company Manual, the Registrant has prepared a summary of the significant ways in which its corporate governance practices differ from those required to be followed by U.S. domestic companies under the NYSE's corporate governance standards, which is accessible on the Registrant's website at *http://www.vermilionenergy.com/about/governance.cfm*.

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

B. Consent to Service of Process

The Registrant has previously filed with the Commission a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

Any change to the name or address of the Registrant's agent for service shall be communicated promptly to the Commission by amendment to Form F-X referencing the file number of the Registrant.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

VERMILION ENERGY INC (the Registrant)

Date: March 5, 2020

By: */s/ ("Lars Glemser")*
Lars Glemser
Vice President and Chief Financial Officer

EXHIBIT INDEX

The following exhibits have been filed as part of this annual report:

Exhibits	Description
99.1	Annual Information Form for the Year Ended December 31, 2019
99.2	Management's Discussion and Analysis from the 2019 Annual Report to Shareholders
99.3	Audited Annual Financial Statements for the Year Ended December 31, 2019
99.4	Consent of Independent Registered Public Accounting Firm
99.5	Consent of Independent Petroleum Consultants
99.6	Officers' Certifications of Chief Executive Officer and Chief Financial Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities Exchange Act of 1934
99.7	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to Rule 13a-14(b) or Rule 15d-14(b) of the Securities Exchange Act of 1934 and Section 1350 of Chapter 63 of Title 18 of the United States Code
101	Interactive data files

Exhibit 99.1

2019 ANNUAL INFORMATION FORM

For the year ended December 31, 2019

Dated March 5, 2020

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Glossary

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

"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).

"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.

"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.

"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 10, 2020 and effective December 31, 2019.

"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, 2019.

"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.

"Shareholders" means holders from time to time of the Company's common shares.

"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.

"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.

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, 2019, based on forecast costs and price assumptions as evaluated in the GLJ Report.

Abbreviations

$M	thousand dollars
$MM	million dollars
°API	An indication of the specific gravity of crude oil measured on the API (American Petroleum Institute) gravity scale
AECO	the daily average benchmark price for natural gas at the AECO 'C' hub in southeast Alberta
bbl(s)	barrel(s)
bbls/d	barrels per day
boe	barrel of oil equivalent, including: crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe for six mcf of natural gas)
mbbl	thousand barrels
mboe	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmboe	million barrels of oil equivalent
mmbtu	million British Thermal Units
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NBP	the reference price paid for natural gas in the United Kingdom at the National Balancing Point Virtual Trading Point operated by National Grid
TTF	the day-ahead price for natural gas at the Title Transfer Facility Virtual Trading Point operated by Dutch TSO Gas Transport Services
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

Conversions

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; and
- the timing of regulatory proceedings and approvals;

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 Information

Oil and gas reserves and production

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 estimated 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.

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 estimated net present value of the future net revenue from the prospective resources does not 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 AIF includes references to certain financial and performance measures which do not have standardized meanings prescribed by International Financial Reporting Standards ("IFRS"). These measures include:

- Fund flows from operations: Fund flows from operations is a measure of profit or loss in accordance with IFRS 8 “Operating Segments”. Please see "Segmented information" in the "Notes to the consolidated financial statements" for a reconciliation of fund flows from operations to net earnings. 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 the Company's ability to generate income necessary to pay dividends, repay debt, fund asset retirement obligations and make capital investments.
- Netbacks: Netbacks are 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.

In addition, this AIF includes references to certain financial measures which are not specified, defined, or determined under IFRS and are therefore considered non-GAAP financial measures. These non-GAAP financial measures are unlikely to be comparable to similar financial measures presented by other issuers. These non-GAAP financial measures include:

- 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 its investment in the Company's existing asset base. Capital expenditures are also referred to as E&D capital.

Vermilion's Organizational Structure

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, 2019, Vermilion had 790 full time employees of which 241 employees were located in its Calgary head office, 144 employees in its Canadian field offices, 148 employees in France, 69 employees in the Netherlands, 32 employees in Australia, 31 employees in the United States, 35 employees in Germany, 7 employees in Hungary, 2 employees in Croatia and 81 employees in Ireland.

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.

The following is a list of the Company's material subsidiaries and where each material subsidiary was incorporated or formed. The Company holds 100% of the votes attaching to all voting securities of each material subsidiary beneficially owned directly or indirectly by Vermilion.

- Vermilion Energy Australia Pty Ltd. (Australia)
- Vermilion Energy Canada Ltd. (Alberta)
- Vermilion Energy Germany GmbH & Co. KG (Germany)
- Vermilion Energy Ireland Limited (Ireland)
- Vermilion Energy Netherlands B.V. (Netherlands)
- Vermilion Energy USA LLC (United States)
- Vermilion Exploration and Production Ireland Limited (Ireland)
- Vermilion Exploration SAS (France)
- Vermilion Hungary Southern Battonya Concession Ltd. (Hungary)
- Vermilion Moraine SAS (France)
- Vermilion Pyrénées SAS (France)
- Vermilion Resources (Alberta)
- Vermilion Zagreb Exploration d.o.o. (Croatia)

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 Germany, France and Australia. Vermilion also holds a 20% 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 "A" List 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, the Netherlands and Germany. Vermilion emphasizes strategic community investment in each of our operating areas.

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 business units and the material oil and natural gas properties, facilities and installations in which Vermilion has an interest are discussed below.

The following table summarizes production, sales, proved reserves, and proved plus probable reserves for each of Vermilion's business units as at and for the year ended December 31, 2019:

Business Unit	Production (boe/d)	Oil sales ($ millions)	NGL sales ($ millions)	Natural gas sales ($ millions)	Sales ($ millions)	Gross Proved Reserves (mboe)[1]	Gross Proved Plus Probable Reserves (mboe)[1]
Canada	59,979	699,290	33,159	95,621	828,070	191,356	300,532
France	10,467	326,578	—	121	326,699	1,731	2,703
Netherlands	8,274	2,411	—	110,446	112,857	11,105	20,980
Germany	3,468	25,783	—	31,529	57,312	40,963	59,692
Ireland	7,762	27	—	104,247	104,274	11,772	17,774
Australia	5,662	184,490	—	—	184,490	8,608	13,160
United States	4,675	63,449	6,499	5,416	75,364	30,623	59,296
Central and Eastern Europe	70	—	—	797	797	13,781	26,740
Total	100,357	1,302,028	39,658	348,177	1,689,863	309,939	500,876

(1) "Gross Reserves" are Vermilion's working interest (operating or non-operating) share before deduction of royalty obligations and without including any royalty interests of Vermilion.

Canada Business Unit

Vermilion's Canadian operations are primarily focused in the West Pembina region of West Central Alberta and in southeast Saskatchewan and Manitoba. In West Pembina, the company targets condensate-rich Mannville natural gas and Cardium light oil plays, while in southeast Saskatchewan and Manitoba the company targets light oil in the Mississippian Midale, Frobisher/Alida and Ratcliffe formations. West Pembina is the Company's main natural gas liquids ("NGL") producing area.

Vermilion holds an average 79% working interest in approximately 837,000 (665,300 net) acres of developed land, and an average 87% working interest in approximately 484,500 (423,200 net) acres of undeveloped land. Vermilion had 538 (439 net) producing natural gas wells and 4,049 (3,402 net) producing oil wells in Canada as at December 31, 2019.

Vermilion has access to ample facilities and processing capacity across the major plays in its Canadian portfolio. In Alberta, Vermilion's operations are concentrated in core geographic regions where the Company owns and operates the large majority of associated key infrastructure including pipelines, compressor stations, oil batteries and gas plants, many of which have surplus capacity for future production. Furthermore, the Company is interconnected in several locations with third party midstream infrastructure that provides significant capacity for growth. In Saskatchewan, where operations are focused on light oil, Vermilion owns and operates an extensive network of pipelines and oil batteries that also have surplus capacity for future production. This high degree of operating control and access to key infrastructure across Vermilion's Canadian properties allows the Company to drive operating efficiencies in the field while supporting future growth opportunities.

During 2019 Vermilion drilled or participated in 22 (21.5 net) wells in Alberta and 130 (110.5 net) wells in Saskatchewan. In 2020, we plan to drill or participate in 87 (76.3 net) light oil wells in Saskatchewan and 20 (19.2 net) wells in Alberta as we continue to develop our light oil projects in Saskatchewan and focus on our condensate-rich natural gas targets in the Mannville.

France Business Unit

Vermilion entered France in 1997 and completed three additional acquisitions in subsequent years. Vermilion is the largest oil producer in the country with approximately three-quarters of the domestic market share. 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. The two major fields in the Paris Basin area are Champotran and Chaunoy and the two major fields in the Aquitaine Basin are Parentis and Cazaux. Vermilion operates several oil batteries in the country and, 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 258,100 (248,900 net) acres of developed land and an average 91% working interest in 244,400 (222,100 net) acres of undeveloped land in the Aquitaine and Paris Basins. Vermilion had 340 (335 net) producing oil wells and two (2.0 net) producing gas wells in France as at December 31, 2019.

In 2019, Vermilion drilled four (4.0 net) wells in the Champotran field. In 2020, Vermilion intends to continue its ongoing program of workovers and well optimizations. By continuing to develop its inventory in France, while mitigating declines through workovers and optimizations, Vermilion seeks to maintain or moderately grow its French production over the long-term.

Netherlands Business Unit

Vermilion entered the Netherlands in 2004 and is the country's second largest onshore operator. Vermilion's natural gas production in the Netherlands is priced off of the TTF index.

Vermilion's Netherlands assets consist of 26 onshore concessions (all operated) and 17 offshore concessions (all non-operated). Production consists primarily of natural gas with a small amount of associated condensate. Vermilion's total land position in the Netherlands covers 1,927,300 (930,000 net) acres at an average 49% working interest, of which 92% is undeveloped. Vermilion had 98 (47 net) producing natural gas wells as at December 31, 2019.

Vermilion successfully drilled and completed the Weststellingwerf well (0.5 net) in 2019, representing our first drilling activity in the Netherlands since 2017. We encountered three gas bearing zones in the Vlieland, Zechstein and Rotliegend formations. 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.

Germany Business Unit

Vermilion entered Germany in 2014 through 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 base in Germany as a result of an extensive farm-in agreement the Company entered into in 2015. Vermilion's natural gas production in Germany is priced off the NCG and GPL indexes, which are both highly correlated to the TTF benchmark, and Vermilion's oil production is priced with reference to Dated Brent.

Vermilion's producing assets in Germany consist of operated and non-operated interests in seven natural gas fields and eight oil fields with extensive infrastructure in place. Vermilion had 133 (105 net) producing oil wells and 22 (8 net) producing natural gas wells as at December 31, 2019.

Vermilion's land position in northwest Germany is comprised of 88,600 (32,700 net) developed acres and 2,815,400 (1,151,200 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.

During 2019, Vermilion successfully drilled, completed and tested the Burgmoor Z5 (46% working interest) well, which we expect to be tied-in in 2021. During 2020, the Company will continue investing in various well optimization initiatives and advance permitting, studies and other activities associated with the farm-in agreement signed in mid-2015.

Ireland Business Unit

Vermilion has a 20% operated interest in the offshore Corrib natural gas field located off the northwest coast of Ireland. Vermilion initially acquired an 18.5% non-operated interest in 2009. In 2018, Vermilion entered into a strategic partnership with the Canadian Pension Plan Investment Board ("CPPIB"), as a result of which Vermilion acquired an additional 1.5% working interest and assumed operatorship of Corrib.

Corrib first began natural gas flow in late December 2015. Production volumes reached full plant capacity of approximately 350 mmcf/d (gross) at the end of 2016. Production plateaued at this level until decline started at the beginning of 2018.

In 2020, Vermilion plans to continue to focus on facility maintenance and compression optimization.

Australia Business Unit

Vermilion holds a 100% operated working interest in the Wandoo offshore oil field and related production assets, located on Western Australia's northwest shelf. Vermilion acquired its interest over two acquisitions completed in 2005 and 2007. Production is sourced from 20 producing well-bores including five dual laterals 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 208,000 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).

Vermilion drilled two (2.0 net) wells in Australia between November 2018 and January 2019 and plans to drill wells approximately every two to three years. Vermilion intends to manage its Australian production and related capital investment programs to achieve corporate targets while meeting long-term supply requirements of our customers.

United States Business Unit

Vermilion entered the United States in 2014 through the acquisition of land and producing assets in the East Finn oil field in the Powder River Basin of northeastern Wyoming and expanded its position through the 2018 acquisition of mineral land and producing assets in the Hilight oil field located approximately 40 miles northwest of the East Finn assets. The Company's assets include 160,100 (144,600 net) acres of land in the Powder River basin, of which 69% is undeveloped. Vermilion had 192 (182 net) producing oil wells in the United States as at December 31, 2019. All of our working interest ownership in Wyoming is Company operated.

During 2019, Vermilion continued work on its early stage Turner Sand development in the Powder River Basin, drilling eight (8.0 net) wells on our Hilight asset, in addition to drilling two additional wells late in 2019, both of which were completed in early 2020. In 2020, Vermilion expects to drill twelve (11.9 net) wells on its Hilight assets.

Central and Eastern Europe ("CEE") Business Unit

Vermilion established its CEE Business unit in 2014 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, Croatia and Ukraine.

Vermilion's land position in the CEE consists of 952,300 (951,900 net) acres in Hungary, 485,600 (242,800 net) acres in Slovakia and 2.2 million (2.2 million net) acres in Croatia. Currently, 99% of Vermilion's land position in the CEE is undeveloped.

During 2019, Vermilion drilled four (3.3 net) exploration wells in Hungary, the first of which was a dry hole. The remaining wells resulted in new gas discoveries and the Company brought two of the wells on production during the fourth quarter of 2019. In Croatia, Vermilion drilled its first two natural gas exploration wells (2.0 net) in the country which also resulted in new gas discoveries. During the third quarter of 2019, Vermilion was awarded two exploration licenses in Ukraine, subject to a final production sharing agreement, in a 50/50 partnership with Ukrgazvydobuvannya ("UGV"), a Ukrainian state owned gas producer. The licenses cover approximately 500,000 gross acres situated in one of Europe's most prolific natural gas regions (Dnieper-Donets Basin). In 2020, Vermilion plans to continue our exploratory drilling activity in CEE by drilling two (1.5 net) wells in Croatia, one (1.0 net) well in Hungary and three (1.5 net) wells in Slovakia.

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.

With the exception of the acquisition of Spartan Energy Corp. ("Spartan") in May 2018, none of the acquisitions described below constituted a "significant acquisition" within the meaning of applicable securities laws. A Business Acquisition Report (Form 51-102F4) relating to the acquisition of Spartan was filed on July 30, 2018. A copy of this report is available on SEDAR at www.sedar.com under Vermilion's SEDAR profile.

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 2017 reduced annual production by approximately 900 boe/d.

Vermilion maintained its monthly dividend at $0.215 per share throughout 2017. Vermilion discontinued the Premium Dividend ^{TM} Component of its dividend reinvestment plan 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.

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, the total facility amount was reduced to $1.4 billion from $2.0 billion.

In July 2017, Vermilion and Canada Pension Plan Investment Board ("CPPIB") announced a strategic partnership in the Corrib Natural Gas Project in Ireland (Corrib), whereby CPPIB will acquire Shell E&P Ireland Limited's 45% interest in Corrib. As part of the transaction, Vermilion assumed operatorship of Corrib and received an additional 1.5% working interest in Corrib. The acquisition had an effective date of January 1, 2017 and closed in late 2018.

In December 2017, Vermilion was awarded a license for the Békéssámson concession in Hungary for a 4-year term. Located adjacent to the existing South Battonya concession in southeast Hungary, the Békéssámson concession covers 330,700 net acres (100% working interest) and more than doubled the size of the Company's total land position in the country.

Vermilion continued to be recognized for its commitment to being a leader on environmental, social and governance matters in 2017. The Company received a top quartile ranking for its 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 placement on the CDP Climate "A" List as a global leader in environmental stewardship, and receipt of the French government's Circular Economy Award for Industrial and Regional Ecology for Vermilion's geothermal energy partnership in Parentis. Vermilion was also ranked 13th by Corporate Knights on the Future 40 Responsible Corporate Leaders in Canada list. This marked 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.

2018

Vermilion achieved record annual production of 87,270 boe/d representing an increase of 28% as compared to 2017. Production in Canada reached record levels as the Company completed the most significant acquisition in its history, acquiring Spartan in May 2018 for total consideration of $1.4 billion. Production also grew in the US due to an acquisition completed in August 2018 near Vermilion's existing assets in the Powder River Basin.

Vermilion increased its monthly dividend to $0.23 per share from $0.215 per share beginning with the April 2018 dividend. Upon closing the acquisition of Spartan, the 2% discount associated with our Dividend Reinvestment Plan was eliminated, beginning with the June 2018 dividend.

In February 2018, Vermilion closed an acquisition of a private southeast Saskatchewan producer. The acquisition added over 1,000 bbl/d of high netback 40° API oil and 42,600 net acres of land straddling the Saskatchewan and Manitoba border, near Vermilion's existing operations in southeast

Saskatchewan. Total consideration of $91 million, which includes both cash paid to the shareholders of the acquired company and the assumption of long-term debt, was funded through the Company's revolving credit facility.

In May 2018, Vermilion acquired all of the issued and outstanding common shares of Spartan, a publicly traded southeast Saskatchewan oil producer. The acquisition added approximately 23,000 boe/d of high-netback, light oil production and approximately 480,000 net acres of land (80% average working interest), including 400,000 net acres in southeast Saskatchewan with multi-zone potential. In addition, the Spartan acquisition included approximately 80,000 net acres of land in other areas of Saskatchewan, Alberta and Manitoba. The Acquisition also includes ownership and control of producing infrastructure synergistic with Vermilion's existing assets, as well as significant 2D and 3D seismic data. Total consideration for the acquisition was $1.4 billion consisting of the issuance of 27.9 million Vermilion common shares valued at approximately $1.2 billion (based on the closing price per Vermilion common share of $44.30 on the Toronto Stock Exchange on May 28, 2018) and the assumption of approximately $175 million of Spartan's outstanding debt at the time the transaction closed.

In August 2018, Vermilion acquired mineral land and producing assets in the Powder River Basin in Wyoming for total cash consideration of approximately $189 million. The acquisition is comprised of low base decline, light oil-weighted production and high-quality mineral leasehold in the Powder River Basin in Campbell County, Wyoming, approximately 40 miles (65 kilometres) northwest of Vermilion's existing operations. The Assets include approximately 55,700 net acres of land (approximately 96% working interest) and approximately 2,500 boe/d (63% oil and NGLs) of production with an estimated annual base decline rate of 13%. Approximately half of the current production comes from three federal secondary recovery units in the Muddy formation, with the remainder coming from higher netback production from Turner Sand horizontal producers.

In December 2018, Vermilion closed the acquisition of an additional 1.5% working interest in the Corrib natural gas project bringing the Company's ownership interest in the project to 20%. Vermilion also assumed operatorship of Corrib resulting in a significant increase in the degree of operating control across the Company's portfolio.

Vermilion received a top quartile ranking for its industry sector in RobecoSAM's annual Corporate Sustainability Assessment. The CSA analyzes sustainability performance across economic, environmental, governance and social criteria, and is the basis of the Dow Jones Sustainability Indices. Vermilion was ranked 11th by Corporate Knights on the Future 40 Responsible Corporate Leaders in Canada list. This marks the fifth year in a row that Vermilion has been recognized by Corporate Knights as one of Canada's top sustainability performers and we continue to be the highest ranked oil and gas company on the list. Vermilion's MSCI ESG (Environment, Social and Governance) received an A rating for the second consecutive year and the Company's Governance Metrics score ranked in the top decile globally. Vermilion scored 82 out of 100 on the annual ratings conducted by Sustainalytics, ranking at the top of its peer group. Sustainalytics rates the sustainability of participating companies based on their environmental, social and governance performance.

Further demonstrating Vermilion's commitment to being a leader in environmental, social and governance practices, the Board of Directors has established a Sustainability Committee to provide oversight with respect to sustainability policy and performance. Members of the committee are Tim Marchant (Chair), Carin Knickel, Steve Larke and Bill Roby, each an independent director.

2019

Vermilion achieved record annual production of 100,357 boe/d representing an increase of 15% compared to 2018. Production in Canada reached record levels as the Company benefitted from a full-year contribution from the Spartan assets acquired in May 2018, achieving average annual production of nearly 60,000 boe/d in 2019. Production also achieved record annual average levels in the Netherlands and in the United States.

Vermilion maintained its monthly dividend at $0.23 per share throughout 2019. In July 2019, Vermilion received approval from the TSX for a normal course issuer bid ("NCIB"), allowing the Company to buy back up to 7.75 million shares. Vermilion intends to use the NCIB, in combination with debt reduction, when excess free cash flow is available (beyond dividends) to enhance per share growth. In October 2019, the Company announced its intention to phase out the Dividend Reinvestment Plan ("DRIP") in 2020 by prorating the available DRIP shares by 25% each quarter starting in Q1 2020. This proration is planned to increase each quarter throughout the year, such that the DRIP will be eliminated at the end of Q3 2020.

In June 2019, Vermilion entered into a series of cross currency interest rate swaps with a syndicate of banks. The cross currency interest rate swaps mature March 15, 2025 and include regular cash receipts and payments on March 15 and September 15 of each year. On a net basis, the cross currency interest swaps result in Vermilion receiving US dollar interest and principal amounts equal to the interest and principal payments under the US$300.0 million of senior unsecured notes. In exchange, Vermilion will make interest and principal payments equal to €265.0 million at a rate of 3.275%.

During the third quarter of 2019, Vermilion was awarded two exploration licenses in Ukraine, subject to a final production sharing agreement, in a 50/50 partnership with Ukrgazvydobuvannya ("UGV"), a Ukrainian state-owned gas producer. The licenses cover approximately 500,000 gross acres situated in one of Europe's most prolific natural gas regions (Dnieper-Donets Basin).

Vermilion's ISS Governance QualityScore increased from 3 to 1 (where a decile score of 1 indicates lowest governance risk), while its Environment and Social QualityScores remained at 1 and 2 respectively in 2019. Vermilion was rated "AA" in MSCI's annual environmental, social and governance ("ESG") rankings for 2019, placing the Company in the top 19% of oil and gas companies worldwide. This rating is an improvement from "A" in the previous two years. Vermilion received top quartile rankings for 2019 for its industry sector in both the Sustainalytics ESG Rating and SAM (formerly known as RobecoSAM) annual Corporate Sustainability Assessment ("CSA"). These rankings are a reflection of Vermilion's continued commitment to ESG matters across the business, positioning Vermilion as one of the most responsible producers of energy in the industry.

Outlook

Vermilion's business model continues to allow for flexibility in response to volatile commodity prices and regulatory changes. The Company intends to maintain a low level of financial leverage and continue to fund dividends and exploration and development ("E&D") capital investment from internally generated fund flows from operations. Consistent with these objectives, in October 2019 Vermilion announced an E&D capital budget for 2020 of $450 million with corresponding production guidance of between 100,000 to 103,000 boe/d. This budget is designed to deliver modest production growth of approximately 1% and also provides for strategic capital expenditures associated with early-stage exploration and development activities. These activities are designed to lay the groundwork for future development and production from a highly economic asset base.

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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 10, 2020 with an effective date of December 31, 2019. 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, 2019 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 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 - Gross and net interest[2], based on forecast prices and costs [1]

Proved Developed Producing [3] [5] [6]	Light Crude Oil & Medium Crude Oil (mbbl)		Heavy Oil (mbbl)		Tight Oil (mbbl)		Conventional Natural Gas (mmcf)	
	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]
Australia	8,608	8,608	—	—	—	—	—	—
Canada	51,225	45,958	10	10	—	—	232,002	215,234
CEE	—	—	—	—	—	—	1,372	1,125
France	35,109	31,724	—	—	—	—	—	—
Germany	4,557	4,422	—	—	—	—	30,822	28,015
Ireland	—	—	—	—	—	—	70,633	70,633
Netherlands	—	—	—	—	—	—	50,917	50,451
United States	5,093	4,268	—	—	—	—	32,984	27,542
Total Proved Developed Producing	**104,591**	**94,981**	**10**	**10**	**—**	**—**	**418,730**	**393,000**

Proved Developed Producing [3] [5] [6]	Shale Gas (mmcf)		Coal Bed Methane (mmcf)		Natural Gas Liquids (mbbl)		BOE (mboe)	
	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]
Australia	—	—	—	—	—	—	8,608	8,608
Canada	696	660	3,197	2,939	20,934	17,359	111,486	99,799
CEE	—	—	—	—	—	—	229	188
France	—	—	—	—	—	—	35,109	31,724
Germany	—	—	—	—	—	—	9,694	9,091
Ireland	—	—	—	—	—	—	11,772	11,772
Netherlands	—	—	—	—	134	133	8,620	8,542
United States	—	—	—	—	3,632	3,032	14,222	11,891
Total Proved Developed Producing	**696**	**660**	**3,197**	**2,939**	**24,701**	**20,524**	**199,740**	**181,615**

Proved Developed Non-Producing [3] [5] [7]	Light Crude Oil & Medium Crude Oil (mbbl)		Heavy Oil (mbbl)		Tight Oil (mbbl)		Conventional Natural Gas (mmcf)	
	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]
Australia	—	—	—	—	—	—	—	—
Canada	5,092	4,195	—	—	—	—	7,237	6,465
CEE	—	—	—	—	—	—	9,016	7,393
France	934	818	—	—	—	—	—	—
Germany	772	751	—	—	—	—	12,949	11,310
Ireland	—	—	—	—	—	—	—	—
Netherlands	—	—	—	—	—	—	11,964	11,895
United States	393	315	—	—	—	—	410	329
Total Proved Developed Non-Producing	**7,191**	**6,080**	**—**	**—**	**—**	**—**	**41,577**	**37,393**

Proved Developed Non-Producing [3] [5] [7]	Shale Gas (mmcf)		Coal Bed Methane (mmcf)		Natural Gas Liquids (mbbl)		BOE (mboe)	
	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]
Australia	—	—	—	—	—	—	—	—
Canada	—	—	781	732	697	596	7,125	5,991
CEE	—	—	—	—	—	—	1,503	1,232
France	—	—	—	—	—	—	934	818
Germany	—	—	—	—	—	—	2,930	2,636
Ireland	—	—	—	—	—	—	—	—
Netherlands	—	—	—	—	41	41	2,035	2,024
United States	—	—	—	—	54	43	515	413
Total Proved Developed Non-Producing	**—**	**—**	**781**	**732**	**792**	**680**	**15,042**	**13,114**

Proved Undeveloped [3] [8]	Light Crude Oil & Medium Crude Oil (mbbl)		Heavy Oil (mbbl)		Tight Oil (mbbl)		Conventional Natural Gas (mmcf)	
	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]
Australia	—	—	—	—	—	—	—	—
Canada	38,586	33,036	77	66	—	—	121,858	111,376
CEE	—	—	—	—	—	—	—	—
France	4,920	4,379	—	—	—	—	—	—
Germany	743	728	—	—	—	—	2,482	2,071
Ireland	—	—	—	—	—	—	—	—
Netherlands	—	—	—	—	—	—	2,700	2,700
United States	10,769	8,873	—	—	—	—	18,214	15,059
Total Proved Undeveloped	**55,017**	**47,016**	**77**	**66**	**—**	**—**	**145,253**	**131,206**

Proved Undeveloped [3] [8]	Shale Gas (mmcf)		Coal Bed Methane (mmcf)		Natural Gas Liquids (mbbl)		BOE (mboe)	
	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]
Australia	—	—	—	—	—	—	—	—
Canada	—	—	259	207	13,730	12,019	72,745	63,718
CEE	—	—	—	—	—	—	—	—
France	—	—	—	—	—	—	4,920	4,379
Germany	—	—	—	—	—	—	1,157	1,073
Ireland	—	—	—	—	—	—	—	—
Netherlands	—	—	—	—	—	—	450	450
United States	—	—	—	—	2,082	1,720	15,886	13,103
Total Proved Undeveloped	**—**	**—**	**259**	**207**	**15,811**	**13,739**	**95,157**	**82,724**

Proved [3]	Light Crude Oil & Medium Crude Oil (mbbl)		Heavy Oil (mbbl)		Tight Oil (mbbl)		Conventional Natural Gas (mmcf)	
	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]
Australia	8,608	8,608	—	—	—	—	—	—
Canada	94,903	83,189	87	76	—	—	361,097	333,074
CEE	—	—	—	—	—	—	10,388	8,518
France	40,963	36,922	—	—	—	—	—	—
Germany	6,072	5,901	—	—	—	—	46,253	41,397
Ireland	—	—	—	—	—	—	70,633	70,633
Netherlands	—	—	—	—	—	—	65,581	65,046
United States	16,254	13,457	—	—	—	—	51,608	42,931
Total Proved	**166,799**	**148,077**	**87**	**76**	**—**	**—**	**605,560**	**561,599**

Proved [3]	Shale Gas (mmcf)		Coal Bed Methane (mmcf)		Natural Gas Liquids (mbbl)		BOE (mboe)	
	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]
Australia	—	—	—	—	—	—	8,608	8,608
Canada	696	660	4,237	3,878	35,361	29,974	191,356	169,508
CEE	—	—	—	—	—	—	1,731	1,420
France	—	—	—	—	—	—	40,963	36,922
Germany	—	—	—	—	—	—	13,781	12,801
Ireland	—	—	—	—	—	—	11,772	11,772
Netherlands	—	—	—	—	175	174	11,105	11,015
United States	—	—	—	—	5,768	4,796	30,623	25,407
Total Proved	**696**	**660**	**4,237**	**3,878**	**41,304**	**34,944**	**309,939**	**277,453**

Probable [4]	Light Crude Oil & Medium Crude Oil (mbbl)		Heavy Oil (mbbl)		Tight Oil (mbbl)		Conventional Natural Gas (mmcf)	
	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]
Australia	4,552	4,552	—	—	—	—	—	—
Canada	46,931	40,935	78	68	—	—	248,227	229,200
CEE	—	—	—	—	—	—	5,829	4,779
France	18,729	16,797	—	—	—	—	—	—
Germany	3,962	3,846	—	—	—	—	53,987	47,548
Ireland	—	—	—	—	—	—	36,013	36,013
Netherlands	—	—	—	—	—	—	58,475	55,086
United States	18,579	15,470	—	—	—	—	35,828	29,933
Total Probable	**92,753**	**81,600**	**78**	**68**	**—**	**—**	**438,359**	**402,559**

Probable [4]	Shale Gas (mmcf)		Coal Bed Methane (mmcf)		Natural Gas Liquids (mbbl)		BOE (mboe)	
	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]
Australia	—	—	—	—	—	—	4,552	4,552
Canada	168	160	1,316	1,209	20,549	17,458	109,177	96,889
CEE	—	—	—	—	—	—	971	797
France	—	—	—	—	—	—	18,729	16,797
Germany	—	—	—	—	—	—	12,959	11,770
Ireland	—	—	—	—	—	—	6,002	6,002
Netherlands	—	—	—	—	128	121	9,874	9,302
United States	—	—	—	—	4,122	3,441	28,673	23,900
Total Probable	**168**	**160**	**1,316**	**1,209**	**24,800**	**21,021**	**190,937**	**170,010**

Proved Plus Probable [3] [4]	Light Crude Oil & Medium Crude Oil (mbbl)		Heavy Oil (mbbl)		Tight Oil (mbbl)		Conventional Natural Gas (mmcf)	
	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]
Australia	13,160	13,160	—	—	—	—	—	—
Canada	141,834	124,124	165	144	—	—	609,324	562,274
CEE	—	—	—	—	—	—	16,217	13,298
France	59,692	53,719	—	—	—	—	—	—
Germany	10,033	9,747	—	—	—	—	100,240	88,945
Ireland	—	—	—	—	—	—	106,647	106,647
Netherlands	—	—	—	—	—	—	124,056	120,132
United States	34,833	28,927	—	—	—	—	87,436	72,864
Total Proved Plus Probable	**259,552**	**229,677**	**165**	**144**	**—**	**—**	**1,043,919**	**964,158**

Proved Plus Probable [3] [4]	Shale Gas (mmcf)		Coal Bed Methane (mmcf)		Natural Gas Liquids (mbbl)		BOE (mboe)	
	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]	Gross [2]	Net [2]
Australia	—	—	—	—	—	—	13,160	13,160
Canada	864	820	5,553	5,087	55,910	47,432	300,532	266,397
CEE	—	—	—	—	—	—	2,703	2,216
France	—	—	—	—	—	—	59,692	53,719
Germany	—	—	—	—	—	—	26,740	24,571
Ireland	—	—	—	—	—	—	17,774	17,774
Netherlands	—	—	—	—	304	296	20,980	20,317
United States	—	—	—	—	9,890	8,237	59,296	49,308
Total Proved Plus Probable	**864**	**820**	**5,553**	**5,087**	**66,103**	**55,965**	**500,876**	**447,463**

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 in “Forecast Prices used in Estimates”. 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 royalty obligations 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.

Oil and gas reserves - Company Interest[2], based on forecast prices and costs[1]

Proved Developed Producing [3] [5] [6]	Light Crude Oil & Medium Crude Oil (mbbl) Company Interest [2]	Heavy Oil (mbbl) Company Interest [2]	Tight Oil (mbbl) Company Interest [2]	Conventional Natural Gas (mmcf) Company Interest [2]	Shale Gas (mmcf) Company Interest [2]	Coal Bed Methane (mmcf) Company Interest [2]	Natural Gas Liquids (mbbl) Company Interest [2]	BOE (mboe) Company Interest [2]
Australia	8,608	—	—	—	—	—	—	8,608
Canada	51,376	10	—	232,365	696	3,199	20,974	111,737
CEE	—	—	—	1,372	—	—	—	229
France	35,109	—	—	—	—	—	—	35,109
Germany	4,557	—	—	30,822	—	—	—	9,694
Ireland	—	—	—	70,633	—	—	—	11,772
Netherlands	—	—	—	50,917	—	—	134	8,620
United States	5,093	—	—	32,984	—	—	3,632	14,222
Total Proved Developed Producing	**104,742**	**10**	**—**	**419,094**	**696**	**3,199**	**24,741**	**199,991**

Proved Developed Non-Producing [3] [5] [7]	Light Crude Oil & Medium Crude Oil (mbbl) Company Interest [2]	Heavy Oil (mbbl) Company Interest [2]	Tight Oil (mbbl) Company Interest [2]	Conventional Natural Gas (mmcf) Company Interest [2]	Shale Gas (mmcf) Company Interest [2]	Coal Bed Methane (mmcf) Company Interest [2]	Natural Gas Liquids (mbbl) Company Interest [2]	BOE (mboe) Company Interest [2]
Australia	—	—	—	—	—	—	—	—
Canada	5,092	—	—	7,237	—	781	697	7,125
CEE	—	—	—	9,016	—	—	—	1,503
France	934	—	—	—	—	—	—	934
Germany	772	—	—	12,949	—	—	—	2,930
Ireland	—	—	—	—	—	—	—	—
Netherlands	—	—	—	11,964	—	—	41	2,035
United States	393	—	—	410	—	—	54	515
Total Proved Developed Non-Producing	**7,191**	**—**	**—**	**41,577**	**—**	**781**	**792**	**15,042**

Proved Undeveloped [3] [8]	Light Crude Oil & Medium Crude Oil (mbbl) Company Interest [2]	Heavy Oil (mbbl) Company Interest [2]	Tight Oil (mbbl) Company Interest [2]	Conventional Natural Gas (mmcf) Company Interest [2]	Shale Gas (mmcf) Company Interest [2]	Coal Bed Methane (mmcf) Company Interest [2]	Natural Gas Liquids (mbbl) Company Interest [2]	BOE (mboe) Company Interest [2]
Australia	—	—	—	—	—	—	—	—
Canada	38,598	77	—	121,858	—	259	13,737	72,764
CEE	—	—	—	—	—	—	—	—
France	4,920	—	—	—	—	—	—	4,920
Germany	743	—	—	2,482	—	—	—	1,157
Ireland	—	—	—	—	—	—	—	—
Netherlands	—	—	—	2,700	—	—	—	450
United States	10,769	—	—	18,214	—	—	2,082	15,886
Total Proved Undeveloped	**55,030**	**77**	**—**	**145,254**	**—**	**259**	**15,818**	**95,176**

Proved [3]	Light Crude Oil & Medium Crude Oil (mbbl) Company Interest [2]	Heavy Oil (mbbl) Company Interest [2]	Tight Oil (mbbl) Company Interest [2]	Conventional Natural Gas (mmcf) Company Interest [2]	Shale Gas (mmcf) Company Interest [2]	Coal Bed Methane (mmcf) Company Interest [2]	Natural Gas Liquids (mbbl) Company Interest [2]	BOE (mboe) Company Interest [2]
Australia	8,608	—	—	—	—	—	—	8,608
Canada	95,066	87	—	361,462	696	4,239	35,408	191,626
CEE	—	—	—	10,388	—	—	—	1,731
France	40,963	—	—	—	—	—	—	40,963
Germany	6,072	—	—	46,253	—	—	—	13,781
Ireland	—	—	—	70,633	—	—	—	11,772
Netherlands	—	—	—	65,581	—	—	175	11,105
United States	16,254	—	—	51,608	—	—	5,768	30,623
Total Proved	**166,962**	**87**	**—**	**605,925**	**696**	**4,239**	**41,351**	**310,210**

Probable [4]	Light Crude Oil & Medium Crude Oil (mbbl) Company Interest [2]	Heavy Oil (mbbl) Company Interest [2]	Tight Oil (mbbl) Company Interest [2]	Conventional Natural Gas (mmcf) Company Interest [2]	Shale Gas (mmcf) Company Interest [2]	Coal Bed Methane (mmcf) Company Interest [2]	Natural Gas Liquids (mbbl) Company Interest [2]	BOE (mboe) Company Interest [2]
Australia	4,552	—	—	—	—	—	—	4,552
Canada	46,985	78	—	248,337	168	1,316	20,563	109,263
CEE	—	—	—	5,829	—	—	—	971
France	18,729	—	—	—	—	—	—	18,729
Germany	3,962	—	—	53,987	—	—	—	12,959
Ireland	—	—	—	36,013	—	—	—	6,002
Netherlands	—	—	—	58,475	—	—	128	9,874
United States	18,579	—	—	35,828	—	—	4,122	28,673
Total Probable	**92,807**	**78**	**—**	**438,469**	**168**	**1,316**	**24,813**	**191,023**

Proved Plus Probable [3] [4]	Light Crude Oil & Medium Crude Oil (mbbl) Company Interest [2]	Heavy Oil (mbbl) Company Interest [2]	Tight Oil (mbbl) Company Interest [2]	Conventional Natural Gas (mmcf) Company Interest [2]	Shale Gas (mmcf) Company Interest [2]	Coal Bed Methane (mmcf) Company Interest [2]	Natural Gas Liquids (mbbl) Company Interest [2]	BOE (mboe) Company Interest [2]
Australia	13,160	—	—	—	—	—	—	13,160
Canada	142,051	165	—	609,798	864	5,555	55,971	300,889
CEE	—	—	—	16,217	—	—	—	2,703
France	59,692	—	—	—	—	—	—	59,692
Germany	10,033	—	—	100,240	—	—	—	26,740
Ireland	—	—	—	106,647	—	—	—	17,774
Netherlands	—	—	—	124,056	—	—	304	20,980
United States	34,833	—	—	87,436	—	—	9,890	59,296
Total Proved Plus Probable	**259,769**	**165**	**—**	**1,044,394**	**864**	**5,555**	**66,164**	**501,233**

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 in “Forecast Prices used in Estimates”. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

(2) "Company Interest Reserves" are Vermilion's interest (operating, non-operating, or royalty) share before deduction of royalty obligations.

(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.

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(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	110,537	176,968	199,222	202,095	196,718	134,368	160,626	164,503	159,389	151,072
Canada	2,232,060	1,831,045	1,531,267	1,317,440	1,160,296	2,232,060	1,831,045	1,531,267	1,317,440	1,160,296
CEE	6,152	5,737	5,384	5,082	4,822	6,152	5,737	5,384	5,082	4,822
France	1,746,114	1,270,508	996,356	822,490	703,526	1,425,273	1,053,557	833,519	691,548	593,207
Germany	181,953	196,476	176,111	154,291	136,067	181,953	196,476	176,111	154,291	136,067
Ireland	328,547	309,972	284,374	259,383	237,177	328,547	309,972	284,374	259,383	237,177
Netherlands	144,080	145,324	143,210	139,286	134,492	126,698	128,573	127,033	123,633	119,320
United States	286,910	217,089	173,884	145,668	126,129	286,910	217,089	173,884	145,668	126,129
Total Proved Developed Producing	**5,036,354**	**4,153,117**	**3,509,807**	**3,045,735**	**2,699,227**	**4,721,961**	**3,903,074**	**3,296,075**	**2,856,434**	**2,528,091**
Proved Developed Non-Producing [2] [4] [6]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada	224,965	143,652	100,503	75,216	59,114	224,965	143,652	100,503	75,216	59,114
CEE	33,057	27,600	23,278	19,811	16,997	28,008	23,240	19,473	16,461	14,023
France	37,890	27,103	20,823	16,675	13,770	28,035	19,684	14,872	11,709	9,500
Germany	86,482	69,188	55,841	44,874	36,258	86,482	69,188	55,841	44,874	36,258
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	60,511	58,670	55,035	50,946	46,953	33,304	33,963	32,454	30,186	27,769
United States	13,002	7,954	4,997	3,161	1,959	13,002	7,954	4,997	3,161	1,959
Total Proved Developed Non-Producing	**455,908**	**334,167**	**260,478**	**210,683**	**175,051**	**413,796**	**297,681**	**228,141**	**181,607**	**148,622**
Proved Undeveloped [2] [7]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada	1,816,807	1,121,401	750,231	530,401	389,585	1,569,870	993,411	679,753	489,634	365,025
CEE	—	—	—	—	—	—	—	—	—	—
France	220,719	166,101	125,515	96,721	75,849	159,414	119,212	87,816	65,636	49,745
Germany	48,967	36,721	27,860	21,439	16,758	37,961	30,854	24,606	19,570	15,649
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	11,979	9,826	8,099	6,733	5,653	7,847	6,206	4,897	3,878	3,088
United States	443,855	268,875	177,603	124,354	90,571	412,422	253,579	169,483	119,739	87,803
Total Proved Undeveloped	**2,542,328**	**1,602,924**	**1,089,307**	**779,649**	**578,417**	**2,187,514**	**1,403,261**	**966,556**	**698,457**	**521,311**
Proved [2]										
Australia	110,537	176,968	199,222	202,095	196,718	134,368	160,626	164,503	159,389	151,072
Canada	4,273,832	3,096,097	2,382,001	1,923,057	1,608,995	4,026,896	2,968,107	2,311,523	1,882,291	1,584,436
CEE	39,210	33,336	28,662	24,894	21,820	34,160	28,976	24,857	21,543	18,845
France	2,004,723	1,463,712	1,142,694	935,887	793,145	1,612,722	1,192,452	936,207	768,894	652,453
Germany	317,401	302,385	259,812	220,604	189,083	306,395	296,518	256,558	218,735	187,974
Ireland	328,547	309,972	284,374	259,383	237,177	328,547	309,972	284,374	259,383	237,177
Netherlands	216,571	213,820	206,344	196,964	187,098	167,849	168,742	164,384	157,697	150,176
United States	743,767	493,919	356,484	273,182	218,659	712,333	478,623	348,365	268,567	215,890
Total Proved	**8,034,589**	**6,090,208**	**4,859,593**	**4,036,067**	**3,452,695**	**7,323,270**	**5,604,016**	**4,490,771**	**3,736,498**	**3,198,024**
Probable [3]										
Australia	194,455	170,899	140,919	114,880	94,340	120,561	104,520	85,430	69,157	56,443
Canada	3,110,174	1,804,031	1,203,716	875,747	674,786	2,336,078	1,356,842	915,793	676,907	530,808
CEE	31,427	25,656	21,388	18,146	15,626	26,288	21,399	17,796	15,071	12,959
France	1,159,623	646,203	413,440	289,038	214,005	851,091	473,698	299,307	205,931	149,769
Germany	465,081	307,846	205,929	144,919	106,943	313,593	210,468	139,426	97,313	71,590
Ireland	238,036	167,187	117,992	85,582	64,142	238,036	167,187	117,992	85,582	64,142
Netherlands	290,974	221,381	173,228	138,250	112,241	183,238	134,018	100,987	77,475	60,331
United States	1,081,256	586,361	365,993	250,651	182,852	854,384	463,093	290,030	199,943	147,157
Total Probable	**6,571,024**	**3,929,564**	**2,642,606**	**1,917,213**	**1,464,936**	**4,923,268**	**2,931,223**	**1,966,762**	**1,427,380**	**1,093,200**

	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	304,992	347,866	340,142	316,976	291,058	254,929	265,146	249,933	228,546	207,515
Canada	7,384,007	4,900,128	3,585,717	2,798,804	2,283,781	6,362,973	4,324,949	3,227,317	2,559,197	2,115,244
CEE	70,636	58,993	50,049	43,040	37,446	60,448	50,375	42,653	36,614	31,804
France	3,164,346	2,109,914	1,556,134	1,224,925	1,007,151	2,463,812	1,666,149	1,235,514	974,825	802,222
Germany	782,482	610,231	465,741	365,523	296,027	619,988	506,986	395,984	316,048	259,565
Ireland	566,583	477,159	402,366	344,965	301,319	566,583	477,159	402,366	344,965	301,319
Netherlands	507,545	435,201	379,572	335,214	299,339	351,087	302,760	265,371	235,172	210,507
United States	1,825,023	1,080,280	722,478	523,833	401,511	1,566,718	941,715	638,395	468,510	363,048
Total Proved Plus Probable	**14,605,614**	**10,019,772**	**7,502,199**	**5,953,280**	**4,917,631**	**12,246,538**	**8,535,239**	**6,457,533**	**5,163,878**	**4,291,223**

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 in “Forecast Prices used in Estimates”. 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 [4]	Future Net Revenue After Income Taxes
Proved [2]								
Australia	772,191	—	394,259	41,769	225,625	110,537	(23,830)	134,368
Canada	11,096,365	1,726,372	3,702,416	1,072,086	321,659	4,273,832	246,937	4,026,896
CEE	84,621	15,232	17,184	12,714	281	39,210	5,049	34,160
France	4,049,809	394,071	1,256,082	144,840	250,093	2,004,723	392,001	1,612,722
Germany	860,128	49,819	294,221	37,372	161,315	317,401	11,006	306,395
Ireland	611,136	—	196,244	20,586	65,758	328,547	—	328,547
Netherlands	562,719	4,032	219,493	6,001	116,623	216,571	48,722	167,849
United States	1,972,813	536,691	434,714	231,965	25,676	743,767	31,434	712,333
Total Proved	**20,009,782**	**2,726,217**	**6,514,612**	**1,567,335**	**1,167,029**	**8,034,589**	**711,319**	**7,323,270**
Proved Plus Probable [2] [3]								
Australia	1,214,497	—	617,469	52,482	239,554	304,992	50,063	254,929
Canada	17,666,033	2,712,303	5,583,901	1,595,574	390,248	7,384,007	1,021,034	6,362,973
CEE	134,503	24,211	26,639	12,714	303	70,636	10,188	60,448
France	6,120,688	606,389	1,781,120	267,442	301,390	3,164,346	700,533	2,463,812
Germany	1,737,365	118,540	502,409	119,229	214,705	782,482	162,494	619,988
Ireland	969,282	—	286,896	41,749	74,054	566,583	—	566,583
Netherlands	1,105,018	33,869	361,447	61,690	140,467	507,545	156,458	351,087
United States	4,221,183	1,134,862	775,020	449,385	36,893	1,825,023	258,305	1,566,718
Total Proved Plus Probable	**33,168,568**	**4,630,175**	**9,934,901**	**2,600,264**	**1,397,614**	**14,605,614**	**2,359,076**	**12,246,538**

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 in “Forecast Prices used in Estimates”. 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) "Future Income Taxes" are calculated using future net revenue before income taxes as shown, after incorporating Vermilion's existing tax pools, corporate charge-outs, and related expenditures. This calculation applies the year-end statutory rate, taking into account future tax rates already legislated.

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) ($M)	Unit Value ($/boe)
Proved Developed Producing		
Light Crude Oil & Medium Crude Oil [3]	2,655,419	23.20
Heavy Oil [3]	243	15.45
Conventional Natural Gas [4]	853,479	12.83
Shale Gas	529	3.63
Coal Bed Methane	137	0.28
Total Proved Developed Producing	**3,509,807**	**19.33**
Proved Developed Non-Producing		
Light Crude Oil & Medium Crude Oil [3]	136,446	19.96
Heavy Oil [3]	—	—
Conventional Natural Gas [4]	123,592	20.08
Shale Gas	—	—
Coal Bed Methane	440	3.58
Total Proved Developed Non-Producing	**260,478**	**19.86**
Proved Undeveloped		
Light Crude Oil & Medium Crude Oil [3]	923,812	15.58
Heavy Oil [3]	622	5.94
Conventional Natural Gas [4]	164,868	7.08
Shale Gas	—	—
Coal Bed Methane	6	0.16
Total Proved Undeveloped	**1,089,307**	**13.17**
Proved		
Light Crude Oil & Medium Crude Oil [3]	3,710,377	20.55
Heavy Oil [3]	823	6.86
Conventional Natural Gas [4]	1,147,280	11.95
Shale Gas	544	3.73
Coal Bed Methane	568	0.87
Total Proved	**4,859,593**	**17.52**
Probable		
Light Crude Oil & Medium Crude Oil [3]	1,937,937	18.87
Heavy Oil [3]	1,396	12.83
Conventional Natural Gas [4]	701,923	10.48
Shale Gas	168	4.69
Coal Bed Methane	1,182	5.81
Total Probable	**2,642,606**	**15.54**
Proved Plus Probable		
Light Crude Oil & Medium Crude Oil [3]	5,652,853	19.96
Heavy Oil [3]	2,165	9.46
Conventional Natural Gas [4]	1,844,761	11.32
Shale Gas	719	3.96
Coal Bed Methane	1,701	1.98
Total Proved Plus Probable	**7,502,199**	**16.77**

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 in “Forecast Prices used in Estimates”. 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)(2)]

	Light Crude Oil and & Medium Crude Oil			Crude Oil	Conventional Natural Gas Canada	Europe	Natural Gas Liquids				Inflation Rate	Exchange Rate	
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40˚ API ($Cdn/bbl)	Cromer Light 35˚ API ($Cdn/bbl)	Brent Blend FOB North Sea ($US/bbl)	AECO Gas Price ($Cdn/mmbtu)	UK National Balancing Point ($US/mmbtu)	Edmonton Ethane ($Cdn/bbl)	Edmonton Propane ($Cdn/bbl)	Edmonton Butane ($Cdn/bbl)	Edmonton C5+ ($Cdn/bbl)	Percent Per Year	USD/CAD	CAD/EUR
2019	57.05	69.22	69.69	64.33	1.70	4.85	9.38	12.45	19.55	70.16	1.90%	0.75	1.49
Forecast													
2020	61.00	72.64	72.16	66.33	2.04	5.68	6.42	26.36	42.09	76.83	—%	0.76	1.47
2021	63.75	76.06	75.23	67.94	2.32	6.08	7.41	29.80	47.03	79.82	1.70%	0.77	1.47
2022	66.18	78.35	77.50	70.06	2.62	6.46	8.33	32.94	50.66	82.30	2.00%	0.79	1.46
2023	67.91	80.71	79.83	71.66	2.71	6.83	8.65	34.00	52.21	84.72	2.00%	0.79	1.46
2024	69.48	82.64	81.76	73.27	2.81	7.04	8.98	34.89	53.48	86.71	2.00%	0.79	1.46
2025	71.07	84.60	83.69	74.57	2.89	7.26	9.24	35.78	54.77	88.73	2.00%	0.79	1.46
2026	72.68	86.57	85.66	76.22	2.96	7.43	9.46	36.69	56.07	90.77	2.00%	0.79	1.46
2027	74.24	88.49	87.57	77.83	3.03	7.55	9.67	37.57	57.32	92.76	2.00%	0.79	1.46
2028	75.73	90.31	89.37	79.36	3.10	7.66	9.89	38.41	58.50	94.65	2.00%	0.79	1.46
2029	77.24	92.17	91.21	80.92	3.17	7.77	10.12	39.26	59.71	96.57	2.00%	0.79	1.46
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	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.79	1.46

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 above. The pricing assumptions above are the January 2020, 3 Consultants' Average pricing which were provided by GLJ, an independent qualified reserves evaluator appointed pursuant to NI 51-101. The consultants are GLJ, Sproule and McDaniel and Associates, all independent qualified reverse evaluators.

(2) For light oil and medium crude oil, the pricing assumptions used are WTI, Edmonton Par Price, Cromer Medium, and Brent Blend. For conventional natural gas in Canada, the pricing assumptions used are AECO and for conventional natural gas in Europe, the pricing assumptions used are National Balancing Point.

For 2019, average realized prices before hedging were:

Country	Crude oil ($/bbl)	NGLs ($/bbl)	Natural gas ($/mcf)
Australia	93.33	—	—
Canada	67.84	33.03	1.77
CEE	—	—	5.23
France	83.22	—	1.76
Germany	80.22	—	5.64
Ireland	—	—	6.13
Netherlands	—	72.44	6.16
United States	68.76	18.04	2.15

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, 2019 compared to such reserves as at December 31, 2018 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[3]

Australia	Total Oil [4]			Light & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)
At December 31, 2018	9,668	4,812	14,480	9,668	4,812	14,480	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	1,007	(260)	747	1,007	(260)	747	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	(2,067)	—	(2,067)	(2,067)	—	(2,067)	—	—	—	—	—	—
At December 31, 2019	**8,608**	**4,552**	**13,160**	**8,608**	**4,552**	**13,160**	**—**	**—**	**—**	**—**	**—**	**—**

Australia	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane			Shale Gas		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)
At December 31, 2018	—	—	—	—	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—	—	—	—	—
At December 31, 2019	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

Australia	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mbbl)	(mbbl)	(mbbl)	(mboe)	(mboe)	(mboe)
At December 31, 2018	—	—	—	9,668	4,812	14,480
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—
Technical Revisions	—	—	—	1,007	(260)	747
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—
Production	—	—	—	(2,067)	—	(2,067)
At December 31, 2019	**—**	**—**	**—**	**8,608**	**4,552**	**13,160**

Canada	Total Oil [4]			Light & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)
At December 31, 2018	94,665	46,461	141,126	94,564	46,378	140,943	100	83	183	—	—	—
Discoveries	249	281	530	249	281	530	—	—	—	—	—	—
Extensions & Improved Recovery	8,166	3,200	11,366	8,166	3,200	11,366	—	—	—	—	—	—
Technical Revisions	2,125	(3,328)	(1,204)	2,124	(3,323)	(1,199)	—	(5)	(5)	—	—	—
Acquisitions	447	136	583	447	136	583	—	—	—	—	—	—
Dispositions	(7)	(3)	(11)	(7)	(3)	(11)	—	—	—	—	—	—
Economic Factors	(337)	263	(74)	(337)	263	(74)	—	—	—	—	—	—
Production	(10,317)	—	(10,317)	(10,304)	—	(10,304)	(13)	—	(13)	—	—	—
At December 31, 2019	**94,990**	**47,009**	**141,999**	**94,903**	**46,931**	**141,834**	**87**	**78**	**165**	**—**	**—**	**—**

Canada	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane			Shale Gas		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)
At December 31, 2018	321,074	215,089	536,163	318,340	212,020	530,360	1,828	2,856	4,683	906	213	1,120
Discoveries	1,025	1,122	2,148	1,025	1,122	2,148	—	—	—	—	—	—
Extensions & Improved Recovery	47,748	27,596	75,344	47,748	27,596	75,344	—	—	—	—	—	—
Technical Revisions	38,134	1,597	39,731	34,694	3,181	37,875	3,585	(1,540)	2,045	(145)	(45)	(190)
Acquisitions	14,093	5,187	19,280	14,093	5,187	19,280	—	—	—	—	—	—
Dispositions	(23)	(1,235)	(1,258)	(23)	(1,235)	(1,258)	—	—	—	—	—	—
Economic Factors	(1,872)	355	(1,517)	(1,872)	355	(1,517)	—	—	—	—	—	—
Production	(54,149)	—	(54,149)	(52,907)	—	(52,907)	(1,176)	—	(1,176)	(66)	—	(66)
At December 31, 2019	**366,030**	**249,712**	**615,741**	**361,097**	**248,227**	**609,324**	**4,237**	**1,316**	**5,553**	**696**	**168**	**864**

Canada	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mbbl)	(mbbl)	(mbbl)	(mboe)	(mboe)	(mboe)
At December 31, 2018	33,486	20,502	53,988	181,663	102,812	284,474
Discoveries	72	84	156	491	553	1,044
Extensions & Improved Recovery	4,857	2,420	7,277	20,981	10,219	31,200
Technical Revisions	(1,457)	(2,766)	(4,223)	7,023	(5,828)	1,195
Acquisitions	1,051	502	1,553	3,847	1,502	5,350
Dispositions	(1)	(206)	(208)	(13)	(415)	(428)
Economic Factors	(96)	13	(83)	(744)	335	(410)
Production	(2,551)	—	(2,551)	(21,892)	—	(21,892)
At December 31, 2019	**35,361**	**20,549**	**55,910**	**191,356**	**109,177**	**300,532**

CEE	Total Oil [4]			Light & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)
At December 31, 2018	—	—	—	—	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—	—	—	—	—
At December 31, 2019	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

CEE	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane			Shale Gas		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)
At December 31, 2018	788	356	1,143	788	356	1,143	—	—	—	—	—	—
Discoveries	10,350	5,769	16,119	10,350	5,769	16,119	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	(598)	(296)	(893)	(598)	(296)	(893)	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	(152)	—	(152)	(152)	—	(152)	—	—	—	—	—	—
At December 31, 2019	**10,388**	**5,829**	**16,217**	**10,388**	**5,829**	**16,217**	**—**	**—**	**—**	**—**	**—**	**—**

CEE	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mbbl)	(mbbl)	(mbbl)	(mboe)	(mboe)	(mboe)
At December 31, 2018	—	—	—	131	59	191
Discoveries	—	—	—	1,725	961	2,686
Extensions & Improved Recovery	—	—	—	—	—	—
Technical Revisions	—	—	—	(100)	(49)	(149)
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—
Production	—	—	—	(25)	—	(25)
At December 31, 2019	**—**	**—**	**—**	**1,731**	**971**	**2,703**

France	Total Oil [4]			Light & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)
At December 31, 2018	42,379	20,355	62,734	42,379	20,355	62,734	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	551	260	810	551	260	810	—	—	—	—	—	—
Technical Revisions	1,882	(1,260)	622	1,882	(1,260)	622	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(40)	(626)	(666)	(40)	(626)	(666)	—	—	—	—	—	—
Production	(3,809)	—	(3,809)	(3,809)	—	(3,809)	—	—	—	—	—	—
At December 31, 2019	**40,963**	**18,729**	**59,692**	**40,963**	**18,729**	**59,692**	**—**	**—**	**—**	**—**	**—**	**—**

France	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane			Shale Gas		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)
At December 31, 2018	6,522	580	7,102	6,522	580	7,102	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	(6,453)	(580)	(7,033)	(6,453)	(580)	(7,033)	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	(69)	—	(69)	(69)	—	(69)	—	—	—	—	—	—
At December 31, 2019	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

France	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mbbl)	(mbbl)	(mbbl)	(mboe)	(mboe)	(mboe)
At December 31, 2018	—	—	—	43,466	20,452	63,918
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	551	260	810
Technical Revisions	—	—	—	807	(1,357)	(550)
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	(40)	(626)	(666)
Production	—	—	—	(3,821)	—	(3,821)
At December 31, 2019	**—**	**—**	**—**	**40,963**	**18,729**	**59,692**

Germany	Total Oil [4]			Light & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)
At December 31, 2018	5,737	3,841	9,578	5,737	3,841	9,578	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	307	405	712	307	405	712	—	—	—	—	—	—
Technical Revisions	362	(284)	78	362	(284)	78	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	(335)	—	(335)	(335)	—	(335)	—	—	—	—	—	—
At December 31, 2019	**6,072**	**3,962**	**10,033**	**6,072**	**3,962**	**10,033**	**—**	**—**	**—**	**—**	**—**	**—**

Germany	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane			Shale Gas		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)
At December 31, 2018	43,519	53,415	96,934	43,519	53,415	96,934	—	—	—	—	—	—
Discoveries	5,065	2,435	7,499	5,065	2,435	7,499	—	—	—	—	—	—
Extensions & Improved Recovery	980	270	1,250	980	270	1,250	—	—	—	—	—	—
Technical Revisions	2,276	(2,133)	144	2,276	(2,133)	144	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	(5,587)	—	(5,587)	(5,587)	—	(5,587)	—	—	—	—	—	—
At December 31, 2019	**46,253**	**53,987**	**100,240**	**46,253**	**53,987**	**100,240**	**—**	**—**	**—**	**—**	**—**	**—**

Germany	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mbbl)	(mbbl)	(mbbl)	(mboe)	(mboe)	(mboe)
At December 31, 2018	—	—	—	12,990	12,743	25,734
Discoveries	—	—	—	844	406	1,250
Extensions & Improved Recovery	—	—	—	470	450	920
Technical Revisions	—	—	—	742	(640)	102
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—
Production	—	—	—	(1,266)	—	(1,266)
At December 31, 2019	**—**	**—**	**—**	**13,781**	**12,959**	**26,740**

Ireland	Total Oil [4]			Light & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)
At December 31, 2018	—	—	—	—	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—	—	—	—	—
At December 31, 2019	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

Ireland	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane			Shale Gas		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)
At December 31, 2018	78,560	44,890	123,451	78,560	44,890	123,451	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	9,072	(8,877)	195	9,072	(8,877)	195	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	(16,999)	—	(16,999)	(16,999)	—	(16,999)	—	—	—	—	—	—
At December 31, 2019	**70,633**	**36,013**	**106,647**	**70,633**	**36,013**	**106,647**	**—**	**—**	**—**	**—**	**—**	**—**

Ireland	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mbbl)	(mbbl)	(mbbl)	(mboe)	(mboe)	(mboe)
At December 31, 2018	—	—	—	13,093	7,482	20,575
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—
Technical Revisions	—	—	—	1,512	(1,480)	32
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—
Production	—	—	—	(2,833)	—	(2,833)
At December 31, 2019	**—**	**—**	**—**	**11,772**	**6,002**	**17,774**

Netherlands	Total Oil [4]			Light & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)
At December 31, 2018	—	—	—	—	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—	—	—	—	—
At December 31, 2019	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

Netherlands	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane			Shale Gas		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)
At December 31, 2018	69,706	61,527	131,233	69,706	61,527	131,233	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	4,222	2,432	6,654	4,222	2,432	6,654	—	—	—	—	—	—
Technical Revisions	9,572	(5,484)	4,088	9,572	(5,484)	4,088	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	(17,920)	—	(17,920)	(17,920)	—	(17,920)	—	—	—	—	—	—
At December 31, 2019	**65,581**	**58,475**	**124,056**	**65,581**	**58,475**	**124,056**	**—**	**—**	**—**	**—**	**—**	**—**

Netherlands	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mbbl)	(mbbl)	(mbbl)	(mboe)	(mboe)	(mboe)
At December 31, 2018	185	140	325	11,802	10,395	22,197
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	16	6	22	720	411	1,131
Technical Revisions	7	(18)	(10)	1,603	(932)	671
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—
Production	(33)	—	(33)	(3,020)	—	(3,020)
At December 31, 2019	**175**	**128**	**304**	**11,105**	**9,874**	**20,980**

United States	Total Oil [4]			Light & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)
At December 31, 2018	12,989	20,223	33,211	12,989	20,223	33,211	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	2,740	(907)	1,833	2,740	(907)	1,833	—	—	—	—	—	—
Technical Revisions	1,101	(974)	127	1,101	(974)	127	—	—	—	—	—	—
Acquisitions	348	238	586	348	238	586	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	(924)	—	(924)	(924)	—	(924)	—	—	—	—	—	—
At December 31, 2019	**16,254**	**18,579**	**34,833**	**16,254**	**18,579**	**34,833**	**—**	**—**	**—**	**—**	**—**	**—**

United States	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)
At December 31, 2018	44,705	39,681	84,387	44,705	39,681	84,387	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	5,446	(2,405)	3,041	5,446	(2,405)	3,041	—	—	—	—	—	—
Technical Revisions	3,203	(2,004)	1,200	3,203	(2,004)	1,200	—	—	—	—	—	—
Acquisitions	767	555	1,322	767	555	1,322	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	(2,514)	—	(2,514)	(2,514)	—	(2,514)	—	—	—	—	—	—
At December 31, 2019	**51,608**	**35,828**	**87,436**	**51,608**	**35,828**	**87,436**	**—**	**—**	**—**	**—**	**—**	**—**

United States	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mbbl)	(mbbl)	(mbbl)	(mboe)	(mboe)	(mboe)
At December 31, 2018	4,707	4,231	8,939	25,147	31,068	56,214
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	606	(252)	353	4,254	(1,561)	2,693
Technical Revisions	733	82	815	2,368	(1,226)	1,142
Acquisitions	85	61	146	561	392	953
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—
Production	(364)	—	(364)	(1,706)	—	(1,706)
At December 31, 2019	**5,768**	**4,122**	**9,890**	**30,623**	**28,673**	**59,296**

Total Company	Total Oil [4]			Light & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)
At December 31, 2018	165,437	95,691	261,129	165,337	95,609	260,946	100	83	183	—	—	—
Discoveries	249	281	530	249	281	530	—	—	—	—	—	—
Extensions & Improved Recovery	11,764	2,957	14,721	11,764	2,957	14,721	—	—	—	—	—	—
Technical Revisions	6,477	(6,106)	370	6,476	(6,101)	375	—	(5)	(5)	—	—	—
Acquisitions	795	374	1,169	795	374	1,169	—	—	—	—	—	—
Dispositions	(7)	(3)	(11)	(7)	(3)	(11)	—	—	—	—	—	—
Economic Factors	(377)	(363)	(740)	(377)	(363)	(740)	—	—	—	—	—	—
Production	(17,451)	—	(17,451)	(17,438)	—	(17,438)	(13)	—	(13)	—	—	—
At December 31, 2019	**166,886**	**92,830**	**259,717**	**166,799**	**92,753**	**259,552**	**87**	**78**	**165**	**—**	**—**	**—**

Total Company	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)	(mmcf)
At December 31, 2018	564,874	415,539	980,413	562,140	412,470	974,610	1,828	2,856	4,683	906	213	1,120
Discoveries	16,440	9,326	25,766	16,440	9,326	25,766	—	—	—	—	—	—
Extensions & Improved Recovery	58,396	27,893	86,290	58,396	27,893	86,290	—	—	—	—	—	—
Technical Revisions	55,208	(17,777)	37,431	51,768	(16,192)	35,575	3,585	(1,540)	2,045	(145)	(45)	(190)
Acquisitions	14,859	5,743	20,602	14,859	5,743	20,602	—	—	—	—	—	—
Dispositions	(23)	(1,235)	(1,258)	(23)	(1,235)	(1,258)	—	—	—	—	—	—
Economic Factors	(1,872)	355	(1,517)	(1,872)	355	(1,517)	—	—	—	—	—	—
Production	(97,390)	—	(97,390)	(96,148)	—	(96,148)	(1,176)	—	(1,176)	(66)	—	(66)
At December 31, 2019	**610,493**	**439,844**	**1,050,336**	**605,560**	**438,359**	**1,043,919**	**4,237**	**1,316**	**5,553**	**696**	**168**	**864**

Total Company	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(mbbl)	(mbbl)	(mbbl)	(mboe)	(mboe)	(mboe)
At December 31, 2018	38,378	24,874	63,252	297,960	189,822	487,783
Discoveries	72	84	156	3,060	1,920	4,980
Extensions & Improved Recovery	5,479	2,173	7,652	26,976	9,779	36,754
Technical Revisions	(716)	(2,702)	(3,418)	14,962	(11,771)	3,191
Acquisitions	1,136	563	1,700	4,408	1,894	6,302
Dispositions	(1)	(206)	(208)	(13)	(415)	(428)
Economic Factors	(96)	13	(83)	(784)	(291)	(1,076)
Production	(2,947)	—	(2,947)	(36,630)	—	(36,630)
At December 31, 2019	**41,304**	**24,800**	**66,103**	**309,939**	**190,937**	**500,876**

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 in “Forecast Prices used in Estimates”. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

(4) For reporting purposes, “Total Oil” is the sum of Light 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.

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		Conventional Natural Gas		Heavy Oil		Coal Bed Methane		Natural Gas Liquids		Total Oil Equivalent	
	First Attributed [1]	Booked (mbbl)	First Attributed [1]	Booked (mmcf)	First Attributed [1]	Booked (mmcf)	First Attributed [1]	Booked (mmcf)	First Attributed [1]	Booked (mbbl)	First Attributed [1]	Booked (mboe)
Proved												
Prior to 2016	25,459	68,207	119,492	760,729			13,467	62,714	9,057	22,508	56,676	227,956
2016	1,411	16,140	25,023	90,934	—	—	—	3,043	1,737	7,546	7,319	39,349
2017	2,221	16,816	36,709	99,458	—	—	—	2,023	3,988	9,133	12,327	42,863
2018	12,910	50,334	39,940	133,931	39	78	—	453	5,649	16,265	25,255	89,074
2019	7,220	55,017	28,369	145,253	—	77	—	259	3,080	15,811	15,029	95,157
Probable												
Prior to 2016	36,549	110,660	192,842	562,854			7,830	38,942	14,194	28,364	84,188	239,323
2016	4,918	27,863	66,129	167,973	—	—	—	3,328	1,611	10,506	17,551	66,919
2017	4,336	28,646	38,537	197,647	—	—	—	1,055	2,802	11,455	13,561	73,218
2018	12,521	57,802	49,186	247,148	61	72	—	78	5,556	18,176	26,336	117,254
2019	5,470	54,566	54,866	273,081	—	74	—	513	3,900	17,165	18,515	117,403

Note:

[1] "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year.

Future development costs

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).

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.

($M)	Total Proved Estimated Using Forecast Prices and Costs [1]	Total Proved Plus Probable Estimated Using Forecast Prices and Costs [1]
Australia		
2020	22,697	22,697
2021	2,852	2,852
2022	2,972	2,972
2023	3,153	3,153
2024	3,299	3,299
Remainder	6,797	17,509
Australia total for all years undiscounted	**41,769**	**52,482**
Canada		
2020	245,734	285,068
2021	309,739	383,382
2022	196,391	330,782
2023	126,049	251,420
2024	57,525	156,524
Remainder	136,648	188,398
Canada total for all years undiscounted	**1,072,086**	**1,595,574**
CEE		
2020	1,400	1,400
2021	11,314	11,314
2022	—	—
2023	—	—
2024	—	—
Remainder	—	—
CEE total for all years undiscounted	**12,714**	**12,714**
France		
2020	28,117	45,443
2021	31,852	60,639
2022	49,306	86,084
2023	16,500	51,567
2024	5,518	10,055
Remainder	13,547	13,655
France total for all years undiscounted	**144,840**	**267,442**
Germany		
2020	13,874	16,085
2021	5,191	7,806
2022	15,707	35,221
2023	1,726	13,658
2024	129	45,715
Remainder	744	744
Germany for all years undiscounted	**37,372**	**119,229**

($M)	Total Proved Estimated Using Forecast Prices and Costs [1]	Total Proved Plus Probable Estimated Using Forecast Prices and Costs [1]
Ireland		
2020	1,913	1,913
2021	—	—
2022	—	21,162
2023	—	—
2024	—	—
Remainder	18,674	18,674
Ireland total for all years undiscounted	**20,586**	**41,749**
Netherlands		
2020	742	11,523
2021	3,672	11,100
2022	1,367	12,077
2023	220	14,197
2024	—	12,650
Remainder	—	143
Netherlands total for all years undiscounted	**6,001**	**61,690**
United States		
2020	57,846	57,846
2021	70,477	70,477
2022	51,194	98,241
2023	44,466	107,613
2024	7,983	115,208
Remainder	—	—
United States total for all years undiscounted	**231,965**	**449,385**
Total Company		
2020	372,323	441,975
2021	435,097	547,570
2022	316,937	586,539
2023	192,115	441,608
2024	74,454	343,450
Remainder	176,409	239,123
Total for all years undiscounted	**1,567,335**	**2,600,264**

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 detailed in “Forecast Prices used in Estimates”.

Oil and gas properties and wells

The following table sets forth the number of wells (based on wellbores) in which Vermilion held a working interest as at December 31, 2019:

	Oil				Gas			
	Producing		Non-Producing [4]		Producing		Non-Producing [4]	
	Gross Wells [2]	Net Wells [3]	Gross Wells [2]	Net Wells [3]	Gross Wells [2]	Net Wells [3]	Gross Wells [2]	Net Wells [3]
Canada								
Alberta	809	667	1,533	1,127	520	421	780	485
Saskatchewan	3,240	2,735	7,076	5,698	18	18	195	177
Total Canada	4,049	3,402	8,609	6,825	538	439	975	662
Australia [1]	17	17	3	3	—	—	1	1
Croatia	—	—	—	—	—	—	2	2
France	340	335	97	95	1	1	2	2
Germany	133	105	40	34	22	8	4	1
Hungary	—	—	—	—	2	1	1	1
Ireland [1]	—	—	—	—	6	1	—	—
Netherlands	—	—	—	—	98	47	106	48
United States (Wyoming)	132	128	60	54	—	—	—	—
Total Vermilion	**4,671**	**3,986**	**8,809**	**7,011**	**667**	**498**	**1,091**	**718**

Notes:

(1) Wells for Australia and Ireland are located offshore.

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

(3) "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.

(4) 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, 2019:

($M)	Acquisition Costs for Proved Properties	Acquisition Costs for Unproved Properties	Exploration Costs	Development Costs	Total Costs
Australia	—	—	—	30,550	30,550
Canada	24,064	—	—	293,744	317,808
Croatia	—	—	9,714	—	9,714
France	—	—	62	74,579	74,641
Germany	7,570	—	10,878	10,806	29,254
Hungary	2,131	—	11,458	(1,436)	12,153
Ireland	—	—	—	1,372	1,372
Netherlands	908	—	3,739	19,866	24,513
Slovakia	—	—	636		636
United States	3,799	—	—	57,196	60,995
Total	**38,472**	**—**	**36,487**	**486,677**	**561,636**

Acreage

The following table summarizes the acreage for the year ended December 31, 2019:

	Developed [1]		Undeveloped		Total	
	Gross [2]	Net [3]	Gross [2]	Net [3]	Gross [2][4]	Net [3][4]
Australia	20,164	20,164	39,389	39,389	59,552	59,552
Canada	837,014	665,305	484,471	423,234	1,321,485	1,088,539
Croatia	1,800	1,800	2,215,647	2,215,647	2,217,447	2,217,447
France	258,125	248,873	244,354	222,126	502,479	470,999
Germany	88,603	32,662	2,815,399	1,151,203	2,904,002	1,183,865
Hungary	1,220	832	951,035	951,035	952,255	951,867
Ireland	7,200	1,440	—	—	—	—
Netherlands	194,423	80,953	1,732,877	849,047	1,927,300	930,000
Slovakia	—	—	485,591	242,796	485,591	242,796
United States	49,901	44,670	110,983	99,958	160,884	144,628
Total	**1,451,249**	**1,095,258**	**9,172,181**	**6,250,096**	**10,623,431**	**7,345,355**

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 2019 financial year:

	Exploration Wells		Development Wells	
	Gross [1]	Net [2]	Gross [1]	Net [2]
Canada				
Oil	—	—	130.0	111.4
Gas	—	—	22.0	21.5
Dry Holes	—	—	—	—
Total Canada	**—**	**—**	**152.0**	**132.9**
Croatia				
Oil	—	—	—	—
Gas	2.0	2.0	—	—
Dry holes	—	—	—	—
Total Croatia	**2.0**	**2.0**	**—**	**—**
France				
Oil	—	—	4.0	4.0
Gas	—	—	—	—
Dry Holes	—	—	—	—
Total France	**—**	**—**	**4.0**	**4.0**
Germany				
Oil	—	—	—	—
Gas	2.0	0.7	—	—
Dry Holes	—	—	—	—
Total Germany	**2.0**	**0.7**	**—**	**—**
Hungary				
Oil	—	—	—	—
Gas	3.0	2.3	—	—
Dry Holes	1.0	1.0	—	—
Total Hungary	**4.0**	**3.3**	**—**	**—**
Ireland				
Oil	—	—	—	—
Gas	—	—	—	—
Dry Holes	—	—	—	—
Total Ireland	**—**	**—**	**—**	**—**
Netherlands				
Oil	—	—	—	—
Gas	—	—	2.0	0.5
Dry Holes	—	—	—	—
Total Netherlands	**—**	**—**	**2.0**	**0.5**
United States				
Oil	—	—	8.0	8.0
Gas	—	—	—	—
Dry Holes	—	—	—	—
Total United States	**—**	**—**	**8.0**	**8.0**
Total Company				
Oil	—	—	144.0	125.4
Gas	7.0	5.0	24.0	22.0
Dry Holes	1.0	1.0	—	—
Total Company	**8.0**	**6.0**	**168.0**	**147.4**

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.

Properties with no attributed reserves

The following table sets out Vermilion's properties with no attributed reserves as at December 31, 2019:

Country	Gross Acres [1]	Net Acres [2]
Australia	39,389	39,389
Canada	50,170	43,648
Croatia	2,215,647	2,215,647
France	90,683	82,521
Germany	2,771,389	1,136,269
Hungary	950,253	950,253
Ireland	—	—
Netherlands	1,585,852	777,068
Slovakia	485,592	242,796
United States	64,592	58,132
Total	**8,253,567**	**5,545,724**

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 111,968 (108,948 net) acres in Canada, 893,711 (893,711 net) acres in Croatia, 321,895 (321,895 net) acres in Hungary, 65,975 (65,975 net) acres in France, and 1,326 (1,326 net) acres in the United States 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, Germany, Ireland, the Netherlands, and Slovakia. 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 $30.6 million in the next year.

During the third quarter of 2019, Vermilion was awarded two exploration licenses in Ukraine, subject to a final production sharing agreement, in a 50/50 partnership with Ukrgazvydobuvannya ("UGV"), a Ukrainian state owned gas producer. The licenses, excluded from the table above, cover approximately 500,000 gross acres situated in one of Europe's most prolific natural gas regions (Dnieper-Donets Basin).

Vermilion's properties with no attributed reserves do not have any significant abandonment and reclamation costs. 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.

Production estimates

The following table sets forth the volume of production estimated for the year ended December 31, 2020 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	4,698	—	—	—	—	—	—	4,698
Probable	185	—	—	—	—	—	—	185
Proved Plus Probable	**4,883**	**—**	**—**	**—**	**—**	**—**	**—**	**4,883**
Canada								
Proved	25,559	4	—	135,192	296	2,584	12,764	61,339
Probable	2,772	—	—	22,460	7	43	1,546	8,070
Proved Plus Probable	**28,331**	**5**	**—**	**157,653**	**303**	**2,628**	**14,310**	**69,409**
CEE								
Proved	—	—	—	1,965	—	—	—	327
Probable	—	—	—	254	—	—	—	42
Proved Plus Probable	**—**	**—**	**—**	**2,219**	**—**	**—**	**—**	**370**
France								
Proved	10,228	—	—	—	—	—	—	10,228
Probable	511	—	—	—	—	—	—	511
Proved Plus Probable	**10,739**	**—**	**—**	**—**	**—**	**—**	**—**	**10,739**
Germany								
Proved	1,292	—	—	15,210	—	—	—	3,827
Probable	109	—	—	632	—	—	—	214
Proved Plus Probable	**1,400**	**—**	**—**	**15,843**	**—**	**—**	**—**	**4,041**
Ireland								
Proved	—	—	—	38,392	—	—	—	6,399
Probable	—	—	—	825	—	—	—	138
Proved Plus Probable	**—**	**—**	**—**	**39,217**	**—**	**—**	**—**	**6,536**
Netherlands								
Proved	—	—	—	42,896	—	—	130	7,280
Probable	—	—	—	4,029	—	—	12	684
Proved Plus Probable	**—**	**—**	**—**	**46,925**	**—**	**—**	**143**	**7,963**
United States								
Proved	3,928	—	—	10,250	—	—	1,131	6,767
Probable	502	—	—	780	—	—	86	718
Proved Plus Probable	**4,430**	**—**	**—**	**11,030**	**—**	**—**	**1,217**	**7,485**
Corporate								
Total Proved	45,705	4	—	243,905	296	2,584	14,025	100,865
Probable	4,078	—	—	28,981	7	43	1,645	10,561
Total Proved Plus Probable	**49,783**	**5**	**—**	**272,886**	**303**	**2,628**	**15,670**	**111,427**

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:

	Three Months Ended March 31, 2019	Three Months Ended June 31, 2019	Three Months Ended September 31, 2019	Three Months Ended December 31, 2019
Australia				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	5,862	6,689	5,564	4,548
Conventional Natural Gas (mmcf/d)	—	—	—	—
Natural Gas Liquids (bbl/d)	—	—	—	—
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	91.02	99.39	93.71	88.35
Conventional Natural Gas ($/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 ($/bbl)	30.64	18.77	19.81	34.09
Conventional Natural Gas ($/mcf)	—	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	60.38	80.62	73.90	54.26
Conventional Natural Gas ($/mcf)	—	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Canada				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	25,067	23,973	23,610	23,259
Conventional Natural Gas (mmcf/d)	151.37	151.87	145.14	145.14
Natural Gas Liquids (bbl/d)	11,064	12,224	10,704	11,144
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	65.67	73.50	66.67	66.32
Conventional Natural Gas ($/mcf)	2.47	1.12	1.16	2.33
Natural Gas Liquids ($/bbl)	37.71	33.36	28.26	33.08
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	8.15	10.46	9.40	9.24
Conventional Natural Gas ($/mcf)	0.13	(0.35)	0.09	0.05
Natural Gas Liquids ($/bbl)	5.18	2.39	2.32	3.58
Transportation				
Light Crude Oil and Medium Crude Oil ($/bbl)	1.75	1.46	1.73	1.59
Conventional Natural Gas ($/mcf)	0.18	0.18	0.18	0.22
Natural Gas Liquids ($/bbl)	0.77	0.75	0.79	0.76
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	9.23	8.51	8.70	8.98
Conventional Natural Gas ($/mcf)	1.49	1.31	1.34	1.41
Natural Gas Liquids ($/bbl)	4.07	4.34	3.94	4.30
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	46.54	53.06	46.84	46.51
Conventional Natural Gas ($/mcf)	0.67	(0.02)	(0.45)	0.65
Natural Gas Liquids ($/bbl)	27.68	25.88	21.21	24.43

	Three Months Ended March 31, 2019	Three Months Ended June 31, 2019	Three Months Ended September 31, 2019	Three Months Ended December 31, 2019
France				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	11,342	9,800	10,347	10,264
Conventional Natural Gas (mmcf/d)	0.77	—	—	—
Natural Gas Liquids (bbl/d)	—	—	—	—
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	81.52	91.17	79.89	80.87
Conventional Natural Gas ($/mcf)	1.76	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	11.14	11.72	11.18	10.68
Conventional Natural Gas ($/mcf)	0.01	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Transportation				
Light Crude Oil and Medium Crude Oil ($/bbl)	3.13	9.75	6.05	3.34
Conventional Natural Gas ($/mcf)	—	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	15.53	15.43	14.77	16.78
Conventional Natural Gas ($/mcf)	—	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	51.72	54.27	47.89	50.07
Conventional Natural Gas ($/mcf)	1.75	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Germany				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	978	1,047	845	800
Conventional Natural Gas (mmcf/d)	16.71	14.56	14.54	15.44
Natural Gas Liquids (bbl/d)	—	—	—	—
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	78.50	87.05	76.51	77.58
Conventional Natural Gas ($/mcf)	7.94	5.52	3.92	4.96
Natural Gas Liquids ($/bbl)	—	—	—	—
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	5.83	3.64	2.50	2.21
Conventional Natural Gas ($/mcf)	1.11	0.89	0.56	0.32
Natural Gas Liquids ($/bbl)	—	—	—	—
Transportation				
Light Crude Oil and Medium Crude Oil ($/bbl)	10.86	9.07	16.54	14.56
Conventional Natural Gas ($/mcf)	0.43	(0.03)	0.30	0.08
Natural Gas Liquids ($/bbl)	—	—	—	—
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	27.52	20.67	25.75	30.08
Conventional Natural Gas ($/mcf)	2.20	2.54	3.28	3.99
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	34.29	53.67	31.72	30.73
Conventional Natural Gas ($/mcf)	4.20	2.12	(0.22)	0.57
Natural Gas Liquids ($/bbl)	—	—	—	—

	Three Months Ended March 31, 2019	Three Months Ended June 31, 2019	Three Months Ended September 31, 2019	Three Months Ended December 31, 2019
Hungary				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	—	—	—	—
Conventional Natural Gas (mmcf/d)	—	—	—	1.66
Natural Gas Liquids (bbl/d)	—	—	—	—
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/mcf)	—	—	—	5.23
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 ($/bbl)	—	—	—	—
Conventional Natural Gas ($/mcf)	—	—	—	0.39
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/mcf)	—	—	—	4.84
Natural Gas Liquids ($/bbl)	—	—	—	—
Ireland				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	—	—	—	—
Conventional Natural Gas (mmcf/d)	51.71	49.21	43.21	42.30
Natural Gas Liquids (bbl/d)	—	—	—	—
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/mcf)	8.55	5.79	4.20	5.61
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)	0.25	0.26	0.28	0.26
Natural Gas Liquids ($/bbl)	—	—	—	—
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/mcf)	0.82	0.59	0.79	0.73
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/mcf)	7.48	4.94	3.13	4.62
Natural Gas Liquids ($/bbl)	—	—	—	—

	Three Months Ended March 31, 2019	Three Months Ended June 31, 2019	Three Months Ended September 31, 2019	Three Months Ended December 31, 2019
Netherlands				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	—	—	—	—
Conventional Natural Gas (mmcf/d)	51.51	52.90	44.08	47.99
Natural Gas Liquids (bbl/d)	93	100	82	90
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/mcf)	8.63	5.73	4.49	5.57
Natural Gas Liquids ($/bbl)	67.10	79.10	69.12	73.51
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/mcf)	0.13	0.09	0.07	0.03
Natural Gas Liquids ($/bbl)	—	—	—	—
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/mcf)	1.79	1.60	1.58	2.21
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/mcf)	6.71	4.04	2.84	3.33
Natural Gas Liquids ($/bbl)	67.10	79.10	69.12	73.51
United States				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	1,750	2,421	2,717	3,149
Conventional Natural Gas (mmcf/d)	5.89	7.06	6.38	8.20
Natural Gas Liquids (bbl/d)	921	817	1,144	1,168
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	68.60	72.09	68.95	66.73
Conventional Natural Gas ($/mcf)	3.80	1.74	1.67	1.73
Natural Gas Liquids ($/bbl)	25.06	18.30	9.56	20.94
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	1.23	1.81	2.01	2.07
Conventional Natural Gas ($/mcf)	1.09	0.40	0.43	0.44
Natural Gas Liquids ($/bbl)	0.59	0.33	0.25	0.54
Transportation				
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)	7.11	6.65	7.21	7.16
Conventional Natural Gas ($/mcf)	1.55	1.43	1.29	1.46
Natural Gas Liquids ($/bbl)	3.74	2.25	3.04	2.65
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	60.26	63.63	59.72	57.51
Conventional Natural Gas ($/mcf)	1.16	(0.09)	(0.05)	(0.17)
Natural Gas Liquids ($/bbl)	20.73	15.72	6.27	17.75

	Three Months Ended March 31, 2019	Three Months Ended June 31, 2019	Three Months Ended September 31, 2019	Three Months Ended December 31, 2019
Total Company				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	45,001	43,938	43,084	42,024
Conventional Natural Gas (mmcf/d)	277.95	275.60	253.36	260.72
Natural Gas Liquids (bbl/d)	12,078	13,132	11,929	12,398
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	77.38	77.90	77.20	68.65
Conventional Natural Gas ($/mcf)	5.10	3.09	2.43	3.61
Natural Gas Liquids ($/bbl)	36.97	32.74	26.76	32.22
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	14.62	17.41	16.77	16.17
Conventional Natural Gas ($/mcf)	0.19	(0.12)	0.11	0.08
Natural Gas Liquids ($/bbl)	5.77	2.72	2.57	4.13
Transportation Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	1.84	2.61	2.32	1.84
Conventional Natural Gas ($/mcf)	0.17	0.14	0.17	0.17
Natural Gas Liquids ($/bbl)	0.49	0.78	0.64	0.54
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	12.72	10.56	10.89	11.54
Conventional Natural Gas ($/mcf)	1.47	1.30	1.40	1.60
Natural Gas Liquids ($/bbl)	3.41	3.15	3.01	3.40
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	48.20	47.32	47.23	39.11
Conventional Natural Gas ($/mcf)	3.27	1.77	0.75	1.76
Natural Gas Liquids ($/bbl)	27.29	26.08	20.53	24.15

Tax information

Vermilion pays current taxes in France, the Netherlands, and Australia.

In France, current income taxes are applied to taxable income after eligible deductions. Based on legislation passed in 2019, corporate tax rates in France are 32.0% 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 at a tax rate of 50%.

In Australia, current taxes include both corporate income taxes and Petroleum Resource Rent Tax ("PRRT"). Corporate income taxes are applied at a rate of 30% on taxable income after eligible deductions, which include PRRT paid. PRRT is applied at a rate of 40% on sales less eligible expenditures, including operating expenses and capital expenditures.

As a function of the impact of Vermilion's tax pools, the Company does not presently pay current taxes in Canada, Germany, Hungary, Ireland, and the United States.

The following table sets forth Vermilion's tax pools as at December 31, 2019:

($M)	Oil & Gas Assets	Tax Losses	Other	Total
Australia	252,581(1)	—	—	252,581
Canada	2,096,939(1)	1,221,855(4)	28,558	3,347,352
France	389,115(2)	—	—	389,115
Germany	161,888(3)	112,090(5)	9,828	283,806
Ireland	—	1,128,178(4)	—	1,128,178
Netherlands	52,452(3)	1,239	—	53,691
United States	278,849(2)	62,295(6)	—	341,144
Total	**3,231,824**	**2,525,657**	**38,386**	**5,795,867**

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 and applied at 100% against taxable income.
(5) 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.
(6) Tax losses created prior to January 1, 2018 are carried forward and applied at 100% against taxable income, tax losses created after January 1, 2018 are carried forward and applied to 80% of taxable income in each taxation year.

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, 2019 are summarized in Supplemental Table 2: Hedges, included in the Company's 2019 Management's Discussion and Analysis, dated March 5, 2020, available on SEDAR at www.sedar.com, under Vermilion's SEDAR profile.

Directors and Officers

As at January 31, 2020, the directors and officers of Vermilion beneficially owned, or controlled or directed, directly or indirectly, 4,001,330 common shares representing approximately 2.6% 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.

Board of Directors

Vermilion's Board of Directors currently consists of ten 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
Larry J. Macdonald Okotoks, Alberta Canada	(2) (4) (6) (8)	Lead Director	2002	Since March 1, 2016, Lead Director of Vermilion 2012 to March 1, 2016, Chairman of the Board of Vermilion 2012 to 2016, Chairman Northpoint Resources, a private oil and gas company Since June 2018, Chairman of the Board of United Way Canada Gives Across Borders, a non-profit organization 2003 to 2019, Chairman & Chief Executive Officer and Director of Point Energy Ltd., a private oil and gas company
Carin S. Knickel Golden, Colorado USA	(6) (8) (12)	Director	2018	Since 2015, Director of Hudbay Minerals, Inc., a public mining company Since 2015, Director of Whiting Petroleum Corporation, a public oil and gas company Since 2014, Director of National MS Society (Colorado/Wyoming Chapter), a non-profit organization 2012 to 2015, Director of Rosetta Resources Inc., a private oil and gas company 2013 to 2014, Director of University of Colorado Denver, a public research university
Stephen Larke Calgary, Alberta Canada	(4) (6) (12)	Director	2017	Since 2020, Director of Headwater Exploration Inc., a public oil and gas company Since 2019, Director of Topaz Energy Corp., a private energy company 2016 to 2018, 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 McKinney, Texas USA	(10)	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

Timothy R. Marchant Calgary, Alberta Canada	(7) (10) (11)	Director		2010	Since 2015, Non-Executive 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
Anthony W. Marino Calgary, Alberta Canada		President & Chief Executive Officer and Director		2016	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
Robert Michaleski Calgary, Alberta Canada	(4) (5)	Director		2016	2013 to 2018, Director of United Way of Calgary and Area, a non-profit organization 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
William Roby Katy, Texas USA	(8) (9) (12)	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
Catherine L. Williams Calgary, Alberta Canada	(3) (6)	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) Audit Committee Chair (Independent)
(4) Audit Committee Member
(5) Governance and Human Resources Committee Chair (Independent)
(6) Governance and Human Resources Committee Member
(7) Health, Safety and Environment Committee Chair (Independent)
(8) Health, Safety and Environment Committee Member
(9) Independent Reserves Committee Chair (Independent)
(10) Independent Reserves Committee Member
(11) Sustainability Committee Chair (Independent)
(12) Sustainability Committee Member

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
Lars Glemser Calgary, Alberta Canada	Vice President & Chief Financial Officer	Since April 2018, Vice President and Chief Financial Officer of Vermilion December 2017 – April 2018, Director, Finance of Vermilion June 2015 – December 2017, Finance Professional of Vermilion January 2013 – June 2015, Treasurer Lightstream Resources Ltd, a public oil and gas company
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
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
Terry Hergott Calgary, Alberta Canada	Vice President Marketing	Since April 2012, Vice President, Marketing of Vermilion
Kyle Preston Calgary, Alberta Canada	Vice President Investor Relations	Since July 2019, Vice President, Investor Relations of Vermilion May 2016 to July 2019, Director, Investor Relations of Vermilion October 2011 to May 2016, Director, Oil & Gas Research, National Bank of Canada
Gerard Schut Den Haag The Netherlands	Vice President European Operations	Since July 2012, Vice President European Operations of Vermilion
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
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

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 credit rating of the Company or the Company's debt 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 enter into ordinary course hedging arrangements or contracts with customers and suppliers.

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.

As at March 5, 2020, Vermilion had the following credit ratings from Standard & Poors Ratings Services ("S&P"), Moody's Investors Service ("Moody's"), and Fitch Ratings ("Fitch"):

Rating Agency	Company Rating	Outlook	Senior Unsecured Notes
S&P (1)	BB- (1)	Stable	BB- (4)
Moody's (2)	Ba3 (2)	Stable	B2 (5)
Fitch (3)	BB- (3)	Stable	BB- (6)

Notes:

(1) S&P rates long-term corporate credit ratings by rating categories ranging from a high of "AAA" to a low of "D". 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.

(2) 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. An obliger rated Ba3 is considered non-investment grade speculative and is subject to substantial credit risk.

(3) Fitch's corporate credit rating categories range from "investment grade" for those with ratings of "AAA" to "BBB", and "speculative grade" for those with "BB" to "D" ratings. Modifiers may be used by Fitch within these rating categories, either (+) or (-), appended to a rating to indicate relative status within the major rating categories. Rating outlooks may be provided to direct where a rating may potentially move within the next year or two, and fall under four outlooks: "positive", "stable", "negative", or "evolving". A "BB-" rating for an obliger denotes an increased vulnerability to default risk, especially if experiencing adverse changes in economic or business conditions over time; conversely, there remains a financial or business flexibility that sustains the servicing of financial obligations.

(4) 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, an obligation rated "BB-" 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.

(5) 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.

(6) Fitch's long-term debt instrument ratings are categorized from "investment grade" for those with ratings of "AAA" to "BBB", and "speculative grade" for those with "BB" to "D" ratings. Modifiers may be used by Fitch within these rating categories, either (+) or (-), appended to a rating to indicate relative status within the major rating categories. A "BB-" rating for an obliger denotes an increased vulnerability to default risk, especially if experiencing adverse changes in economic or business conditions over time; conversely, there remains a financial or business flexibility that sustains the servicing of financial obligations.

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 pursuant to which a holder may receive Common Shares have been issued under certain Vermilion compensation arrangements. See Vermilion's annual financial statements as at and for the year ended December 31, 2019 (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.

Dividend history

The Company currently pays dividends on a monthly basis. Solvency tests imposed by the ABCA on corporations for the declaration and payment of dividends must be satisfied prior to the declaration of a dividend. In addition, decisions with respect to the declaration of dividends on the common shares will be made by the Board of Directors on the basis of the Company's net earnings, financial requirements, and other conditions. Dividends are generally paid on the 15th day of the month following the month of declaration.

The following table sets forth the history of Vermilion's monthly dividend per share (pre-September 2010 distribution per unit):

Date		Monthly dividend per unit or share
January 2003 to December 2007	$	0.170
January 2008 to December 2012	$	0.190
January 2013 to December 2013	$	0.200
January 2014 to March 2018	$	0.215
April 2018 to February 2020	$	0.230
March 2020 onwards	$	0.115

The following table outlines dividends declared per share for each of the three most recently completed financial years:

Date		Dividends per common share
January 2017 to December 2017	$	2.58
January 2018 to December 2018	$	2.72
January 2019 to December 2019	$	2.76

Dividend Reinvestment Plan

Under the Premium Dividend™ and Dividend Reinvestment Plan (the "Plan"), Eligible Shareholders who elect to participate in the Dividend Reinvestment Component can reinvest their dividends in common shares at the Average Market Price (with no broker commissions or trading costs).

From February 2015 to July 2017, Vermilion used the Premium Dividend™ Component of the Dividend Reinvestment Plan to provide access to low cost source of equity capital. Vermilion discontinued the Premium Dividend™ Component in July 2017.

Vermilion elected to phase out the Dividend Reinvestment Plan ("DRIP"), prorating the available DRIP shares by 25% each quarter starting in Q1 2020. The intention is to increase this proration each quarter throughout next year, such that the DRIP will be eliminated at the end of Q3 2020.

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.

Market for Securities

The outstanding common shares of the Company are listed and posted for trading on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("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:

2019	High	Low	Close	Volume
January	$ 33.46	$ 27.87	$ 32.20	19,161,582
February	$ 34.48	$ 30.73	$ 33.66	15,499,462
March	$ 36.04	$ 32.63	$ 32.99	19,330,980
April	$ 36.83	$ 32.29	$ 34.21	22,515,096
May	$ 34.21	$ 28.02	$ 28.34	23,195,870
June	$ 29.33	$ 26.54	$ 28.45	19,270,343
July	$ 29.19	$ 21.97	$ 23.65	33,967,364
August	$ 23.49	$ 18.28	$ 18.95	29,268,596
September	$ 24.47	$ 18.18	$ 22.07	34,552,859
October	$ 22.51	$ 17.13	$ 17.40	38,646,103
November	$ 20.84	$ 17.52	$ 19.10	44,410,760
December	$ 21.93	$ 18.06	$ 21.23	31,876,009

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 the Queen's University. Ms. Williams brings 32 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 brings over 20 years of experience in energy capital markets, including research, sales, trading, and equity finance. From 2017 to 2018, he was 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 48 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, 2019 and 2018, Deloitte LLP, the auditors of the Company, received the following fees from the Company:

Item		2019		2018
Audit fees [1]	$	1,846,197	$	1,934,531
Audit-related fees [2]	$	34,500	$	81,500
Tax fees [3]	$	97,638	$	800

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, 2019 and 2018.
(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.
(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, 2019, 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 March 5, 2020.

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 AIF. 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.

Market risks

Volatility of oil and gas prices

The Company's reserves, financial performance, financial position, and cash flows 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. Supply factors can include availability (or lack thereof) of transportation capacity and production curtailments by independent producers or by OPEC members. 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. Shifts in supply and demand for certain commodities, products, and services may occur as climate-related risks are increasingly taken into account.

Volatility of foreign exchange rates

The Company's reserves, financial performance, financial position, and cash flows are affected by prevailing foreign exchange rates. An increase in the exchange rate for the Canadian dollar versus the U.S. dollar and Euro would reduce the Canadian equivalent cash receipts for Vermilion's production. Conversely, a decrease in the exchange rate for the Canadian dollar versus the U.S. dollar and Euro would increase the Canadian equivalent cash outflows for Vermilion's operating and capital expenditures.

Volatility of market price of Common Shares

The market price of Vermilion's Common Shares may be volatile and this volatility may affect the ability of Shareholders to sell Common Shares at an advantageous price. Market price fluctuations in the common shares may be due to: the Company's operating results or financial performance 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 AIF. In addition, the market price for securities in stock markets including Common Shares may experience significant price and trading fluctuations. These fluctuations may result in volatility in the market prices of securities that may be unrelated or disproportionate to changes in the Company's operating and financial performance.

Hedging arrangements

Vermilion may enter into agreements to fix commodity prices, interest rates, and foreign exchange rates to offset the risks affecting the business. To the extent that Vermilion engages in price risk management activities to protect the Company from unfavourable fluctuations in prices and rates, the Company may also be prevented from realizing the full benefits of favourable fluctuations in prices and rates.

To the extent that risk management activities and hedging strategies are employed to address these risks, the Company would also be exposed to risks associated with such activities and strategies, including: counterparty risk, settlement risk, basis risk, liquidity risk and market risk. These risks could impact or negate any benefits of risk management activities and hedging strategies.

In addition, commodity hedging arrangements could expose the Company to the risk of financial loss if: 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; or a sudden unexpected event materially impacts oil and natural gas prices.

Operational risks

Increase in operating costs or a decline in production level

The Company's financial performance, financial position, and cash flows are affected by the Company's operating costs and production levels. Operating costs may increase and production levels may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond Vermilion's control.

Production levels may decline due to an inability for Vermilion to market oil and natural gas production. This could result from the availability, proximity and capacity of gathering systems, pipelines and processing facilities that Vermilion depends on in the jurisdictions in which it operates.

Operating costs could increase as a result of blowouts, environmental damage, unforeseen circumstances related to climate-change, and other unexpected and dangerous conditions which could result from a number of operating and natural hazards associated with Vermilion's operations. In addition to higher costs, Vermilion may have a potential liability to regulators and third parties as a result. 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.

Operator performance and payment delays

Continuing production from a property are dependent upon the ability of the operator of the property, and the operator may fail to perform these functions properly. 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.

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.

Weather conditions

Vermilion's operations may be impacted by changing weather conditions, which may include: changes in temperature extremes, changes in precipitation patterns (including drought and flooding), rising sea levels, and increased severity of extreme weather events such as cyclones or floods. These events can impact Vermilion's operations, causing shutdowns and increased costs. In the Netherlands, rising water levels could impact facilities below sea level and in Australia a severe cyclonic event could cause damage to the Company's Wandoo platform.

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 Vermilion does. There can be no assurance that Vermilion 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 the Company or implemented in the future may become obsolete.

Regulatory and political risks

Tax, royalty, and other government legislation

Income tax laws, royalty and other government legislation relating to the oil and gas industry in the jurisdictions in which the Company operates may change in a manner that adversely affects Vermilion.

Government regulations

Vermilion's operations are governed by many levels of governments in which jurisdiction the Company operates. 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, not obtained, or revoked, 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 reduced production and increased capital, operating and compliance costs.

Policy and legal risks

Policy actions that attempt to constrain actions that contribute to the adverse effects of climate change or policy actions that seek to promote adaptation to climate change continue to evolve. Policy changes could include implementing carbon-pricing mechanisms to reduce GHG emissions, shifting energy-efficient solutions, and promoting more sustainable land-use practices. The risks and financial impact of policy changes depend on the nature and timing of the policy change.

Vermilion may be exposed to increased litigation risk relating to climate change. The oil and gas industry has seen an increase in climate-related litigation claims being brought before the courts by property owners, municipalities, and public interest organizations. Some of these claims include the failure of organizations to mitigate the impacts of climate change, failure to adapt to climate change, and the insufficiency of disclosure around material financial risks. As the value of loss and damage arising from climate change increases, litigation risk will also grow.

Political events and terrorist attacks

Political events throughout the world that cause disruptions in the supply of oil 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.

Vermilion’s oil and natural gas properties, wells and facilities could be subject to a terrorist attack. 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 financial performance, financial position, and cash flows.

Financing risks

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, including the satisfaction of the liquidity and solvency tests under the ABCA for the declaration and payment of dividends and the amount of the Company's cash flows. The Company's cash flows may be impacted by risks affecting the Company's business including: fluctuations in commodity prices, foreign exchange and interest rates; production and sales volume levels; production costs; capital expenditure requirements; royalty and tax burdens; external financing availability, and debt service requirements.

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, 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.

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.

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 oil and natural gas reserves may 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.

Debt service

Vermilion may 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.

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.

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. A decrease in the exchange rate of the Canadian dollar versus the Euro would result in higher interest and ultimate principle payment on the Company's Senior Unsecured Notes, which are denominated in US dollar but have been swapped to a Euro equivalent obligation.

Environmental risks

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 include carbon taxes, enhanced emissions reporting obligations, mandates on the equipment specifications, and emissions regulations. Such legislation may be changed to impose higher standards and potentially more costly obligations on Vermilion. In addition, such legislation may inhibit Vermilion's ability to operate the Company's assets and may make it more difficult for Vermilion to compete in the acquisition of new property rights. Presently, the Company does not believe the financial impact of these regulations on capital expenditures and earnings will be material. However, the Company actively monitors and assesses its exposure to this legislation.

Vermilion expects to incur abandonment and reclamation costs in the ordinary course of business as existing oil and gas properties are abandoned and reclaimed. These costs may materially differ from the Company's estimates due to changes in environmental regulations.

Vermilion's exploration and production facilities and other operations and activities emit some amount of greenhouse gases, which may be subject to legislation regulating emissions of greenhouse gases. This may result in a requirement to reduce emissions or emissions intensity from Vermilion's operations and facilities. It is possible that future regulations may require further reductions of emissions or emissions intensity.

Hydraulic fracturing regulations

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate oil and natural gas production. Hydraulic fracturing is used to produce commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Hydraulic fracturing has 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 Vermilion's 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 the Company is ultimately able to produce from its reserves, as well as increase costs.

With activist groups expressing concern about the impact of hydraulic fracturing on the environment and water supplies, Vermilion's corporate reputation may be negatively affected by the negative public perception and public protests against hydraulic

fracturing. In addition, concerns regarding hydraulic fracturing may result in changes in regulations that delay the development of oil and natural gas resources and adversely affect Vermilion's costs of compliance and reputation. Changes in government may result in new or enhanced regulatory burdens in respect of hydraulic fracturing which could affect Vermilion's business.

Climate change

In addition to other climate-related risks discussed elsewhere in this AIF, Vermilion faces transition risks and physical risks.

Transition risks are risks that relate to the transition to a lower-carbon economy. Transition risks impact the volatility of oil and gas prices (as consumer demand for oil and gas may decrease); environmental legislation and hydraulic fracturing regulations (which may delay or restrict the development of oil and gas); the ability to obtain additional financing (as sources of financing for oil and gas development may become more restricted); and the reliance on key personnel, management, and labour (as the workforce may transition to other sources of energy development). 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 the Company's ability to hire and retain employees; to compete for reserve acquisitions, exploration leases, licenses and concessions; and to receive regulatory approvals required to execute operating programs.

Physical risks relate to the physical impact of climate change, which can be event driven (acute) or longer-term shifts (chronic) in climate patterns. Physical risks can have financial implications for the Company, such as direct damage to assets and indirect impacts from production disruptions. Physical risks may also increase Vermilion's operating costs.

Acquisition and expansion risks

Competition

Vermilion actively competes for reserve acquisitions, exploration leases, licences, 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 Vermilion's 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 Vermilion may acquire or move into new industry related activities, enter into new geographical areas, or acquire different energy related assets. These actions may result in unexpected risks or alternatively, significantly increase the Company's exposure to one or more existing risk factors.

Acquisition assumptions

When making acquisitions, Vermilion estimates the future performance of the assets to be acquired. These estimates are subject to inherent risks associated with predicting the future performance of those assets. These estimates may not be realized over time. As such, assets acquired may not possess the value Vermilion attributed to them.

Failure to realize anticipated benefits of prior acquisitions

Vermilion may 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. 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.

Reserves and resource estimates

Reserve estimates

Reserves and estimated future net revenue to be derived from reserves are estimates and have been independently evaluated by GLJ. The estimation of reserves is a complex process and requires significant judgment. Actual production and ultimate reserves will vary from those estimates and these variations may be material.

Assumptions incorporated into the estimation of reserves are based on information available when the estimate was prepared. These assumptions are subject to change and many are beyond the Company's control. These assumptions include: 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 costs; royalties, taxes, and other government levies that may be imposed over the producing life of the reserves.

In addition, estimates of reserves that may be developed and produced in the future are often based on methods other than actual production history, including: volumetric calculations, probabilistic methods, and upon analogy to similar types of reserves. Estimates based on these methods are generally 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. As such, reserve estimates may require revision based on actual production experience.

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.

Contingent and prospective resource estimates

Information regarding quantities of contingent and prospective resources included in Appendix A to this Annual Information Form are estimates only. References to “contingent resources” and "prospective 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 may be material.

Other risks

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 damage to the Company's reputation. Vermilion relies upon a variety of advanced controls as protection from such attacks including:

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.

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 and such adjustments may be viewed unfavourably by the market and may result in an inability to borrow funds or a decline in price of Common Shares.

Ineffective internal controls

Effective internal controls are necessary for Vermilion to provide reliable financial reports and to help prevent fraud. Although the Company has undertaken and will undertake a number of procedures in order to help ensure the reliability of its financial reports, including those that may be imposed on Vermilion under Canadian Securities Laws and applicable U.S. federal and state securities laws, Vermilion cannot be certain that such measures will ensure that the Company 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 Vermilion's results of operations or cause the Company to fail to meet its reporting obligations. Additionally, implementing and monitoring effective internal controls can be costly. If Vermilion or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in Vermilion's consolidated financial statements and may result in a decline in the price of Common Shares.

Reliance on key personnel, management, and labour

Vermilion's 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 the Company's business, financial condition, results of operations and prospects. Vermilion does not have any key person insurance in effect. The contributions of Vermilion's 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 the Company operates 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 the Company's projects. Vermilion's 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 the Company will be able to continue to attract and retain all personnel necessary for the development and operation of the business.

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 compete with Vermilion. No assurances can be given that opportunities identified by such persons will be provided to Vermilion.

Brexit

On June 23, 2016, the United Kingdom ("UK") held a referendum where voters decided to leave the European Union ("Brexit"). Effective January 31, 2020, the United Kingdom is no longer a member of the European Union ("EU") and has entered an 11-month transition period. During the transition, the UK effectively remains in the EU's customs union and single market and continues to comply with EU rules.

At the date of this AIF, there remains uncertainty regarding the form of Brexit as a result of these pending negotiations for future trade agreements. Brexit may result in interruptions to Vermilion's business and expose Vermilion to financial volatility, with risks including: disruption in the delivery of supplies to the Company's operations in Ireland, administrative delays to day-to-day banking activities, and foreign exchange volatility.

Vermilion's operations in Ireland are supported by contractors and suppliers, some of whom operate in the UK. Vermilion currently believes that the ability to mobilize contractor personnel from the UK to Ireland will not be impacted by Brexit. Vermilion has reviewed all of its UK based suppliers and has identified certain products that are presently sourced from the UK that may be impacted by Brexit related delays.

Vermilion recently awarded our production chemicals contract to an Irish-based supplier. The only remaining production critical supplier based in the UK is our odorant vendor. We have increased our odorant inventory prior to the January 31, 2020 Brexit deadline and have identified alternate EU based suppliers if required.

In the event of a supply disruption, Vermilion has developed contingency plans that include ensuring that the Company has maintained adequate inventory of supplies and has alternate sourcing plans from EU based suppliers.

Brexit has resulted in uncertainty and volatility for the Euro and British Pound Sterling ("GBP") as compared to each other and other currencies. This volatility is expected to continue as negotiations continue. Vermilion's natural gas produced in Ireland is priced based on the NBP index, which is denominated in GBP. Thus, a weakening of the GBP against the Canadian dollar could result in Vermilion receiving fewer Canadian equivalent dollars for its production. However, due to the interconnected nature of the UK and European natural gas markets, changes in the exchange ratio for the Euro and GBP are expected to result in offsetting changes to related commodity prices.

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, 2019.

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, 2019. 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 139.0 million boe (low estimate) to 330.2 million boe (high estimate), with a best estimate of 236.8 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 10.8 million boe (low estimate) to 54.1 million boe (high estimate), with a best estimate of 37.6 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, 2019 (1) (2) - Forecast prices and costs (3) (4

	Light & Medium Crude Oil		Conventional Natural Gas		Shale Gas		Natural Gas Liquids		BOE			Unrisked BOE	
Development Pending (10)	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													
Australia	—	—	—	—	—	—	—	—	—	—	—	—	—
Canada	39,909	30,966	229,050	213,267			18,284	16,188	96,368	82,695	81%	118,801	101,028
CEE	—	—	1,544	1,466	—	—	—	—	257	244	90%	286	272
France	11,987	11,053	2,555	2,288	—	—	—	—	12,413	11,435	87%	14,212	13,093
Germany	—	—	18,920	16,109	—	—	—	—	3,153	2,685	80%	3,935	3,348
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	61	61	15,138	15,138	—	—	12	12	2,596	2,596	73%	3,567	3,567
USA	17,869	14,962	21,008	17,625	—	—	2,879	2,413	24,250	20,313	90%	26,944	22,570
Total	**69,827**	**57,041**	**288,216**	**265,891**			**21,175**	**18,613**	**139,037**	**119,970**	**83%**	**167,745**	**143,878**
Contingent (2C) - Best Estimate (10)													
Australia	3,240	3,240	—	—	—	—	—	—	3,240	3,240	80%	4,050	4,050
Canada	59,298	46,295	410,828	381,439			30,982	26,946	158,754	136,817	80%	199,669	171,088
CEE	—	—	3,484	3,310	—	—	—	—	581	552	90%	645	613
France	27,123	24,854	3,177	2,905	—	—	—	—	27,653	25,338	85%	32,491	29,761
Germany	82	82	36,731	31,746	—	—	—	—	6,204	5,373	78%	7,993	6,929
Ireland	—	—	6,715	6,715	—	—	—	—	1,119	1,119	70%	1,599	1,599
Netherlands	121	121	30,553	30,553	—	—	26	26	5,239	5,239	73%	7,153	7,153
United States	25,000	20,929	29,679	24,894	—	—	4,102	3,438	34,048	28,516	90%	37,832	31,685
Total	**114,864**	**95,521**	**521,167**	**481,562**			**35,113**	**30,411**	**236,838**	**206,193**	**81%**	**291,432**	**252,878**
Contingent (3C) - High Estimate													
Australia	4,386	4,386	—	—	—	—	—	—	4,386	4,386	80%	5,483	5,483
Canada	74,469	57,594	573,921	531,588			43,064	36,625	213,189	182,815	79%	269,056	229,538
CEE	—	—	6,615	6,284	—	—	—	—	1,103	1,047	90%	1,225	1,164
France	42,131	38,552	2,664	2,386	—	—	—	—	42,575	38,949	84%	50,591	46,261
Germany	112	112	67,206	58,081	—	—	—	—	11,313	9,792	77%	14,716	12,749
Ireland	—	—	9,285	9,285	—	—	—	—	1,547	1,547	70%	2,211	2,211
Netherlands	242	242	52,124	52,124	—	—	42	42	8,971	8,971	74%	12,077	12,077
USA	34,546	28,912	40,814	34,218	—	—	5,729	4,800	47,077	39,415	90%	52,308	43,794
Total	**155,886**	**129,800**	**752,629**	**693,964**			**48,837**	**41,466**	**330,161**	**286,927**	**81%**	**407,666**	**353,278**

	Light & Medium Crude Oil		Conventional Natural Gas		Shale Gas		Natural Gas Liquids		BOE			Unrisked BOE	
Development Unclarified [11]	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 (mbbl)	Net (mbbl)
Contingent (1C) - Low Estimate													
Australia	—	—	—	—	—	—	—	—	—	—	—	—	—
Canada	3,022	2,778	27,440	24,978	—	—	914	751	8,509	7,692	59%	14,481	13,117
CEE	—	—	—	—	—	—	—	—	—	—	—	—	—
France	1,227	1,140	—	—	—	—	—	—	1,227	1,140	40%	3,086	2,868
Germany	—	—	—	—	—	—	—	—	—	—	—	—	—
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	—	—	6,192	6,192	—	—	—	—	1,032	1,032	51%	2,023	2,023
USA	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	**4,248**	**3,918**	**33,632**	**31,170**	**—**	**—**	**914**	**751**	**10,767**	**9,864**	**55%**	**19,590**	**18,008**
Contingent (2C) - Best Estimate[11]													
Australia	—	—	—	—	—	—	—	—	—	—	—	—	—
Canada	4,414	4,068	58,276	52,934	60,886	57,639	7,300	6,536	31,574	29,033	47%	67,476	62,329
CEE	—	—	—	—	—	—	—	—	—	—	—	—	—
France	2,385	2,217	—	—	—	—	—	—	2,385	2,217	44%	5,433	5,050
Germany	—	—	1,496	1,190	—	—	—	—	249	198	35%	712	566
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	—	—	20,083	19,509	—	—	32	16	3,379	3,267	50%	6,719	6,441
USA	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	**6,798**	**6,285**	**79,854**	**73,633**	**60,886**	**57,639**	**7,331**	**6,552**	**37,587**	**34,715**	**47%**	**80,340**	**74,386**
Contingent (3C) - High Estimate													
Australia	—	—	—	—	—	—	—	—	—	—	—	—	—
Canada	5,588	5,122	85,971	77,683	77,410	72,759	11,273	9,697	44,091	39,893	47%	94,223	85,511
CEE	—	—	—	—	—	—	—	—	—	—	—	—	—
France	3,400	3,160	—	—	—	—	—	—	3,400	3,160	45%	7,541	7,010
Germany	—	—	2,327	1,850	—	—	—	—	388	308	—%	1,108	881
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	—	—	36,751	35,869	—	—	49	24	6,174	6,002	53%	11,605	11,177
USA	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	**8,988**	**8,282**	**125,049**	**115,402**	**77,410**	**72,759**	**11,322**	**9,721**	**54,053**	**49,364**	**47%**	**114,477**	**104,579**

Summary of risked net present value of future net revenues as at December 31, 2019 - Forecast prices and costs [3]

	Before Income Taxes, Discounted at [5]					After Income Taxes, Discounted at [5]				
($M)	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Contingent (1C) - Low Estimate [6]										
Development Pending [10]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada	2,208,363	1,162,874	652,620	385,547	237,138	1,626,120	836,415	454,292	257,331	150,070
CEE	8,635	6,932	5,697	4,775	4,068	6,801	5,439	4,447	3,705	3,137
France	637,391	369,606	225,434	142,870	93,319	474,132	267,069	157,407	95,721	59,428
Germany	24,776	15,432	7,723	1,953	(2,208)	13,732	7,069	1,218	(3,223)	(6,407)
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	108,637	68,849	45,257	30,705	21,360	57,418	35,682	22,521	14,390	9,206
USA	793,000	388,426	205,782	115,523	67,626	624,170	305,749	161,413	90,060	52,254
Total	**3,780,802**	**2,012,119**	**1,142,512**	**681,372**	**421,303**	**2,802,371**	**1,457,423**	**801,298**	**457,985**	**267,688**
Contingent (2C) - Best Estimate [7]										
Development Pending [10]										
Australia	112,417	79,594	56,684	40,557	29,073	26,395	13,398	4,863	(695)	(4,284)
Canada	3,706,038	1,897,823	1,058,611	627,676	388,666	2,746,264	1,376,659	744,767	424,214	249,379
CEE	22,782	17,506	14,077	11,699	9,962	17,973	13,790	11,064	9,171	7,789
France	1,444,024	813,191	488,761	307,703	200,555	1,073,099	586,772	340,210	205,078	126,762
Germany	118,768	88,059	64,830	47,729	35,153	77,382	56,292	39,767	27,503	18,519
Ireland	2,968	3,518	1,172	(50)	(455)	(3,088)	1,060	144	(486)	(639)
Netherlands	219,258	138,586	91,969	63,495	45,238	117,670	71,733	45,170	29,150	19,084
USA	1,361,462	647,347	345,351	199,423	121,791	1,073,270	510,776	272,256	156,954	95,640
Total	**6,987,717**	**3,685,623**	**2,121,455**	**1,298,234**	**829,982**	**5,128,965**	**2,630,482**	**1,458,241**	**850,890**	**512,250**
Contingent (3C) - High Estimate [8]										
Development Pending [10]										
Australia	222,923	164,131	123,059	93,870	72,748	76,449	51,150	34,153	22,602	14,652
Canada	5,348,716	2,624,350	1,454,319	872,641	552,960	3,969,895	1,917,543	1,038,108	604,746	369,667
CEE	46,435	34,597	27,597	22,967	19,662	36,653	27,291	21,743	18,071	15,451
France	2,463,466	1,377,601	833,187	532,062	353,753	1,829,413	1,000,387	589,396	365,281	234,665
Germany	313,224	234,347	178,401	138,455	109,373	210,946	157,243	118,272	90,291	69,952
Ireland	20,457	7,293	1,255	(435)	(684)	9,342	4,002	247	(741)	(766)
Netherlands	426,236	268,900	180,938	127,821	93,722	230,704	142,453	93,124	63,593	44,873
USA	2,180,550	980,609	515,604	298,965	184,986	1,718,962	774,085	406,926	235,789	145,763
Total	**11,022,006**	**5,691,829**	**3,314,359**	**2,086,346**	**1,386,520**	**8,082,365**	**4,074,153**	**2,301,970**	**1,399,633**	**894,256**
Contingent (1C) - Low Estimate [6]										
Development Unclarified [11]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada	128,865	65,958	35,940	20,591	12,252	101,369	50,469	26,446	14,399	8,018
CEE	—	—	—	—	—	—	—	—	—	—
France	89,459	51,674	31,328	19,761	12,877	64,024	36,555	21,850	13,560	8,678
Germany	—	—	—	—	—	—	—	—	—	—
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	21,932	13,102	7,584	4,129	1,953	12,814	6,947	3,270	1,008	(367)
USA	—	—	—	—	—	—	—	—	—	—
Total	**240,256**	**130,734**	**74,852**	**44,481**	**27,081**	**178,207**	**93,970**	**51,566**	**28,968**	**16,329**
Contingent (2C) - Best Estimate [7]										
Development Unclarified [11]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada	449,262	221,217	111,659	55,519	25,209	328,331	154,765	71,445	29,218	6,897
CEE	—	—	—	—	—	—	—	—	—	—
France	162,175	87,407	50,069	30,055	18,716	117,524	62,140	34,767	20,296	12,235
Germany	130	470	505	429	323	(704)	(231)	(91)	(82)	(119)
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	109,118	66,146	41,311	26,385	17,081	62,354	36,176	21,016	12,021	6,547
United States	—	—	—	—	—	—	—	—	—	—
Total	**720,685**	**375,239**	**203,544**	**112,388**	**61,328**	**507,503**	**252,849**	**127,136**	**61,454**	**25,561**
Contingent (3C) - High Estimate [8]										
Development Unclarified [11]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada	817,260	416,944	236,010	144,272	93,319	594,942	297,097	161,937	93,815	56,482
CEE	—	—	—	—	—	—	—	—	—	—
France	248,467	129,091	72,734	43,384	27,000	181,230	92,680	51,229	29,889	18,143
Germany	4,227	3,745	3,116	2,529	2,034	2,169	2,087	1,758	1,400	1,083
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	261,111	147,395	90,475	58,912	40,033	151,082	82,646	48,649	30,061	19,154
United States	—	—	—	—	—	—	—	—	—	—
Total	**1,331,065**	**697,175**	**402,335**	**249,096**	**162,386**	**929,423**	**474,511**	**263,573**	**155,165**	**94,861**

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 uncertainty 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 2019 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) Summary of risks for development pending contingent resources at December 31, 2019[a]

Development Pending [b][c][d]	Risked Volume Gross[e] (mboe)	Risked Estimated Development Cost [f] Gross ($M)	Development Timing (yrs)
Contingent (2C) - Best Estimate			
Australia	3,240	186,353	2 to 6
Canada	158,754	1,754,103	1 to 12
CEE	581	1,139	—
France	27,653	591,562	2 to 14
Germany	6,204	86,238	3 to 5
Ireland	1,119	15,015	17
Netherlands	5,239	60,339	1 to 6
United States	34,048	398,569	6 to 10
Total	236,838	3,093,318	1 to 17

(a) 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 in "Forecast Prices used in Estimates". GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.
(b) 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).
(c) Risked development pending best estimate contingent resources for each business unit 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.
(d) The specific contingencies for these resources are corporate commitment and development timing.
(e) "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.
(f) The risked estimated cost to bring these contingent resources on commercial production.

(11) Summary of risks for development unclarified contingent resources at December 31, 2019 [a]

Development Unclarified [b][c][d]	Risked Volume Gross[e] (mboe)	Risked Estimated Development Cost [f] Gross ($M)	Development Timing (yrs)
Contingent (2C) - Best Estimate			
Australia	—	—	—
Canada	31,574	406,445	2 to 14
CEE	—	—	—
France	2,385	41,088	6 to 8
Germany	249	4,501	3
Ireland	—	—	—
Netherlands	3,379	56,025	3
United States	—	—	—
Total	37,587	508,059	2 to 14

(a) 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 in "Forecast Prices used in Estimates". GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.
(b) 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.
(c) Risked development unclarified best estimate contingent resources for each business unit 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.
(d) The specific contingencies for these resources are corporate commitment and development timing.
(e) "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.
(f) The risked estimated cost to bring these contingent resources on commercial production.

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, 2019. 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 51.9 million boe (low estimate) to 330.2 million boe (high estimate), with a best estimate of 179.2 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, 2019[(1) (2)] - Forecast prices and costs[(3) (4)]

	Light & Medium Crude Oil		Conventional Natural Gas		Shale Gas		Natural Gas Liquids		BOE			Unrisked BOE	
Prospect [(10)]	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mmcf)	Net (mmcf)	Gross (mbbl)	Net (mbbl)	Gross (mboe)	Net (mboe)	Chance of Commerciality %[(9)]	Gross (mboe)	Net (mboe)
Prospective - Low Estimate													
Australia	—	—	—	—	—	—	—	—	—	—	—	—	—
Canada	496	476	57,718	53,365	—	—	4,068	3,447	14,183	12,818	32%	44,537	40,283
CEE	1,872	1,491	2,877	2,675	—	—	—	—	2,352	1,937	25%	9,411	7,679
France	2,808	2,651	—	—	—	—	—	—	2,808	2,651	42%	6,716	6,321
Germany	341	341	147,069	125,573	—	—	—	—	24,853	21,270	30%	82,420	71,015
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	—	—	46,193	43,171	—	—	48	44	7,746	7,240	11%	73,308	68,454
USA	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	**5,517**	**4,958**	**253,859**	**224,785**	**—**	**—**	**4,115**	**3,492**	**51,942**	**45,914**	**24%**	**216,392**	**193,752**
Prospective - Best Estimate [(10)]													
Australia	529	529	—	—	—	—	—	—	529	529	48%	1,103	1,103
Canada	2,263	2,047	165,748	151,888	112,623	106,207	25,303	22,095	73,960	67,160	24%	313,816	286,672
CEE	7,134	5,714	9,481	8,728	38,233	37,469	—	—	15,086	13,414	25%	61,193	53,830
France	9,945	9,039	—	—	—	—	—	—	9,945	9,039	31%	31,737	28,348
Germany	1,050	1,002	327,821	281,402	—	—	—	—	55,686	47,902	32%	175,511	151,870
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	58	58	86,032	80,794	—	—	88	83	14,485	13,607	11%	136,635	128,222
USA	6,305	5,269	11,506	9,615	—	—	1,261	1,054	9,483	7,925	49	19,453	16,256
Total	**27,284**	**23,659**	**600,587**	**532,427**	**150,857**	**143,676**	**26,652**	**23,232**	**179,177**	**159,577**	**24%**	**739,448**	**666,301**
Prospective - High Estimate													
Australia	1,182	1,182	—	—	—	—	—	—	1,182	1,182	48%	2,463	2,463
Canada	3,064	2,738	249,104	227,353	147,282	137,249	39,048	32,704	108,175	96,210	24%	450,444	400,956
CEE	26,185	21,084	18,130	16,713	92,308	90,462	—	—	44,592	38,946	23%	192,249	166,212
France	23,612	21,633	—	—	—	—	—	—	23,612	21,633	32%	74,374	66,765
Germany	1,753	1,659	643,031	553,839	—	—	—	—	108,925	93,965	32%	337,136	292,810
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	278	278	164,708	153,139	—	—	168	156	27,897	25,957	11%	262,592	244,009
USA	10,545	8,813	19,245	16,084	—	—	2,109	1,763	15,862	13,256	49	32,538	27,193
Total	**66,619**	**57,386**	**1,094,218**	**967,127**	**239,590**	**227,711**	**41,326**	**34,623**	**330,247**	**291,151**	**24%**	**1,351,795**	**1,200,407**

Summary of risked net present value of future net revenues as at December 31, 2019 - Forecast prices and costs[3]

	Before Income Taxes, Discounted at [5]					After Income Taxes, Discounted at [5]				
(M$)	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Prospective (Pr1) - Low Estimate [6]										
Prospect [10]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada	220,271	91,627	39,029	16,348	6,190	174,813	70,287	28,005	10,206	2,558
CEE	71,886	53,665	40,924	31,758	24,998	54,427	39,882	29,762	22,523	17,215
France	96,308	48,377	24,174	11,772	5,341	71,407	33,437	14,806	5,667	1,224
Germany	380,135	220,652	117,106	57,767	24,596	261,903	157,839	81,413	36,354	11,166
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	300,584	119,627	57,334	31,005	18,180	158,876	57,396	23,129	9,631	3,725
USA	—	—	—	—	—	—	—	—	—	—
Total	**1,069,184**	**533,950**	**278,566**	**148,650**	**79,304**	**721,426**	**358,841**	**177,115**	**84,381**	**35,888**
Prospective (Pr2) - Best Estimate [7]										
Prospect [10]										
Australia	35,757	24,539	17,183	12,256	8,892	13,332	8,795	5,903	4,024	2,783
Canada	1,366,100	561,708	242,049	104,861	42,684	954,528	374,898	147,106	52,259	11,557
CEE	524,383	322,112	214,029	150,168	109,551	364,233	224,054	147,334	101,567	72,380
France	359,962	197,960	114,560	69,477	43,919	240,496	125,168	68,003	38,465	22,539
Germany	1,472,961	741,197	386,910	207,470	111,978	1,072,877	541,851	277,846	143,447	72,301
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	706,276	307,665	163,421	97,807	63,250	381,328	160,125	80,725	45,630	27,820
USA	305,647	90,172	28,302	8,505	1,865	240,685	70,003	21,086	5,651	648
Total	**4,771,086**	**2,245,354**	**1,166,454**	**650,545**	**382,139**	**3,267,480**	**1,504,894**	**748,004**	**391,043**	**210,028**
Prospective (Pr3) - High Estimate [8]										
Prospect [10]										
Australia	101,130	70,051	49,614	35,846	26,367	40,789	27,910	19,524	13,932	10,122
Canada	2,508,723	1,039,136	485,448	245,851	131,257	1,733,676	695,544	309,072	145,696	70,213
CEE	1,979,450	1,143,078	741,517	516,836	378,263	1,396,429	820,028	534,387	371,908	270,858
France	1,238,728	654,583	371,593	224,134	142,236	894,660	459,442	253,330	148,517	91,714
Germany	3,448,586	1,689,888	885,088	486,827	276,491	2,518,791	1,233,547	638,697	344,034	189,127
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	1,498,855	676,946	372,501	230,115	153,086	815,896	362,053	194,685	117,533	76,520
USA	739,264	241,241	93,417	40,339	18,732	584,019	190,286	73,461	31,566	14,553
Total	**11,514,735**	**5,514,922**	**2,999,177**	**1,779,947**	**1,126,431**	**7,984,259**	**3,788,810**	**2,023,156**	**1,173,186**	**723,107**

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 2019 reserves report were also utilized by GLJ in preparing the GLJ Resource Assessment. See ”GLJ December 31, 2019 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) Summary of risks for prospect prospective resources at December 31, 2019[a]

Prospect [b][c]	Risked Volume Gross[d] (mboe)	Development Risks	Discovery Risks	Chance of Development Aggregate %	Chance of Discovery Aggregate %	Chance of Commerciality Aggregate %	Risked Estimated Development Cost [e] Gross ($M)	Development Timing (yrs)
Prospective (Pr2) - Best Estimate								
Australia	529	Development timing	Reservoir	80%	60%	48%	16,150	6
Canada	73,960	Development timing, economics	Reservoir	27%	87%	24%	1,062,708	4 to 16
CEE	15,086	Development timing	Reservoir, seal, source, trap	82%	30%	25%	156,757	1 to 9
France	9,945	Development timing	Reservoir, seal, trap,	69%	45%	31%	362,136	4 to 12
Germany	55,686	Development timing	Reservoir, seal, source, trap	70%	45%	32%	394,810	4 to 8
Ireland	—	—	—	—	—	—	—	—
Netherlands	14,485	Development timing, permitting	Reservoir, seal, source, timing and migration	27%	39%	11%	120,169	4 to 13
United States	9,483	Development timing	Reservoir, source, maturity	75%	65%	49%	233,371	10 to 16
Total	**179,177**			**45%**	**54%**	**24%**	**2,346,101**	**1 to 16**

(a) 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 in “Forecast Prices used in Estimates”. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

(b) 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.

(c) Risked prospect best estimate prospective resources for each business unit 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.

(d) "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.

(e) The risked estimated cost to bring these prospective resources on commercial production.

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, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, 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 2019, 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, 2019	Australia	—	340,142	—	340,142
GLJ Petroleum Consultants	December 31, 2019	Canada	—	3,585,717	—	3,585,717
GLJ Petroleum Consultants	December 31, 2019	CEE	—	50,049	—	50,049
GLJ Petroleum Consultants	December 31, 2019	France	—	1,556,134	—	1,556,134
GLJ Petroleum Consultants	December 31, 2019	Germany	—	465,741	—	465,741
GLJ Petroleum Consultants	December 31, 2019	Ireland	—	402,366	—	402,366
GLJ Petroleum Consultants	December 31, 2019	Netherlands	—	379,572	—	379,572
GLJ Petroleum Consultants	December 31, 2019	United States	—	722,478	—	722,478
Total			—	7,502,199	—	7,502,199

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 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 10, 2020

"Jodi L. Anhorn"

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

Executive Vice President & COO

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, 2019. 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, 2019, 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, 2019	Australia	3,240	—	56,684	56,684
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2019	Canada	158,754	—	1,058,611	1,058,611
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2019	CEE	581	—	14,077	14,077
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2019	France	27,653	—	488,761	488,761
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2019	Germany	6,204	—	64,830	64,830
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2019	Netherlands	5,239	—	91,969	91,969
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2019	USA	34,048	—	345,351	345,351
Total				**236,838**	**—**	**2,121,455**	**2,121,455**

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, 2019	Canada	31,574
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2019	France	2,385
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2019	Germany	249
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2019	Netherlands	3,379
Total				**37,587**

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, 2019	Australia	529
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2019	Canada	73,960
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2019	CEE	15,086
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2019	France	9,945
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2019	Germany	55,686
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2019	Netherlands	14,485
Total				**179,177**

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 10, 2020

"Jodi L. Anhorn"

Jodi L. Anhorn, M.Sc., P.Eng.
Executive Vice President & COO

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, 2019, 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 Appendix A to the Annual Information Form of the Company for the year ended December 31, 2019.

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 judgments regarding future events, actual results will vary and the variations may be material.

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

"Lars Glemser"
Lars Glemser, Vice President and Chief Financial Officer

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

"William Roby"
William Roby, Director

March 5, 2020

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.

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.

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
    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

A. 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.

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

Disclaimer

Certain statements included or incorporated by reference in this document 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 document may include, but are not limited to: capital expenditures and Vermilion's ability to fund such expenditures; Vermilion's additional debt capacity providing it with additional working capital; the flexibility of Vermilion's capital program and operations; business strategies and objectives; operational and financial performance; estimated volumes of reserves and resources; petroleum and natural gas sales; future production levels and the timing thereof, including Vermilion's 2020 guidance, and rates of average annual production growth; the effect of changes in crude oil and natural gas prices, changes in exchange rates and significant declines in production or sales volumes due to unforeseen circumstances; the effect of possible changes in critical accounting estimates; statements regarding the growth and size of Vermilion's future project inventory, and the wells expected to be drilled in 2020; exploration and development plans and the timing thereof; Vermilion's ability to reduce its debt, including its ability to redeem senior unsecured notes prior to maturity; statements regarding Vermilion's hedging program, its plans to add to its hedging positions, and the anticipated impact of Vermilion's hedging program on project economics and free cash flows; the potential financial impact of climate-related risks; acquisition and disposition plans and the timing thereof; operating and other expenses, including the payment and amount of future dividends; royalty and income tax rates and Vermilion's expectations regarding future taxes and taxability; and the timing of regulatory proceedings and approvals.

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 Vermilion to obtain equipment, services and supplies in a timely manner to carry out its activities in Canada and internationally; the ability of Vermilion 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 Vermilion 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 exploration and development activities.

Although Vermilion 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 Vermilion can give no assurance that such expectations will prove to be correct. Financial outlooks are provided for the purpose of understanding Vermilion's financial position 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 Vermilion 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 Vermilion's marketing operations, including credit risk; the uncertainty of reserves estimates and reserves life and estimates of resources and associated expenditures; the uncertainty of estimates and projections relating to production and associated expenditures; potential delays or changes in plans with respect to exploration or development projects; Vermilion'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 Vermilion to add production and reserves through exploration and development activities; 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 Vermilion; and other risks and uncertainties described elsewhere in this document or in Vermilion's other filings with Canadian securities regulatory authorities.

The forward-looking statements or information contained in this document are made as of the date hereof and Vermilion 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.

All crude oil and natural gas reserve and resource information contained in this document has been prepared and presented in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities and the Canadian Oil and Gas Evaluation Handbook. Reserves estimates have been made assuming that development of each property in respect of which the estimate is made will occur, without regard to the likely availability of funding required for such development. The actual crude oil and natural gas reserves and future production will be greater than or less than the estimates provided in this document.

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 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.

Financial data contained within this document are reported in Canadian dollars unless otherwise stated.

Abbreviations

$M	thousand dollars
$MM	million dollars
AECO	the daily average benchmark price for natural gas at the AECO ‘C’ hub in Alberta
bbl(s)	barrel(s)
bbls/d	barrels per day
boe	barrel of oil equivalent, including: crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe for six mcf of natural gas)
boe/d	barrel of oil equivalent per day
GJ	gigajoules
LSB	light sour blend crude oil reference price
mbbls	thousand barrels
mcf	thousand cubic feet
mmcf/d	million cubic feet per day
NBP	the reference price paid for natural gas in the United Kingdom at the National Balancing Point Virtual Trading Point.
NGLs	natural gas liquids, which includes butane, propane, and ethane
PRRT	Petroleum Resource Rent Tax, a profit based tax levied on petroleum projects in Australia
tCO2e	tonnes of carbon dioxide equivalent
TTF	the price for natural gas in the Netherlands, quoted in megawatt hours of natural gas, at the Title Transfer Facility Virtual Trading Point
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma

Management's Discussion and Analysis

The following is Management's Discussion and Analysis ("MD&A"), dated March 5, 2020, of Vermilion Energy Inc.'s ("Vermilion", "we", "our", "us" or the "Company") operating and financial results as at and for the three months and year ended December 31, 2019 compared with the corresponding periods in the prior year.

This discussion should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2019 and 2018, together with the accompanying notes. Additional information relating to Vermilion, including its Annual Information Form, is available on SEDAR at www.sedar.com or on Vermilion's website at www.vermilionenergy.com.

The audited consolidated financial statements for the year ended December 31, 2019 and comparative information have been prepared in Canadian dollars and in accordance with International Financial Reporting Standards ("IFRS" or, alternatively, "GAAP") as issued by the International Accounting Standards Board ("IASB").

This MD&A includes references to certain financial and performance measures which do not have standardized meanings prescribed by IFRS. These measures include:

- Fund flows from operations: Fund flows from operations is a measure of profit or loss in accordance with IFRS 8 "Operating Segments". Please see "Segmented Information" in the "Notes to the Consolidated Financial Statements" for a reconciliation of fund flows from operations to net earnings. We analyze 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.
- Net debt: Net debt is a capital management measure in accordance with IAS 1 "Presentation of Financial Statements". Net debt is comprised of long-term debt plus current liabilities less current assets and represents Vermilion's net financing obligations after adjusting for the timing of working capital fluctuations. Net debt excludes lease obligations which are secured by a corresponding right-of-use asset. Please see "Capital disclosures" in the "Notes to the Consolidated Financial Statements" for additional information.
- Netbacks: Netbacks are per boe and per mcf performance measures used in the analysis of operational activities. We assess 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.

In addition, this MD&A includes references to certain financial measures which are not specified, defined, or determined under IFRS and are therefore considered non-GAAP financial measures. These non-GAAP financial measures are unlikely to be comparable to similar financial measures presented by other issuers. For a full description of these non-GAAP financial measures and a reconciliation of these measures to their most directly comparable GAAP measures, please refer to "Non-GAAP Financial Measures".

Condensate Presentation

We report our condensate production in Canada and the Netherlands business units within the crude oil and condensate production line. We believe that this presentation better reflects the historical and forecasted pricing for condensate, which is more closely correlated with crude oil pricing than with pricing for propane, butane, and ethane (collectively "NGLs" for the purposes of this report).

Guidance

On October 25, 2018, we released our 2019 capital budget and related guidance. On February 27, 2019, we deferred some activity to later in the year and reallocated capital between business units, although the 2019 total budget and production guidance remained unchanged. On October 31, 2019, we reduced our 2019 capital expenditure guidance to $520 million and our 2019 annual production guidance to 100,000 to 101,000 boe/d. Actual 2019 capital spending of $523 million was within 1% of our guidance and 2019 average production of 100,357 boe/d was approximately at the mid-point of our revised guidance range.

On October 31, 2019, we released our 2020 capital budget and associated production guidance.

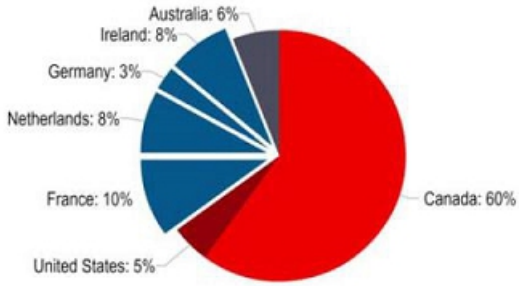
The following table summarizes our guidance:

	Date	Capital Expenditures ($MM)	Production (boe/d)
2019 Guidance			
2019 Guidance	October 25, 2018	530	101,000 to 106,000
2019 Guidance	October 31, 2019	520	100,000 to 101,000
2019 Actual Results	March 6, 2020	523	100,357
2020 Guidance			
2020 Guidance	October 31, 2019	450	100,000 to 103,000

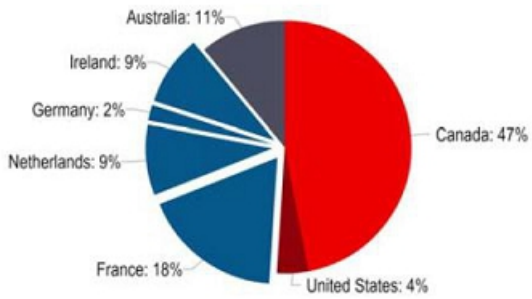
Vermilion's Business

Vermilion is a Calgary, Alberta based international oil and gas producer focused on the acquisition, exploration, development, and optimization of producing properties in North America, Europe, and Australia. We manage our business through our Calgary head office and our international business unit offices. This MD&A separately discusses each of our business units in addition to our corporate segment.

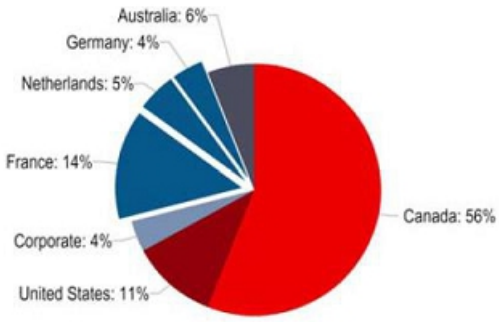
2019 production of 100,357 boe/d by business unit



2019 fund flows from operations of $908MM by business unit



2019 capital expenditures of $523MM by business unit

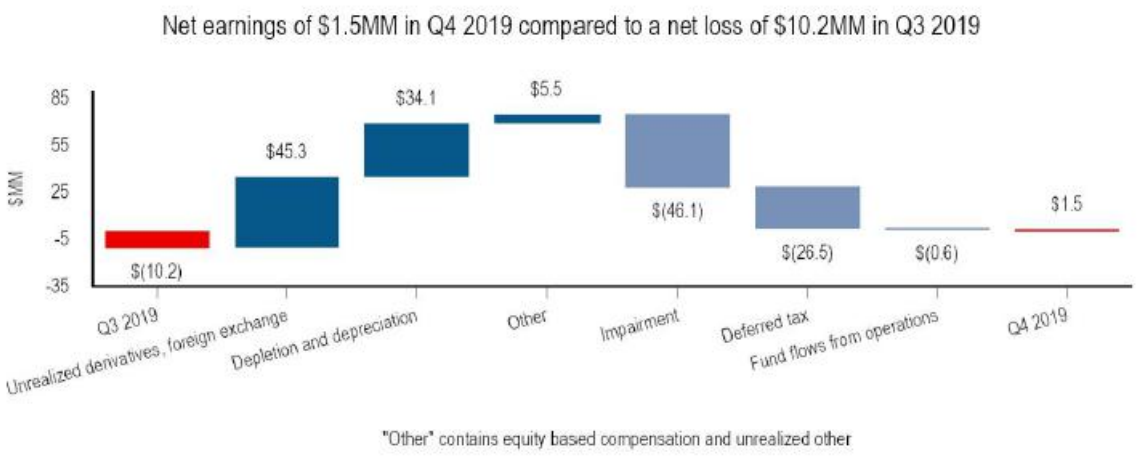


Consolidated Results Overview

	Q4 2019	Q3 2019	Q4 2018	Q4/19 vs. Q3/19	Q4/19 vs. Q4/18	2019	2018	2019 vs. 2018
Production								
Crude oil and condensate (bbls/d)	**46,261**	47,242	47,678	(2.1)%	(3.0)%	**47,902**	39,182	22.3%
NGLs (bbls/d)	**8,160**	7,772	7,815	5.0%	4.4%	**7,984**	6,366	25.4%
Natural gas (mmcf/d)	**260.72**	253.36	276.77	2.9%	(5.8)%	**266.82**	250.33	6.6%
Total (boe/d)	**97,875**	97,239	101,621	0.7%	(3.7)%	**100,357**	87,270	15.0%
Sales								
Crude oil and condensate (bbls/d)	**44,423**	48,979	47,620	(9.3)%	(6.7)%	**47,936**	38,741	23.7%
NGLs (bbls/d)	**8,160**	7,772	7,815	5.0%	4.4%	**7,984**	6,366	25.4%
Natural gas (mmcf/d)	**260.72**	253.36	276.77	2.9%	(5.8)%	**266.82**	250.33	6.6%
Total (boe/d)	**96,037**	98,976	101,563	(3.0)%	(5.4)%	**100,391**	86,829	15.6%
Build (draw) in inventory (mbbls)	**169**	(159)	5			**(12)**	160	
Financial metrics								
Fund flows from operations ($M)	**215,592**	216,153	222,342	(0.3)%	(3.0)%	**908,055**	838,652	8.3%
Per share ($/basic share)	**1.38**	1.39	1.46	(0.7)%	(5.5)%	**5.87**	5.96	(1.5)%
Net earnings (loss) ($M)	**1,477**	(10,229)	323,373	N/A	(99.5)%	**32,799**	271,650	(87.9)%
Per share ($/basic share)	**0.01**	(0.07)	2.12	N/A	(99.5)%	**0.21**	1.93	(89.1)%
Net debt ($M)	**1,993,194**	2,001,870	1,929,529	(0.4)%	3.3%	**1,993,194**	1,929,529	3.3%
Cash dividends ($/share)	**0.690**	0.690	0.690	—%	—%	**2.760**	2.715	1.7%
Activity								
Capital expenditures ($M)	**100,625**	127,879	163,580	(21.3)%	(38.5)%	**523,164**	518,214	1.0%
Acquisitions ($M)	**9,165**	4,657	2,689			**38,472**	1,759,425	
Gross wells drilled	**28.00**	47.00	73.00			**176.00**	185.00	
Net wells drilled	**17.25**	45.31	45.08			**153.38**	147.93	

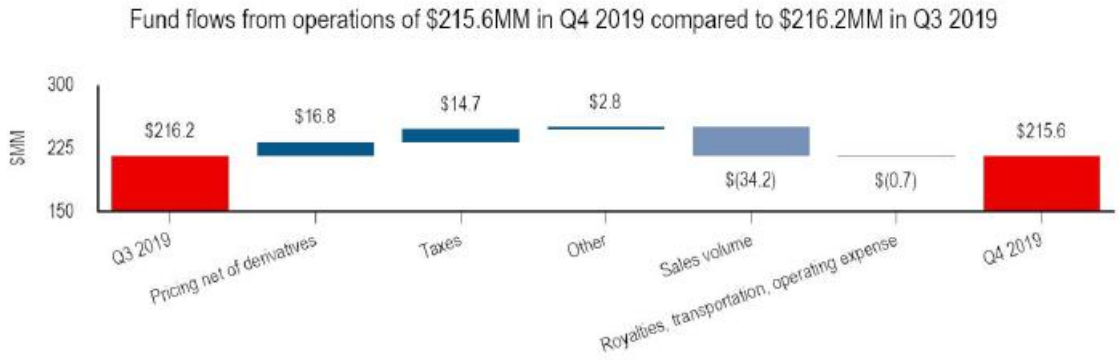
Financial performance review

Q4 2019 vs. Q3 2019



"Other" contains equity based compensation and unrealized other

- We recorded net earnings for Q4 2019 of $1.5 million ($0.01/basic share) compared to a net loss of $10.2 million ($0.07/basic share) in Q3 2019. This quarter-over-quarter increase in net earnings was primarily driven by a net unrealized gain on derivatives and foreign exchange of $12.5 million (compared to a net unrealized loss of $32.8 million in Q3 2019) and a decrease in depletion and depreciation expense of $34.1 million. This increase to net earnings was partially offset by an increase in deferred tax expense of $26.5 million and a $46.1 million impairment charge recorded on our Corrib asset.



"Other" contains general and administration, interest, realized foreign exchange, and realized other

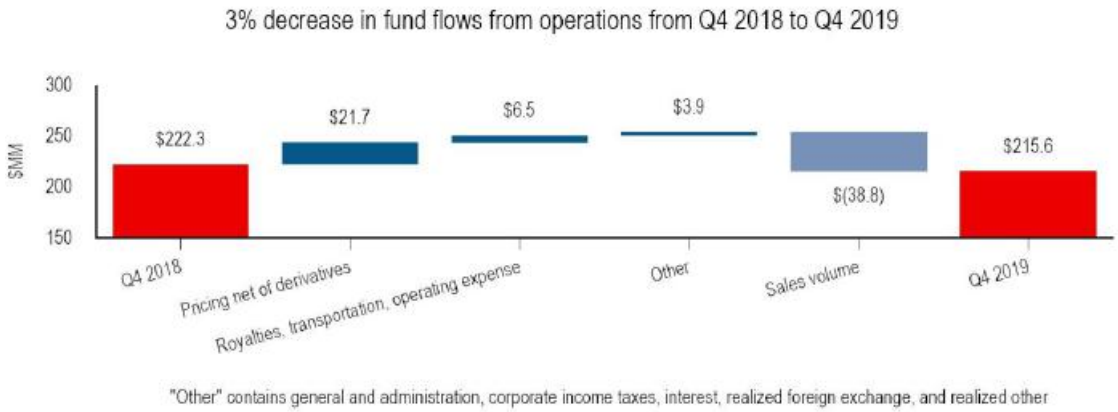
- Fund flows from operations of $215.6 million during Q4 2019 was flat versus Q3 2019. We recorded lower sales volumes as the result of an Australian inventory build during the current quarter. This decrease was offset by stronger natural gas prices and a tax recovery in the Netherlands.

Q4 2019 vs. Q4 2018



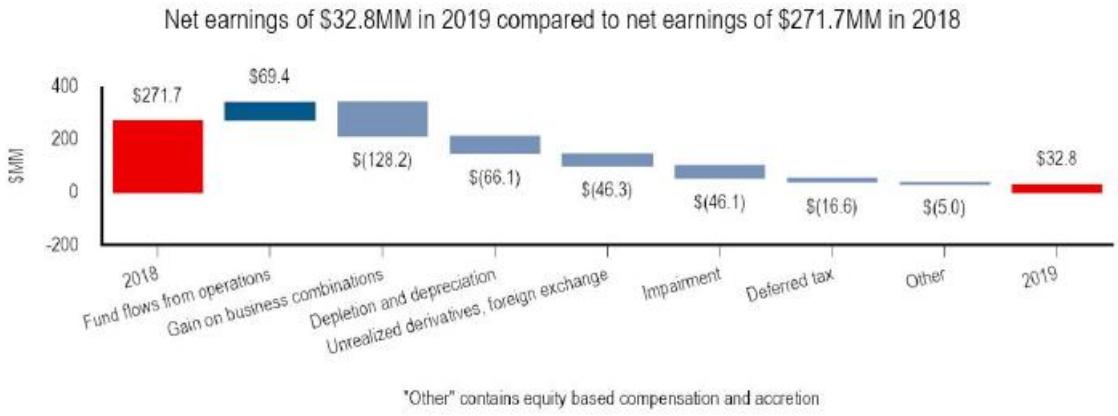
"Other" contains depletion and depreciation, equity based compensation, accretion, and unrealized other

- We recorded net earnings for Q4 2019 of $1.5 million ($0.01/basic share) compared to net earnings of $323.4 million ($2.12/basic share) in Q4 2018. This change was primarily driven by a smaller unrealized derivative gain in the current quarter of $12.5 million (compared to an unrealized derivative gain of $236.7 million in Q4 2018), the gain on business combinations of $128.2 million recorded in Q4 2018, and an impairment charge of $46.1 million in Q4 2019.

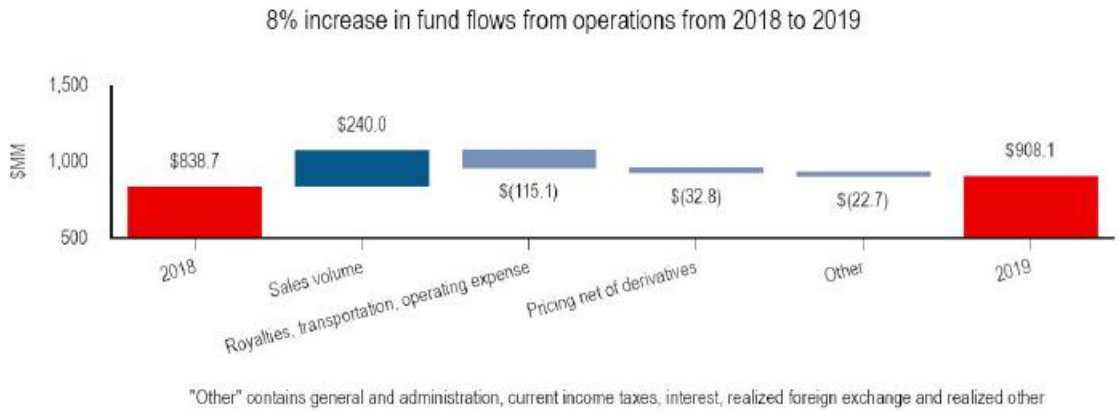


- We generated fund flows from operations of $215.6 million in Q4 2019, a 3% decrease from $222.3 million in Q4 2018 primarily due to lower sales volumes. This decrease was partially offset by increased pricing net of derivatives.
- Our consolidated realized price per boe decreased from $48.90/boe to $44.00/boe as a result of decreases in crude oil and European natural gas pricing. However, we were able to mitigate the impact of lower commodity prices with our hedge program, resulting in a net increase to fund flows from operations of $21.7 million.

2019 vs. 2018



- For the year ended December 31, 2019, net earnings of $32.8 million were recorded compared to net earnings of $271.7 million in 2018. The decrease in net earnings is attributable to the gain on business combinations recorded in 2018 of $128.2 million, higher depletion and depreciation expense of $66.1 million, an impairment charge recorded in 2019 of $46.1 million, and higher non-cash expenses and net unrealized losses on derivatives and foreign exchange in the current year. The decreases were partially offset by a year-over-year increase in fund flows from operations of $69.4 million.



- Fund flows from operations increased 8% for the year ended December 31, 2019 versus the same period in 2018 due to a 16% increase in sales volumes, partially offset by related incremental expenses associated with the increased volumes.
- Our consolidated realized price decreased by 13% from $52.95/boe to $46.12/boe due to weaker crude oil and natural gas pricing. We were able to mitigate a portion of the impact of lower commodity prices with our hedge program. As a result, the $6.83/boe reduction in our realized price was partially offset by a $5.81/boe increase in realized derivative gains.

Production review

Q4 2019 vs. Q3 2019

- Consolidated average production of 97,875 boe/d during Q4 2019 increased by 1% compared to Q3 2019 production of 97,239 boe/d. Production increased in the United States from wells brought online late in Q3 2019 and in the Netherlands due to planned and unplanned downtime in the previous quarter. These increases were offset by lower production primarily due to the planned shutdown of the Wandoo platform in Australia for eight days to perform facility upgrades and regular maintenance and five days of Corrib downtime in Ireland.

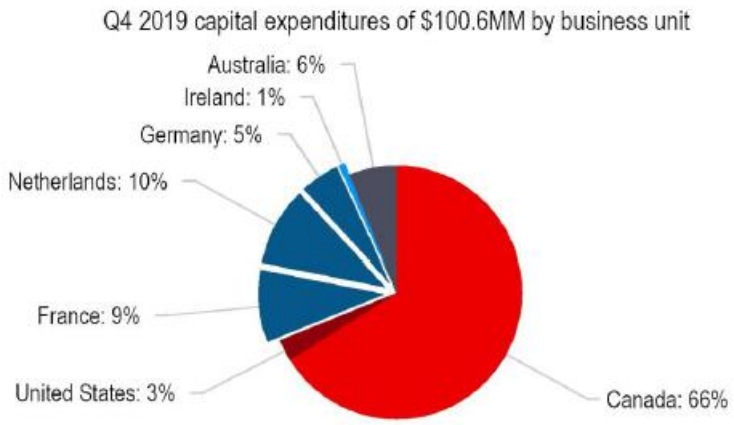
Q4 2019 vs. Q4 2018

- Consolidated average production of 97,875 boe/d in Q4 2019 represented a decrease of 4% from Q4 2018 primarily as a result of production decreases in Canada following delays in our 2019 capital program and natural decline in Ireland. These decreases were partially offset by continued organic growth in the United States.

2019 vs. 2018

- For the year ended December 31, 2019, consolidated average production of 100,357 boe/d represented an increase of 15% from the comparable period in 2018 due to growth in Canada, the United States, Australia, and the Netherlands. In Canada and the United States, production increased as a result of acquisitions in 2018 and continued organic growth. Production in Australia increased due to a successful two-well drilling program completed in Q1 2019. In the Netherlands, production increased as a result of a new well brought on production in Q3 2018 and from a successful workover program in the first half of 2019.

Activity review



- For the three months ended December 31, 2019, capital expenditures of $100.6 million primarily related to activity in Canada, the Netherlands, and France. In Canada, capital expenditures of $66.6 million included the drilling of 16 (15.2 net) operated wells in Alberta and Saskatchewan. Capital expenditures of $9.7 million in the Netherlands related to drilling the Weststellingwerf well (0.5 net). In France, capital expenditures of $8.7 million related to our workover and optimization programs in the Aquitaine and Paris Basins. In the United States, capital expenditures of $3.1 million related to the drilling of two wells, which were rig released in the subsequent quarter.

Sustainability review

Dividends

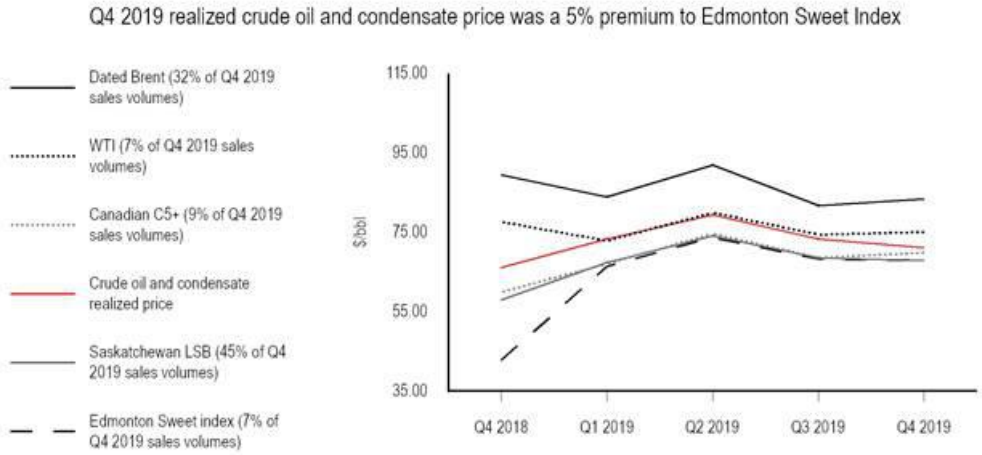
- Declared dividends of $0.23 per common share per month throughout 2019, resulting in total dividends declared of $2.76 per common share for the year ended December 31, 2019.

Long-term debt and net debt

- Long-term debt increased to $1.9 billion as at December 31, 2019 from $1.8 billion as at December 31, 2018. This increase was primarily a result of increased borrowings on the revolving credit facility.
- Net debt increased to $2.0 billion as at December 31, 2019, from $1.9 billion as at December 31, 2018, primarily due to increased borrowings on our revolving credit facility.
- The ratio of net debt to four quarter trailing fund flows from operations decreased to 2.20 (December 31, 2018 - 2.30) as the increase to net debt was offset by higher four quarter trailing fund flows from operations.

Benchmark Commodity Prices

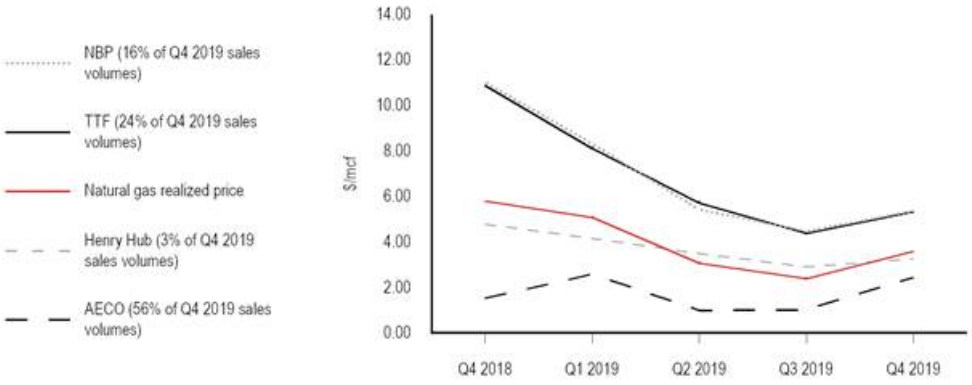
	Q4 2019	Q3 2019	Q4 2018	Q4/19 vs. Q3/19	Q4/19 vs. Q4/18	2019	2018	2019 vs. 2018
Crude oil								
WTI ($/bbl)	**75.19**	74.55	77.71	0.9%	(3.2)%	**75.67**	83.94	(9.9)%
WTI (US $/bbl)	**56.96**	56.45	58.81	0.9%	(3.1)%	**57.03**	64.77	(11.9)%
Edmonton Sweet index ($/bbl)	**68.10**	68.39	42.96	(0.4)%	58.5%	**69.19**	69.53	(0.5)%
Edmonton Sweet index (US $/bbl)	**51.59**	51.79	32.51	(0.4)%	58.7%	**52.15**	53.65	(2.8)%
Saskatchewan LSB index ($/bbl)	**68.09**	68.68	58.18	(0.9)%	17.0%	**69.66**	73.17	(4.8)%
Saskatchewan LSB index (US $/bbl)	**51.58**	52.01	44.03	(0.8)%	17.1%	**52.50**	56.46	(7.0)%
Canadian C5+ Condensate index ($/bbl)	**69.97**	68.70	60.08	1.8%	16.5%	**70.13**	79.08	(11.3)%
Canadian C5+ Condensate index (US $/bbl)	**53.01**	52.02	45.47	1.9%	16.6%	**52.86**	61.02	(13.4)%
Dated Brent ($/bbl)	**83.49**	81.80	89.54	2.1%	(6.8)%	**85.31**	92.07	(7.3)%
Dated Brent (US $/bbl)	**63.25**	61.94	67.76	2.1%	(6.7)%	**64.30**	71.04	(9.5)%
Natural gas								
AECO ($/mcf)	**2.48**	1.06	1.56	134.0%	59.0%	**1.76**	1.50	17.3%
NBP ($/mcf)	**5.38**	4.50	11.03	19.6%	(51.2)%	**5.90**	10.35	(43.0)%
NBP (€/mcf)	**3.68**	3.07	7.31	19.9%	(49.7)%	**3.97**	6.76	(41.3)%
TTF ($/mcf)	**5.36**	4.40	10.91	21.8%	(50.9)%	**5.90**	10.23	(42.3)%
TTF (€/mcf)	**3.67**	3.00	7.23	22.3%	(49.2)%	**3.97**	6.69	(40.7)%
Henry Hub ($/mcf)	**3.30**	2.94	4.82	12.2%	(31.5)%	**3.49**	4.01	(13.0)%
Henry Hub (US $/mcf)	**2.50**	2.23	3.65	12.1%	(31.5)%	**2.63**	3.09	(14.9)%
Average exchange rates								
CDN $/US $	**1.32**	1.32	1.32	—%	—%	**1.33**	1.30	2.3%
CDN $/Euro	**1.46**	1.47	1.51	(0.7)%	(3.3)%	**1.49**	1.53	(2.6)%
Realized prices								
Crude oil and condensate ($/bbl)	**71.25**	73.45	66.19	(3.0)%	7.6%	**74.42**	79.16	(6.0)%
NGLs ($/bbl)	**14.63**	6.14	25.69	138.3%	(43.1)%	**13.61**	26.33	(48.3)%
Natural gas ($/mcf)	**3.61**	2.43	5.83	48.6%	(38.1)%	**3.58**	5.45	(34.3)%
Total ($/boe)	**44.00**	43.04	48.90	2.2%	(10.0)%	**46.12**	52.95	(12.9)%



- Crude oil prices rose in Q4 2019 relative to Q3 2019, driven by improved sentiment on global oil demand growth, geopolitical risk events, and supportive OPEC policy. By the end of Q4 2019, quarter-over-quarter WTI and Brent prices increased by 0.9% and 2.1% respectively, in Canadian dollar terms. For the three months ended December 31, 2019, WTI and Brent prices in Canadian dollar terms decreased by 3.2% and 6.8%, respectively, versus the comparable period in the prior year.

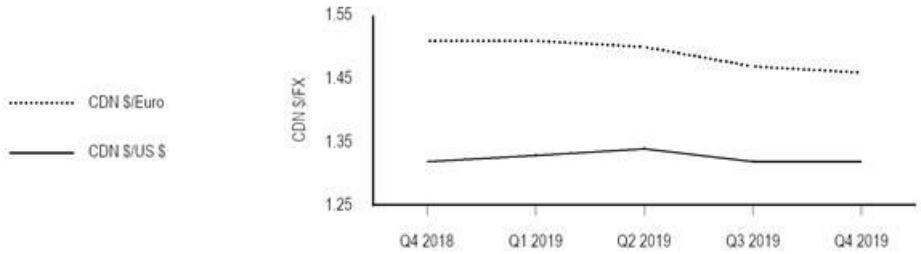
- In Canadian dollar terms, quarter-over-quarter, the Edmonton Sweet differential widened by $0.93/bbl to a discount of $7.09/bbl against WTI, and the Saskatchewan LSB differential widened by $1.23/bbl to a discount of $7.10/bbl against WTI. This was mainly driven by the broader market weakness experienced across all western Canadian grades in December 2019 due to the TC Energy Keystone pipeline spill announced on October 30th, 2019 and subsequent western Canada inventory build that followed.
- Vermilion's crude oil production benefits from light oil pricing and no exposure to significantly discounted heavy crude oil. Approximately 32% of our Q4 2019 crude oil and condensate production was priced at the Dated Brent index (which averaged a premium to WTI of US$6.29/bbl), while the remainder of our crude oil and condensate production was priced at the Saskatchewan LSB, Canadian C5+, Edmonton Sweet, and WTI indices. Saskatchewan LSB, Canadian C5+, and Wyoming light-oil historically had lower differentials than the more significantly constrained WCS and MSW markers, making Vermilion's North American crude oil production price-advantaged relative to other North American benchmark prices.

Q4 2019 realized natural gas price was a $1.13/mcf premium to AECO



- In Canadian dollar terms, market prices for European natural gas (TTF and NBP) increased by 21.8% and 19.6% respectively in Q4 2019 compared to Q3 2019 as demand shifted seasonally due to winter heating consumption.
- Natural gas prices at AECO in Q4 2019 increased by 134% compared to Q3 2019, due to both the seasonal shift to winter heating consumption as well as improved access to storage and export markets as a result of the Canada Energy Regulator approving TC Energy's Temporary Service Protocol.
- For Q4 2019, average European natural gas prices represented a $2.89/mcf premium to AECO and a $2.07/mcf premium to Henry Hub pricing. Approximately 40% of our natural gas production in Q4 2019 benefited from this premium European pricing. As a result, our consolidated natural gas realized price was a $1.13/mcf premium to AECO.

Quarter-over-quarter, the Canadian dollar strengthened slightly versus the Euro and USD



- For the three months ended December 31, 2019, the Canadian dollar remained flat against the US dollar quarter-over-quarter. The annual average in 2019 was 2.3% weaker versus 2018.
- For the three months ended December 31, 2019, the Canadian dollar strengthened 0.7% against the Euro quarter-over-quarter. The annual average in 2019 was 2.6% stronger versus 2018.

Canada Business Unit

Overview

Production and assets focused in West Pembina near Drayton Valley, Alberta and in southeast Saskatchewan and Manitoba.

- Potential for three significant resource plays sharing the same surface infrastructure in the West Pembina region in Alberta:
  - Mannville condensate-rich gas (2,400 - 2,700m depth) - in development phase
  - Cardium light oil (1,800m depth) - modest investment at present
  - Duvernay condensate-rich gas (3,200 - 3,400m depth) - no investment at present
- Southeast Saskatchewan light oil development:
  - Targeting the Mississippian Midale (1,400 - 1,700m depth), Frobisher/Alida (1,200 - 1,400m depth) and Ratcliffe (1,800 - 1,900m) formations

Operational and financial review

Canada business unit ($M except as indicated)	Q4 2019	Q3 2019	Q4 2018	Q4/19 vs. Q3/19	Q4/19 vs. Q4/18	2019	2018	2019 vs. 2018
Production and sales								
Crude oil and condensate (bbls/d)	**27,399**	27,682	29,557	(1.0)%	(7.3)%	**28,266**	21,154	33.6%
NGLs (bbls/d)	**7,005**	6,632	6,816	5.6%	2.8%	**6,988**	5,914	18.2%
Natural gas (mmcf/d)	**145.14**	145.14	146.65	—%	(1.0)%	**148.35**	129.37	14.7%
Total (boe/d)	**58,593**	58,504	60,814	0.2%	(3.7)%	**59,979**	48,630	23.3%
Production mix (% of total)								
Crude oil and condensate	**47%**	47%	49%			**47%**	43%	
NGLs	**12%**	12%	11%			**12%**	13%	
Natural gas	**41%**	41%	40%			**41%**	44%	
Activity								
Capital expenditures	**66,643**	69,963	90,211	(4.7)%	(26.1)%	**293,744**	277,857	5.7%
Acquisitions	**5,003**	1,746	12,233			**24,064**	1,573,964	
Gross wells drilled	**26.00**	40.00	72.00			**152.00**	173.00	
Net wells drilled	**16.74**	38.31	44.08			**132.86**	135.93	
Financial results								
Sales	**206,897**	188,073	186,308	10.0%	11.1%	**828,070**	671,172	23.4%
Royalties	**(24,127)**	(23,909)	(25,584)	0.9%	(5.7)%	**(94,079)**	(84,696)	11.1%
Transportation	**(10,384)**	(10,404)	(11,129)	(0.2)%	(6.7)%	**(41,261)**	(29,912)	37.9%
Operating	**(60,931)**	(57,851)	(62,064)	5.3%	(1.8)%	**(242,790)**	(177,499)	36.8%
General and administration	**(7,424)**	(5,793)	(2,150)	28.2%	245.3%	**(23,341)**	(6,057)	285.4%
Fund flows from operations	**104,031**	90,116	85,381	15.4%	21.8%	**426,599**	373,008	14.4%
Netbacks ($/boe)								
Sales	**38.38**	34.94	33.30	9.8%	15.3%	**37.82**	37.81	—%
Royalties	**(4.48)**	(4.44)	(4.57)	0.9%	(2.0)%	**(4.30)**	(4.77)	(9.9)%
Transportation	**(1.93)**	(1.93)	(1.99)	—%	(3.0)%	**(1.88)**	(1.69)	11.2%
Operating	**(11.30)**	(10.75)	(11.09)	5.1%	1.9%	**(11.09)**	(10.00)	10.9%
General and administration	**(1.38)**	(1.08)	(0.38)	27.8%	263.2%	**(1.07)**	(0.34)	214.7%
Fund flows from operations netback	**19.29**	16.74	15.27	15.2%	26.3%	**19.48**	21.01	(7.3)%
Realized prices								
Crude oil and condensate ($/bbl)	**66.27**	66.45	54.04	(0.3)%	22.6%	**67.70**	70.16	(3.5)%
NGLs ($/bbl)	**13.63**	5.57	25.53	144.7%	(46.6)%	**13.00**	26.20	(50.4)%
Natural gas ($/mcf)	**2.33**	1.16	1.73	100.9%	34.7%	**1.77**	1.54	14.9%
Total ($/boe)	**38.38**	34.94	33.30	9.8%	15.3%	**37.82**	37.81	—%
Reference prices								
WTI (US $/bbl)	**56.96**	56.45	58.81	0.9%	(3.1)%	**57.03**	64.77	(11.9)%
Edmonton Sweet index ($/bbl)	**68.10**	68.39	42.96	(0.4)%	58.5%	**69.19**	69.53	(0.5)%
Saskatchewan LSB index ($/bbl)	**68.09**	68.68	58.18	(0.9)%	17.0%	**69.66**	73.17	(4.8)%
Canadian C5+ Condensate index ($/bbl)	**69.97**	68.70	60.08	1.8%	16.5%	**70.13**	79.08	(11.3)%
AECO ($/mcf)	**2.48**	1.06	1.56	134.0%	59.0%	**1.76**	1.50	17.3%

Production

- Q4 2019 production increased slightly from the prior quarter as production from new well completions more than offset natural decline. In addition, production in Q3 2019 was negatively impacted by planned turnaround activity and other unplanned, weather-related downtime. Quarterly production decreased 4% year-over-year primarily due to delays in our 2019 capital program caused by abnormally wet weather in Alberta in Q3 2019.

Activity

Vermilion drilled 16 (15.2 net) operated wells and participated in the drilling of ten (1.6 net) non-operated wells in Canada during Q4 2019.

Alberta

- In Q4 2019, we drilled eight (8.0 net) operated wells, completed four (4.0 net) operated wells, and brought on production four (4.0 net) operated wells in Alberta.
- In 2019, we drilled or participated in 22 (21.5 net) wells in Alberta.

Saskatchewan

- In Q4 2019, we drilled eight (7.2 net) operated wells and participated in the drilling of ten (1.6 net) non-operated wells, completed twelve (11.8 net) operated wells and ten (1.6 net) non-operated wells, and brought 23 (21.9 net) operated wells and ten (1.6 net) non-operated wells on production in Saskatchewan.
- In 2019, we drilled or participated in 130 (111.4 net) wells in Saskatchewan.

Sales

- The realized price for our crude oil and condensate production in Canada is linked to WTI and is subject to market conditions in western Canada as reflected by the Saskatchewan LSB, Canadian Condensate C5+, and Edmonton Sweet index prices. The realized price of our natural gas in Canada is based on the AECO index.
- Q4 2019 sales increased 10% compared to Q3 2019 primarily due to higher realized natural gas and NGL prices. Quarter-over-quarter, our crude oil and condensate production mix remained stable at approximately 50% of production.
- Sales increased by 11% from Q4 2018 to Q4 2019 due to an increase in realized crude oil and condensate and natural gas prices partially offset by a decrease in realized NGL prices and production.
- For the year ended December 31, 2019 sales increased 23% compared to the prior year period primarily driven by a full-year impact to production from the Spartan assets.

Royalties

- Q4 2019 royalties as a percentage of sales of 11.7% decreased from 12.7% in Q3 2019 as a result of an adjustment related to gas cost allowance recorded in the prior quarter.
- For the three months and year ended December 31, 2019, royalties as a percentage of sales of 11.7% and 11.4%, decreased from 13.7% and 12.6% in the comparable prior year periods. This decrease was due to the manner in which Alberta crude royalties are calculated which deferred the royalty impact of lower oil prices in Q4 2018 into 2019, in addition to lower average royalty rates for new wells brought on production.

Transportation

- Q4 2019 transportation expense on a per unit basis remained relatively consistent compared to Q3 2019 and Q4 2018. Transportation expense on a dollar basis decreased in Q4 2019 as compared to Q4 2018 due to lower production.
- For the year ended December 31, 2019, transportation expense on a per unit basis increased versus 2018 due to an increased weighting towards crude oil production, which incurs higher transportation expense.

Operating

- Q4 2019 operating expense on a dollar and per unit basis increased compared to Q3 2019 largely due to an increase in project activity.
- Q4 2019 operating expense on a dollar and per unit basis remained relatively consistent compared to Q4 2018.
- For the year ended December 31, 2019, operating expense increased on a dollar and per unit basis versus the comparable period in 2018. On a dollar basis, the increase in operating expense was primarily due to higher production volumes during 2019. On a per unit basis, the increase in operating expense was primarily attributable to an increased weighting towards crude oil production which has a higher associated per unit operating expense.

General and administration

- For the three months and year ended December 31, 2019, general and administrative expenses increased versus all comparable periods primarily due to an increase in allocations from our Corporate segment and increased headcount costs.

France Business Unit

Overview

- Entered France in 1997.
- Largest oil producer in France, constituting approximately three-quarters of domestic oil production.
- Low base decline producing assets comprised of large conventional oil fields with high working interests located in the Aquitaine and Paris Basins.
- Identified inventory of workover, waterflood, and infill drilling opportunities.

Operational and financial review

France business unit ($M except as indicated)	Q4 2019	Q3 2019	Q4 2018	Q4/19 vs. Q3/19	Q4/19 vs. Q4/18	2019	2018	2019 vs. 2018
Production								
Crude oil (bbls/d)	**10,264**	10,347	11,317	(0.8)%	(9.3)%	**10,435**	11,362	(8.2)%
Natural gas (mmcf/d)	**—**	—	0.82	—%	—%	**0.19**	0.21	—%
Total (boe/d)	**10,264**	10,347	11,454	(0.8)%	(10.4)%	**10,467**	11,396	(8.2)%
Sales								
Crude oil (bbls/d)	**10,454**	11,112	10,975	(5.9)%	(4.7)%	**10,752**	11,012	(2.4)%
Natural gas (mmcf/d)	**—**	—	0.82	—%	—%	**0.19**	0.21	—%
Total (boe/d)	**10,454**	11,112	11,111	(5.9)%	(5.9)%	**10,783**	11,047	(2.4)%
Inventory (mbbls)								
Opening crude oil inventory	**227**	297	293			**325**	197	
Crude oil production	**944**	952	1,041			**3,809**	4,147	
Crude oil sales	**(962)**	(1,022)	(1,009)			**(3,925)**	(4,019)	
Closing crude oil inventory	**209**	227	325			**209**	325	
Activity								
Capital expenditures	**8,745**	18,139	17,008	(51.8)%	(48.6)%	**74,641**	79,758	(6.4)%
Gross wells drilled	**—**	—	—			**4.00**	5.00	
Net wells drilled	**—**	—	—			**4.00**	5.00	
Financial results								
Sales	**77,781**	81,676	85,889	(4.8)%	(9.4)%	**326,699**	360,602	(9.4)%
Royalties	**(10,265)**	(11,476)	(11,976)	(10.6)%	(14.3)%	**(43,895)**	(46,781)	(6.2)%
Transportation	**(3,215)**	(6,183)	(3,242)	(48.0)%	(0.8)%	**(21,609)**	(10,426)	107.3%
Operating	**(16,142)**	(15,098)	(14,015)	6.9%	15.2%	**(61,281)**	(54,690)	12.1%
General and administration	**(4,821)**	(3,379)	(3,792)	42.7%	27.1%	**(15,406)**	(14,170)	8.7%
Current income taxes	**(4,966)**	(3,419)	(884)	45.2%	461.8%	**(21,431)**	(15,084)	42.1%
Fund flows from operations	**38,372**	42,121	51,980	(8.9)%	(26.2)%	**163,077**	219,451	(25.7)%
Netbacks ($/boe)								
Sales	**80.87**	79.89	84.02	1.2%	(3.7)%	**83.01**	89.44	(7.2)%
Royalties	**(10.67)**	(11.23)	(11.72)	(5.0)%	(9.0)%	**(11.15)**	(11.60)	(3.9)%
Transportation	**(3.34)**	(6.05)	(3.17)	(44.8)%	5.4%	**(5.49)**	(2.59)	112.0%
Operating	**(16.78)**	(14.77)	(13.71)	13.6%	22.4%	**(15.57)**	(13.56)	14.8%
General and administration	**(5.01)**	(3.31)	(3.71)	51.4%	35.0%	**(3.91)**	(3.51)	11.4%
Current income taxes	**(5.16)**	(3.34)	(0.86)	54.5%	500.0%	**(5.45)**	(3.74)	45.7%
Fund flows from operations netback	**39.91**	41.19	50.85	(3.1)%	(21.5)%	**41.44**	54.44	(23.9)%
Reference prices								
Dated Brent (US $/bbl)	**63.25**	61.94	67.76	2.1%	(6.7)%	**64.30**	71.04	(9.5)%
Dated Brent ($/bbl)	**83.49**	81.80	89.54	2.1%	(6.8)%	**85.31**	92.07	(7.3)%

Production

- Q4 2019 production decreased 1% from the prior quarter primarily due to weather-related downtime in the Aquitaine Basin. Production in the Paris Basin was relatively consistent with the prior quarter, benefitting from a full quarter of uninterrupted service at the Grandpuits refinery which restarted in mid-August.

Activity

- Our 2019 capital program included the drilling of four (4.0 net) wells in the Champotran field during the first half of the year. In addition to the drilling activity, we continued our workover and optimization programs in the Aquitaine and Paris Basins throughout 2019.

Sales

- Crude oil in France is priced with reference to Dated Brent.
- Q4 2019 sales decreased by 5% versus Q3 2019 primarily due to a decrease in sales volumes, partially offset by an increase in prices, consistent with the increase in the Dated Brent reference price.
- For the three months and year ended December 31, 2019, sales decreased 9% versus the comparable periods in the prior year due to a decrease in both the Dated Brent reference price and sales volumes.

Royalties

- Royalties in France relate to two components: RCDM (levied on units of production and not subject to changes in commodity prices) and R31 (based on a percentage of sales).
- For the three months ended December 31, 2019, royalties as a percentage of sales of 13.2% were slightly lower than the comparable periods due to an adjustment associated with the year-end royalty calculation which impacted Q4 2019.
- For the year ended December 31, 2019, royalties as a percentage of sales of 13.4% remained relatively consistent with the prior year.

Transportation

- Transportation expense decreased in Q4 2019 compared to Q3 2019 due to the use of alternate delivery points and transportation methods during the aforementioned third party refinery outage, which increased transportation costs in Q2 2019 and Q3 2019.
- Transportation expense for the year ended December 31, 2019 increased versus the comparable period in the prior year due to the refinery outage.

Operating

- For the three months and year ended December 31, 2019 operating expenses increased against all comparable periods on both a per unit and dollar basis. The increases were primarily due to higher electricity prices in the current year periods.

General and administration

- Fluctuations in general and administration expense for all comparable periods were due to the timing of expenditures and allocations from our corporate segment.

Current income taxes

- In France, current income taxes are applied to taxable income, after eligible deductions, at a statutory rate of 32.0%.
- Current income taxes for the year ended December 31, 2019 versus the comparative period were higher, mainly due to realized derivative gains.
- Current income taxes for Q4 2019 versus the comparative quarters were higher, mainly due to decreased tax deductions for depletion.
- On December 28, 2019, the French Parliament approved the Finance Bill for 2020. The Finance Bill for 2020 provides for a progressive decrease of the French corporate income tax rate for companies with sales below €250 million from 32.0% to 25.8% by 2022, with a reduction in 2020 to 28.9%.

Netherlands Business Unit

Overview

- Entered the Netherlands in 2004.
- Second largest onshore operator.
- Interests include 26 onshore licenses (all operated) and 17 offshore licenses (all non-operated).
- Licenses include more than 930,000 net acres of land, 90% of which is undeveloped.

Operational and financial review

Netherlands business unit ($M except as indicated)	Q4 2019	Q3 2019	Q4 2018	Q4/19 vs. Q3/19	Q4/19 vs. Q4/18	2019	2018	2019 vs. 2018
Production and sales								
Condensate (bbls/d)	**90**	82	112	9.8%	(19.6)%	**91**	90	1.1%
Natural gas (mmcf/d)	**47.99**	44.08	51.82	8.9%	(7.4)%	**49.10**	46.13	6.4%
Total (boe/d)	**8,088**	7,429	8,749	8.9%	(7.6)%	**8,274**	7,779	6.4%
Activity								
Capital expenditures	**9,651**	3,028	2,454	218.7%	293.3%	**23,605**	17,483	35.0%
Acquisitions	**—**	—	(7,860)			**908**	(2,087)	
Gross wells drilled	**2.00**	—	—			**2.00**	—	
Net wells drilled	**0.51**	—	—			**0.51**	—	
Financial results								
Sales	**25,215**	18,729	52,937	34.6%	(52.4)%	**112,857**	165,916	(32.0)%
Royalties	**(130)**	(279)	(537)	(53.4)%	(75.8)%	**(1,469)**	(3,181)	(53.8)%
Operating	**(9,758)**	(6,396)	(6,765)	52.6%	44.2%	**(32,125)**	(26,681)	20.4%
General and administration	**(763)**	(300)	(709)	154.3%	7.6%	**(2,659)**	(1,947)	36.6%
Current income taxes	**11,198**	(462)	(7,492)	N/A	N/A	**3,961**	(16,561)	N/A
Fund flows from operations	**25,762**	11,292	37,434	128.1%	(31.2)%	**80,565**	117,546	(31.5)%
Netbacks ($/boe)								
Sales	**33.88**	27.40	65.77	23.6%	(48.5)%	**37.37**	58.44	(36.1)%
Royalties	**(0.17)**	(0.41)	(0.67)	(58.5)%	(74.6)%	**(0.49)**	(1.12)	(56.3)%
Operating	**(13.11)**	(9.36)	(8.40)	40.1%	56.1%	**(10.64)**	(9.40)	13.2%
General and administration	**(1.03)**	(0.44)	(0.88)	134.1%	17.0%	**(0.88)**	(0.69)	27.5%
Current income taxes	**15.05**	(0.68)	(9.31)	N/A	N/A	**1.31**	(5.83)	N/A
Fund flows from operations netback	**34.62**	16.51	46.51	109.7%	(25.6)%	**26.67**	41.40	(35.6)%
Realized prices								
Condensate ($/bbl)	**73.51**	69.12	69.95	6.4%	5.1%	**72.44**	74.85	(3.2)%
Natural gas ($/mcf)	**5.57**	4.49	10.95	24.1%	(49.1)%	**6.16**	9.71	(36.6)%
Total ($/boe)	**33.88**	27.40	65.77	23.6%	(48.5)%	**37.37**	58.44	(36.1)%
Reference prices								
TTF ($/mcf)	**5.36**	4.40	10.91	21.8%	(50.9)%	**5.90**	10.23	(42.3)%
TTF (€/mcf)	**3.67**	3.00	7.23	22.3%	(49.2)%	**3.97**	6.69	(40.7)%

Production

- Q4 2019 production increased 9% from the prior quarter primarily due to the restoration of production following planned and unplanned facility downtime in Q3 2019. Quarterly production decreased 8% year-over-year primarily due to Q4 2018 benefitting from the first full quarter of production from the Eesveen-02 well, which was brought on production in September 2018, in addition to natural decline.

Activity

- During Q4 2019, we successfully drilled and completed the Weststellingwerf well (0.5 net), representing our first drilling activity in the Netherlands since 2017.

Sales

- The price of our natural gas in the Netherlands is based on the TTF index.
- Q4 2019 sales increased versus Q3 2019 consistent with increases in the TTF reference price and increased sales volumes.
- For the three months and year ended December 31, 2019, sales decreased versus comparable periods consistent with decreases in the TTF reference price.

Royalties

- In the Netherlands, certain wells are subject to overriding royalties while some wells are subject to royalties that take effect only when specified production levels are exceeded. As such, royalty expense may fluctuate from period to period depending on the amount of production from those wells.
- Royalties in Q4 2019 represented 0.5% of sales. Effective March 1, 2019, certain royalty rights were acquired which resulted in lower royalties.

Transportation

- Our production in the Netherlands is not subject to transportation expense as gas is sold at the plant gate.

Operating

- Operating expense on a per unit basis increased in Q4 2019 compared to Q3 2019 and Q4 2018 primarily as a result of the timing of activity.
- For the year ended December 31, 2019, operating expense per unit increased compared to the prior year as a result of increased maintenance activity, higher surface lease rentals and water disposal costs.

General and administration

- Fluctuations in general and administration expense for all comparable periods were due to the timing of expenditures and allocations from our corporate segment.

Current income taxes

- 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 asset retirement obligations, at a tax rate of 50%.
- Current income taxes for the year ended December 31, 2019 versus the comparative period were lower mainly due to decreased TTF prices resulting in decreased sales and other prior year adjustments.
- Current income taxes for Q4 2019 versus the comparative quarters were lower mainly due to increased tax deductions for depletion, asset retirement obligations, and other prior year adjustments.
- On December 17, 2019, the Dutch government approved the 2020 Tax Plan. The Bill provides for reduced corporate tax rates from 25.0% in 2020 to 21.7% by 2021. Due to the tax regime applicable to natural gas producers in the Netherlands, the reduction to the corporate tax rate is not expected to have a material impact to Vermilion taxes in the Netherlands.

Germany Business Unit

Overview

- Entered Germany in 2014 through the acquisition of a non-operated natural gas producing property.
- Executed a significant exploration license farm-in agreement in 2015 and acquired operated producing properties in 2016.
- Producing assets consist of seven gas and eight oil-producing fields with extensive infrastructure in place.
- Significant land position of approximately 1.2 million net acres (97% undeveloped).

Operational and financial review

Germany business unit ($M except as indicated)	Q4 2019	Q3 2019	Q4 2018	Q4/19 vs. Q3/19	Q4/19 vs. Q4/18	2019	2018	2019 vs. 2018
Production								
Crude oil (bbls/d)	**800**	845	913	(5.3)%	(12.4)%	**917**	1,004	(8.7)%
Natural gas (mmcf/d)	**15.44**	14.54	16.94	6.2%	(8.9)%	**15.31**	15.66	(2.2)%
Total (boe/d)	**3,373**	3,269	3,736	3.2%	(9.7)%	**3,468**	3,614	(4.0)%
Sales								
Crude oil (bbls/d)	**629**	864	970	(27.2)%	(35.2)%	**881**	1,065	(17.3)%
Natural gas (mmcf/d)	**15.44**	14.54	16.94	6.2%	(8.9)%	**15.31**	15.66	(2.2)%
Total (boe/d)	**3,202**	3,287	3,794	(2.6)%	(15.6)%	**3,432**	3,675	(6.6)%
Production mix (% of total)								
Crude oil	**24%**	26%	24%			**26%**	28%	
Natural gas	**76%**	74%	76%			**74%**	72%	
Activity								
Capital expenditures	**5,177**	4,229	4,580	22.4%	13.0%	**21,684**	15,806	37.2%
Acquisitions	**1,456**	947	706			**7,570**	1,665	
Gross wells drilled	**—**	—	—			**2.00**	—	
Net wells drilled	**—**	—	—			**0.71**	—	
Financial results								
Sales	**11,531**	11,320	21,897	1.9%	(47.3)%	**57,312**	82,449	(30.5)%
Royalties	**(587)**	(952)	(1,190)	(38.3)%	(50.7)%	**(5,264)**	(6,626)	(20.6)%
Transportation	**(963)**	(1,709)	(1,452)	(43.7)%	(33.7)%	**(5,117)**	(6,420)	(20.3)%
Operating	**(7,405)**	(6,433)	(6,615)	15.1%	11.9%	**(24,970)**	(23,048)	8.3%
General and administration	**(1,957)**	(2,436)	(2,308)	(19.7)%	(15.2)%	**(8,452)**	(7,401)	14.2%
Fund flows from operations	**619**	(210)	10,332	N/A	(94.0)%	**13,509**	38,954	(65.3)%
Netbacks ($/boe)								
Sales	**39.14**	37.43	62.74	4.6%	(37.6)%	**45.75**	61.47	(25.6)%
Royalties	**(1.99)**	(3.15)	(3.41)	(36.8)%	(41.6)%	**(4.20)**	(4.94)	(15.0)%
Transportation	**(3.27)**	(5.65)	(4.16)	(42.1)%	(21.4)%	**(4.09)**	(4.79)	(14.6)%
Operating	**(25.14)**	(21.27)	(18.95)	18.2%	32.7%	**(19.93)**	(17.18)	16.0%
General and administration	**(6.64)**	(8.05)	(6.61)	(17.5)%	0.5%	**(6.75)**	(5.52)	22.3%
Fund flows from operations netback	**2.10**	(0.69)	29.61	N/A	(92.9)%	**10.78**	29.04	(62.9)%
Realized prices								
Crude oil ($/bbl)	**77.58**	76.51	75.53	1.4%	2.7%	**80.22**	84.14	(4.7)%
Natural gas ($/mcf)	**4.96**	3.92	9.72	26.5%	(49.0)%	**5.64**	8.70	(35.2)%
Total ($/boe)	**39.14**	37.43	62.74	4.6%	(37.6)%	**45.75**	61.47	(25.6)%
Reference prices								
Dated Brent (US $/bbl)	**63.25**	61.94	67.76	2.1%	(6.7)%	**64.30**	71.04	(9.5)%
Dated Brent ($/bbl)	**83.49**	81.80	89.54	2.1%	(6.8)%	**85.31**	92.07	(7.3)%
TTF ($/mcf)	**5.36**	4.40	10.91	21.8%	(50.9)%	**5.90**	10.23	(42.3)%
TTF (€/mcf)	**3.67**	3.00	7.23	22.3%	(49.2)%	**3.97**	6.69	(40.7)%

Production

- Q4 2019 production increased 3% from the prior quarter due to better uptime on our operated oil and natural gas assets, partially offset by unplanned downtime on our non-operated oil assets. Quarterly production decreased 10% year-over-year due to unplanned downtime on our operated and non-operated oil and natural gas assets.

Activity

- During Q4 2019, we continued to evaluate tie-in alternatives for the Burgmoor Z5 (46% working interest) well, which was tested early in the third quarter of 2019. We expect production from this well to begin early next year. We also continued to evaluate and perform workover opportunities on our operated assets.

Sales

- The price of our natural gas in Germany is based on the NCG and GPL indexes, which are both highly correlated to the TTF benchmark. Crude oil in Germany is priced with reference to Dated Brent.
- Q4 2019 sales were consistent versus Q3 2019 due to increases in crude oil and natural gas reference prices offset by a decrease in sales volumes.
- For the three months and year ended December 31, 2019, sales decreased versus the comparable periods in 2018 due to decreases in crude oil and natural gas reference prices, as well as a decrease in sales volumes.

Royalties

- Our production in Germany is subject to state and private royalties on sales after certain eligible deductions.
- Royalties as a percentage of sales were lower in Q4 2019 versus Q3 2019 due to an adjustment in Q4 2019 related to prior periods.
- Royalties as a percentage of sales for the year ended December 31, 2019 compared to 2018 remained relatively consistent.

Transportation

- Transportation expense in Germany relates to costs incurred to deliver natural gas from the processing facility to the customer and deliver crude oil to the refinery.
- Transportation expense for the three months and year ended December 31, 2019 decreased compared to the prior periods due to the impact of prior period adjustments associated with final billings from the transportation systems operators.

Operating

- Operating expense for the three months and year ended December 31, 2019 increased versus the comparable periods due to higher costs associated with facility maintenance and repairs.

General and administration

- Fluctuations in general and administration expense for all comparable periods were due to the timing of expenditures and allocations from our corporate segment.

Current income taxes

- As a result of our tax pools in Germany, we did not incur current income taxes in the Germany Business Unit for the years ended December 31, 2019 and 2018.

Ireland Business Unit

Overview

- Entered Ireland in 2009 with an investment in the offshore Corrib gas field.
- The Corrib gas field is located offshore northwest Ireland and comprises of six offshore wells, offshore and onshore sales and transportation pipeline segments, as well as a natural gas processing facility.
- In Q4 2018, Vermilion assumed operatorship of the Corrib Natural Gas Project (the "Corrib Project") and increased its ownership stake by 1.5% to 20% following the completion of a strategic partnership with Canada Pension Plan Investment Board (“CPPIB”).

Operational and financial review

Ireland business unit ($M except as indicated)	Q4 2019	Q3 2019	Q4 2018	Q4/19 vs. Q3/19	Q4/19 vs. Q4/18	2019	2018	2019 vs. 2018
Production and sales								
Natural gas (mmcf/d)	**42.30**	43.21	52.03	(2.1)%	(18.7)%	**46.57**	55.17	(15.6)%
Total (boe/d)	**7,049**	7,202	8,672	(2.1)%	(18.7)%	**7,762**	9,195	(15.6)%
Activity								
Capital expenditures	**923**	354	140	160.7%	559.3%	**1,372**	224	512.5%
Acquisitions	**—**	—	(5,572)			**—**	(5,572)	
Financial results								
Sales	**21,824**	16,722	53,385	30.5%	(59.1)%	**104,274**	205,150	(49.2)%
Transportation	**(1,008)**	(1,130)	(1,115)	(10.8)%	(9.6)%	**(4,459)**	(5,129)	(13.1)%
Operating	**(2,854)**	(3,136)	(4,497)	(9.0)%	(36.5)%	**(12,431)**	(15,366)	(19.1)%
General and administration	**(484)**	(1,436)	(2,037)	(66.3)%	(76.2)%	**(2,491)**	(8,386)	(70.3)%
Fund flows from operations	**17,478**	11,020	45,736	58.6%	(61.8)%	**84,893**	176,269	(51.8)%
Netbacks ($/boe)								
Sales	**33.65**	25.24	66.91	33.3%	(49.7)%	**36.81**	61.12	(39.8)%
Transportation	**(1.55)**	(1.71)	(1.40)	(9.4)%	10.7%	**(1.57)**	(1.53)	2.6%
Operating	**(4.40)**	(4.73)	(5.64)	(7.0)%	(22.0)%	**(4.39)**	(4.58)	(4.1)%
General and administration	**(0.75)**	(2.17)	(2.55)	(65.4)%	(70.6)%	**(0.88)**	(2.50)	(64.8)%
Fund flows from operations netback	**26.95**	16.63	57.32	62.1%	(53.0)%	**29.97**	52.51	(42.9)%
Reference prices								
NBP ($/mcf)	**5.38**	4.50	11.03	19.6%	(51.2)%	**5.90**	10.35	(43.0)%
NBP (€/mcf)	**3.68**	3.07	7.31	19.9%	(49.7)%	**3.97**	6.76	(41.3)%

Production

- Q4 2019 production decreased 2% from the prior quarter due to natural decline, partially offset by less downtime at the Corrib natural gas processing facility compared to the prior quarter. Quarterly production decreased 19% year-over-year due to a combination of unplanned downtime and natural decline.

Activity

- Our 2019 capital program focused on planned turnarounds and optimization opportunities at the Corrib natural gas processing facility.

Sales

- The price of our natural gas in Ireland is based on the NBP index.
- Q4 2019 sales increased versus Q3 2019 primarily as a result of an increase in the NBP reference price.
- Sales for the three months and year ended December 31, 2019 decreased versus the comparable periods consistent with decreases in the NBP reference price and production volumes.

Royalties

- Our production in Ireland is not subject to royalties.

Transportation

- Transportation expense in Ireland relates to payments under a ship-or-pay agreement.
- Transportation expense for Q4 2019 versus Q3 2019 and Q4 2018 remained relatively consistent.
- Transportation expense for the year ended December 31, 2019 decreased versus the comparable period in the prior year due to a lower ship-or-pay obligation in the current year.

Operating

- For the three months and year ended December 31, 2019, operating expense decreased versus all comparable periods due to Vermilion's focus on cost management following our appointment as operator in December 2018.

General and administration

- Fluctuations in general and administration expense versus all comparable periods is primarily due to the timing of expenditures and allocations from our corporate segment.

Current income taxes

- Given the significant level of investment in Corrib and the resulting tax pools, we do not expect to incur current income taxes in the Ireland Business Unit for the foreseeable future.

Australia Business Unit

Overview

- Entered Australia in 2005.
- Hold a 100% operated working interest in the Wandoo field, located approximately 80 km offshore on the northwest shelf of Australia.
- Production is operated from two off-shore platforms and originates from 20 producing wells including five dual lateral wells for a total of 25 producing laterals.
- Wells that utilize horizontal legs (ranging in length from 500 to 3,000 plus metres) are located 600m below the seabed in approximately 55m of water depth.

Operational and financial review

Australia business unit ($M except as indicated)	Q4 2019	Q3 2019	Q4 2018	Q4/19 vs. Q3/19	Q4/19 vs. Q4/18	2019	2018	2019 vs. 2018
Production								
Crude oil (bbls/d)	**4,548**	5,564	4,174	(18.3)%	9.0%	**5,662**	4,494	26.0%
Sales								
Crude oil (bbls/d)	**2,691**	6,517	4,401	(58.7)%	(38.9)%	**5,416**	4,342	24.7%
Inventory (mbbls)								
Opening crude oil inventory	**108**	196	210			**189**	134	
Crude oil production	**418**	512	384			**2,067**	1,640	
Crude oil sales	**(247)**	(600)	(405)			**(1,977)**	(1,585)	
Closing crude oil inventory	**279**	108	189			**279**	189	
Activity								
Capital expenditures	**6,452**	2,995	43,760	115.4%	(85.3)%	**30,550**	75,638	(59.6)%
Gross wells drilled	**—**	—	—			**2.00**	—	
Net wells drilled	**—**	—	—			**2.00**	—	
Financial results								
Sales	**21,872**	56,188	39,351	(61.1)%	(44.4)%	**184,490**	150,733	22.4%
Operating	**(8,438)**	(11,876)	(15,757)	(28.9)%	(46.4)%	**(49,810)**	(53,199)	(6.4)%
General and administration	**(1,477)**	(1,260)	(1,391)	17.2%	6.2%	**(4,940)**	(4,918)	0.4%
Current income taxes	**(1,948)**	(6,222)	2,206	(68.7)%	N/A	**(34,354)**	(11,419)	200.8%
Fund flows from operations	**10,009**	36,830	24,409	(72.8)%	(59.0)%	**95,386**	81,197	17.5%
Netbacks ($/boe)								
Sales	**88.35**	93.71	97.19	(5.7)%	(9.1)%	**93.33**	95.11	(1.9)%
Operating	**(34.09)**	(19.81)	(38.92)	72.1%	(12.4)%	**(25.20)**	(33.57)	(24.9)%
General and administration	**(5.97)**	(2.10)	(3.44)	184.3%	73.5%	**(2.50)**	(3.10)	(19.4)%
PRRT	**(5.87)**	(9.72)	5.98	(39.6)%	N/A	**(13.13)**	(3.04)	331.9%
Corporate income taxes	**(2.00)**	(0.66)	(0.53)	203.0%	277.4%	**(4.25)**	(4.16)	2.2%
Fund flows from operations netback	**40.42**	61.42	60.28	(34.2)%	(32.9)%	**48.25**	51.24	(5.8)%
Reference prices								
Dated Brent (US $/bbl)	**63.25**	61.94	67.76	2.1%	(6.7)%	**64.30**	71.04	(9.5)%
Dated Brent ($/bbl)	**83.49**	81.80	89.54	2.1%	(6.8)%	**85.31**	92.07	(7.3)%

Production

- Q4 2019 production decreased 18% quarter-over-quarter primarily due to the planned shutdown of the Wandoo platform for eight days to perform facility upgrades and regular maintenance. Quarterly production increased 9% year-over-year primarily due to the production contribution from the two (2.0 net) well drilling program completed at the end of January 2019.
- Production volumes are managed to targets while meeting long-term supply requirements of our customers.

Activity

- Our 2019 capital program included the completion of our two (2.0 net) well drilling program at the end of January 2019, in addition to performing various asset optimization projects and proactive maintenance.

Sales

- Crude oil in Australia is priced with reference to Dated Brent and sold at an $8.02 premium to Dated Brent during 2019.
- Q4 2019 sales decreased compared to Q3 2019 due to lower sales volumes resulting from more liftings in the prior quarter. This decrease in sales volumes was partially offset by higher sales per bbl due to an increase in the Dated Brent reference price and premium received.
- Sales increased for the three months and year ended December 31, 2019 versus the comparable periods in 2018, despite decreases in the Dated Brent reference pricing, due to the timing of sales in the relevant periods.

Royalties and transportation

- Our production in Australia is not subject to royalties or transportation expense as crude oil is sold directly at the Wandoo B platform.

Operating

- Q4 2019 operating expense decreased compared to Q3 2019 on a dollar basis due to lower sales volumes in the fourth quarter. Operating expenses are deferred on the balance sheet until oil is sold at which point the related expenses are recognized into income. On a per unit basis, operating expenses increased in Q4 2019 compared to Q3 2019 due to the timing of major project activity.
- For the year ended December 31, 2019, operating expense decreased on a per unit basis primarily due to lower diesel usage and helicopter costs, coupled with increased production.

General and administration

- Fluctuations in general and administration expense for all comparable periods are primarily due to the timing of expenditures and allocations from our corporate segment.

Current income taxes

- In Australia, current income taxes include both Petroleum Resource Rent Tax ("PRRT") and corporate income taxes. PRRT is a profit based tax applied at a rate of 40% on sales less eligible expenditures, including operating expenses and capital expenditures. Corporate income taxes are applied at a rate of 30% on taxable income after eligible deductions, which includes PRRT paid.
- Current income taxes for the year ended December 31, 2019 versus the comparative period were higher mainly due to increased production resulting in higher sales.
- Current income taxes for Q4 2019 versus Q3 2019 were lower mainly due to decreased sales. Current income taxes for Q4 2019 versus Q4 2018 were higher mainly due to increased Q4 2018 PRRT tax deductions for the capital expenditures related to the drilling campaign.

United States Business Unit

Overview

- Entered the United States in 2014 and acquired additional producing assets in the Hilight field in 2018.
- Interests include approximately 144,600 net acres of land (69% undeveloped) in the Powder River Basin of northeastern Wyoming.
- Tight oil development targeting the Turner Sands at depths of approximately 1,500m (East Finn) and 2,600m (Hilight).

Operational and financial review

United States business unit ($M except as indicated)	Q4 2019	Q3 2019	Q4 2018	Q4/19 vs. Q3/19	Q4/19 vs. Q4/18	2019	2018	2019 vs. 2018
Production and sales								
Crude oil (bbls/d)	**3,161**	2,722	1,605	16.1%	96.9%	**2,531**	1,078	134.8%
NGLs (bbls/d)	**1,156**	1,140	998	1.4%	15.8%	**996**	452	120.4%
Natural gas (mmcf/d)	**8.20**	6.38	5.65	28.5%	45.1%	**6.89**	2.78	147.8%
Total (boe/d)	**5,683**	4,925	3,545	15.4%	60.3%	**4,675**	1,992	134.7%
Production mix (% of total)								
Crude oil	**56%**	55%	45%			**54%**	54%	
NGLs	**20%**	23%	28%			**21%**	23%	
Natural gas	**24%**	22%	27%			**25%**	23%	
Activity								
Capital expenditures	**3,132**	21,064	2,881	(85.1)%	8.7%	**57,196**	40,837	40.1%
Acquisitions	**575**	1,964	3,674			**3,799**	191,740	
Gross wells drilled	**—**	4.00	1.00			**8.00**	6.00	
Net wells drilled	**—**	4.00	1.00			**8.00**	6.00	
Financial results								
Sales	**22,885**	19,227	14,625	19.0%	56.5%	**75,364**	38,465	95.9%
Royalties	**(5,316)**	(4,874)	(4,053)	9.1%	31.2%	**(18,706)**	(10,070)	85.8%
Operating	**(4,996)**	(4,400)	(2,848)	13.5%	75.4%	**(16,370)**	(6,421)	154.9%
General and administration	**(2,099)**	(2,005)	(1,396)	4.7%	50.4%	**(7,566)**	(6,306)	20.0%
Fund flows from operations	**10,474**	7,948	6,328	31.8%	65.5%	**32,722**	15,668	108.8%
Netbacks ($/boe)								
Sales	**43.77**	42.43	44.85	3.2%	(2.4)%	**44.17**	52.90	(16.5)%
Royalties	**(10.17)**	(10.76)	(12.43)	(5.5)%	(18.2)%	**(10.96)**	(13.85)	(20.9)%
Operating	**(9.56)**	(9.71)	(8.73)	(1.5)%	9.5%	**(9.59)**	(8.83)	8.6%
General and administration	**(4.01)**	(4.43)	(4.28)	(9.5)%	(6.3)%	**(4.43)**	(8.67)	(48.9)%
Fund flows from operations netback	**20.03**	17.53	19.41	14.3%	3.2%	**19.19**	21.55	(11.0)%
Realized prices								
Crude oil ($/bbl)	**66.65**	68.91	70.78	(3.3)%	(5.8)%	**68.67**	79.18	(13.3)%
NGLs ($/bbl)	**20.69**	9.44	26.81	119.2%	(22.8)%	**17.88**	28.02	(36.2)%
Natural gas ($/mcf)	**1.73**	1.67	3.29	3.6%	(47.4)%	**2.15**	2.67	(19.5)%
Total ($/boe)	**43.77**	42.43	44.85	3.2%	(2.4)%	**44.17**	52.90	(16.5)%
Reference prices								
WTI (US $/bbl)	**56.96**	56.45	58.81	0.9%	(3.1)%	**57.03**	64.77	(11.9)%
WTI ($/bbl)	**75.19**	74.55	77.71	0.9%	(3.2)%	**75.67**	83.94	(9.9)%
Henry Hub (US $/mcf)	**2.50**	2.23	3.65	12.1%	(31.5)%	**2.63**	3.09	(14.9)%
Henry Hub ($/mcf)	**3.30**	2.94	4.82	12.2%	(31.5)%	**3.49**	4.01	(13.0)%

Production

- Q4 2019 production increased 15% from the prior quarter due to a full quarter of contributions from the four wells we brought on production during the third quarter of 2019, in addition to better uptime across our asset base. Quarterly production increased 60% year-over-year primarily due to the contributions from our 2019 Hilight drilling program.

Activity

- During Q4 2019, we began drilling two (1.98 net) Turner horizontal wells in the Hilight field, both of which were rig released in January 2020.
- In 2019, we drilled eight (8.0 net) Turner horizontal wells in the Hilight field.

Sales

- The price of our crude oil in the United States is directly linked to WTI and subject to local market differentials within the United States. The price of our natural gas in the United States is based on the Henry Hub index.
- For the three months and year ended December 31, 2019 versus all comparable periods, sales increased due to increased production, which more than offset the decrease in lower commodity prices.

Royalties

- Our production in the United States is subject to federal and private royalties, severance tax, and ad valorem tax. In Hilight, approximately 65% of the current production is subject to Fee royalties, 30% to Federal royalties and the remainder to State royalties. In East Finn, approximately 70% of the current production is subject to Federal royalties with the remainder split between State and Fee royalties.
- For the three months and year ended December 31, 2019, royalties as a percentage of sales remained relatively consistent.

Operating

- For the three months and year ended December 31, 2019 versus all comparable periods, operating expense increased primarily due to incremental expenses associated with the year-over-year production increase.

General and administration

- Fluctuations in general and administration expense for all comparable periods were due to the incremental staffing of the United States business unit, timing of expenditures, and allocations from our corporate segment.

Current income taxes

- As a result of our tax pools in the United States, we do not expect to incur current income taxes in the United States Business Unit for the foreseeable future.

Corporate

Overview

- Our Corporate segment includes costs related to our global hedging program, financing expenses, and general and administration expenses that are primarily incurred in Canada and are not directly related to the operations of our business units. Gains or losses relating to Vermilion's global hedging program are allocated to Vermilion's business units for statutory reporting and income tax purposes.
- Results of our activities in Central and Eastern Europe are also included in the Corporate segment.

Operational and financial review

Corporate ($M)	Q4 2019	Q3 2019	Q4 2018	2019	2018
Production and sales					
Natural gas (mmcf/d)	**1.66**	—	2.86	**0.42**	1.02
Total (boe/d)	**276**	—	477	**70**	169
Activity					
Capital expenditures	**(98)**	8,107	2,546	**20,372**	10,611
Acquisitions	**2,131**	—	(492)	**2,131**	(285)
Gross wells drilled	**—**	3.00	—	**6.00**	1.00
Net wells drilled	**—**	3.00	—	**5.30**	1.00
Financial results					
Sales	**797**	—	2,547	**797**	3,630
Royalties	**(254)**	—	(534)	**(253)**	(813)
Sales of purchased commodities	**74,951**	41,449	—	**221,274**	—
Purchased commodities	**(74,951)**	(41,449)	—	**(221,274)**	—
Operating	**(59)**	(2)	91	**(301)**	(110)
General and administration recovery (expense)	**2,456**	2,957	969	**5,879**	(2,744)
Current income taxes	**98**	(250)	646	**(406)**	(513)
Interest expense	**(19,169)**	(19,661)	(20,827)	**(81,377)**	(72,759)
Realized gain (loss) on derivatives	**22,712**	36,968	(28,319)	**84,219**	(111,258)
Realized foreign exchange gain (loss)	**2,013**	(3,348)	5,894	**(4,954)**	243
Realized other income	**253**	372	275	**7,700**	883
Fund flows from operations	**8,847**	17,036	(39,258)	**11,304**	(183,441)

Production

- Q4 2019 production averaged 276 boe/d. In Hungary, we brought on production the Mh-21 (0.3 net) and Battonya E-09 (1.0 net) wells, drilled in the second and third quarters of 2019, respectively. The wells were brought on production mid-way through the fourth quarter of 2019.

Activity

- During the fourth quarter, we were provisionally awarded the Kadarkút exploration license in western Hungary. The license covers approximately 298,500 net acres and consists of primarily oil prospects. Most of the license is covered by existing 3D seismic and the agreement covers a four year period, with the option to extend the license for a further two years.

Sales, royalties, and operating expense

- Sales, royalties, and operating expense in the corporate segment in Q4 2019 and Q4 2018 relate to natural gas production in Hungary.
- Sales of natural gas in Hungary are priced with reference to the TTF index less adjustments for processing. During the quarter we realized a price of $5.22/mcf versus the $5.36/mcf benchmark price.
- The calculation for royalties on natural gas in Hungary incorporates the Dated Brent benchmark prices and as a result the quarterly realized royalty percentage will fluctuate depending on the relative pricing for TTF as compared to Dated Brent. As TTF weakened by 51% in Q4 2019 versus Q4 2018 while Dated Brent decreased 7% over the same period, our realized royalty rate increased to 32% in Q4 2019 versus 22% in Q4 2018.
- Operating expense relates to contract operating costs, which equated to $2.30/boe during Q4 2019.

Purchased commodities

- Purchased commodities and the associated sales relate to amounts purchased from third parties, primarily to manage positions on pipelines. There is no net impact on fund flows from operations.

General and administration

- Fluctuations in general and administration expense for the year ended December 31, 2019 versus all comparable periods were due to allocations to the various business unit segments.

Current income taxes

- Taxes in our corporate segment relate to holding companies that pay current taxes in foreign jurisdictions.

Interest expense

- Interest expense in Q4 2019 remained relatively consistent compared to Q3 2019 and Q4 2018.
- For the year ended December 31, 2019, interest expense increased versus the comparative period in 2018 due to higher drawings on the revolving credit facility, partially offset by the impact of the USD-to-EUR cross-currency interest rate swaps entered into in Q2 2019.

Realized gain or loss on derivatives

- The realized gain on derivatives for the year ended December 31, 2019 is related primarily to receipts for European natural gas and crude oil hedges.
- A listing of derivative positions as at December 31, 2019 is included in “Supplemental Table 2” of this MD&A.

Realized other income

- Realized other income recognized in the year ended December 31, 2019, relates primarily to amounts received pursuant to a negotiated settlement of a legal matter in Canada.

Financial Performance Review

($M except per share)	Dec 31, 2019	Dec 31, 2018	Dec 31, 2017
Total assets	**5,866,120**	6,270,671	3,974,965
Long-term debt	**1,924,665**	1,796,207	1,270,330
Petroleum and natural gas sales	**1,689,863**	1,678,117	1,098,838
Net earnings	**32,799**	271,650	62,258
Net earnings per share			
Basic	**0.21**	1.93	0.52
Diluted	**0.21**	1.91	0.51
Cash dividends ($/share)	**2.76**	2.72	2.58

($M except per share)	Q4 2019	Q3 2019	Q2 2019	Q1 2019	Q4 2018	Q3 2018	Q2 2018	Q1 2018
Petroleum and natural gas sales	**388,802**	391,935	428,043	481,083	456,939	508,411	394,498	318,269
Net earnings (loss)	**1,477**	(10,229)	2,004	39,547	323,373	(15,099)	(61,364)	24,740
Net earnings (loss) per share								
Basic	**0.01**	(0.07)	0.01	0.26	2.12	(0.10)	(0.46)	0.20
Diluted	**0.01**	(0.07)	0.01	0.26	2.10	(0.10)	(0.46)	0.20

The following table shows the calculation of fund flows from operations:

	Q4 2019		Q3 2019		Q4 2018		2019		2018	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Petroleum and natural gas sales	**388,802**	**44.00**	391,935	43.04	456,939	48.90	**1,689,863**	46.12	1,678,117	52.95
Royalties	**(40,679)**	**(4.60)**	(41,490)	(4.56)	(43,874)	(4.70)	**(163,666)**	(4.47)	(152,167)	(4.80)
Petroleum and natural gas revenues	**348,123**	**39.40**	350,445	38.48	413,065	44.20	**1,526,197**	41.65	1,525,950	48.15
Transportation	**(15,570)**	**(1.76)**	(19,426)	(2.13)	(16,938)	(1.81)	**(72,446)**	(1.98)	(51,887)	(1.64)
Operating	**(110,583)**	**(12.52)**	(105,192)	(11.55)	(112,470)	(12.04)	**(440,078)**	(12.01)	(357,014)	(11.26)
General and administration	**(16,569)**	**(1.88)**	(13,652)	(1.50)	(12,814)	(1.37)	**(58,976)**	(1.61)	(51,929)	(1.64)
PRRT	**(1,453)**	**(0.16)**	(5,826)	(0.64)	2,422	0.26	**(25,947)**	(0.71)	(4,824)	(0.15)
Corporate income taxes	**5,835**	**0.66**	(4,527)	(0.50)	(7,946)	(0.85)	**(26,283)**	(0.72)	(38,753)	(1.22)
Interest expense	**(19,169)**	**(2.17)**	(19,661)	(2.16)	(20,827)	(2.23)	**(81,377)**	(2.22)	(72,759)	(2.30)
Realized gain (loss) on derivative instruments	**22,712**	**2.57**	36,968	4.06	(28,319)	(3.03)	**84,219**	2.30	(111,258)	(3.51)
Realized foreign exchange gain (loss)	**2,013**	**0.23**	(3,348)	(0.37)	5,894	0.63	**(4,954)**	(0.14)	243	0.01
Realized other income	**253**	**0.03**	372	0.04	275	0.03	**7,700**	0.21	883	0.03
Fund flows from operations	**215,592**	**24.40**	216,153	23.73	222,342	23.79	**908,055**	24.77	838,652	26.47

Fluctuations in fund flows from operations may occur as a result of changes in production levels, commodity prices, and costs to produce petroleum and natural gas. In addition, fund flows from operations may be affected by the timing of crude oil shipments in Australia and France. When crude oil inventory is built up, the related operating expense, royalties, and depletion expense are deferred and carried as inventory on the consolidated balance sheet. When the crude oil inventory is subsequently drawn down, the related expenses are recognized.

The following table shows a reconciliation from fund flows from operations to net earnings (loss):

($M)	Q4 2019	Q3 2019	Q4 2018	2019	2018
Fund flows from operations	**215,592**	216,153	222,342	**908,055**	838,652
Equity based compensation	**(11,233)**	(15,564)	(16,979)	**(64,233)**	(60,746)
Unrealized (loss) gain on derivative instruments	**(30,362)**	17,817	273,096	**(57,427)**	109,326
Unrealized foreign exchange gain (loss)	**42,848**	(50,679)	(36,366)	**57,225**	(63,243)
Unrealized other expense	**(204)**	(347)	(204)	**(825)**	(801)
Accretion	**(7,833)**	(8,701)	(8,205)	**(32,667)**	(31,219)
Depletion and depreciation	**(139,940)**	(174,077)	(174,435)	**(675,177)**	(609,056)
Deferred tax	**(21,335)**	5,169	(64,084)	**(56,096)**	(39,471)
Gain on business combinations	**—**	—	128,208	**—**	128,208
Impairment	**(46,056)**	—	—	**(46,056)**	—
Net earnings (loss)	**1,477**	(10,229)	323,373	**32,799**	271,650

Fluctuations in net income from period-to-period are caused by changes in both cash and non-cash based income and charges. Cash based items are reflected in fund flows from operations. Non-cash items include: equity based compensation expense, unrealized gains and losses on derivative instruments, unrealized foreign exchange gains and losses, accretion, depletion and depreciation expense, and deferred taxes. In addition, non-cash items may also include gains resulting from business combinations or charges resulting from impairment or impairment reversals.

Equity based compensation

Equity based compensation expense relates primarily to non-cash compensation expense attributable to long-term incentives granted to directors, officers, and employees under security-based arrangements, including the Vermilion Incentive Plan ("VIP"), a security-based compensation arrangement ("Five-Year Compensation Arrangement"), and the Deferred Share Unit Plan ("DSU Plan").

Equity based compensation expense in Q4 2019 decreased compared to Q3 2019 and Q4 2018, primarily due to a revision of performance factor in Q4 2019. For the year ended December 31, 2019, equity based compensation expense increased versus the comparable period in 2018 primarily due to a higher value of outstanding share awards in 2019.

Unrealized gain or loss on derivative instruments

Unrealized gain or loss on derivative instruments arise as a result of changes in forecasts for future prices and rates. As Vermilion uses derivative instruments to manage the commodity price exposure of our future crude oil and natural gas production, we will normally recognize unrealized gains on derivative instruments when future commodity price forecasts decline and vice-versa. As derivative instruments are settled, the unrealized gain or loss previously recognized is reversed, and the settlement results in a realized gain or loss on derivative instruments.

For the three months and year ended December 31, 2019, we recognized an unrealized loss on derivative instruments of $30.4 million and $57.4 million respectively. Of those amounts, $39.0 million and $82.6 million relates to our crude oil commodity derivative instruments, offset by an unrealized gain of $51.3 million and $102.5 million on our European natural gas derivative instruments.

For the three months and year ended December 31, 2019 the unrealized loss also consists of an unrealized loss of $42.5 million and $74.2 million respectively from our USD-to-CAD cross currency interest rate swaps. These USD-to-CAD cross currency interest rate swaps are entered into on a monthly basis to hedge the foreign exchange movements on USD borrowings on our revolving credit facility. As such, unrealized gains and losses on our cross currency interest swaps are offset by unrealized losses and gains on foreign exchange relating to the underlying USD borrowings from our revolving credit facility.

Unrealized foreign exchange gains or losses

As a result of Vermilion's international operations, Vermilion has monetary assets and liabilities denominated in currencies other than the Canadian dollar. These monetary assets and liabilities include cash, receivables, payables, long-term debt, derivative instruments and intercompany loans. Unrealized foreign exchange gains and losses result from translating these monetary assets and liabilities from their underlying currency to the Canadian dollar.

In 2019, unrealized foreign exchange gains and losses primarily resulted from:

- The translation of Euro denominated intercompany loans from Vermilion Energy Inc. to our international subsidiaries. An appreciation in the Euro against the Canadian dollar will result in an unrealized foreign exchange gain (and vice-versa). Under IFRS, the offsetting foreign exchange loss or gain is recorded as a currency translation adjustment within other comprehensive income. As a result, consolidated comprehensive income reflects the offsetting of these translation adjustments while net earnings reflects only the parent company's side of the translation.

- The translation of USD borrowings on our revolving credit facility. The unrealized foreign exchange gains or losses on these borrowings are offset by unrealized derivative gains or losses on associated USD-to-CAD cross currency interest rate swaps (discussed further above).
- The translation of our USD denominated senior unsecured notes for the period from December 31, 2018 to June 12, 2019. Effective June 12, 2019, the USD senior notes were hedged by a USD-to-CAD cross currency interest rate swap.

For the three months ended December 31, 2019, the impact of the Euro strengthening against the Canadian dollar resulted in a $5.5 million unrealized gain on our intercompany loans. This was coupled with an unrealized gain of $37.3 million on our USD borrowings from our revolving credit facility.

For the year ended December 31, 2019, the impact of the Euro weakening against the Canadian dollar resulted in a $29.4 million unrealized loss on our intercompany loans. This was offset by a $19.8 million unrealized gain on our USD denominated senior unsecured notes for the period from December 31, 2018 to June 12, 2019 (when the USD senior notes were hedged by a USD-to-EUR cross currency interest rate swap) and a $66.8 million unrealized gain on our USD borrowings from our revolving credit facility.

As at December 31, 2019, a $0.01 appreciation of the Euro against the Canadian dollar would result in a $1.6 million increase to net earnings as a result of an unrealized gain on foreign exchange. In contrast, a $0.01 appreciation of the US dollar against the Canadian dollar would result in a $(5.6) million decrease to net earnings as a result of an unrealized loss on foreign exchange.

Accretion

Accretion expense is recognized to update the present value of the asset retirement obligation balance. Accretion expense in Q4 2019 was relatively consistent with Q3 2019 and Q4 2018. For the year ended December 31, 2019, accretion expense increased versus the comparable period in 2018, primarily attributable to new obligations recognized following acquisition activity in 2018.

Depletion and depreciation

Depletion and depreciation expense is recognized to allocate the cost of capital assets over the useful life of the respective assets. Depletion and depreciation expense per unit of production is determined for each depletion unit (which are groups of assets within a specific production area that have similar economic lives) by dividing the sum of the net book value of capital assets and future development costs by total proved plus probable reserves.

Fluctuations in depletion and depreciation expense are primarily the result of changes in produced crude oil and natural gas volumes and changes in depletion and depreciation per unit. Fluctuations in depletion and depreciation per unit are the result of changes in reserves, future development costs, and relative production mix.

Depletion and depreciation on a per boe basis for Q4 2019 of $15.84 decreased from $19.12 in Q3 2019 due to an increase in proved plus probable reserves. For the three months and year ended December 31, 2019, depletion and depreciation on a per boe basis of $15.84 and $18.43 respectively, decreased from $18.67 and $19.22 in the respective comparable periods in 2018 due to the increase in proved plus probable reserves in Q4 2019.

Deferred tax

Deferred tax assets arise when the tax basis of an asset exceeds its accounting basis (known as a deductible temporary difference). Conversely, deferred tax liabilities arise when the tax basis of an asset is less than its accounting basis (known as a taxable temporary difference). Deferred tax assets are recognized only to the extent that it is probable that there are future taxable profits against which the deductible temporary difference can be utilized. Deferred tax assets and liabilities are measured at the enacted or substantively enacted tax rate that is expected to apply when the asset is realized or the liability is settled.

As such, fluctuations in deferred tax expenses and recoveries primarily arise as a result of: changes in the accounting basis of an asset or liability without a corresponding tax basis change (e.g. when derivative assets and liabilities are marked-to-market or when accounting depletion differs from tax depletion), changes in available tax losses (e.g. if they are utilized to offset taxable income), changes in estimated future taxable profits resulting in a de-recognition or re-recognition of deferred tax assets, and changes in enacted or substantively enacted tax rates.

For the three months and year ended December 31, 2019, deferred tax expense of $21.3 million and $56.1 million, respectively, was recognized primarily related to the de-recognition of a portion of non-expiring tax loss pools in Ireland as there is uncertainty as to Vermilion's ability to fully utilize such losses based on commodity price forecasts as at December 31, 2019.

Impairment

Impairment losses are recognized when indicators of impairment arise and the carrying amount of a cash generating unit ("CGU") exceeds its recoverable amount, determined as the higher of fair value less costs of disposal or value-in-use. In 2019, as a result of declining European natural gas price forecasts a non-cash impairment charge of $46.1 million was recorded in the Ireland CGU. The recoverable amount was determined using fair value less costs to sell, which considered future after-tax cash flows from proved plus probable reserves using forecast price and cost estimates and an after-tax discount rate of 9.0%.

Gain on business combinations

A gain on business combination is recognized when the total consideration paid in a business combination is less than the fair value of the net assets acquired. For the year ended December 31, 2018, gains of $68.8 million and $59.4 million were recognized on our purchases of Assets in Wyoming and Shell E&P Ireland Limited, respectively.

Taxes

Current income tax rates

Vermilion pays corporate income taxes in France, Netherlands, and Australia. In addition, Vermilion pays PRRT in Australia which is a profit based tax applied at a rate of 40% on sales less operating expenses, capital expenditures, and other eligible expenditures. PRRT is deductible in the calculation of taxable income in Australia.

For 2019 and 2018, taxable income was subject to corporate income tax at the following statutory rates:

Jurisdiction	2019	2018
Canada	26.7%	27.0%
France	32.0%	34.4%
Netherlands (1)	50.0%	50.0%
Germany	31.8%	30.2%
Ireland	25.0%	25.0%
Australia	30.0%	30.0%
United States	21.0%	21.0%

(1) In the Netherlands, an additional 10% uplift deduction is allowed against taxable income that is applied to operating expenses, eligible general and administration expenses, and tax deductions for depletion and abandonment retirement obligations.

Tax legislation changes

On June 28, 2019, the Alberta government enacted a Bill to gradually reduce the provincial corporate tax rate from 12% to 8% by 2022, with the first reduction to 11% effective July 1, 2019.

On December 28, 2019, the French Parliament approved the Finance Bill for 2020. The Finance Bill for 2020 provides for a progressive decrease of the French corporate income tax rate for companies with sales below €250 million from 32.0% to 25.8% by 2022, with a reduction in 2020 to 28.9%.

On December 17, 2019, the Dutch government approved the 2020 Tax Plan. The Bill provides for reduced corporate tax rates from 25.0% in 2020 to 21.7% by 2021. Due to the tax regime applicable to natural gas producers in the Netherlands, the reduction to the corporate tax rate is not expected to have a material impact to Vermilion taxes in the Netherlands.

Tax pools

As at December 31, 2019, we had the following tax pools:

($M)	Oil & Gas Assets		Tax Losses		Other	Total
Canada	2,096,939	(1)	1,221,855	(4)	28,558	3,347,352
France	389,115	(2)	—		—	389,115
Netherlands	52,452	(3)	1,239	(4)	—	53,691
Germany	161,888	(3)	112,090	(5)	9,828	283,806
Ireland	—		1,128,178	(4)	—	1,128,178
Australia	252,581	(1)	—		—	252,581
United States	278,849	(2)	62,295	(6)	—	341,144
Total	**3,231,824**		**2,525,657**		**38,386**	**5,795,867**

(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 and applied at 100% against taxable income.
(5) 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.
(6) Tax losses created prior to January 1, 2018 are carried forward and applied at 100% against taxable income, tax losses created after January 1, 2018 are carried forward and applied to 80% of taxable income in each taxation year.

Financial Position Review

Balance sheet strategy

We believe that our balance sheet supports our defined growth initiatives and our focus is on managing and maintaining a conservative balance sheet. To ensure that our balance sheet continues to support our defined growth initiatives, we regularly review whether our forecast of fund flows from operations is sufficient to finance planned capital expenditures, dividends, and abandonment and reclamation expenditures. To the extent that fund flows from operations forecasts are not expected to be sufficient to fulfill such expenditures, we will evaluate our ability to finance any shortfall with debt (including borrowing using the unutilized capacity of our existing revolving credit facility), issue equity, or by reducing some or all categories of expenditures to ensure that total expenditures do not exceed available funds. To ensure that we maintain a conservative balance sheet, we monitor the ratio of net debt to fund flows from operations.

We remain focused on maintaining and strengthening our balance sheet by aligning our exploration and development capital budget with forecasted fund flows from operations to target a payout ratio (a non-GAAP financial measure) of approximately 100%. We continually monitor for changes in forecasted fund flows from operations as a result of changes to forward commodity prices and as appropriate, we will adjust our dividend policy and exploration and development capital plans. In the current economic and commodity outlook following the outbreak of novel coronavirus (COVID-19), there is uncertainty regarding our ability to achieve a 100% payout ratio at a reasonable level of capital expenditures. Therefore, effective for the March 2020 dividend (payable April 15, 2020), we reduced our monthly dividend by 50%.

Net debt

Net debt is reconciled to long-term debt, as follows:

	As at	
($M)	Dec 31, 2019	Dec 31, 2018
Long-term debt	**1,924,665**	1,796,207
Current liabilities	**416,210**	563,199
Current assets	**(347,681)**	(429,877)
Net debt	**1,993,194**	1,929,529
Ratio of net debt to four quarter trailing fund flows from operations	**2.20**	2.30

As at December 31, 2019, net debt increased to $2.0 billion (December 31, 2018 - $1.9 billion) primarily due to the impact of increased borrowings on the revolving credit facility to fund our capital program. The ratio of net debt to four quarter trailing fund flows from operations decreased to 2.20 (December 31, 2018 - 2.30) as the increase to net debt was offset by higher four quarter trailing fund flows from operations.

Long-term debt

The balances recognized on our balance sheet are as follows:

	As at	
($M)	Dec 31, 2019	Dec 31, 2018
Revolving credit facility	**1,539,225**	1,392,206
Senior unsecured notes	**385,440**	404,001
Long-term debt	**1,924,665**	1,796,207

Revolving Credit Facility

In Q2 2019, we negotiated an amendment to our $2.1 billion revolving credit facility to extend the maturity to May 31, 2023. The amendment included changes to the financial covenants, as described below.

As at December 31, 2019, Vermilion had in place a bank revolving credit facility maturing May 31, 2023 with terms and outstanding positions as follows:

	As at	
($M)	Dec 31, 2019	Dec 31, 2018
Total facility amount	**2,100,000**	1,800,000
Amount drawn	**(1,539,225)**	(1,392,206)
Letters of credit outstanding	**(10,230)**	(15,400)
Unutilized capacity	**550,545**	392,394

As at December 31, 2019, the revolving credit facility was subject to the following financial covenants:

		As at	
Financial covenant	Limit	Dec 31, 2019	Dec 31, 2018
Consolidated total debt to consolidated EBITDA	Less than 4.0	**1.94**	1.72
Consolidated total senior debt to consolidated EBITDA	Less than 3.5	**1.56**	1.34
Consolidated EBITDA to consolidated interest expense	Greater than 2.5	**13.46**	14.57

In Q2 2019, our financial covenants were updated to replace the consolidated total senior debt to total capitalization covenant with an interest coverage covenant (calculated as consolidated EBITDA to consolidated interest expense) and to add provisions relating to our liability management ratings in Alberta and Saskatchewan. If our security adjusted liability management ratings fall below specified limits in a province, a portion of the asset retirement obligations are included in the definitions of consolidated total debt and consolidated total senior debt. An event of default occurs if our security adjusted liability management ratings breach additional lower limits for a period greater than 90 days. As of December 31, 2019, Vermilion's liability management ratings were higher than the specified levels and as such no amounts relating to asset retirement obligations were included in the calculation of consolidated total debt and consolidated total senior debt.

Our financial covenants include financial measures defined within our revolving credit facility agreement that are not defined under IFRS. These financial measures are defined by our revolving credit facility agreement as follows:

- Consolidated total debt: Includes all amounts classified as “Long-term debt”, “Current portion of long-term debt”, and “Lease obligations” (including the current portion included within "Accounts payable and accrued liabilities" but excluding operating leases as defined under IAS 17) on our balance sheet.
- Consolidated total senior debt: Defined as consolidated total debt excluding unsecured and subordinated debt.
- Consolidated EBITDA: Defined as consolidated net earnings before interest, income taxes, depreciation, accretion and certain other non-cash items, adjusted for the impact of the acquisition of a material subsidiary.
- Total interest expense: Includes all amounts classified as "Interest expense", but excluding interest on operating leases as defined under IAS 17.

Senior Unsecured Notes

On March 13, 2017, Vermilion issued US$300.0 million of senior unsecured notes at par. The notes bear interest at a rate of 5.625% per annum, paid semi-annually on March 15 and September 15, and mature on March 15, 2025. As direct senior unsecured obligations of Vermilion, the notes rank equally in right of payment with existing and future senior indebtedness of the Company.

The senior unsecured notes were recognized at amortized cost and include the transaction costs directly related to the issuance.

Vermilion may, at its option, redeem the senior unsecured notes prior to maturity as follows:

- Prior to March 15, 2020, Vermilion may redeem up to 35% of the original principal amount of the senior unsecured notes with the proceeds of certain equity offerings by the Company at a redemption price of 105.625% of the principal amount, plus any accrued and unpaid interest to but excluding the applicable redemption date.
- Prior to March 15, 2020, Vermilion may redeem some or all of the senior unsecured notes at a price equal to 100% of the principal amount of the senior unsecured notes, plus a “make-whole” premium and any accrued and unpaid interest.
- On or after March 15, 2020, Vermilion may redeem some or all of the senior unsecured notes at the redemption prices set forth in the following table, plus any accrued and unpaid interest.

Year	Redemption price
2020	104.219%
2021	102.813%
2022	101.406%
2023 and thereafter	100.000%

Cross currency interest rate swaps

On June 12, 2019, Vermilion entered into a series of cross currency interest rate swaps with a syndicate of banks. The cross currency interest rate swaps mature March 15, 2025 and include regular cash receipts and payments on March 15 and September 15 of each year. On a net basis, the cross currency interest swaps result in Vermilion receiving US dollar interest and principal amounts equal to the interest and principal payments under the US $300.0 million of senior unsecured notes. In exchange, Vermilion will make interest and principal payments equal to €265.0 million at a rate of 3.275%.

The cross currency interest rate swaps were executed as two separate sets of instruments, wherein Vermilion:

- Receives US dollar interest and principal amounts equal to US$300.0 million of debt at 5.625% interest and pays Canadian dollar interest and principal amounts equal to $398.5 million of debt at 5.40% interest.
- Receives Canadian dollar interest and principal amounts equal to $398.5 million of debt at 5.40% interest and pays Euro interest and principal amounts equal to €265.0 million at a rate of 3.275%.

Shareholders' capital

In total, dividends declared for the year ended December 31, 2019 were $427.3 million.

The following table outlines our dividend payment history:

Date	Monthly dividend per unit or share
January 2003 to December 2007	$0.170
January 2008 to December 2012	$0.190
January 2013 to December 2013	$0.200
January 2014 to March 2018	$0.215
April 2018 to February 2020	$0.230
March 2020 onwards	$0.115

Our policy with respect to dividends is to be conservative and maintain a low ratio of dividends to fund flows from operations. During low commodity price cycles, we will initially maintain dividends and allow the ratio to rise. Should low commodity price cycles remain for an extended period of time, we will evaluate the necessity of changing the level of dividends, taking into consideration capital development requirements, debt levels, and acquisition opportunities.

In the current economic and commodity outlook following the outbreak of novel coronavirus (COVID-19), there is uncertainty regarding our ability to achieve a 100% payout ratio at a reasonable level of capital expenditures. Therefore, effective for the March 2020 dividend (payable April 15, 2020), we reduced our monthly dividend by 50%. Although we expect to be able to maintain our dividend, fund flows from operations may not be sufficient to fund cash dividends, capital expenditures, and asset retirement obligations. We will evaluate our ability to finance any shortfall with debt, issuances of equity, or by reducing some or all categories of expenditures to ensure that total expenditures do not exceed available funds.

The following table reconciles the change in shareholders' capital:

Shareholders' Capital	Number of Shares ('000s)	Amount ($M)
Balance at December 31, 2018	**152,704**	**4,008,828**
Shares issued for the Dividend Reinvestment Plan	**1,417**	**34,937**
Vesting of equity based awards	**1,359**	**51,108**
Equity based compensation	**552**	**15,868**
Share-settled dividends on vested equity based awards	**258**	**8,290**
Balance as at December 31, 2019	**156,290**	**4,119,031**

As at December 31, 2019, there were approximately 2.3 million equity based compensation awards outstanding. As at March 5, 2020, there were approximately 156.6 million common shares issued and outstanding.

We have a normal course issuer bid ("NCIB") approved by the Toronto Stock Exchange ("TSX") that allows us to purchase up to 7,750,000 common shares (representing approximately 5% of shares outstanding common shares) beginning August 9, 2019 and ending August 8, 2020. Any common shares that are purchased under the NCIB will be canceled upon their purchase. As at December 31, 2019, no shares have been purchased pursuant to the NCIB.

Contractual Obligations and Commitments

As at December 31, 2019, we had the following contractual obligations and commitments:

($M)	Less than 1 year	1 - 3 years	3 - 5 years	After 5 years	Total
Long-term debt [1]	63,948	127,896	1,577,713	399,179	2,168,736
Lease obligations	44,077	49,129	38,846	28,110	160,162
Processing and transportation agreements	30,529	47,688	12,774	3,004	93,995
Purchase obligations	27,220	9,856	557	—	37,633
Drilling and service agreements	16,071	58,398	21,207	—	95,676
Total contractual obligations and commitments	181,845	292,967	1,651,097	430,293	2,556,202

[1] Interest on revolving credit facility calculated assuming an annual interest rate of 3.35%.

[2] Commitments denominated in foreign currencies have been translated using the related spot rates on December 31, 2019.

Asset Retirement Obligations

As at December 31, 2019, asset retirement obligations were $618.2 million compared to $650.2 million as at December 31, 2018.

The present value of the obligation is calculated using a credit-adjusted risk-free rate, calculated using a credit spread added to risk-free rates based on long-term, risk-free government bonds. The decrease in asset retirement obligations is largely attributable to an increase in the credit spread from December 31, 2018 to December 31, 2019.

The Euro weakening against the Canadian dollar also contributed to the decrease in the asset retirement obligations. This decrease was partially offset by changes in the estimated costs and accretion expense.

The risk-free rates used as inputs to discount the obligations were as follows:

	Dec 31, 2019	Dec 31, 2018	Change
Canada	**1.7%**	2.2%	(0.5)%
France	**0.9%**	1.6%	(0.7)%
Netherlands	**(0.1)%**	0.4%	(0.5)%
Germany	**0.3%**	0.9%	(0.6)%
Ireland	**0.6%**	1.6%	(1.0)%
Australia	**1.6%**	2.6%	(1.0)%
United States	**2.4%**	2.7%	(0.3)%
Credit spread	**5.3%**	4.0%	1.3%

Risks and Uncertainties

Crude oil and natural gas exploration, production, acquisition and marketing operations involve a number of risks and uncertainties that have affected the financial statements and are reasonably likely to affect them in the future. These risks and uncertainties are discussed further below.

Commodity prices
Crude oil and natural gas prices have fluctuated significantly in recent years due to supply and demand factors. Changes in crude oil and natural gas prices affect the level of revenue we generate, the amount of proceeds we receive and payments we make on our commodity derivative instruments, and the level of taxes that we pay. In addition, lower crude oil and natural gas prices would reduce the recoverable amount of our capital assets and could result in impairments or impairment reversals.

Exchange rates
Exchange rate changes impact the Canadian dollar equivalent revenue and costs that we recognize. The majority of our crude oil and condensate revenue stream is priced in US dollars and as such an increase in the strength of the Canadian dollar relative to the US dollar would result in the receipt of fewer Canadian dollars for our revenue. We also incur expenses and capital costs in US dollars, Euros and Australian dollars and thus a decrease in strength of the Canadian dollar relative to those currencies may result in the payment of more Canadian dollars for our expenditures.

In addition, exchange rate changes impact the Canadian equivalent carrying balances for our assets and liabilities. For foreign currency denominated monetary assets (such as cash and cash equivalents, long-term debt, and intercompany loans), the impact of changes in exchange rates is recorded in net earnings as a foreign exchange gain or loss.

Production and sales volumes
Our production and sales volumes affect the level of revenue we generate and correspondingly the royalties and taxes that we pay. In addition, significant declines in production or sales volumes due to unforeseen circumstances may also result in an indicator of impairment and potential impairment charges.

Interest rates
Changes in interest rates impact the amount of interest expense we pay on our variable rate debt and also our ability to obtain fixed rate financing in the future.

Tax and royalty rates
Changes in tax and royalty rates in the jurisdictions that we operate in would impact the amount of current taxes and royalties that we pay. In addition, changes to substantively enacted tax rates would impact the carrying balance of deferred tax assets and liabilities, potentially resulting in a deferred tax recovery or incremental deferred tax expense.

In addition to the above, we are exposed to risk factors that impact our company and business. For further information on these risk factors, please refer to our Annual Information Form, available on SEDAR at www.sedar.com or on our website at www.vermilionenergy.com.

Financial Risk Management

To mitigate the risks affecting our business whenever possible, we seek to hire personnel with experience in specific areas. In addition, we provide continued training and development to staff to further develop their skills. When appropriate, we use third party consultants with relevant experience to augment our internal capabilities with respect to certain risks.

We consider our commodity price risk management program as a form of insurance that protects our cash flow and rate of return. The primary objective of the risk management program is to support our dividends and our internal capital development program. The level of commodity price risk management that occurs is dependent on the amount of debt that is carried. When debt levels are higher, we will be more active in protecting our cash flow stream through our commodity price risk management strategy.

When executing our commodity price risk management programs, we use derivative financial instruments encompassing over-the-counter financial structures as well as fixed and collar structures to economically hedge a part of our physical crude oil and natural gas production. We have strict controls and guidelines in relation to these activities and contract principally with counterparties that have investment grade credit ratings.

Critical Accounting Estimates

The preparation of financial statements in accordance with IFRS requires us to make estimates. Critical accounting estimates are those accounting estimates that require us to make assumptions about matters that are highly uncertain at the time the estimate is made and a different estimate could have been made in the current period or the estimate could change period-to-period.

The carrying amount of asset retirement obligations

The carrying amount of asset retirement obligations ($618.2 million as at December 31, 2019) is the present value of estimated future costs, discounted from the estimated abandonment date using a credit-adjusted risk-free rate. Estimated future costs are based on our assessment of regulatory requirements and the present condition of our assets. The estimated abandonment date is based on the reserve life of the associated assets. The credit-adjusted risk-free rate is based on prevailing interest rates for the appropriate term, risk-free government bonds adjusted for our estimated credit spread (determined by reference to the trading prices for debt issued by similarly rated independent oil and gas producers, including our own senior unsecured notes). Changes in these estimates would result in a change in the carrying amount of asset retirement obligations and capital assets and, to a significantly lesser degree, future accretion and depletion expense.

The estimated abandonment date may change from period to period as the estimated abandonment date changes in response to new information, such as changes in reserve life assumptions or regulations. A one year increase or decrease in the estimated abandonment date would decrease or increase asset retirement obligations (with an offsetting increase to capital assets) by approximately $27.5 million.

The estimated credit-adjusted risk-free rate may change from period to period in response to market conditions in Canada and the international jurisdictions that we operate in. A 0.5% increase or decrease in the credit-adjusted risk-free rate would decrease or increase asset retirement obligations by approximately $52.7 million.

The recognition of deferred tax assets in Ireland

In Ireland, we have $0.6 billion of non-expiring tax loss pools where $152.9 million of deferred tax assets has not been recognized as there is uncertainty on our ability to fully use these losses based on estimated future taxable profits. Estimated future taxable profits are calculated using proved and probable reserves and forecast pricing for European natural gas.

As a result, the carrying value of deferred tax assets may change from period-to-period due to changes in forecast pricing for European natural gas. A 5% increase or decrease in proved and probable reserves in our Ireland segment would increase or decrease deferred tax assets (with a corresponding deferred tax recovery or expense) by approximately $12.8 million. A €0.50/GJ increase or decrease in forecast European natural gas prices would increase or decrease deferred tax assets (with a corresponding deferred tax recovery or expense) by approximately $22.1 million.

The estimated recoverable amount of cash generating units

Each reporting period, we assess our cash generating units for indicators of impairment or impairment reversal. If an indicator of impairment or impairment reversal is identified, we estimate the recoverable amount of the cash generating unit. As a result of declining European natural gas price forecasts during the year ended December 31, 2019 an indicator of impairment was identified in the Ireland cash generating unit. The recoverable amount was determined using fair value less costs to sell which considered future after-tax cash flows from proved plus probable reserves using forecast price and cost estimates and an after-tax discount rate of 9.0%. A non-cash impairment charge of $46.1 million was recorded in the consolidated statement of net earnings.

Changes in any of the key judgments, such as a revision in reserves, changes in forecast commodity prices, foreign exchange rates, capital or operating costs would impact the estimated recoverable amount. As at December 31, 2019, a 1% increase in the assumed after-tax discount rate would reduce the estimated recoverable amount by $14.7 million (resulting in a $60.8 million impairment) while a 5% decrease in revenues (due to a decrease in commodity price forecasts or reserve estimates) would reduce the estimated recoverable amount by $28.6 million (resulting in a $74.7 million impairment).

Off Balance Sheet Arrangements

We have not entered into any guarantee or off balance sheet arrangements that would materially impact our financial position or results of operations.

Recently Adopted Accounting Pronouncements

Definition of a Business - Amendments to IFRS 3 "Business Combinations"

Vermilion elected to early adopt the amendments to IFRS 3 " *Business Combinations*" effective January 1, 2019, which will be applied prospectively to acquisitions that occur on or after January 1, 2019. The amendments introduce an optional concentration test, narrow the definitions of a business and outputs, and clarify that an acquired set of activities and assets must include an input and a substantive process that together significantly contribute to the ability to create outputs. These amendments did not result in changes to Vermilion's accounting policies for applying the acquisition method.

Health, Safety and Environment

We are committed to ensuring our activities are conducted in a manner that will protect the health and safety of our employees, contractors, and the public. Our health, safety, and environment ("HSE") vision is "Best in Class HSE", our mission is to fully integrate health, safety, and environment into our business, where our culture is recognized as a model by industry and stakeholders, resulting in a safe and healthy workplace. Our mantra is HSE: Everywhere. Everyday. Everyone.

We maintain health, safety and environmental practices and procedures in compliance with or exceeding regulatory requirements and industry standards. All of our personnel are expected to work safely and in accordance with established regulations and procedures, and we seek to reduce impacts to land, water and air. During 2019 we:

- Maintained clear priorities around 5 key focus areas of HSE Culture, Communication and Knowledge Management, Technical Safety Management, Incident Prevention and Operational Stewardship & Sustainability;
- Initiated a strategic review of current HSE program and long-term plan;
- Continued comprehensive investigations of our incidents and near misses to ensure root causes were identified and corrective actions effectively implemented;
- Completed our HSE Perception Survey, which we conduct every three years. Our results all factored in the favorable range. A plan was developed to address areas for further improvement;
- Expanded our Emergency Response Plan capabilities to align with our Central and Eastern European drilling and completions activity;
- Completed a comprehensive assessment of our Event Management Information System to prepare for an upgrade in 2020 that will add environmental data management;
- Completed numerous corporate standard/practice updates related to operational risk management, contractor management, marine transportation, and environmental management;
- Continued reinforcement of the "Vermilion High 5", an individual safety awareness initiative aimed at keeping front-line workers safe;
- Further developed and validated critical procedures and initiated competency assessments as part of fit-for-purpose training and competency programs;
- Continued comprehensive HSE integration plan for Vermilion's new and emerging operations (includes Central and Eastern Europe, Germany, United States, Ireland and Canada expansion);
- Initiated data gathering and quantification to meet the CDP Water reporting requirements for the 2019 data set;
- Managed our waste products by reducing, recycling and recovering;
- Reduced long-term environmental liabilities through decommissioning, abandoning and reclaiming well leases and facilities;
- Further refined and expanded our enterprise wide corporate risk register;
- Expanded our company-wide HSE leadership training program to improve hazard identification and risk reduction;
- Continued the development of a robust hazard identification and risk mitigation program specific to environmentally sensitive areas;
- Continued the development of our Corporate Process Safety Management System with emphasis on Process Hazards Analysis and risk reduction measures;
- Performed auditing, management inspections and workforce observations to measure compliance and identify potential hazards and apply risk reduction measures; and
- Developed, communicated and measured against leading and lagging HSE key performance indicators.

We are a member of several organizations concerned with environment, health and safety, including numerous regional co-operatives and synergy groups. In the area of stakeholder relations, we work to build long-term relationships with environmental stakeholders and communities.

Environmental, Social and Governance (ESG)

Furthering our focus on sustainability (ESG) strategy, in 2019 we continued to support the recommendations from the Task Force on Climate-related Financial Disclosures (TCFD), including in our reporting, focusing on climate but also on sustainability issues and opportunities in a wider context. In 2019, our Board of Directors and senior management participated in a robust scenario analysis process based on reporting from the World Economic Forum. This included analyzing factors such as the influence of new technologies, technology growth, government policy, and emerging markets that will impact the speed of the energy transition, and the resulting risks and opportunities for Vermilion. Our 2019 performance in sustainability rankings such as CDP, SAM, and Sustainalytics continued to be in the top quartile of our peer group.

Sustainability

As a responsible oil and gas producer, we consistently seek to deliver long-term shareholder value by operating in an economically, environmentally and socially sustainable manner that is recognized as a model in our industry.

Vermilion understands our stakeholders' expectations that we deliver strong financial results in a responsible and ethical way. As a result, we align our strategic priorities in the following order:

- the safety and health of our staff and those involved directly or indirectly in our operations;
- our responsibility to protect the environment. We follow the Precautionary Principle introduced in 1992 by the United Nations "Rio Declaration on Environment and Development" by using environmental risk as part of our development decision criteria, and by continually seeking improved environmental performance in our operations; and
- economic success through a focus on operational excellence across our business, which includes technical and process excellence, efficiency, expertise, stakeholder relations, and respectful and fair treatment of staff, contractors, partners and suppliers.

Reflecting these priorities, we have positioned Vermilion purposefully within the energy transition. Predictions differ about the manner and speed of the transition, but our own scenario analyses are clear that Vermilion can best contribute by focusing on producing energy responsibly: reliably, cost-effectively and safely. We also believe those stakeholders who are concerned about sustainability, including investors, governments, regulators, communities and citizens, should turn to best-in-class operators such as Vermilion. Our crude oil and natural gas assets are strategic resources that can, and should, be deployed in the service of the transition and, indeed, of the framework for the planet's health and wellbeing represented by the United Nations Sustainable Development Goals (SDGs).

To support our strategy, we regularly communicate with our stakeholders, including through our sustainability reporting. In 2018, reflecting our review of TCFD recommendations, we updated our engagement to include a broader inclusion of sustainability in regulatory reporting; we have continued this approach in 2019.

For more information, please see references to sustainability throughout this document, including the Climate Risk discussion. For additional context, our Sustainability Report is available online at www.vermilionenergy.com (under the heading "Our Responsibility").

Vermilion's sustainability performance and reporting have earned consistently strong recognition from external stakeholders:

Accomplishments

- The Company received a top quartile ranking for our industry sector in SAM's 2019 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.
- Vermilion was ranked second in our peer group in the Sustainalytics ESG (environment, social, governance) rankings.
- Vermilion's MSCI ESG rating increased to AA in 2019, and our Governance Metrics score ranked in the top decile globally.
- We received ISS QualityScore decile ratings of 1 for both Environmental and Social, which assess corporate disclosure and transparency practices in these areas, where 1 indicates the lowest risk.

Climate-related Disclosures

Vermilion has publicly released our identified climate risks and opportunities since our first annual CDP Climate Response in 2014. In alignment with recommendations from the TCFD and under the TCFD's Strategy category, we are also including a summary of them in this document. For more information on our sustainability-related governance, strategy, risk management, and metrics and targets, including those related to climate, please see our 2020 Proxy Statement and Information Circular, and our online sustainability reporting, particularly the Performance Metrics section and our 2019 CDP Response, which includes detailed information on the following risk and opportunity summaries.

Risk / Opportunity	Description of Impacts[1,2] - Risk Category - Risk Timeframe	Potential Financial Impact	Management Context
Increased Pricing of GHG Emissions e.g. Carbon Tax	- Policy and Legal - Medium-term In April 2019, our Saskatchewan operations became subject to the federal Greenhouse Gas Pollution Pricing Act, with carbon tax rates set at $20 per tonne of CO2e in 2019, rising to $50 by 2022. Our Alberta operations are subject to the fuel charge element of the Act beginning in January 2020.	Beginning in 2019, the direct and indirect impact of carbon taxes on the Canada Business Unit is estimated at approximately $2.3MM. For European operations, our Carbon Liability Assessment Tool indicates carbon tax is not forecasted to exceed $0.5MM per annum.	The potential financial impact is based on proposed changes to carbon pricing in our operating regions out to 2023, resulting in expansion of emission sources covered, and does not account for Vermilion's proactive programs to manage emissions. This estimate is based on the probable cost scenario identified in our Carbon Liability Assessment Tool.
Enhanced Emissions Reporting Obligations	- Policy and Legal - Short-term Emissions reporting obligations are an ongoing risk and can change due to political and regulatory evolution. The impact to Vermilion would be a decreased netback on a per BOE basis, due to increased expenditures for personnel time and system development and implementation, to allow for more robust emissions quantification.	Based on our current output in Canada and Europe, current regulated thresholds, and growth, we anticipate that cost associated with meeting emission reporting obligations will increase in the short-term, likely as a small increase in operational costs.	Regulations in all of our business units are monitored on an ongoing basis, and assumptions/scenario planning is used annually to assess risk. Vermilion also engages stakeholders relating to emissions reporting obligations. Management of this risk is built into Vermilion's operations and our Enterprise Risk Matrix.
Mandates on and Regulation of Existing Products and Services	- Policy and Legal; Technology - Short-term Vermilion's operations are subject to regional regulatory changes that result in changes to equipment requirements such as engineering and equipment modifications to reduce carbon emissions and / or emissions of criteria air contaminants.	The operational changes to comply with methane reduction regulations is expected at approximately $1.5MM in the short term, with those associated with eliminating routine flaring in France not expected to exceed $0.5MM. Costs associated with the Netherlands MJA3 program are built into our operating costs and no significant expenditures are anticipated in the short term.	Vermilion's participation in the MJA3 program in the Netherlands since 2005, for example, has resulted in projects that have reduced our operations energy intensity by 76%. We have allocated resources to complete methane reduction on a planned program basis, as opposed to a single reactive replacement program, resulting in an overall reduction in associated costs.
Changes in Emissions Regulations	- Policy and Legal - Medium-term The risk associated with a change in emission regulations in one or more of our business units is accounted for by Vermilion's Enterprise Risk Matrix, with mitigation measures being reviewed, updated, and implemented on an annual basis. A shift in international regulations may also result in an impact to Vermilion's supply chain, resulting in a limitation of market access or direct impact to the price of our products. As Vermilion maintains a diversified asset base, we believe the risk to the marketability of our products is low.	Following the COP21 conference, the importance of sustainable development and reduction of emission levels was confirmed by the commitments made by national governments. Based on the anticipated changes in the various regulatory regimes under which Vermilion operates, the financial impact due to a regulatory change over the next 3 years is anticipated to be less than $2.0MM. This does not include the cost associated with emission reduction projects completed on an annual basis, or previous projects that have annual emissions reductions.	The formalization of Integrated Sustainability as a strategic objective in Vermilion's long-term strategic plan allows us to better understand, identify, proactively respond, and manage the potential risk and uncertainty inherent in an evolving sustainability framework, both at a regional and corporate level. As an example, beginning in 2017, Vermilion added requirements to assess capital expenditures for potential sustainability-related impacts; in 2018, we established a Sustainability Committee at the Board of Directors level, and a Sustainability Steering Committee at the senior management level.
Changes in Temperature Extremes	- Physical - Long-term A decrease in temperature extremes experienced in the winter months (i.e. lower seasonal lows) could increase the amount of fuel gas used by a variety of equipment essential for safe production. Additional equipment could also be required (e.g. building heaters, line heaters) to ensure safe and efficient operation, thus increasing our carbon footprint and costs. Temperature extremes could also increase capital costs associated with drilling, completion and workover operations due to increased timelines, decreased productivity, equipment breakdown, etc. For example, warmer winters would have a direct impact on Vermilion's more northern operations, through a decreased ability to access lands and increased construction capital requirements.	The financial implications on an annual basis are difficult to quantify; however, based on Vermilion's experience, the most significant financial implications would result from shutdowns in drilling or completions locations. The estimated cost of this would be $0.5MM per day of delay.	As extreme weather cannot be controlled, Vermilion uses our various Management Systems and processes to protect the health and safety of our workers, contractors and the public, and to protect the environment from adverse effect. As an example of how we have reduced the potential impact related to access in remote assets, we use multi-well pads wherever possible, with multiple horizontal wells drilled from a single location. This reduces the aerial impact of these activities on the environment, habitat fragmentation and carbon emissions associated with lease construction and equipment mobilization/demobilization. Using multi-well locations would significantly decrease capital considerations in the event that limited frost days were realized in the coming years.
Changes In Precipitation Patterns and Extreme Variability in Weather Patterns	- Physical - Long-term Vermilion holds assets inland, in coastal regions, and offshore. A change in precipitation in any of these locations could have a negative impact on operations due to drought or flooding. Flooding could result in limited access to locations / facilities, and poses a risk to our corporate headquarters. Alternatively, drought conditions could impact the availability of surface and / or groundwater, which Vermilion, in part, relies on for drilling and completion activities. This could negatively impact forecasted growth by increasing the timelines and capital costs to bring new infrastructure onto production.	The financial implications of a single time event (e.g. wildfire) and continued strain event (e.g. drought) have been assessed on a case-specific basis, and the financial implications of these events is believed to be manageable (impact under $10.0MM). Vermilion maintains insurance to mitigate the potential impact of precipitation extreme events (e.g. flooding). Insurance for locations that have been identified as potentially being impacted by drought-induced events (e.g. wildfire) is estimated at $0.5MM per annum.	As these incidents are beyond Vermilion's control, we take measures to ensure effective emergency response to extreme weather events, to protect the health and safety of our workers, contractors and the public, to protect the environment, and to limit the financial impact of the event. In the case of a longer term extreme precipitation event or drought, Vermilion has implemented water management programs to reduce our reliance on fresh water sources.

Rising Sea Levels	- Physical - Long-term Vermilion owns and operates assets in the Netherlands. We have identified and assessed the potential risk associated with rising sea levels here, as it has the potential to physically impact our operations due to issues such as flooding, transportation difficulties and supply chain interruptions. Rising sea levels also pose a threat related to the salinization of groundwater.	Vermilion reviews the potential impact of rising sea levels annually as part of our Enterprise Risk Matrix. We estimate the potential total financial implication to be $153.0MM, before mitigation measures, in our Netherland operations.	There is no measure available to protect Vermilion's Netherlands assets in the event that water levels rise to a level that would impact facilities below sea level. Salinization of the groundwater regime would impact the entire region; similarly, no measures are currently available to protect against this. Based on Vermilion's assessment of the probability of these events occurring over the next 5 years being less than 0.5%, we have accepted this level of risk exposure.

Risk / Opportunity	Description of Impacts[1,2] - Risk Category - Risk Timeframe	Potential Financial Impact	Management Context
Increased Severity of Extreme Weather Events such as Cyclones and Floods	- Physical - Medium-term Vermilion owns and operates an offshore platform in the Wandoo field off northwestern Australia, and co-owns and operates the Corrib project off the Irish coast. Extreme weather events have the potential to directly impact our offshore operations resulting in down time or damage to infrastructure, and can impact the downstream handling capacity of our partners, resulting in a limitation to the distribution and sale of our products.	Based on the value of the Wandoo Platform and a 1-in-2000 year cyclonic event, the financial implications associated with damage due to a severe weather event is estimated at $179.0MM (total impact before insurance). The third-party costs associated with potential damages from extreme weather events are not tracked by Vermilion.	Vermilion maintains insurance as a mitigative measure to reduce the financial impact associated with damage to our assets due to severe weather events. We also have protocols for monitoring and preparing for cyclones, and have invested in our emergency response capabilities in the event of damage to our assets as a result of a severe weather event. Operational changes are made as required to ensure (in order of priority) worker health and safety, protection of the environment, and protection of Vermilion's assets.
Changing Customer Behaviour	- Market; Reputational - Long-term As consumers and governments become more socially aware of the sources of their energy, negative perceptions of organizations or production methods have the potential to impact energy sector companies through company valuations, restricted licensing and permitting, and stakeholder opposition.	The impact of decreased consumer confidence and perception is not calculable. On a per share basis, the market impact of the loss of $1 per share would be approximately $156.0MM. The direct cost of Vermilion's operating excellence and risk management cannot be quantified on a single risk basis.	Vermilion is positioned within the evolving energy transition, with an unwavering commitment to our priorities of health and safety, environmental protection, and economic prosperity. We believe that those commitments, and our contributions to the UN SDGs constitute qualitative advantages that set us apart from our competitors. Sustainable practices are ingrained into the way we operate, and we will continue to focus on our Integrated Sustainability strategic objective. We believe this advantage attracts investors to Vermilion and will continue to give Vermilion a competitive advantage in the future.
Opportunity: Participation in Carbon Market	- Financial - Medium-term The European Union Emissions Trading Scheme (ETS) allows for the generation and movement of certified carbon credits from emissions-saving projects around the world. With the revisions pending in Phase 4, it is anticipated that there will be an active market and consumers for the offset credits generated at some of our sustainability initiatives around the world, likely providing opportunities for Vermilion to generate certified energy reduction and offset credits.	Vermilion is not accounting for any short term financial impact. It is estimated that following the change to the EU ETS in Phase 4, the carbon price will stabilize at between approximately €15 and €30 per tCO2e. The financial impact to Vermilion annually is estimated to be up to $1.0MM.	We are currently evaluating the benefit that certified offset credits from various emission reduction projects across our operations could provide. Examples of projects with this potential include our Tomato Greenhouse Cogeneration project in France, our partnerships for geothermal applications in residential neighborhoods in France, and our developing geothermal projects in the Netherlands. Vermilion's project assessment framework is applied to each identified opportunity, including considerations associated with emissions offset.
Opportunity: Development of New Products and Services through R&D and Innovation	- Products - Short-term As Vermilion has developed our emissions quantification programs across the globe, we have developed more robust methods for sharing of technologies and techniques from across our operations, both internally and externally. Our increased focus on tracking emissions has supported the assessment of opportunities across business units and sharing of technical expertise.	As this opportunity is in the early stage of assessment, it is difficult to quantify the financial impact, but it is estimated at up to $2.0MM per year. Potential also exists for significant cost adjustments, as assets slated for abandonment could be repurposed to generate geothermal energy.	We have technical experts who provide input into potential geothermal projects as they are identified. These teams are supported by corporate sustainability staff in connecting internal and external stakeholders. These teams have responsibilities specific to geothermal opportunities as these projects move through their preliminary stages. To further support identification of opportunities, and engagement with stakeholders, Vermilion has appointed sustainability leads in all our business units.
Opportunity: Shift in Consumer Preferences	- Products, Reputational - Long-term Under the Canadian Environmental Protection Act and based on commitments made by the Canadian and Alberta governments relating to COP21, there is a commitment to reduce emissions for coal-fired power generation. Based on this and with a number of power generating facilities in Alberta nearing the end of their service life, the demand for natural gas is likely to increase due to increased use of combined cycle gas turbine (CCGT) power generation. Alberta has also committed to significantly reducing its demand for coal for power generation by 2050.	The short term impact on gas pricing is anticipated to be low, increasing to medium in the mid to long term. Once the regulations are implemented, there is a potential for an increase in the demand and pricing for natural gas, from which Vermilion would benefit. Based on current estimates, an increase in gas price of $1 per mcf would result in a positive impact to sales of approximately $35.0MM.	As we move further into the energy transition, we foresee natural gas playing an impactful role as a less carbon intense fuel than other options (i.e. coal). Vermilion continues to focus on the identification of resources and assets where we have the opportunity to apply our industry leading expertise to optimize production while reducing emissions. An example of our strategy to realize this opportunity is our asset base in Alberta, which currently includes a large liquids rich gas play. Vermilion's marketing team is also actively pursuing options for our natural gas production that will enable Vermilion to achieve the best netbacks on production.

Opportunity: Ability to Diversify Business Activities	- Products - Long-term Vermilion maintains a diverse, stable global portfolio of oil and gas assets. Our strong record of safe and socially conscious development of energy resources has provided opportunities to access and develop these resources. We see our commitment to sustainability as core to our business, which has provided important organizational focus on emissions quantification and management. As consumers become more aware of and involved in the selection of their energy sources and associated carbon intensity, we believe that Vermilion will continue to be a top quartile choice, providing us with opportunities not available to peer organizations.	The financial impact of changing consumer preferences is difficult to quantify. We foresee opportunities in two distinct areas: first, in consumers selecting premium energy products (top quartile, low carbon intensity), with these products demanding a higher price than other energy sources on the market. Currently we estimate the potential impact of premium pricing in the long term to be $1-5 per boe ($24.8MM based on $1 per boe). The second opportunity, which we are already receiving benefit from, is access to more stringent markets, supported by our environmental and sustainability performance, such as our entry into German, Hungarian and Croatian oil and gas operations in the last several years.	Vermilion made the organizational change to established Integrated Sustainability as one of our strategic objectives in 2015. This provided important organizational focus on matters such as environmental performance, including climate change. Our strategy is to continue to support Integrated Sustainability, with personnel who are experts in their field, as well as financially supporting programs and projects that reduce emissions while optimizing production. An example of this is the addition of personnel who have specific responsibilities associated with sustainability in our business units, including study and feasibility assessment of green energy generation.

Risk / Opportunity	Description of Impacts[1,2] - Risk Category - Risk Timeframe	Potential Financial Impact	Management Context
Opportunity: Shift Toward Decentralized Energy Generation	- Products, Reputational - Long-term The carbon intensity of energy used around the world has a direct relationship to where the energy product was generated. Vermilion's business unit structure supports production and distribution of energy products into local markets. This strategy results in the significant reduction of the carbon footprint of our energy when compared to non-local sources.	On an operating netback (sales) basis, based on current estimates, the financial premium of our non-Canadian assets was $340.8MM. The potential future advantage is anticipated to increase as we expand production in markets outside North America and provide sources of energy to local markets. The costs associated with adjustment of our organizational structure are built into our costs across the company.	Vermilion continues to assess where we can access local markets for our production, while exploring regions to expand our operations. The actions taken in the past several years to realize this opportunity include alterations to our structure, our strategic objectives and our operational development plans to support Vermilion as a distributed energy provider, and exploration and development programs in regions with relatively low energy production as compared to consumption (i.e. Hungary).

Notes:
(1) Short-term (0 to 3 years); Medium-term (3 to 6 years); Long-term (6 to 50 years).
(2) Risk summary is based on our fiscal year 2018 environmental reporting through CDP. Fiscal year 2019 environmental reporting will be available in mid-2020.

Corporate Governance

We are committed to a high standard of corporate governance practices, a dedication that begins at the Board level and extends throughout the Company. We believe good corporate governance is in the best interest of our shareholders, and that successful companies are those that deliver growth and a competitive return along with a commitment to the environment, to the communities where they operate, and to their employees.

We comply with the objectives and guidelines relating to corporate governance adopted by the Canadian Securities Administrators and the Toronto Stock Exchange ("TSX"). In addition, the Board monitors and considers the implementation of corporate governance standards proposed by various regulatory and non-regulatory authorities in Canada. A discussion of corporate governance policies is included each year in our proxy materials for our annual general meeting of shareholders, copies of which are available on SEDAR (www.sedar.com).

As a Canadian reporting issuer with securities listed on the TSX and the New York Stock Exchange ("NYSE"), Vermilion is required to comply with all applicable Canadian requirements adopted by the Canadian Securities Administrators and the TSX, and applicable rules for foreign private issuers adopted by the U.S. Securities and Exchange Commission that give effect to the provisions of the *Sarbanes-Oxley Act of 2002*.

Our corporate governance practices also incorporate many "best practices" derived from those required to be followed by US domestic companies under the NYSE listing standards. We are required by Section 303A.11 of the NYSE Listed Company Manual to identify any significant ways in which our corporate governance practices differ from those required to be followed by US domestic companies under NYSE listing standards. We believe that there are no such significant differences in our corporate governance practices, except as follows:

- *Shareholder Approval of Equity Compensation Plans*. Section 303A.8 of the NYSE Listed Company Manual requires shareholder approval of all "equity compensation plans" and material revisions to those plans. The definition of "equity compensation plans" covers plans that provide for the delivery of newly issued securities, and also plans which rely on securities reacquired on the market by the issuing company for the purpose of redistribution to employees and directors. The TSX rules provide that equity compensation plans and material amendments thereto require shareholder approval only if they involve newly issued securities and the amendments are not otherwise addressed in the plan's amendment procedures. In addition, the TSX rules require that every three years after institution, all unallocated options, rights or other entitlements under equity compensation plans which do not have a fixed maximum aggregate of securities issuable must be approved by shareholders. Vermilion follows the TSX rules with respect to shareholder approval of equity compensation plans and material revisions to those plans.

Disclosure Controls and Procedures

Our officers have established and maintained disclosure controls and procedures and evaluated the effectiveness of these controls in conjunction with our filings.

As of December 31, 2019, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded and certified that our disclosure controls and procedures are effective.

Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

The Chief Executive Officer and the Chief Financial Officer of Vermilion have assessed the effectiveness of Vermilion's internal control over financial reporting as defined in Rule 13a-15 under the US Securities Exchange Act of 1934 and as defined in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. The assessment was based on the framework in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Chief Executive Officer and the Chief Financial Officer of Vermilion have concluded that Vermilion's internal control over financial reporting was effective as of December 31, 2019. The effectiveness of Vermilion's internal control over financial reporting as of December 31, 2019 has been audited by Deloitte LLP, as reflected in their report included in the 2019 audited annual financial statements filed with the US Securities and Exchange Commission. No changes were made to Vermilion's internal control over financial reporting during the year ended December 31, 2019, that have materially affected, or are reasonably likely to materially affect, the internal controls over financial reporting.

Supplemental Table 1: Netbacks

The following table includes financial statement information on a per unit basis by business unit. Liquids includes crude oil, condensate, and NGLs. Natural gas sales volumes have been converted on a basis of six thousand cubic feet of natural gas to one barrel of oil equivalent.

	Q4 2019			2019			Q4 2018	2018
	Liquids $/bbl	Natural Gas $/mcf	Total $/boe	Liquids $/bbl	Natural Gas $/mcf	Total $/boe	Total $/boe	Total $/boe
Canada								
Sales	55.55	2.33	**38.38**	56.92	1.77	**37.82**	33.30	37.81
Royalties	(7.41)	(0.05)	**(4.48)**	(7.40)	0.02	**(4.30)**	(4.57)	(4.77)
Transportation	(2.35)	(0.22)	**(1.93)**	(2.40)	(0.19)	**(1.88)**	(1.99)	(1.69)
Operating	(13.28)	(1.41)	**(11.30)**	(13.02)	(1.39)	**(11.09)**	(11.09)	(10.00)
Operating netback	32.51	0.65	**20.67**	34.10	0.21	**20.55**	15.65	21.35
General and administration			**(1.38)**			**(1.07)**	(0.38)	(0.34)
Fund flows from operations netback			**19.29**			**19.48**	15.27	21.01
France								
Sales	80.87	—	**80.87**	83.22	1.76	**83.01**	84.02	89.44
Royalties	(10.68)	—	**(10.67)**	(11.17)	(0.73)	**(11.15)**	(11.72)	(11.60)
Transportation	(3.34)	—	**(3.34)**	(5.51)	—	**(5.49)**	(3.17)	(2.59)
Operating	(16.78)	—	**(16.78)**	(15.62)	—	**(15.57)**	(13.71)	(13.56)
Operating netback	50.07	—	**50.08**	50.92	1.03	**50.80**	55.42	61.69
General and administration			**(5.01)**			**(3.91)**	(3.71)	(3.51)
Current income taxes			**(5.16)**			**(5.45)**	(0.86)	(3.74)
Fund flows from operations netback			**39.91**			**41.44**	50.85	54.44
Netherlands								
Sales	73.51	5.57	**33.88**	72.44	6.16	**37.37**	65.77	58.44
Royalties	—	(0.03)	**(0.17)**	—	(0.08)	**(0.49)**	(0.67)	(1.12)
Operating	—	(2.21)	**(13.11)**	—	(1.79)	**(10.64)**	(8.40)	(9.40)
Operating netback	73.51	3.33	**20.60**	72.44	4.29	**26.24**	56.70	47.92
General and administration			**(1.03)**			**(0.88)**	(0.88)	(0.69)
Current income taxes			**15.05**			**1.31**	(9.31)	(5.83)
Fund flows from operations netback			**34.62**			**26.67**	46.51	41.40
Germany								
Sales	77.58	4.96	**39.14**	80.22	5.64	**45.75**	62.74	61.47
Royalties	(2.21)	(0.32)	**(1.99)**	(3.75)	(0.73)	**(4.20)**	(3.41)	(4.94)
Transportation	(14.56)	(0.08)	**(3.27)**	(12.43)	(0.20)	**(4.09)**	(4.16)	(4.79)
Operating	(30.08)	(3.99)	**(25.14)**	(25.64)	(2.99)	**(19.93)**	(18.95)	(17.18)
Operating netback	30.73	0.57	**8.74**	38.40	1.72	**17.53**	36.22	34.56
General and administration			**(6.64)**			**(6.75)**	(6.61)	(5.52)
Fund flows from operations netback			**2.10**			**10.78**	29.61	29.04
Ireland								
Sales	—	5.61	**33.65**	—	6.13	**36.81**	66.91	61.12
Transportation	—	(0.26)	**(1.55)**	—	(0.26)	**(1.57)**	(1.40)	(1.53)
Operating	—	(0.73)	**(4.40)**	—	(0.73)	**(4.39)**	(5.64)	(4.58)
Operating netback	—	4.62	**27.70**	—	5.14	**30.85**	59.87	55.01
General and administration			**(0.75)**			**(0.88)**	(2.55)	(2.50)
Fund flows from operations netback			**26.95**			**29.97**	57.32	52.51

	Q4 2019				2019		Q4 2018	2018
	Liquids $/bbl	Natural Gas $/mcf	Total $/boe	Liquids $/bbl	Natural Gas $/mcf	Total $/boe	Total $/boe	Total $/boe
Australia								
Sales	88.35	—	**88.35**	93.33	—	**93.33**	97.19	95.11
Operating	(34.09)	—	**(34.09)**	(25.20)	—	**(25.20)**	(38.92)	(33.57)
PRRT [1]	(5.87)	—	**(5.87)**	(13.13)	—	**(13.13)**	5.98	(3.04)
Operating netback	48.39	—	**48.39**	55.00	—	**55.00**	64.25	58.50
General and administration			**(5.97)**			**(2.50)**	(3.44)	(3.10)
Current income taxes			**(2.00)**			**(4.25)**	(0.53)	(4.16)
Fund flows from operations netback			**40.42**			**48.25**	60.28	51.24
United States								
Sales	54.34	1.73	**43.77**	54.33	2.15	**44.17**	44.85	52.90
Royalties	(12.55)	(0.44)	**(10.17)**	(13.43)	(0.56)	**(10.96)**	(12.43)	(13.85)
Operating	(9.81)	(1.46)	**(9.56)**	(9.92)	(1.43)	**(9.59)**	(8.73)	(8.83)
Operating netback	31.98	(0.17)	**24.04**	30.98	0.16	**23.62**	23.69	30.22
General and administration			**(4.01)**			**(4.43)**	(4.28)	(8.67)
Fund flows from operations netback			**20.03**			**19.19**	19.41	21.55
Total Company								
Sales	62.46	3.61	**44.00**	65.73	3.58	**46.12**	48.90	52.95
Realized hedging gain (loss)	2.60	0.42	**2.57**	1.78	0.49	**2.30**	(3.03)	(3.51)
Royalties	(8.03)	(0.08)	**(4.60)**	(7.72)	(0.06)	**(4.47)**	(4.70)	(4.80)
Transportation	(2.38)	(0.17)	**(1.76)**	(2.77)	(0.16)	**(1.98)**	(1.81)	(1.64)
Operating	(14.94)	(1.60)	**(12.52)**	(14.68)	(1.44)	**(12.01)**	(12.04)	(11.26)
PRRT [1]	(0.30)	—	**(0.16)**	(1.27)	—	**(0.71)**	0.26	(0.15)
Operating netback	39.41	2.18	**27.53**	41.07	2.41	**29.25**	27.58	31.59
General and administration			**(1.88)**			**(1.61)**	(1.37)	(1.64)
Interest expense			**(2.17)**			**(2.22)**	(2.23)	(2.30)
Realized foreign exchange loss			**0.23**			**(0.14)**	0.63	0.01
Other income			**0.03**			**0.21**	0.03	0.03
Corporate income taxes			**0.66**			**(0.72)**	(0.85)	(1.22)
Fund flows from operations netback			**24.40**			**24.77**	23.79	26.47

(1) Vermilion considers Australian PRRT to be an operating item and, accordingly, has included PRRT in the calculation of operating netbacks. Current income taxes presented above excludes PRRT.

Supplemental Table 2: Hedges

The prices in these tables may represent the weighted averages for several contracts with foreign currency amounts translated to the disclosure currency using forward rates as at the month-end date. The weighted average price for the portfolio of options listed below may not have the same payoff profile as the individual contracts. As such, the presentation of the weighted average prices is purely for indicative purposes.

The following tables outline Vermilion's outstanding risk management positions as at December 31, 2019:

	Unit	Currency	Bought Put Volume	Weighted Average Bought Put Price	Sold Call Volume	Weighted Average Sold Call Price	Sold Put Volume	Weighted Average Sold Put Price	Swap Volume	Weighted Average Swap Price
Dated Brent										
Q1 2020	bbl	USD	3,000	62.25	3,000	67.39	3,000	55.58	—	—
Q2 2020	bbl	USD	3,000	62.25	3,000	67.39	3,000	55.58	—	—
WTI										
Q1 2020	bbl	USD	9,750	54.18	6,000	60.95	9,750	46.23	1,500	59.17
Q2 2020	bbl	USD	7,250	53.07	4,000	60.23	7,250	44.86	—	—
Q3 2020	bbl	USD	500	57.00	500	61.25	500	52.00	—	—
Q4 2020	bbl	USD	500	57.00	500	61.25	500	52.00	—	—
AECO										
Q1 2020	mcf	CAD	10,426	1.58	10,426	2.56	—	—	—	—
Q2 2020	mcf	CAD	—	—	—	—	—	—	10,426	1.39
Q3 2020	mcf	CAD	—	—	—	—	—	—	10,426	1.39
Q4 2020	mcf	CAD	—	—	—	—	—	—	3,513	1.39
AECO Basis (AECO less NYMEX Henry Hub)										
Q1 2020	mcf	USD	—	—	—	—	—	—	32,500	(0.94)
Q2 2020	mcf	USD	—	—	—	—	—	—	52,500	(1.12)
Q3 2020	mcf	USD	—	—	—	—	—	—	50,000	(1.12)
Q4 2020	mcf	USD	—	—	—	—	—	—	36,739	(1.11)
Q1 2021	mcf	USD	—	—	—	—	—	—	30,000	(1.11)
Q2 2021	mcf	USD	—	—	—	—	—	—	45,000	(1.08)
Q3 2021	mcf	USD	—	—	—	—	—	—	45,000	(1.08)
Q4 2021	mcf	USD	—	—	—	—	—	—	35,054	(1.09)
Q1 2022	mcf	USD	—	—	—	—	—	—	30,000	(1.10)
Q2 2022	mcf	USD	—	—	—	—	—	—	35,000	(1.09)
Q3 2022	mcf	USD	—	—	—	—	—	—	35,000	(1.09)
Q4 2022	mcf	USD	—	—	—	—	—	—	11,793	(1.09)
NYMEX Henry Hub										
Q1 2020	mcf	USD	10,000	2.75	10,000	3.10	10,000	2.25	—	—

	Unit	Currency	Bought Put Volume	Weighted Average Bought Put Price	Sold Call Volume	Weighted Average Sold Call Price	Sold Put Volume	Weighted Average Sold Put Price	Swap Volume	Weighted Average Swap Price
NBP										
Q1 2020	mcf	EUR	49,135	5.27	49,135	5.83	49,135	3.98	—	—
Q2 2020	mcf	EUR	41,765	5.21	41,765	5.53	41,765	3.83	—	—
Q3 2020	mcf	EUR	41,765	5.21	41,765	5.52	41,765	3.83	—	—
Q4 2020	mcf	EUR	61,419	5.28	63,875	5.77	61,419	3.90	—	—
Q1 2021	mcf	EUR	54,048	5.44	56,505	5.85	54,048	3.94	—	—
Q2 2021	mcf	EUR	46,678	5.42	46,678	5.80	46,678	3.92	—	—
Q3 2021	mcf	EUR	46,678	5.42	46,678	5.77	46,678	3.92	—	—
Q4 2021	mcf	EUR	54,048	5.44	54,048	5.72	54,048	3.94	—	—
Q1 2022	mcf	EUR	19,654	5.42	19,654	6.30	19,654	3.79	—	—
Q2 2022	mcf	EUR	12,284	5.33	12,284	6.03	12,284	3.60	—	—
NBP Basis (NBP less NYMEX Henry Hub)										
Q1 2020	mcf	USD	17,500	2.74	17,500	3.99	—	—	—	—
Q2 2020	mcf	USD	15,000	2.61	15,000	3.98	—	—	—	—
Q3 2020	mcf	USD	15,000	2.61	15,000	3.98	—	—	—	—
Q4 2020	mcf	USD	10,000	3.24	10,000	3.98	—	—	—	—
TTF										
Q1 2020	mcf	EUR	7,370	5.37	7,370	6.25	7,370	3.81	—	—
Q2 2020	mcf	EUR	13,512	5.36	9,827	6.15	13,512	3.73	4,913	5.54
Q3 2020	mcf	EUR	13,512	5.36	9,827	6.15	13,512	3.73	3,258	5.45
Q4 2020	mcf	EUR	7,370	5.37	7,370	6.25	7,370	3.81	—	—
TTF Basis (TTF less NYMEX Henry Hub)										
Q2 2020	mcf	USD	2,500	3.50	2,500	4.00	—	—	5,000	3.21
Q3 2020	mcf	USD	2,500	3.50	2,500	4.00	—	—	5,000	3.21

Cross Currency Interest Rate		Receive Notional Amount		Receive Rate	Pay Notional Amount		Pay Rate
Swap	Jan 2020 - Mar 2025	300,000,000	USD	5.625%	265,048,910	EUR	3.275%
Swap	Q1 2020	1,735,895,470	USD	LIBOR + 1.70%	2,304,900,000	CAD	CDOR + 1.25%

VET Equity Swaps		Initial Share Price		Share Volume
Swap	Jan 2020 - Sep 2021	20.9788	CAD	2,250,000
Swap	Jan 2020 - Oct 2021	22.4587	CAD	1,500,000

The following sold option instruments allow the counterparties, at the specified date, to enter into a derivative instrument contract with Vermilion at the detailed terms:

Period if Option Exercised	Unit	Currency	Option Expiration Date	Bought Put Volume	Weighted Average Bought Put Price	Sold Call Volume	Weighted Average Sold Call Price	Sold Put Volume	Weighted Average Sold Put Price	Swap Volume	Weighted Average Swap Price
Dated Brent											
Feb 2020 - Jan 2021	bbl	USD	28-Jan-20	—	—	—	—	—	—	500	63.00
Feb 2020 - Jan 2021	bbl	USD	31-Jan-20	—	—	—	—	—	—	3,000	62.00
Mar 2020 - Feb 2021	bbl	USD	28-Feb-20	—	—	—	—	—	—	4,500	62.71
Apr 2020 - Mar 2021	bbl	USD	31-Mar-20	—	—	—	—	—	—	3,500	63.32
Apr 2020 - Mar 2021	bbl	USD	31-Mar-20	1,000	64.00	1,000	69.00	1,000	59.00	—	—
May 2020 - Apr 2021	bbl	USD	30-Apr-20	—	—	—	—	—	—	4,000	62.63
NBP											
Oct 2020 - Jun 2022	mcf	EUR	30-Jun-20	—	—	—	—	—	—	2,457	5.86
Jan 2021 - Sep 2022	mcf	EUR	30-Jun-20	—	—	—	—	—	—	2,457	5.86
Jan 2021 - Sep 2022	mcf	USD	30-Jun-20	—	—	—	—	—	—	2,457	6.45
Jan 2022 - Dec 2022	mcf	USD	30-Jun-20	—	—	—	—	—	—	9,827	6.45
Oct 2020 - Jun 2022	mcf	EUR	30-Sep-20	—	—	—	—	—	—	2,457	6.15

Supplemental Table 3: Capital Expenditures and Acquisitions

By classification ($M)	Q4 2019	Q3 2019	Q4 2018	2019	2018
Drilling and development	**97,114**	117,123	160,359	**486,677**	503,842
Exploration and evaluation	**3,511**	10,756	3,221	**36,487**	14,372
Capital expenditures	**100,625**	127,879	163,580	**523,164**	518,214
Acquisitions	**9,165**	4,657	(31,314)	**38,472**	276,308
Shares issued for acquisition	**—**	—	—	**—**	1,235,221
Contingent consideration	**—**	—	2	**—**	2
Long-term debt net of working capital assumed	**—**	—	34,005	**—**	247,898
Acquisitions	**9,165**	4,657	2,689	**38,472**	1,759,425

By category ($M)	Q4 2019	Q3 2019	Q4 2018	2019	2018
Drilling, completion, new well equip and tie-in, workovers and recompletions	**72,515**	93,681	151,511	**411,390**	434,875
Production equipment and facilities	**29,221**	28,722	9,166	**87,711**	62,496
Seismic, studies, land and other	**(1,111)**	5,476	2,903	**24,063**	20,843
Capital expenditures	**100,625**	127,879	163,580	**523,164**	518,214
Acquisitions	**9,165**	4,657	2,689	**38,472**	1,759,425
Total capital expenditures and acquisitions	**109,790**	132,536	166,269	**561,636**	2,277,639

Capital expenditures by country ($M)	Q4 2019	Q3 2019	Q4 2018	2019	2018
Canada	**66,643**	69,963	90,211	**293,744**	277,857
France	**8,745**	18,139	17,008	**74,641**	79,758
Netherlands	**9,651**	3,028	2,454	**23,605**	17,483
Germany	**5,177**	4,229	4,580	**21,684**	15,806
Ireland	**923**	354	140	**1,372**	224
Australia	**6,452**	2,995	43,760	**30,550**	75,638
United States	**3,132**	21,064	2,881	**57,196**	40,837
Corporate	**(98)**	8,107	2,546	**20,372**	10,611
Total capital expenditures	**100,625**	127,879	163,580	**523,164**	518,214

Acquisitions by country ($M)	Q4 2019	Q3 2019	Q4 2018	2019	2018
Canada	**5,003**	1,746	12,233	**24,064**	1,573,964
Netherlands	**—**	—	(7,860)	**908**	(2,087)
Germany	**1,456**	947	706	**7,570**	1,665
Ireland	**—**	—	(5,572)	**—**	(5,572)
United States	**575**	1,964	3,674	**3,799**	191,740
Corporate	**2,131**	—	(492)	**2,131**	(285)
Total acquisitions	**9,165**	4,657	2,689	**38,472**	1,759,425

In 2019, included in cash expenditures on acquisitions of $38.5 million is: $16.0 million net paid to vendors in relation to the purchase of assets from other oil and gas producers; $4.7 million in asset improvements incurred subsequent to acquisitions for compliance with safety, environmental, and Vermilion's operating standards; $6.2 million paid to acquire land; $0.9 million paid to acquire royalty interests, and $10.6 million relating to the carry component of farm-in arrangements.

Supplemental Table 4: Production

	Q4/19	Q3/19	Q2/19	Q1/19	Q4/18	Q3/18	Q2/18	Q1/18	Q4/17	Q3/17	Q2/17	Q1/17
Canada												
Crude oil & condensate (bbls/d)	**27,399**	27,682	28,844	29,164	29,557	28,477	17,009	9,272	9,703	9,288	9,205	7,987
NGLs (bbls/d)	**7,005**	6,632	7,352	6,968	6,816	6,126	5,589	5,106	5,235	4,891	3,745	2,670
Natural gas (mmcf/d)	**145.14**	145.14	151.87	151.37	146.65	136.77	127.32	106.21	107.91	103.92	93.68	85.74
Total (boe/d)	**58,593**	58,504	61,507	61,360	60,814	57,397	43,817	32,078	32,923	31,499	28,563	24,947
% of consolidated	**61%**	60%	60%	59%	60%	59%	55%	46%	45%	46%	43%	38%
France												
Crude oil (bbls/d)	**10,264**	10,347	9,800	11,342	11,317	11,407	11,683	11,037	11,215	10,918	11,368	10,834
Natural gas (mmcf/d)	**—**	—	—	0.77	0.82	—	—	—	—	—	—	0.01
Total (boe/d)	**10,264**	10,347	9,800	11,470	11,454	11,407	11,683	11,037	11,215	10,918	11,368	10,836
% of consolidated	**10%**	11%	10%	11%	11%	12%	14%	16%	15%	16%	17%	17%
Netherlands												
Condensate (bbls/d)	**90**	82	100	93	112	84	87	77	105	74	104	76
Natural gas (mmcf/d)	**47.99**	44.08	52.90	51.51	51.82	44.37	43.49	44.79	55.66	34.90	31.58	39.92
Total (boe/d)	**8,088**	7,429	8,917	8,677	8,749	7,479	7,335	7,541	9,381	5,890	5,368	6,729
% of consolidated	**8%**	8%	9%	8%	9%	8%	9%	11%	13%	9%	8%	10%
Germany												
Crude oil (bbls/d)	**800**	845	1,047	978	913	1,019	1,008	1,078	1,148	1,054	1,047	989
Natural gas (mmcf/d)	**15.44**	14.54	14.56	16.71	16.94	14.88	14.63	16.19	18.19	20.12	19.86	19.39
Total (boe/d)	**3,373**	3,269	3,474	3,763	3,736	3,498	3,447	3,777	4,180	4,407	4,357	4,220
% of consolidated	**3%**	3%	3%	4%	4%	4%	4%	5%	6%	7%	6%	7%
Ireland												
Natural gas (mmcf/d)	**42.30**	43.21	49.21	51.71	52.03	51.38	56.56	60.87	56.23	49.04	63.81	64.82
Total (boe/d)	**7,049**	7,202	8,201	8,619	8,672	8,563	9,426	10,144	9,372	8,173	10,634	10,803
% of consolidated	**7%**	7%	8%	8%	9%	9%	12%	14%	13%	12%	16%	17%
Australia												
Crude oil (bbls/d)	**4,548**	5,564	6,689	5,862	4,174	4,704	4,132	4,971	4,993	5,473	6,054	6,581
% of consolidated	**5%**	6%	6%	6%	4%	5%	5%	7%	7%	8%	9%	10%
United States												
Crude oil (bbls/d)	**3,161**	2,722	2,483	1,742	1,605	1,461	655	574	667	880	747	365
NGLs (bbls/d)	**1,156**	1,140	754	929	998	714	62	20	43	56	76	24
Natural gas (mmcf/d)	**8.20**	6.38	7.06	5.89	5.65	4.82	0.40	0.15	0.29	0.64	0.44	0.20
Total (boe/d)	**5,683**	4,925	4,414	3,653	3,545	2,979	784	618	758	1,043	896	422
% of consolidated	**6%**	5%	4%	4%	3%	3%	1%	1%	1%	2%	1%	1%
Corporate												
Natural gas (mmcf/d)	**1.66**	—	—	—	2.86	1.17	—	—	—	—	—	—
Total (boe/d)	**276**	—	—	—	477	195	—	—	—	—	—	—
% of consolidated	**—**	—	—	—	—	—	—	—	—	—	—	—
Consolidated												
Liquids (bbls/d)	**54,421**	55,014	57,071	57,078	55,493	53,991	40,225	32,134	33,109	32,634	32,346	29,526
% of consolidated	**56%**	57%	55%	55%	55%	56%	50%	46%	45%	48%	48%	46%
Natural gas (mmcf/d)	**260.72**	253.36	275.60	277.96	276.77	253.38	242.40	228.20	238.28	208.62	209.36	210.07
% of consolidated	**44%**	43%	45%	45%	45%	44%	50%	54%	55%	52%	52%	54%
Total (boe/d)	**97,875**	97,239	103,003	103,404	101,621	96,222	80,625	70,167	72,821	67,403	67,240	64,537

	2019	2018	2017	2016	2015	2014
Canada						
Crude oil & condensate (bbls/d)	**28,266**	21,154	9,051	9,171	11,357	12,491
NGLs (bbls/d)	**6,988**	5,914	4,144	2,552	2,301	1,233
Natural gas (mmcf/d)	**148.35**	129.37	97.89	84.29	71.65	55.67
Total (boe/d)	**59,979**	48,630	29,510	25,771	25,598	23,001
% of consolidated	**60%**	56%	45%	40%	46%	47%
France						
Crude oil (bbls/d)	**10,435**	11,362	11,084	11,896	12,267	11,011
Natural gas (mmcf/d)	**0.19**	0.21	—	0.44	0.97	—
Total (boe/d)	**10,467**	11,396	11,085	11,970	12,429	11,011
% of consolidated	**10%**	13%	16%	19%	23%	22%
Netherlands						
Condensate (bbls/d)	**91**	90	90	88	99	77
Natural gas (mmcf/d)	**49.10**	46.13	40.54	47.82	44.76	38.20
Total (boe/d)	**8,274**	7,779	6,847	8,058	7,559	6,443
% of consolidated	**8%**	9%	10%	13%	14%	13%
Germany						
Crude oil (bbls/d)	**917**	1,004	1,060	—	—	—
Natural gas (mmcf/d)	**15.31**	15.66	19.39	14.90	15.78	14.99
Total (boe/d)	**3,468**	3,614	4,291	2,483	2,630	2,498
% of consolidated	**3%**	4%	6%	4%	5%	5%
Ireland						
Natural gas (mmcf/d)	**46.57**	55.17	58.43	50.89	0.03	—
Total (boe/d)	**7,762**	9,195	9,737	8,482	5	—
% of consolidated	**8%**	11%	14%	13%	—	—
Australia						
Crude oil (bbls/d)	**5,662**	4,494	5,770	6,304	6,454	6,571
% of consolidated	**6%**	5%	8%	10%	12%	13%
United States						
Crude oil (bbls/d)	**2,531**	1,078	666	393	231	49
NGLs (bbls/d)	**996**	452	50	29	7	—
Natural gas (mmcf/d)	**6.89**	2.78	0.39	0.21	0.05	—
Total (boe/d)	**4,675**	1,992	781	457	247	49
% of consolidated	**5%**	2%	1%	1%	—	—
Corporate						
Natural gas (mmcf/d)	0.42	1.02	—	—	—	—
Total (boe/d)	70	169	—	—	—	—
% of consolidated	**—**	—	—	—	—	—
Consolidated						
Liquids (bbls/d)	**55,886**	45,548	31,915	30,433	32,716	31,432
% of consolidated	**56%**	52%	47%	48%	60%	63%
Natural gas (mmcf/d)	**266.82**	250.33	216.64	198.55	133.24	108.85
% of consolidated	**44%**	48%	53%	52%	40%	37%
Total (boe/d)	**100,357**	87,270	68,021	63,526	54,922	49,573

Supplemental Table 5: Segmented Financial Results

	Three Months Ended December 31, 2019								
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	USA	Corporate	Total
Drilling and development	66,643	8,807	6,571	6,355	923	6,452	3,132	(1,769)	97,114
Exploration and evaluation	—	(62)	3,080	(1,178)	—	—	—	1,671	3,511
Crude oil and condensate sales	167,045	77,781	608	4,491	11	21,872	19,381	—	291,189
NGL sales	8,784	—	—	—	—	—	2,200	—	10,984
Natural gas sales	31,068	—	24,607	7,040	21,813	—	1,304	797	86,629
Sales of purchased commodities	—	—	—	—	—	—	—	74,951	74,951
Royalties	(24,127)	(10,265)	(130)	(587)	—	—	(5,316)	(254)	(40,679)
Revenue from external customers	182,770	67,516	25,085	10,944	21,824	21,872	17,569	75,494	423,074
Purchased commodities	—	—	—	—	—	—	—	(74,951)	(74,951)
Transportation	(10,384)	(3,215)	—	(963)	(1,008)	—	—	—	(15,570)
Operating	(60,931)	(16,142)	(9,758)	(7,405)	(2,854)	(8,438)	(4,996)	(59)	(110,583)
General and administration	(7,424)	(4,821)	(763)	(1,957)	(484)	(1,477)	(2,099)	2,456	(16,569)
PRRT	—	—	—	—	—	(1,453)	—	—	(1,453)
Corporate income taxes	—	(4,966)	11,198	—	—	(495)	—	98	5,835
Interest expense	—	—	—	—	—	—	—	(19,169)	(19,169)
Realized gain on derivative instruments	—	—	—	—	—	—	—	22,712	22,712
Realized foreign exchange gain	—	—	—	—	—	—	—	2,013	2,013
Realized other income	—	—	—	—	—	—	—	253	253
Fund flows from operations	**104,031**	**38,372**	**25,762**	**619**	**17,478**	**10,009**	**10,474**	**8,847**	**215,592**

	Year Ended December 31, 2019								
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	USA	Corporate	Total
Total assets	3,088,947	841,875	226,834	261,712	470,316	233,581	421,609	321,246	5,866,120
Drilling and development	293,744	74,579	19,866	10,806	1,372	30,550	57,196	(1,436)	486,677
Exploration and evaluation	—	62	3,739	10,878	—	—	—	21,808	36,487
Crude oil and condensate sales	699,290	326,578	2,411	25,783	27	184,490	63,449	—	1,302,028
NGL sales	33,159	—	—	—	—	—	6,499	—	39,658
Natural gas sales	95,621	121	110,446	31,529	104,247	—	5,416	797	348,177
Sales of purchased commodities	—	—	—	—	—	—	—	221,274	221,274
Royalties	(94,079)	(43,895)	(1,469)	(5,264)	—	—	(18,706)	(253)	(163,666)
Revenue from external customers	733,991	282,804	111,388	52,048	104,274	184,490	56,658	221,818	1,747,471
Purchased commodities	—	—	—	—	—	—	—	(221,274)	(221,274)
Transportation	(41,261)	(21,609)	—	(5,117)	(4,459)	—	—	—	(72,446)
Operating	(242,790)	(61,281)	(32,125)	(24,970)	(12,431)	(49,810)	(16,370)	(301)	(440,078)
General and administration	(23,341)	(15,406)	(2,659)	(8,452)	(2,491)	(4,940)	(7,566)	5,879	(58,976)
PRRT	—	—	—	—	—	(25,947)	—	—	(25,947)
Corporate income taxes	—	(21,431)	3,961	—	—	(8,407)	—	(406)	(26,283)
Interest expense	—	—	—	—	—	—	—	(81,377)	(81,377)
Realized gain on derivative instruments	—	—	—	—	—	—	—	84,219	84,219
Realized foreign exchange loss	—	—	—	—	—	—	—	(4,954)	(4,954)
Realized other income	—	—	—	—	—	—	—	7,700	7,700
Fund flows from operations	**426,599**	**163,077**	**80,565**	**13,509**	**84,893**	**95,386**	**32,722**	**11,304**	**908,055**

Non-GAAP Financial Measures

This MD&A includes references to certain financial measures which do not have standardized meanings and may not be comparable to similar measures presented by other issuers. These financial measures include fund flows from operations, a measure of profit or loss in accordance with IFRS 8 “Operating Segments” (please see Segmented Information in the Notes to the Consolidated Financial Statements) and net debt, a measure of capital in accordance with IAS 1 “Presentation of Financial Statements” (please see Capital Disclosures in the Notes to the Consolidated Financial Statements).

In addition, this MD&A includes financial measures which are not specified, defined, or determined under IFRS and are therefore considered non-GAAP financial measures and may not be comparable to similar measures presented by other issuers. These non-GAAP financial measures include:

Acquisitions: The sum of acquisitions from the Consolidated Statements of Cash Flows, Vermilion common shares issued as consideration, the estimated value of contingent consideration, the amount of acquiree's outstanding long-term debt assumed plus or net of acquired working capital deficit or surplus. We believe that including these components provides a useful measure of the economic investment associated with our acquisition activity.

Capital expenditures: The sum of drilling and development and exploration and evaluation from the Consolidated Statements of Cash Flows. We consider 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.

Cash dividends per share: Represents cash dividends declared per share and is a useful measure of the dividends a common shareholder was entitled to during the period.

Covenants: The financial covenants on our revolving credit facility contain non-GAAP measures. The definitions for these financial covenants are included in Financial Position Review.

Diluted shares outstanding: The sum of shares outstanding at the period end plus outstanding awards under the VIP, based on current estimates of future performance factors and forfeiture rates.

Free cash flow: Represents fund flows from operations in excess of capital expenditures. We use free cash flow to determine the funding available for investing and financing activities, including payment of dividends, repayment of long-term debt, reallocation to existing business units, and deployment into new ventures. We also assess free cash flow as a percentage of fund flows from operations, which is a measure of the percentage of fund flows from operations that is retained for incremental investing and financing activities.

Fund flows from operations per basic and diluted share: Management assesses fund flows from operations on a per share basis as we believe this provides a measure of our operating performance after taking into account the issuance and potential future issuance of Vermilion common shares. Fund flows from operations per basic share is calculated by dividing fund flows from operations by the basic weighted average shares outstanding as defined under IFRS. Fund flows from operations per diluted share is calculated by dividing fund flows from operations by the sum of basic weighted average shares outstanding and incremental shares issuable under the equity based compensation plans as determined using the treasury stock method.

Net dividends: We define net dividends as dividends declared less proceeds received for the issuance of shares pursuant to the Dividend Reinvestment Plan. Management monitors net dividends and net dividends as a percentage of fund flows from operations to assess our ability to pay dividends.

Operating netback: Sales less royalties, operating expense, transportation costs, PRRT, and realized hedging gains and losses presented on a per unit basis. Management assesses operating netback as a measure of the profitability and efficiency of our field operations. In contrast, fund flows from operations netback also includes general and administration expense, corporate income taxes, and interest. Fund flows from operations netback is used by management to assess the profitability of our business units and Vermilion as a whole.

Payout: We define payout as net dividends plus drilling and development costs, exploration and evaluation costs, and asset retirement obligations settled. Management uses payout and payout as a percentage of fund flows from operations (also referred to as the **payout or sustainability ratio**) to assess the amount of cash distributed back to shareholders and re-invested in the business for maintaining production and organic growth.

Return on capital employed (ROCE): ROCE is a measure that we use to analyze our profitability and the efficiency of our capital allocation process. ROCE is calculated by dividing net earnings before interest and taxes ("EBIT") by average capital employed over the preceding twelve months. Capital employed is calculated as total assets less current liabilities while average capital employed is calculated using the balance sheets at the beginning and end of the twelve-month period.

The following tables reconcile net dividends, payout, and diluted shares outstanding from their most directly comparable GAAP measures as presented in our financial statements:

($M)	Q4 2019	Q3 2019	Q4 2018	2019	2018
Dividends declared	**107,702**	107,176	105,310	**427,311**	388,111
Shares issued for the Dividend Reinvestment Plan	**(10,200)**	(8,860)	(5,115)	**(34,937)**	(49,051)
Net dividends	**97,502**	98,316	100,195	**392,374**	339,060
Drilling and development	**97,114**	117,123	160,359	**486,677**	503,842
Exploration and evaluation	**3,511**	10,756	3,221	**36,487**	14,372
Asset retirement obligations settled	**7,352**	3,586	6,562	**19,442**	15,765
Payout	**205,479**	229,781	270,337	**934,980**	873,039
% of fund flows from operations	**95%**	106%	122%	**103%**	104%

('000s of shares)	Q4 2019	Q3 2019	Q4 2018
Shares outstanding	**156,290**	155,505	152,704
Potential shares issuable pursuant to the VIP	**3,622**	3,755	3,469
Diluted shares outstanding	**159,912**	159,260	156,173

The following tables reconciles the calculation of return on capital employed:

	Twelve Months Ended	
($M)	Dec 31, 2019	Dec 31, 2018
Net earnings	**32,799**	271,650
Taxes	**108,326**	83,048
Interest expense	**81,377**	72,759
EBIT	**222,502**	427,457
Average capital employed	**5,578,691**	4,659,566
Return on capital employed	**4%**	9%

Disclaimer

Certain statements included or incorporated by reference in this document 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 document may include, but are not limited to: capital expenditures and Vermilion's ability to fund such expenditures; Vermilion's additional debt capacity providing it with additional working capital; the flexibility of Vermilion's capital program and operations; business strategies and objectives; operational and financial performance; estimated volumes of reserves and resources; petroleum and natural gas sales; future production levels and the timing thereof, including Vermilion's 2020 guidance, and rates of average annual production growth; the effect of changes in crude oil and natural gas prices, changes in exchange rates and significant declines in production or sales volumes due to unforeseen circumstances; the effect of possible changes in critical accounting estimates; statements regarding the growth and size of Vermilion's future project inventory, and the wells expected to be drilled in 2020; exploration and development plans and the timing thereof; Vermilion's ability to reduce its debt, including its ability to redeem senior unsecured notes prior to maturity; statements regarding Vermilion's hedging program, its plans to add to its hedging positions, and the anticipated impact of Vermilion's hedging program on project economics and free cash flows; the potential financial impact of climate-related risks; acquisition and disposition plans and the timing thereof; operating and other expenses, including the payment and amount of future dividends; royalty and income tax rates and Vermilion's expectations regarding future taxes and taxability; and the timing of regulatory proceedings and approvals.

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 Vermilion to obtain equipment, services and supplies in a timely manner to carry out its activities in Canada and internationally; the ability of Vermilion 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 Vermilion 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 exploration and development activities.

Although Vermilion 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 Vermilion can give no assurance that such expectations will prove to be correct. Financial outlooks are provided for the purpose of understanding Vermilion's financial position 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 Vermilion 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 Vermilion's marketing operations, including credit risk; the uncertainty of reserves estimates and reserves life and estimates of resources and associated expenditures; the uncertainty of estimates and projections relating to production and associated expenditures; potential delays or changes in plans with respect to exploration or development projects; Vermilion'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 Vermilion to add production and reserves through exploration and development activities; 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 Vermilion; and other risks and uncertainties described elsewhere in this document or in Vermilion's other filings with Canadian securities regulatory authorities.

The forward-looking statements or information contained in this document are made as of the date hereof and Vermilion 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.

All crude oil and natural gas reserve and resource information contained in this document has been prepared and presented in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities and the Canadian Oil and Gas Evaluation Handbook. Reserves estimates have been made assuming that development of each property in respect of which the estimate is made will occur, without regard to the likely availability of funding required for such development. The actual crude oil and natural gas reserves and future production will be greater than or less than the estimates provided in this document.

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 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.

Financial data contained within this document are reported in Canadian dollars unless otherwise stated.

Abbreviations

$M	thousand dollars
$MM	million dollars
AECO	the daily average benchmark price for natural gas at the AECO ‘C’ hub in Alberta
bbl(s)	barrel(s)
bbls/d	barrels per day
boe	barrel of oil equivalent, including: crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe for six mcf of natural gas)
boe/d	barrel of oil equivalent per day
GJ	gigajoules
LSB	light sour blend crude oil reference price
mbbls	thousand barrels
mcf	thousand cubic feet
mmcf/d	million cubic feet per day
NBP	the reference price paid for natural gas in the United Kingdom at the National Balancing Point Virtual Trading Point.
NGLs	natural gas liquids, which includes butane, propane, and ethane
PRRT	Petroleum Resource Rent Tax, a profit based tax levied on petroleum projects in Australia
tCO2e	tonnes of carbon dioxide equivalent
TTF	the price for natural gas in the Netherlands, quoted in megawatt hours of natural gas, at the Title Transfer Facility Virtual Trading Point
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma

Management's Report to Shareholders

Management's Responsibility for Financial Statements

The accompanying consolidated financial statements of Vermilion Energy Inc. are the responsibility of management and have been approved by the Board of Directors of Vermilion Energy Inc. The consolidated financial statements have been prepared in accordance with the accounting policies detailed in the notes to the consolidated financial statements and are prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. Where necessary, management has made informed judgments and estimates of transactions that were not yet completed at the balance sheet date. Financial information throughout the Annual Report is consistent with the consolidated financial statements.

Management ensures the integrity of the consolidated financial statements by maintaining high-quality systems of internal control. Procedures and policies are designed to provide reasonable assurance that assets are safeguarded and transactions are properly recorded, and that the financial records are reliable for preparation of the consolidated financial statements. Deloitte LLP, Vermilion's Independent Registered Public Accounting Firm, have conducted an audit of the consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States) and have provided their report.

The Board of Directors is responsible for ensuring that management fulfills its responsibility for financial reporting and internal control. The Board carries out this responsibility principally through the Audit Committee, which is appointed by the Board and is comprised entirely of independent Directors. The Committee meets periodically with management and Deloitte LLP to satisfy itself that each party is properly discharging its responsibilities and to review the consolidated financial statements, Management's Discussion and Analysis and the Report of the Independent Registered Public Accounting Firm before they are presented to the Board of Directors.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining an adequate system of internal control over financial reporting. Management, under the supervision and with the participation of the principal executive officer and principle financial officer, conducted an evaluation of the effectiveness of the system of internal control over financial reporting based on the criteria established in *"Internal Control - Integrated Framework (2013)"* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management has assessed the effectiveness of Vermilion's internal control over financial reporting as defined in Rule 13a-15(f) and 15d-15(f) under the US Securities Exchange Act of 1934 and as defined in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Management concluded that Vermilion's internal control over financial reporting was effective as of December 31, 2019.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

The effectiveness of Vermilion's internal control over financial reporting as of December 31, 2019 has been audited by Deloitte LLP, the Company's Independent Registered Public Accounting Firm, who also audited the Company's consolidated financial statements for the year ended December 31, 2019.

("Anthony Marino")

Anthony Marino
President & Chief Executive Officer
March 5, 2020

("Lars Glemser")

Lars Glemser
Vice President & Chief Financial Officer

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Vermilion Energy Inc.:

Opinion on Internal Control over Financial Reporting
We have audited the internal control over financial reporting of Vermilion Energy Inc. and subsidiaries (the "Company") as of December 31, 2019, based on criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2019, of the Company and our report dated March 5, 2020, expressed an unqualified opinion on those financial statements.

Basis for Opinion
The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report to Shareholders. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting
A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte LLP

Chartered Professional Accountants
Calgary, Canada
March 5, 2020

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Vermilion Energy Inc.:

Opinion on the Financial Statements
We have audited the accompanying consolidated balance sheets of Vermilion Energy Inc. and subsidiaries (the "Company") as of December 31, 2019 and 2018, the related consolidated statements of net earnings and comprehensive (loss) income, consolidated statements of cash flows, and consolidated statements of changes in shareholders' equity for the years then ended and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and its financial performance and its cash flows for the years then ended, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 5, 2020, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion
These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter
The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Deferred Taxes - Refer to Notes 2 and 11 to the Financial Statements

Critical Audit Matter Description

The Company recognizes deferred income taxes for differences between the financial statement and tax basis of assets and liabilities at enacted or substantively enacted statutory tax rates that are expected to be in effect when the temporary differences are expected to reverse. Deferred income tax assets are reduced to the amounts expected to be realized based on forecasts of future taxable profits, specifically forecasts of future revenue (future commodity price forecasts and estimates of reserves). The Company recorded a deferred income tax asset for the Canada and Ireland segments primarily arising from past taxable losses in these jurisdictions.

In order to determine whether it is probable that the deferred income tax assets in the Canada and Ireland segments will be realized, management makes assumptions related to the forecasts of future taxable income, specifically forecasts of future revenue (future commodity price forecasts and estimates of reserves). The Company's management engages an expert, an independent engineering firm ("management's expert"), to determine the estimates of reserves. As such, auditing the probability of the deferred income tax assets being realized and management's future commodity price forecasts and estimates of reserves involved a high degree of auditor judgement as the estimations made by management contain significant measurement uncertainty. This resulted in an increased extent of audit effort, which included the need to involve specialists.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to assessing the probability of the deferred income tax assets being realized and management's forecasts of taxable profit, specifically forecasts of future revenue (future commodity price forecasts and estimates of reserves) to evaluate the deferred income tax assets in the Canada and Ireland segments included the following, among others:

- Evaluated the effectiveness of relevant controls, including those over the determination of the forecasts of future revenue.
- Evaluated management's ability to accurately forecast future revenue by comparing management's assumptions to historical data and available market trends.
- Evaluated the reasonableness of management's forecasts of future revenue by:
    - Evaluating whether management's estimates of future commodity price forecasts and estimates of reserves were consistent with the requirements of IAS 12 relating to the probability of forecasted future revenue and the length of the forecast period.
    - Evaluating the experience, qualifications and objectivity of management's expert.
    - Performing analytical procedures on the estimates of reserves developed by management's expert.
- With the assistance of fair value specialists, evaluated the future commodity price forecasts used in the estimate of future cash flow by:
    - Comparing the forecasts prepared by management's expert to third party forecasts.
    - Comparing the differential between the index commodity prices and the future commodity prices to actual historical results.
- With the assistance of an income tax specialist, evaluated the probability of the deferred tax asset being realized.

/s/ Deloitte LLP

Chartered Professional Accountants
Calgary, Canada
March 5, 2020

We have served as the Company's auditor since 2000.

Consolidated Financial Statements

Consolidated Balance Sheet

thousands of Canadian dollars

	Note	December 31, 2019	December 31, 2018
Assets			
Current			
Cash and cash equivalents	19	**29,028**	26,809
Accounts receivable		**211,409**	260,322
Crude oil inventory		**29,389**	27,751
Derivative instruments	9	**55,645**	95,667
Prepaid expenses		**22,210**	19,328
Total current assets		**347,681**	429,877
Derivative instruments	9	**20,127**	1,215
Deferred taxes	11	**196,543**	219,411
Exploration and evaluation assets	7	**286,149**	303,295
Capital assets	6	**5,015,620**	5,316,873
Total assets		**5,866,120**	6,270,671
Liabilities			
Current			
Accounts payable and accrued liabilities		**312,442**	449,651
Dividends payable	13	**35,947**	35,122
Derivative instruments	9	**62,405**	41,016
Income taxes payable		**5,416**	37,410
Total current liabilities		**416,210**	563,199
Derivative instruments	9	**24,358**	17,527
Long-term debt	12	**1,924,665**	1,796,207
Lease obligations	10	**93,072**	108,189
Asset retirement obligations	8	**618,201**	650,164
Deferred taxes	11	**336,309**	318,134
Total liabilities		**3,412,815**	3,453,420
Shareholders' Equity			
Shareholders' capital	13	**4,119,031**	4,008,828
Contributed surplus		**75,735**	78,478
Accumulated other comprehensive income		**49,578**	118,182
Deficit		**(1,791,039)**	(1,388,237)
Total shareholders' equity		**2,453,305**	2,817,251
Total liabilities and shareholders' equity		**5,866,120**	6,270,671

Approved by the Board

(Signed "Catherine L. Williams")

Catherine L. Williams, Director

(Signed "Anthony Marino")

Anthony Marino, Director

Consolidated Statements of Net Earnings and Comprehensive (Loss) Income

thousands of Canadian dollars, except share and per share amounts

	Note	Year Ended Dec 31, 2019	Dec 31, 2018
Revenue			
Petroleum and natural gas sales		**1,689,863**	1,678,117
Royalties		**(163,666)**	(152,167)
Sales of purchased commodities		**221,274**	—
Petroleum and natural gas revenue		**1,747,471**	1,525,950
Expenses			
Purchased commodities		**221,274**	—
Operating	19	**440,078**	357,014
Transportation		**72,446**	51,887
Equity based compensation	15	**64,233**	60,746
(Gain) loss on derivative instruments	9	**(26,792)**	1,932
Interest expense		**81,377**	72,759
General and administration	19	**58,976**	51,929
Foreign exchange (gain) loss		**(52,271)**	63,000
Other income		**(6,875)**	(82)
Accretion	8	**32,667**	31,219
Depletion and depreciation	6, 7	**675,177**	609,056
Impairment	6	**46,056**	—
Gain on business combination	5	**—**	(128,208)
		1,606,346	1,171,252
Earnings before income taxes		**141,125**	354,698
Taxes	11		
Deferred		**56,096**	39,471
Current		**52,230**	43,577
		108,326	83,048
Net earnings		**32,799**	271,650
Other comprehensive (loss) income			
Currency translation adjustments		**(81,042)**	46,353
Unrealized gain on derivatives designated as cash flow hedges, net of tax	9, 12	**11,295**	—
Unrealized gain on derivatives designated as net investment hedges, net of tax	9, 12	**1,143**	—
Comprehensive (loss) income		**(35,805)**	318,003
Net earnings per share	16		
Basic		**0.21**	1.93
Diluted		**0.21**	1.91
Weighted average shares outstanding ('000s)	16		
Basic		**154,736**	140,619
Diluted		**156,095**	142,335

Consolidated Statements of Cash Flows

thousands of Canadian dollars

	Note	Year Ended Dec 31, 2019	Dec 31, 2018
Operating			
Net earnings		**32,799**	271,650
Adjustments:			
Accretion	8	**32,667**	31,219
Depletion and depreciation	6, 7	**675,177**	609,056
Impairment	6	**46,056**	—
Gain on business combinations	5	**—**	(128,208)
Unrealized loss (gain) on derivative instruments	9	**57,427**	(109,326)
Equity based compensation	15	**64,233**	60,746
Unrealized foreign exchange (gain) loss		**(57,225)**	63,243
Unrealized other expense		**825**	801
Deferred taxes	11	**56,096**	39,471
Asset retirement obligations settled	8	**(19,442)**	(15,765)
Changes in non-cash operating working capital	19	**(65,148)**	(6,876)
Cash flows from operating activities		**823,465**	816,011
Investing			
Drilling and development	6	**(486,677)**	(503,842)
Exploration and evaluation	7	**(36,487)**	(14,372)
Acquisitions	5	**(38,472)**	(276,308)
Changes in non-cash investing working capital	19	**(57,072)**	55,491
Cash flows used in investing activities		**(618,708)**	(739,031)
Financing			
Borrowings on the revolving credit facility	12	**214,895**	251,155
Payments on lease obligations	10	**(26,354)**	(18,884)
Cash dividends	13	**(391,549)**	(330,194)
Cash flows used in financing activities		**(203,008)**	(97,923)
Foreign exchange gain on cash held in foreign currencies		**470**	1,191
Net change in cash and cash equivalents		**2,219**	(19,752)
Cash and cash equivalents, beginning of year		**26,809**	46,561
Cash and cash equivalents, end of year	19	**29,028**	26,809
Supplementary information for cash flows from operating activities			
Interest paid		**73,783**	70,049
Income taxes paid		**84,224**	45,228

Consolidated Statements of Changes in Shareholders' Equity

thousands of Canadian dollars

	Note	Year Ended Dec 31, 2019	Dec 31, 2018
Shareholders' capital	13		
Balance, beginning of year		**4,008,828**	2,650,706
Shares issued for acquisition		**—**	1,234,676
Shares issued for the Dividend Reinvestment Plan		**34,937**	49,051
Vesting of equity based awards		**51,108**	54,057
Equity based compensation		**15,868**	12,565
Share-settled dividends on vested equity based awards		**8,290**	7,773
Balance, end of year		**4,119,031**	4,008,828
Contributed surplus			
Balance, beginning of year		**78,478**	84,354
Equity based compensation		**48,365**	48,181
Vesting of equity based awards		**(51,108)**	(54,057)
Balance, end of year		**75,735**	78,478
Accumulated other comprehensive income			
Balance, beginning of year		**118,182**	71,829
Currency translation adjustments		**(81,042)**	46,353
Gain on derivatives designated as cash flow hedges, net of tax	9, 12	**19,659**	—
Amount reclassified from cash flow hedge reserve to net earnings, net of tax		**(8,364)**	—
Loss on derivatives designated as net investment hedges, net of tax	9, 12	**(3,513)**	—
Amount reclassified from net investment hedge reserve to net earnings, net of tax		**4,656**	—
Balance, end of year		**49,578**	118,182
Deficit			
Balance, beginning of year		**(1,388,237)**	(1,264,003)
Net earnings		**32,799**	271,650
Dividends declared	13	**(427,311)**	(388,111)
Share-settled dividends on vested equity based awards		**(8,290)**	(7,773)
Balance, end of year		**(1,791,039)**	(1,388,237)
Total shareholders' equity		**2,453,305**	2,817,251

Description of equity reserves

Shareholders' capital
Represents the recognized amount for common shares when issued, net of equity issuance costs and deferred taxes.

Contributed surplus
Represents the recognized value of unvested equity based awards that will be settled in shares. Once vested, the value of the awards are transferred to shareholders' capital.

Accumulated other comprehensive income
Represents currency translation adjustments and changes in the fair value of derivative financial instruments in designated hedging relationships.

Currency translation adjustments result from translating the balance sheets of subsidiaries with a foreign functional currency to Canadian dollars at period-end rates. These amounts may be reclassified to net earnings if there is a disposal or partial disposal of a subsidiary.

The effective portion of the change in fair value related to cash flow and net investment hedges are recognized in other comprehensive income, net of tax and reclassified to the consolidated statement of net earnings in the same period in which the transaction associated with the hedged item occurs. Upon discontinuation of hedge accounting, the reserve amounts will be reclassified to net earnings.

Deficit
Represents the cumulative net earnings less distributed earnings of Vermilion Energy Inc.

Notes to the Consolidated Financial Statements for the year ended December 31, 2019 and 2018

tabular amounts in thousands of Canadian dollars, except share and per share amounts

1. Basis of presentation

Vermilion Energy Inc. and its subsidiaries (the "Company" or "Vermilion") are engaged in the business of petroleum and natural gas exploration, development, acquisition, and production.

Vermilion was incorporated in Canada and the Company's registered office and principal place of business is located at 3500, 520, 3rd Avenue SW, Calgary, Alberta, Canada.

These consolidated financial statements were approved and authorized for issuance by Vermilion's Board of Directors on March 5, 2020.

2. Significant accounting policies

Accounting framework
The consolidated financial statements are prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

Principles of consolidation
The consolidated financial statements include the accounts of Vermilion Energy Inc. and its subsidiaries. Vermilion's subsidiaries include entities in each of the jurisdictions that Vermilion operates as described in Note 4 (Segmented information) including: Canada, France, Netherlands, Germany, Ireland, Australia, the United States, and Central and Eastern Europe (Hungary, Slovakia, and Croatia). Vermilion Energy Inc. directly or indirectly through holding companies owns all of the voting securities of each material subsidiary. Transactions between Vermilion Energy Inc. and its subsidiaries have been eliminated.

Vermilion accounts for joint operations by recognizing the Company's share of assets, liabilities, income, and expenses.

Exploration and evaluation assets
Vermilion classifies costs as exploration and evaluation ("E&E") assets when they relate to exploring and evaluating an area for which the Company has the license or right to explore and extract resources. E&E costs may include: geological and geophysical costs; land and license acquisition costs; and costs for the drilling, completion, and testing of exploration wells.

E&E costs are reclassified to capital assets if the technical feasibility and commercial viability of the area can be determined. E&E assets are assessed for impairment prior to any reclassification. The technical feasibility and commercial viability of extracting the reserves is considered to be determinable when proved and probable reserves are identified.

Costs incurred prior to the acquisition of the legal rights to explore an area are expensed as incurred. If reserves are not found within the license area or the area is abandoned, the related E&E costs are depreciated over a period not greater than five years. If an exploration license expires prior to the commencement of exploration activities, the cost of the exploration license is written off through depreciation in the year of expiration.

Capital assets
Vermilion recognizes capital assets at cost less accumulated depletion, depreciation, and impairment losses. Costs include directly attributable costs incurred for the drilling, completion, and tie-in of wells and the construction of production and processing facilities.

When components of capital assets are replaced, disposed of, or no longer in use, they are derecognized. Gains and losses on disposal of capital assets are determined by comparing the proceeds of disposal compared to the carrying amount.

Depletion and depreciation
Capital assets are grouped into depletion units, which are groups of assets within a specific production area that have similar economic lives. Depletion units represent the lowest level of disaggregation for which costs are accumulated for the purposes of calculating depletion and depreciation.

The net carrying value of each depletion unit is depleted using the unit of production method by reference to the ratio of production in the period to the total proved and probable reserves, taking into account the future development costs necessary to bring the applicable reserves into production.

For the purposes of the depletion calculations, oil and gas reserves are converted to a common unit of measure on the basis of their relative energy content based on a conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent.

Impairment of capital assets and exploration and evaluation assets
Depletion units are aggregated into cash generating units ("CGUs") for impairment testing. CGUs are the lowest level for which there are identifiable cash inflows that are largely independent of cash inflows of other groups of assets. CGUs are reviewed for indicators of potential impairment at each reporting date.

E&E assets are tested for impairment when reclassified to capital assets or when indicators of potential impairment are identified. E&E assets are reviewed for indicators of potential impairment at each reporting date. If indicators of potential impairment are identified, E&E assets are tested for impairment as part of the CGU attributable to the jurisdiction in which the exploration area resides.

If an indicator of potential impairment exists, the CGU's carrying value is compared to its recoverable amount. A CGU's recoverable amount is the higher of its fair value less costs of disposal and its value-in-use. If the carrying amount of a CGU exceeds its recoverable amount, an impairment loss is recognized to reduce the carrying value of the CGU to its recoverable amount.

If an impairment loss has been recognized in a prior period, an assessment is performed at each reporting date to determine if there are indicators that the circumstances which led to the impairment loss have reversed. If the change in circumstances results in the recoverable amount being higher than the carrying value after the impairment loss, then the impairment loss (net of depletion that would otherwise have been recorded) is reversed.

Lease obligations and right-of-use assets
A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. At the lease commencement date, a lease obligation is recognized at the present value of future lease payments, typically using the applicable incremental borrowing rate. A corresponding right-of-use asset is recognized at the amount of the lease obligation, adjusted for lease incentives received and initial direct costs. Vermilion does not recognize leases for short-term leases with a lease term of 12 months or less, or leases for low-value assets.

Payments are applied against the lease obligation and interest expense is recognized on the lease obligations using the effective interest rate method. Depreciation is recognized on the right-of-use asset over the lease term.

Cash and cash equivalents
Cash and cash equivalents include cash on deposit with financial institutions and guaranteed investment certificates.

Crude oil inventory
Crude oil inventory is valued at the lower of cost or net realizable value. The cost of crude oil inventory produced includes related operating expense, royalties, and depletion determined on a weighted-average basis.

Asset retirement obligations
Vermilion recognizes a provision for asset retirement obligations when an event occurs giving rise to an obligation of uncertain timing or amount. Asset retirement obligations are recognized on the consolidated balance sheet as a long-term liability with a corresponding increase to E&E or capital assets.

Asset retirement obligations reflect the present value of estimated future settlement costs. The discount rate used to calculate the present value is specific to the jurisdiction the obligation relates to and is reflective of current market assessment of the time value of money and risks specific to the liabilities that have not been reflected in the cash flow estimates.

Asset retirement obligations are remeasured at each reporting period to reflect changes in market rates and estimated future settlement costs. Asset retirement obligations are increased each reporting period to reflect the passage of time with a corresponding charge to accretion expense.

Revenue recognition
Revenue associated with the sale of crude oil and condensate, natural gas, and natural gas liquids is measured based on the consideration specified in contracts with customers.

Revenue from contracts with customers is recognized when or as Vermilion satisfies a performance obligation by transferring control of crude oil and condensate, natural gas, or natural gas liquids to a customer at contractually specified transfer points. This transfer coincides with title passing to the customer and the customer taking physical possession of the commodity. Vermilion principally satisfies its performance obligations at a point in time and the amounts of revenue recognized relating to performance obligations satisfied over time are not significant.

Vermilion invoices customers for delivered products monthly and payment occurs shortly thereafter. Vermilion does not have any contracts where the period between the transfer of control of the commodity to the customer and payment by the customer exceeds one year. As a result, Vermilion does not adjust its revenue transactions to reflect significant financing components.

Financial instruments
On initial recognition, financial instruments are measured at fair value. Measurement in subsequent periods depends on the classification of the financial instrument as described below:

- Fair value through profit or loss ("FVTPL"): Financial instruments under this classification include cash and cash equivalents and derivative assets and liabilities.
- Fair value through other comprehensive income ("FVTOCI"): Financial instruments under this classification include derivative assets and liabilities where hedge accounting is applied.
- Amortized cost: Financial instruments under this classification include accounts receivable, accounts payable and accrued liabilities, dividends payable, lease obligations, and long-term debt.

Accounts receivable are measured net of a loss allowance equal to the lifetime expected credit loss.

Hedge accounting
Hedge accounting is applied to financial instruments designated as hedging instruments in qualifying hedging relationships. Qualifying hedge relationships may include cash flow hedges, fair value hedges, and hedges of net investments in foreign operations. The purpose of hedge accounting is to represent the effect of Vermilion's risk management activities to manage exposures arising from specific risks that affect net earnings such as foreign currency risk.

In order to apply hedge accounting, the eligible hedging instrument must be highly effective in offsetting the exposure to changes in the eligible hedged item. This effectiveness is assessed at inception and at the end of each reporting period thereafter. At inception, formal designation and documentation of the hedging relationship, risk management objective and strategy is required for undertaking the hedge.

For cash flow and net investment hedges, gains and losses on the hedging instrument are recognized in the consolidated statement of earnings in the same period in which the transaction associated with the hedged item occurs. Where the hedging instrument is a derivative instrument, a derivative asset or liability is recognized on the balance sheet at fair value (included in "Derivative instruments") with the effective portion of the gain or loss recorded to other comprehensive income. Any gain or loss associated with the ineffective portion of the hedging relationship is recognized in the consolidated statement of net earnings as other income or expense.

If a hedging relationship no longer qualifies for hedge accounting, any gain or loss resulting from the discontinuation of hedge accounting is deferred in other comprehensive income until the forecasted transaction date. If the forecasted transaction is no longer expected to occur, any gain or loss resulting from the discontinuation of hedge accounting is immediately recognized in the consolidated statement of net earnings.

Equity based compensation

Equity based compensation expense results from equity-settled awards issued under Vermilion's long-term share-based compensation plans as well as the grant date fair value of Vermilion common shares issued under the Company's bonus and employee share savings plans.

Vermilion's long-term share-based compensation plans consist of the Vermilion Incentive Plan ("VIP"), the "Five-Year Compensation Arrangement", and the Deferred Share Unit Plan ("DSU"). Equity-settled awards issued under the VIP vest over a period of one to three years, awards issued under the Five-Year Compensation Arrangement vest in the fifth year following the grant date, and awards issued under the DSU vest immediately upon granting. Awards issued under the VIP and Five-Year Compensation Arrangement plans are adjusted upon vesting by a performance factor determined by the Company's Board of Directors.

Equity based compensation expense for equity-settled plans is recognized over the vesting period with a corresponding adjustment to contributed surplus. The expense recognized is based on the grant date fair value of the awards, an estimate of the performance factor that will be achieved (if applicable), and an estimate of forfeiture rates based on historical vesting data. Dividends notionally accrue to the VIP and Five-Year Compensation Arrangement and are excluded in the determination of grant date fair values. When the awards are converted to Vermilion common shares, the amount recognized in contributed surplus is reclassified to shareholders' capital.

The grant date fair value of awards or Vermilion common shares issued is determined as the closing price of Vermilion's common shares on the Toronto Stock Exchange on the grant date.

Per share amounts

Basic net earnings per share is calculated by dividing net earnings by the weighted-average number of shares outstanding during the period.

Diluted net earnings per share is calculated by dividing net earnings by the diluted weighted-average number of shares outstanding during the period. The diluted weighted-average number of shares outstanding is the sum of the basic weighted-average number of shares outstanding and (to the extent inclusion reduces diluted net earnings per share) the number of shares issuable for equity-settled awards determined using the treasury stock method. The treasury stock method assumes that the unrecognized equity based compensation expense are deemed proceeds used to repurchase Vermilion common shares at the average market price during the period.

Foreign currency translation
Vermilion Energy Inc.'s functional and presentation currency is the Canadian dollar. Vermilion has subsidiaries that transact and operate in countries other than Canada and have functional currencies other than the Canadian dollar.

Foreign currency translation includes the translation of foreign currency transactions and the translation of foreign operations.

Foreign currency transaction translation occurs when translating transactions and balances in foreign currencies to the applicable functional currency of Vermilion Energy Inc. and its subsidiaries. Gains and losses from foreign currency transactions are recorded as foreign exchange gains or losses in the statement of net earnings. Foreign currency transaction translation occurs as follows:

- Income and expenses are translated at the prevailing rates on the date of the transaction.
- Non-monetary assets or liabilities are carried at the prevailing rates on the date of the transaction.
- Monetary items, including intercompany loans that are not deemed to represent net investments in a foreign subsidiary, are translated at the prevailing rates at the balance sheet date.

Foreign operation translation occurs when translating the financial statements of non-Canadian functional currency subsidiaries to the Canadian dollar and when translating intercompany loans that are deemed to represent net investments in a foreign subsidiary. Gains and losses from foreign operation translations are recorded as currency translation adjustments. Foreign operation translation occurs as follows:

- Income and expenses are translated at the average exchange rates for the period.
- Assets and liabilities are translated at the prevailing rates on the balance sheet date.

Income taxes
Deferred tax assets and liabilities are calculated using the balance sheet method. Deferred tax assets and liabilities are recognized for the estimated effect of any temporary differences between the amounts recognized on Vermilion's consolidated balance sheet and the respective tax basis. This calculation uses enacted or substantively enacted tax rates that are expected to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred taxes is recognized in the period the related legislation is substantively enacted.

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

Business combinations
Acquisitions of corporations or groups of assets are accounted for as business combinations using the acquisition method if the acquired assets constitute a business. Under the acquisition method, assets acquired and liabilities assumed in a business combination (with the exception of deferred tax assets and liabilities) are measured at their fair value. Deferred tax assets or liabilities arising from the assets acquired and liabilities assumed are measured in accordance with the policies described in "Income taxes" above.

If applicable, the excess or deficiency of the fair value of net assets acquired compared to consideration paid is recognized as a gain on business combination or as goodwill on the consolidated balance sheet. Acquisition-related costs incurred to effect a business combination are expensed in the period incurred.

As part of the assessment to determine if the acquisition constitutes a business, Vermilion may elect to apply the concentration test on a transaction by transaction basis. The test is met if substantially all of the fair value related to the gross assets acquired is concentrated in a single identifiable asset (or group of similar assets) resulting in the acquisition not being deemed a business and recorded as an asset acquisition.

Segmented information
Vermilion has a decentralized business unit structure designed to manage assets in each country the Company operates. Each of Vermilion's operating segments derives its revenues solely from the production and sale of petroleum and natural gas.

Vermilion's Corporate segment aggregates costs incurred at the Company's Corporate head office located in Calgary, Alberta, Canada as well as costs incurred relating to Vermilion's exploration and production activities in Hungary, Slovakia, and Croatia (Central and Eastern Europe). These operating segments have similar economic characteristics as they do not currently generate material revenue.

Vermilion's chief operating decision maker regularly reviews fund flows from operations generated by each of Vermilion's operating segments. Fund flows from operations is a measure of profit or loss that provides the chief operating decision maker with the ability to assess the profitability of each operating segment and, correspondingly, the ability of each operating segment to fund its share of dividends, asset retirement obligations, and capital investments.

Management judgments and estimation uncertainty
The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, estimates, and assumptions that affect the reported amount of assets, liabilities, income, and expenses. Actual results could differ significantly from these estimates. Key areas where management has made judgments, estimates, and assumptions are described below.

The measurement of the fair value of capital assets acquired in a business combination and the determination of the recoverable amount of cash generating units:

- Calculating the fair value of capital assets acquired in a business combination and the recoverable amount of cash generating units (in the assessment of impairments or reversals of previous impairments if indicators of impairment or impairment reversal are identified) are based on estimated future commodity prices, discount rates and estimated reserves and resources. Reserve and resource estimates are based on: engineering data, estimated future commodity prices, expected future rates of production, and assumptions regarding the timing and amount of future expenditures. Changes in these estimates and assumptions can directly impact the calculated fair value of capital assets acquired (and thus the resulting goodwill or gain on business combination) and the recoverable amount of a CGU (and thus the resulting impairment loss or recovery).
- In addition, the recoverable amount of a CGU is impacted by the composition of CGUs, which are subject to management's judgment of the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. The factors used by Vermilion to determine CGUs vary by jurisdiction due to their unique operating and geographic conditions. In general, Vermilion will assess the following factors: geographic proximity of the assets within a group to one another, geographic proximity of the group of assets to other groups of assets, homogeneity of the production from the group of assets and the sharing of infrastructure used to process and/or transport production. Changes in these judgments can directly impact the calculated recoverable amount of a CGU (and thus the resulting impairment loss or recovery).

The measurement of the carrying value of asset retirement obligations on the balance sheet, including the fair value and subsequent carrying value of asset retirement obligations assumed in a business combination:

- Asset retirement obligations are based on judgments regarding regulatory requirements, estimates of future costs, assumptions on the expected timing of expenditures, and estimates of the underlying risk inherent to the obligation. The carrying balance of asset retirement obligations and accretion expense may differ due to changes in: laws and regulations, technology, the expected timing of expenditures, and market conditions affecting the discount rate applied.

The recognition and measurement of deferred tax assets and liabilities:

- Tax interpretations, regulations, and legislation in the various jurisdictions in which Vermilion and its subsidiaries operate are subject to change and interpretation. Changes in laws and interpretations can affect the timing of the reversal of temporary tax differences, the tax rates in effect when such differences reverse and Vermilion's ability to use tax losses and other tax pools in the future. The Company's income tax filings are subject to audit by taxation authorities in numerous jurisdictions and the results of such audits may increase or decrease the tax liability. The determination of tax amounts recognized in the consolidated financial statements are based on management's assessment of the tax positions, which includes consideration of their technical merits, communications with tax authorities and management's view of the most likely outcome.
- The extent to which deferred tax assets are recognized are based on estimates of future profitability. These estimates are based on estimated future commodity prices and estimates of reserves. Judgments, estimates, and assumptions inherent in reserve estimates are described above.

The measurement of lease obligations and corresponding right-of-use assets:

- The measurement of lease obligations are subject to management's judgments of the applicable incremental borrowing rate and the expected lease term. The carrying balance of the right-of-use assets, lease obligations, and the resulting interest and depletion and depreciation expense, may differ due to changes in the market conditions and expected lease terms. Applicable incremental borrowing rates are based on judgments of the economic environment, term, currency, and the underlying risk inherent to the asset. Lease terms are based on assumptions regarding cancellation and extension terms that allow for operational flexibility based on future market conditions.

3. Changes in accounting pronouncements

Definition of a Business - Amendments to IFRS 3 "Business Combinations"

Vermilion elected to early adopt the amendments to IFRS 3 " *Business Combinations*" effective January 1, 2019, which will be applied prospectively to acquisitions that occur on or after January 1, 2019. The amendments introduce an optional concentration test, narrow the definitions of a business and outputs, and clarify that an acquired set of activities and assets must include an input and a substantive process that together significantly contribute to the ability to create outputs. These amendments did not result in changes to Vermilion's accounting policies for applying the acquisition method.

4. Segmented information

Substantially all sales in the France, Netherlands, and Ireland operating segments for the years ended December 31, 2019 and 2018 were to one customer in each respective segment. In 2019, France contributed more than 10% of Vermilion's consolidated revenues. In 2018, France, Netherlands, and Ireland each contributed more than 10% of Vermilion's consolidated revenues.

	Year Ended December 31, 2019								
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	USA	Corporate	Total
Total assets	3,088,947	841,875	226,834	261,712	470,316	233,581	421,609	321,246	5,866,120
Drilling and development	293,744	74,579	19,866	10,806	1,372	30,550	57,196	(1,436)	486,677
Exploration and evaluation	—	62	3,739	10,878	—	—	—	21,808	36,487
Crude oil and condensate sales	699,290	326,578	2,411	25,783	27	184,490	63,449	—	1,302,028
NGL sales	33,159	—	—	—	—	—	6,499	—	39,658
Natural gas sales	95,621	121	110,446	31,529	104,247	—	5,416	797	348,177
Sales of purchased commodities	—	—	—	—	—	—	—	221,274	221,274
Royalties	(94,079)	(43,895)	(1,469)	(5,264)	—	—	(18,706)	(253)	(163,666)
Revenue from external customers	733,991	282,804	111,388	52,048	104,274	184,490	56,658	221,818	1,747,471
Purchased commodities	—	—	—	—	—	—	—	(221,274)	(221,274)
Transportation	(41,261)	(21,609)	—	(5,117)	(4,459)	—	—	—	(72,446)
Operating	(242,790)	(61,281)	(32,125)	(24,970)	(12,431)	(49,810)	(16,370)	(301)	(440,078)
General and administration	(23,341)	(15,406)	(2,659)	(8,452)	(2,491)	(4,940)	(7,566)	5,879	(58,976)
PRRT	—	—	—	—	—	(25,947)	—	—	(25,947)
Corporate income taxes	—	(21,431)	3,961	—	—	(8,407)	—	(406)	(26,283)
Interest expense	—	—	—	—	—	—	—	(81,377)	(81,377)
Realized gain on derivative instruments	—	—	—	—	—	—	—	84,219	84,219
Realized foreign exchange loss	—	—	—	—	—	—	—	(4,954)	(4,954)
Realized other income	—	—	—	—	—	—	—	7,700	7,700
Fund flows from operations	**426,599**	**163,077**	**80,565**	**13,509**	**84,893**	**95,386**	**32,722**	**11,304**	**908,055**

	Year Ended December 31, 2018								
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	USA	Corporate	Total
Total assets	3,060,291	918,398	277,348	284,063	709,585	263,739	407,323	349,924	6,270,671
Drilling and development	277,857	79,451	17,963	10,863	224	75,638	40,837	1,009	503,842
Exploration and evaluation	—	307	(480)	4,943	—	—	—	9,602	14,372
Crude oil and condensate sales	541,844	360,471	2,462	32,704	—	150,733	31,142	—	1,119,356
NGL sales	56,554	—	—	—	—	—	4,622	—	61,176
Natural gas sales	72,774	131	163,454	49,745	205,150	—	2,701	3,630	497,585
Royalties	(84,696)	(46,781)	(3,181)	(6,626)	—	—	(10,070)	(813)	(152,167)
Revenue from external customers	586,476	313,821	162,735	75,823	205,150	150,733	28,395	2,817	1,525,950
Transportation	(29,912)	(10,426)	—	(6,420)	(5,129)	—	—	—	(51,887)
Operating	(177,499)	(54,690)	(26,681)	(23,048)	(15,366)	(53,199)	(6,421)	(110)	(357,014)
General and administration	(6,057)	(14,170)	(1,947)	(7,401)	(8,386)	(4,918)	(6,306)	(2,744)	(51,929)
PRRT	—	—	—	—	—	(4,824)	—	—	(4,824)
Corporate income taxes	—	(15,084)	(16,561)	—	—	(6,595)	—	(513)	(38,753)
Interest expense	—	—	—	—	—	—	—	(72,759)	(72,759)
Realized loss on derivative instruments	—	—	—	—	—	—	—	(111,258)	(111,258)
Realized foreign exchange gain	—	—	—	—	—	—	—	243	243
Realized other income	—	—	—	—	—	—	—	883	883
Fund flows from operations	**373,008**	**219,451**	**117,546**	**38,954**	**176,269**	**81,197**	**15,668**	**(183,441)**	**838,652**

Reconciliation of fund flows from operations to net earnings:

	Year Ended	
	Dec 31, 2019	**Dec 31, 2018**
Fund flows from operations	**908,055**	838,652
Accretion	**(32,667)**	(31,219)
Depletion and depreciation	**(675,177)**	(609,056)
Impairment	**(46,056)**	—
Gain on business combinations	**—**	128,208
Unrealized (loss) gain on derivative instruments	**(57,427)**	109,326
Equity based compensation	**(64,233)**	(60,746)
Unrealized foreign exchange gain (loss)	**57,225**	(63,243)
Unrealized other expense	**(825)**	(801)
Deferred tax	**(56,096)**	(39,471)
Net earnings	**32,799**	271,650

5. Business combinations

Private Producer in Southeast Saskatchewan and Southwest Manitoba
On February 15, 2018, Vermilion acquired all of the issued and outstanding common shares of a private producer with assets in southeast Saskatchewan and southwest Manitoba. The acquisition comprised of light oil producing fields near Vermilion's existing operations in southeast Saskatchewan. The acquisition complements Vermilion's existing southeast Saskatchewan operations and aligns with the Company's sustainable growth-and-income model. The acquisition was funded through Vermilion's revolving credit facility.

The total consideration paid and the fair value of the assets acquired and liabilities assumed at the date of acquisition are detailed in the table below:

	Consideration
Cash paid to vendor	53,288
Total consideration	**53,288**

	Allocation of consideration
Capital assets	67,549
Deferred tax assets	26,914
Acquired working capital	1,577
Long-term debt	(38,300)
Asset retirement obligations	(4,452)
Net assets acquired	**53,288**

For the year ended December 31, 2018, the acquisition contributed revenues of $18.7 million and net earnings of $6.7 million. Had the acquisition occurred on January 1, 2018, revenues would have increased by $2.9 million and net earnings would have increased by $1.0 million for the year ended December 31, 2018.

Spartan Energy Corp.
On May 28, 2018, Vermilion acquired all of the issued and outstanding common shares of Spartan Energy Corp., a publicly traded oil and gas producer with light oil producing properties in southeast Saskatchewan as well as other areas in Saskatchewan, Alberta, and Manitoba. The acquisition increased Vermilion's position in southeast Saskatchewan and aligned with the Company's sustainable growth-and-income model.

Consideration consisted of the issuance of 27.9 million Vermilion common shares valued at approximately $1.2 billion (based on the closing price per Vermilion common share of $44.30 on the Toronto Stock Exchange on May 28, 2018). Acquisition-related costs of $1.3 million were incurred in the year ended December 31, 2018.

The total consideration paid and the fair value of the assets acquired and liabilities assumed as at the date of the acquisition are detailed in the table below:

	Consideration
Shares issued for acquisition	1,235,221
Total consideration	**1,235,221**

	Allocation of consideration
Capital assets	1,401,686
Deferred tax assets	123,813
Long-term debt	(150,196)
Asset retirement obligations	(92,149)
Lease obligations	(25,455)
Assumed working capital deficit	(22,478)
Net assets acquired	**1,235,221**

For the year ended December 31, 2018, the acquisition contributed revenues of $242.1 million and net earnings of $45.1 million. Had the acquisition occurred on January 1, 2018, revenues would have increased by $182.4 million and net earnings would have increased by $35.0 million for the year ended December 31, 2018.

Assets in Wyoming
In August 2018, Vermilion acquired oil and gas producing assets and mineral leasehold land from a private oil company for total cash consideration of $189.0 million. The assets are located in Campbell County, Wyoming in the Powder River Basin, approximately 65 kilometres northwest of Vermilion's existing operations. The acquired assets complement Vermilion's existing Powder River operations and align with the Company's sustainable growth-and-income model. The acquisition was funded through Vermilion's revolving credit facility.

The total consideration paid and the fair value of the assets acquired and liabilities assumed at the date of acquisition are detailed in the table below:

	Consideration
Cash paid to vendor	189,014
Total consideration	**189,014**

	Allocation of consideration
Capital assets	284,333
Deferred tax liability	(19,019)
Asset retirement obligations	(4,821)
Assumed working capital deficit	(2,651)
Net assets acquired	**257,842**
Gain on business combination	(68,828)
Total net assets acquired, net of gain on business combination	**189,014**

The gain on the business combination primarily resulted from the recognition of additional reserve value when the acquisition closed compared to the estimated value when Vermilion entered into the purchase and sale agreement and the acquisition price was determined.

For the year ended December 31, 2018, the acquisition contributed revenues of $11.6 million and net earnings of $0.3 million. Had the acquisition occurred on January 1, 2018, revenues would have increased by $11.1 million and net earnings would have decreased by $0.1 million for the year ended December 31, 2018.

Shell E&P Ireland Limited

In December 2018, Vermilion acquired all of the issued and outstanding common shares of Shell E&P Ireland Limited, along with an incremental 1.5% working interest in the Corrib Natural Gas Project ("Corrib") in Ireland from Nephin Energy Holdings Limited, a wholly owned subsidiary of Canada Pension Plan Investment Board. The acquisition increased Vermilion's total ownership in Corrib to 20% and aligns with the Company's sustainable growth-and-income model. In addition to this transaction, Vermilion assumed operatorship of Corrib.

The total consideration paid and the fair value of the assets acquired and liabilities assumed as at the date of the acquisition are detailed in the table below:

($M)	Consideration
Cash paid to vendor	40,805
Cash acquired	(82,116)
Contingent consideration	290
Total consideration	**(41,021)**

($M)	Allocation of consideration
Capital assets	53,368
Deferred tax assets	4,239
Assumed working capital deficit	(35,449)
Lease obligations	(2,234)
Asset retirement obligations	(1,565)
Net assets acquired	**18,359**
Gain on business combination	(59,380)
Total net assets acquired, net of gain on business combination	**(41,021)**

The fair value of the contingent consideration obligation is estimated to be approximately $0.3 million based on estimated future commodity prices and estimated reserves. Maximum contingent payments are €5.8 million (approximately $9.1 million) through 2025.

The gain on the business combination primarily resulted from increases in working capital and the fair value of capital assets from when the purchase and sale agreement was entered into in July 2017 and when the acquisition closed in December 2018.

For the year ended December 31, 2018, the acquisition contributed revenues of $1.3 million and net earnings of $0.4 million. Had the acquisition occurred on January 1, 2018, revenues would have increased by $15.2 million and net earnings would have increased by $4.3 million for the year ended December 31, 2018.

Minor acquisitions
Vermilion completed a number of minor acquisitions during the year ended December 31, 2018 for total cash consideration of $56.0 million, in which $147.4 million of capital assets, $28.6 million of exploration and evaluation assets, and $104.0 million of asset retirement obligations were recognized.

6. Capital assets

The following table reconciles the change in Vermilion's capital assets:

	2019	2018
Balance at January 1	**5,316,873**	3,337,965
Acquisitions	**38,472**	1,975,327
Additions	**486,677**	503,842
Increase in right-of-use assets	**12,348**	98,343
Transfers from exploration and evaluation assets	**27,918**	29,615
Impairment	**(46,056)**	—
Depletion and depreciation	**(657,863)**	(605,994)
Changes in asset retirement obligations	**(10,354)**	(100,876)
Foreign exchange	**(152,395)**	78,651
Balance at December 31	**5,015,620**	5,316,873
Cost	**9,604,933**	9,202,604
Accumulated depletion, depreciation, and impairment	**(4,589,313)**	(3,885,731)
Carrying amount at December 31	**5,015,620**	5,316,873

Right-of-use assets
The following table discloses the carrying balance and depreciation charge relating to right-of-use assets by class of underlying asset as at and for the year ended December 31, 2019:

	As at Dec 31, 2019		As at Dec 31, 2018	
($M)	Depreciation	Balance	Depreciation	Balance
Office space	**9,745**	**53,777**	9,119	62,279
Gas processing facilities	**7,089**	**34,701**	5,491	41,788
Oil storage facilities	**2,633**	**16,803**	2,728	20,758
Vehicles and equipment	**3,209**	**10,327**	2,020	9,121
Total	**22,676**	**115,608**	19,358	133,946

2019 impairment
As a result of declining natural gas price forecasts in Ireland during the year ended December 31, 2019 an indication of impairment was identified in the Ireland CGU. This resulted in the performance of an impairment test whereby the Company determined that the carrying amount exceeded its recoverable amount. A non-cash impairment charge of $46.1 million was recorded in the consolidated statement of net earnings.

The recoverable amount was determined using fair value less costs to sell, which considered future after-tax cash flows from proved plus probable reserves using forecasted price and cost estimates and an after-tax discount rate of 9.0%.

The following price estimates as issued by Sproule and effective January 1, 2020 were applied:

NBP (€/mmbtu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Sproule	5.58	5.51	5.54	5.65	5.77	5.88	6.00	6.12	6.24	6.37

Changes in any of the key judgments, such as a revision in reserves, changes in forecast commodity prices, foreign exchange rates, capital or operating costs would impact the estimated recoverable amount. As at December 31, 2019, a 1% increase in the assumed after-tax discount rate would reduce the estimated recoverable amount by $14.7 million (resulting in a $60.8 million impairment) while a 5% decrease in revenues (due to a decrease in commodity price forecasts or reserve estimates) would reduce the estimated recoverable amount by $28.6 million (resulting in a $74.7 million impairment).

7. Exploration and evaluation assets

The following table reconciles the change in Vermilion's exploration and evaluation assets:

	2019	2018
Balance at January 1	**303,295**	292,278
Acquisitions	**—**	28,572
Additions	**36,487**	14,372
Changes in asset retirement obligations	**36**	629
Transfers to capital assets	**(27,918)**	(29,615)
Depreciation	**(18,689)**	(5,942)
Foreign exchange	**(7,062)**	3,001
Balance at December 31	**286,149**	303,295
Cost	**371,632**	371,015
Accumulated depreciation	**(85,483)**	(67,720)
Carrying amount at December 31	**286,149**	303,295

8. Asset retirement obligations

The following table reconciles the change in Vermilion's asset retirement obligations:

	2019	2018
Balance at January 1	**650,164**	517,180
Additional obligations recognized	**7,595**	211,580
Changes in estimated abandonment timing and costs	**39,722**	(98,158)
Obligations settled	**(19,442)**	(15,765)
Accretion	**32,667**	31,219
Changes in discount rates	**(57,635)**	(6,646)
Foreign exchange	**(34,870)**	10,754
Balance at December 31	**618,201**	650,164

Vermilion has estimated the asset retirement obligations based on current cost estimates of $1.8 billion (2018 - $1.8 billion).

Current cost estimates are inflated to the estimated time of abandonment using inflation rates of between 0.4% and 2.7% (2018 - between 0.5% and 2.9%), resulting in inflated cost estimates of $2.6 billion (2018 - $2.6 billion). These payments are expected to be made between 2020 and 2073, with the majority of costs occurring between 2030 and 2040 ($0.7 billion), 2048 to 2055 ($0.9 billion), and 2060 and 2073 ($0.7 billion).

Vermilion calculated the present value of the obligations using a credit-adjusted risk-free rate, calculated using a credit spread of 5.3% (2018 - 4.0%) added to risk-free rates based on long-term, risk-free government bonds.

The risk-free rates used as inputs to discount the obligations were as follows:

	Dec 31, 2019	Dec 31, 2018
Canada	**1.7 %**	2.2%
France	**0.9 %**	1.6%
Netherlands	**(0.1)%**	0.4%
Germany	**0.3 %**	0.9%
Ireland	**0.6 %**	1.6%
Australia	**1.6 %**	2.6%
United States	**2.4 %**	2.7%

A 0.5% increase/decrease in the discount rate applied to asset retirement obligations would decrease/increase asset retirement obligations by approximately $52.7 million. A one-year increase/decrease in the expected timing of abandonment spend would decrease/increase asset retirement obligations by approximately $27.5 million.

9. Derivative instruments

The following table reconciles the change in the fair value of Vermilion's derivative instruments:

	Year Ended	
	Dec 31, 2019	**Dec 31, 2018**
Fair value of contracts, beginning of year	**38,339**	(70,713)
Reversal of opening contracts settled during the year	**(62,735)**	57,719
Assumed in acquisitions	**—**	(274)
Realized gain (loss) on contracts settled during the year	**84,219**	(111,258)
Unrealized gain during the year on contracts outstanding at the end of the year	**5,308**	51,607
Net receipt from counterparties on contract settlements during the year	**(84,219)**	111,258
Unrealized loss on derivatives designated as cash flow hedges	**(1,071)**	—
Unrealized gain on derivatives designated as net investment hedges	**9,168**	—
Fair value of contracts, end of year	**(10,991)**	38,339
Comprised of:		
Current derivative asset	**55,645**	95,667
Current derivative liability	**(62,405)**	(41,016)
Non-current derivative asset	**20,127**	1,215
Non-current derivative liability	**(24,358)**	(17,527)
Fair value of contracts, end of year	**(10,991)**	38,339

The (gain) loss on derivative instruments for 2019 and 2018 were comprised of the following:

	Year Ended	
	Dec 31, 2019	**Dec 31, 2018**
Realized (gain) loss on contracts settled during the year	**(84,219)**	111,258
Reversal of opening contracts settled during the year	**62,735**	(57,719)
Unrealized gain on contracts outstanding at the end of the year	**(5,308)**	(51,607)
(Gain) loss on derivative instruments	**(26,792)**	1,932

Please refer to Note 19 (Supplemental information) for a listing of Vermilion's outstanding derivative instruments as at December 31, 2019.

10. Leases

Vermilion had the following future commitments associated with its lease obligations:

($M)	As at Dec 31, 2019	Dec 31, 2018
Less than 1 year	**29,217**	30,641
1 - 3 years	**46,501**	50,024
3 - 5 years	**38,177**	34,313
After 5 years	**26,168**	42,739
Total lease payments	**140,063**	157,717
Amounts representing interest	**(23,309)**	(24,583)
Present value of net lease payments	**116,754**	133,134
Current portion of lease obligations	**(23,682)**	(24,945)
Non-current portion of lease obligations	**93,072**	108,189
Total cash outflow	**33,276**	27,468
Interest on lease liabilities	**6,984**	7,185

11. Taxes

The following table reconciles Vermilion's deferred tax asset and liability:

	As at Dec 31, 2019	Dec 31, 2018
Deferred tax assets:		
Capital assets	**(296,793)**	(296,591)
Non-capital losses	**454,339**	487,398
Asset retirement obligations	**36,170**	38,429
Derivative contracts	**2,712**	(11,937)
Unrealized foreign exchange	**(3,034)**	(1,873)
Other	**3,149**	3,985
Deferred tax assets	**196,543**	219,411
Deferred tax liabilities:		
Capital assets	**262,669**	319,553
Non-capital losses	**(48,007)**	(57,785)
Asset retirement obligations	**123,257**	51,031
Unrealized foreign exchange	**—**	10,715
Other	**(1,610)**	(5,380)
Deferred tax liabilities	**336,309**	318,134

Income tax expense differs from the amount that would have been expected if the reported earnings had been subject only to the statutory Canadian income tax rate as follows:

	Year Ended	
	Dec 31, 2019	Dec 31, 2018
Earnings before income taxes	**141,125**	354,698
Canadian corporate tax rate [1]	**26.72%**	27.00%
Expected tax expense	**37,709**	95,768
Increase (decrease) in taxes resulting from:		
Petroleum resource rent tax rate (PRRT) differential [2]	**17,455**	5,349
Foreign tax rate differentials [2] [3]	**5,543**	3,086
Equity based compensation expense	**3,733**	13,883
Amended returns and changes to estimated tax pools and tax positions	**(24,387)**	(873)
Statutory rate changes and the estimated reversal rates associated with temporary differences[4]	**9,543**	—
Derecognition (recognition) of deferred tax assets	**65,522**	(26,931)
Adjustment for uncertain tax positions	**3,659**	8,080
Gain on business combinations	**—**	(28,812)
Other non-deductible items	**(10,451)**	13.498
Provision for income taxes	**108,326**	83,048

(1) In Canada, the lower tax rate is a result of reductions to the Alberta corporate tax rate from 12% to 8% over four years.
(2) In Australia, current taxes include both corporate income tax rates and PRRT. Corporate income tax rates were applied at a rate of 30% and PRRT was applied at a rate of 40%.
(3) The applicable tax rates for 2019 were: 32.0% in France, 50.0% in the Netherlands, 31.8% in Germany, 25.0% in Ireland, and 21.0% in the United States (2018: 34.4% in France, 50.0% in the Netherlands, 30.2% in Germany, 25.0% in Ireland, and 21.0% in the United States).
(4) On December 28, 2019, the French Parliament approved the Finance Bill for 2020. The Finance Bill for 2020 provides for a progressive decrease of the French corporate income tax rate for companies with sales below €250 million from 32.0% to 25.8% by 2022. Effective July 1, 2019, Alberta decreased its corporate tax rate from 12% to 11% for 2019 with further 1% rate reductions every year on January 1 until the general corporate tax rate is 8% on January 1, 2022.

At December 31, 2019, Vermilion had $2.5 billion (2018 - $2.6 billion) of unused tax losses of which $1.2 billion (2018 - $1.1 billion) relates to Vermilion's Canada segment and expire between 2025 and 2040. The majority of the remaining unused tax losses relates to Vermilion's Ireland segment and do not expire.

At December 31, 2019, Vermilion derecognized $65.5 million (2018 - recognized $26.9 million) of deferred income assets relating to the aforementioned non-expiring tax loss in Ireland as there is uncertainty as to the Company's ability to fully utilize such losses based on the forecasted commodity prices in effect as at December 31, 2019.

The aggregate amount of temporary differences associated with investments in subsidiaries for which deferred tax liabilities have not been recognized as at December 31, 2019 is approximately $0.5 billion (2018 – approximately $0.5 billion).

12. Long-term debt

The following table summarizes Vermilion's outstanding long-term debt:

	As at	
	Dec 31, 2019	Dec 31, 2018
Revolving credit facility	**1,539,225**	1,392,206
Senior unsecured notes	**385,440**	404,001
Long-term debt	**1,924,665**	1,796,207

The fair value of the revolving credit facility is equal to its carrying value due to the use of short-term borrowing instruments at market rates of interest. The fair value of the senior unsecured notes as at December 31, 2019 was $366.4 million.

The following table reconciles the change in Vermilion's long-term debt:

	2019	2018
Balance at January 1	**1,796,207**	1,270,330
Borrowings on the revolving credit facility	**207,787**	251,155
Assumed on acquisitions [1]	**—**	188,496
Amortization of transaction costs and prepaid interest	**4,379**	2,286
Foreign exchange	**(83,708)**	83,940
Balance at December 31	**1,924,665**	1,796,207

(1) Pursuant to the acquisitions described in Note 5 (Business combinations), Vermilion assumed the credit facilities of the acquired companies and immediately extinguished them following the respective acquisitions using proceeds from Vermilion's revolving credit facility.

Revolving credit facility
At December 31, 2019, Vermilion had in place a bank revolving credit facility maturing May 31, 2023 with the following terms:

	As at Dec 31, 2019	Dec 31, 2018
Total facility amount	**2,100,000**	1,800,000
Amount drawn	**(1,539,225)**	(1,392,206)
Letters of credit outstanding	**(10,230)**	(15,400)
Unutilized capacity	**550,545**	392,394

The facility can be extended from time to time at the option of the lenders and upon notice from Vermilion. If no extension is granted by the lenders, the amounts owing pursuant to the facility are due at the maturity date. The facility is secured by various fixed and floating charges against the subsidiaries of Vermilion.

The facility bears interest at a rate applicable to demand loans plus applicable margins.

As at December 31, 2019, the revolving credit facility was subject to the following financial covenants:

Financial covenant	Limit	As at Dec 31, 2019	Dec 31, 2018
Consolidated total debt to consolidated EBITDA	Less than 4.0	**1.94**	1.72
Consolidated total senior debt to consolidated EBITDA	Less than 3.5	**1.56**	1.34
Consolidated EBITDA to consolidated interest expense	Greater than 2.5	**13.46**	14.57

The financial covenants include financial measures defined within the revolving credit facility agreement that are not defined under IFRS. These financial measures are defined by the revolving credit facility agreement as follows:

- Consolidated total debt: Includes all amounts classified as "Long-term debt" and "Lease obligations" (including the current portion included within "Accounts payable and accrued liabilities" but excluding operating leases as defined under IAS 17) on the balance sheet.
- Consolidated total senior debt: Defined as consolidated total debt excluding unsecured and subordinated debt.
- Consolidated EBITDA: Defined as consolidated net earnings before interest, income taxes, depreciation, accretion and certain other non-cash items, adjusted for the impact of the acquisition of a material subsidiary.
- Consolidated total interest expense: Includes all amounts classified as "Interest expense", but excluding interest on operating leases as defined under IAS 17.

As at December 31, 2019 and 2018, Vermilion was in compliance with the above covenants.

Senior unsecured notes
On March 13, 2017, Vermilion issued US $300.0 million of senior unsecured notes at par. The notes bear interest at a rate of 5.625% per annum, to be paid semi-annually on March 15 and September 15. The notes mature on March 15, 2025. As direct senior unsecured obligations of Vermilion, the notes rank equally with existing and future senior unsecured indebtedness of the Company.

The senior unsecured notes were recognized at amortized cost and include the transaction costs directly related to the issuance.

Vermilion may, at its option, redeem the notes prior to maturity as follows:
- Prior to March 15, 2020, Vermilion may redeem up to 35% of the original principal amount of the senior unsecured notes with the proceeds of certain equity offerings by the Company at a redemption price of 105.625% of the principal amount plus any accrued and unpaid interest to the applicable redemption date.
- Prior to March 15, 2020, Vermilion may redeem some or all of the senior unsecured notes at a price equal to 100% of the principal amount of the senior unsecured notes, plus an applicable premium and any accrued and unpaid interest.
- On or after March 15, 2020, Vermilion may redeem some or all of the senior unsecured notes at the redemption prices set forth in the following table plus any accrued and unpaid interest.

Year	Redemption price
2020	104.219 %
2021	102.813 %
2022	101.406 %
2023 and thereafter	100.000 %

Cross currency interest rate swaps
On June 12, 2019, Vermilion entered into a series of cross currency interest rate swaps with a syndicate of banks. Vermilion applied hedge accounting to these derivative instruments. The cross currency interest rate swaps mature March 15, 2025 and include regular cash receipts and payments on March 15 and September 15 of each year. On a net basis, the cross currency interest swaps result in Vermilion receiving US dollar interest and principal amounts equal to the interest and principal payments under the US $300.0 million of senior unsecured notes. In exchange, Vermilion will make interest and principal payments equal to €265.0 million at a rate of 3.275%.

The cross currency interest rate swaps were executed as two separate sets of instruments:
- US dollar to Canadian dollar ("USD-to-CAD") cross currency interest rate swaps: Vermilion receives US dollar interest and principal amounts equal to US$300.0 million of debt at 5.625% interest and pays Canadian dollar interest and principal amounts equal to $398.5 million of debt at 5.40% interest.
- Canadian dollar to Euro ("CAD-to-EUR") cross currency interest rate swaps: Vermilion receives Canadian dollar interest and principal amounts equal to $398.5 million of debt at 5.40% interest and pays Euro interest and principal amounts equal to €265.0 million at a rate of 3.275%.

The USD-to-CAD cross currency interest swaps have been designated as the hedging instrument in a cash flow hedge to mitigate the risk of the fluctuation of interest and principal cash flows due to changes in foreign currency rates related to the Senior Unsecured Notes described above. The forward element of the swap contract is treated as the excluded component and is initially recognized within other comprehensive income. The excluded component is amortized to net earnings in interest expense on a systematic basis. As the timing and amount of the cash flows received on the USD-to-CAD cross currency interest rate swaps offset the timing and amount of the cash flows paid on the senior unsecured notes, the economic relationship is expected to be highly effective. The change in the value of the hedged item associated with a change in spot foreign exchange rates is initially recognized in other comprehensive income. This change is reclassified from other comprehensive income to net earnings (and recorded as an foreign exchange gain or loss) to offset the associated foreign exchange gain or loss recognized on the senior unsecured notes.

The CAD-to-EUR cross currency interest rate swaps have been designated as the hedging instrument in a net investment hedge to mitigate the effective change in exchange rates on our net investments in Euro denominated foreign subsidiaries. The change in the value of the hedged item associated with a change in spot foreign exchange rates is initially recognized in other comprehensive income. This change is reclassified from other comprehensive income to net earnings (and recorded as a foreign exchange gain or loss) only if the net investment is disposed of by sale. The forward element of the swap contract is treated as the excluded component and is initially recognized within other comprehensive income. The excluded component is amortized to net earnings in interest expense on a systematic basis.

13. Shareholders' capital

The following table reconciles the change in Vermilion's shareholders' capital:

	2019		2018	
Shareholders' capital	**Shares ('000s)**	**Amount ($M)**	**Shares ('000s)**	**Amount ($M)**
Balance at January 1	**152,704**	**4,008,828**	122,119	2,650,706
Shares issued for acquisition	**—**	**—**	27,883	1,234,676
Shares issued for the Dividend Reinvestment Plan	**1,417**	**34,937**	1,179	49,051
Vesting of equity based awards	**1,359**	**51,108**	1,025	54,057
Shares issued for equity based compensation	**552**	**15,868**	314	12,565
Share-settled dividends on vested equity based awards	**258**	**8,290**	184	7,773
Balance at December 31	**156,290**	**4,119,031**	152,704	4,008,828

Vermilion is authorized to issue an unlimited number of common shares with no par value.

Dividends are approved by the Board of Directors and are paid monthly. Dividends declared to shareholders for the year ended December 31, 2019 were $427.3 million or $2.76 per common share (2018 - $388.1 million or $2.72 per common share).

Subsequent to the end of year-end and prior to the consolidated financial statements being authorized for issue on March 5, 2020, Vermilion declared dividends of $72.0 million or $0.23 per share for each of January and February of 2020.

14. Capital disclosures

Vermilion defines capital as net debt (long-term debt plus net working capital) and shareholders' capital. Vermilion excludes from its definition of capital any obligations secured by an offsetting asset, such as lease obligations.

Vermilion monitors the ratio of net debt to fund flows from operations. As at December 31, 2019, our ratio of net debt to trailing fund flows from operations is 2.20 (2018 - 2.30). Vermilion manages the ratio of net debt to fund flows from operations (refer to Note 4 - Segmented information) by monitoring capital expenditures, dividends, and asset retirement obligations with expected fund flows from operations. Vermilion intends for the ratio of net debt to fund flows from operations to trend towards 1.5 over time.

The following table calculates Vermilion's ratio of net debt to fund flows from operations:

	Year Ended	
	Dec 31, 2019	**Dec 31, 2018**
Long-term debt	**1,924,665**	1,796,207
Current liabilities	**416,210**	563,199
Current assets	**(347,681)**	(429,877)
Net debt	**1,993,194**	1,929,529
Ratio of net debt to four quarter trailing fund flows from operations	**2.20**	2.30

15. Equity based compensation

The following table summarizes the number of awards outstanding under the VIP and the Five-Year Compensation Arrangement:

Number of VIP and Five Year Compensation Awards ('000s)	2019	2018
Opening balance	**1,931**	1,685
Granted	**1,193**	932
Vested	**(688)**	(520)
Forfeited	**(168)**	(166)
Closing balance [(1)]	**2,268**	1,931

(1) As at December 31, 2019, 51,860 awards (2018 - 36,845 awards) are included in the closing balance related to the Five-Year Compensation Arrangement.

For the year ended December 31, 2019, the awards had a weighted average grant date fair value of $30.92 (2018 - $40.57). Equity based compensation expense for the awards is calculated based on the number of awards outstanding multiplied by the estimated performance factor that will be realized upon vesting (2019 - 1.7; 2018 - 1.9) adjusted by an estimated annual forfeiture rate (2019 - 5.2%; 2018 - 4.6%). Equity based compensation expense of $46.6 million was recorded during the year ended December 31, 2019 (2018 - $48.2 million) relating to the awards.

For the year ended December 31, 2019, there were 72,191 DSUs granted and outstanding with a weighted average grant date fair value of $25.25. Equity based compensation expense of $1.8 million was recorded during the year ended December 31, 2019 relating to the DSUs.

16. Per share amounts

Basic and diluted net earnings per share have been determined based on the following:

	Year Ended	
	Dec 31, 2019	Dec 31, 2018
Net earnings	**32,799**	271,650
Basic weighted average shares outstanding ('000s)	**154,736**	140,619
Dilutive impact of equity based compensation ('000s)	**1,359**	1,716
Diluted weighted average shares outstanding ('000s)	**156,095**	142,335
Basic earnings per share	**0.21**	1.93
Diluted earnings per share	**0.21**	1.91

17. Financial instruments

Classification of financial instruments

The following table summarizes the carrying value relating to Vermilion's financial instruments:

	As at Dec 31, 2019				As at Dec 31, 2018			
($M)	FVTPL	FVTOCI	Amortized Cost	Total	FVTPL	FVTOCI	Amortized Cost	Total
Cash and cash equivalents	**29,028**	**—**	**—**	**29,028**	26,809	—	—	26,809
Derivative assets	**64,135**	**11,637**	**—**	**75,772**	96,882	—	—	96,882
Derivative liabilities	**(83,223)**	**(3,540)**	**—**	**(86,763)**	(58,543)	—	—	(58,543)
Accounts receivable	**—**	**—**	**211,409**	**211,409**	—	—	260,322	260,322
Accounts payable and accrued liabilities	**—**	**—**	**(312,442)**	**(312,442)**	—	—	(449,651)	(449,651)
Dividends payable	**—**	**—**	**(35,947)**	**(35,947)**	—	—	(35,122)	(35,122)
Lease obligations	**—**	**—**	**(93,072)**	**(93,072)**	—	—	(108,189)	(108,189)
Long-term debt [1]	**—**	**—**	**(1,924,665)**	**(1,924,665)**	—	—	(1,796,207)	(1,796,207)

(1) The carrying value of the above equals fair value except for long-term debt. The fair value of long-term debt was $1,905,588 (2018 - $1,781,809).

The carrying value of accounts receivable, accounts payable and accrued liabilities, dividends payable and lease obligations are a reasonable approximation of their fair value due to the short maturity of these financial instruments. The carrying value of long-term debt outstanding on the revolving credit facility approximates its fair value due to the use of short-term borrowing instruments at market rates of interest.

Fair value measurements are categorized into a fair value hierarchy based on the lowest level input that is significant to the fair value measurement:

- Level 1 inputs are determined by reference to unadjusted quoted prices in active markets for identical assets or liabilities. Inputs used in fair value measurement of cash and cash equivalents, the revolving credit facility, and the senior unsecured notes are categorized as Level 1.
- Level 2 inputs are determined based on inputs other than unadjusted quoted prices that are observable, either directly or indirectly. The fair value of Vermilion's derivative assets and liabilities are determined using pricing models that incorporate future price forecasts (supported by prices from observable market transactions) and credit risk adjustments.
- Level 3 inputs are not based on observable market data. Vermilion does not have any financial instruments classified as Level 3.

There were no transfers between levels in the hierarchy in the years ended December 31, 2019 and 2018.

Nature and Extent of Risks Associated with Financial Instruments

Vermilion is exposed to financial risks from its financial instruments. These financial risks include: market risk (includes commodity price risk, interest rate risk, and currency risk), credit risk, and liquidity risk.

Commodity price risk

Vermilion is exposed to commodity price risk on its derivative assets and liabilities which are used as part of the Company's risk management program to mitigate the effects of changes in commodity prices on future cash flows. While transactions of this nature relate to future petroleum and natural gas production, Vermilion does not designate these derivative assets and liabilities as accounting hedges. As such, changes in commodity prices impact the fair value of derivative instruments and the corresponding gains or losses recognized on derivative instruments.

Currency risk

Vermilion is exposed to currency risk on its financial instruments denominated in foreign currencies. These financial instruments include cash and cash equivalents, accounts receivables, accounts payables, lease obligations, long-term debt, derivative assets and derivative liabilities. These financial instruments are primarily denominated in the US dollar and the Euro. Vermilion monitors its exposure to currency risk and reviews whether the use of derivative financial instruments is appropriate to manage potential fluctuations in foreign exchange rates.

Interest rate risk

Vermilion is exposed to interest rate risk on its revolving credit facility, which consists of short-term borrowing instruments that bear interest at market rates. Thus, changes in interest rates could result in an increase or decrease in the amount paid by Vermilion to service this debt.

The following table summarizes the increase (positive values) or decrease (negative values) to net earnings before tax due to a change in the value of Vermilion's financial instruments as a result of a change in the relevant market risk variable. This analysis does not attempt to reflect any interdependencies between the relevant risk variables.

($M)	Dec 31, 2019	Dec 31, 2018
Currency risk - Euro to Canadian dollar		
$0.01 increase in strength of the Canadian dollar against the Euro	**(1,599)**	(2,205)
$0.01 decrease in strength of the Canadian dollar against the Euro	**1,599**	2,205
Currency risk - US dollar to Canadian dollar		
$0.01 increase in strength of the Canadian dollar against the US $	**(5,594)**	2,981
$0.01 decrease in strength of the Canadian dollar against the US $	**5,594**	(2,981)
Commodity price risk - Crude oil		
US $5.00/bbl increase in crude oil price used to determine the fair value of derivatives	**(44,106)**	(18,421)
US $5.00/bbl decrease in crude oil price used to determine the fair value of derivatives	**47,777**	17,351
Commodity price risk - European natural gas		
€ 0.5/GJ increase in European natural gas price used to determine the fair value of derivatives	**(28,192)**	(36,508)
€ 0.5/GJ decrease in European natural gas price used to determine the fair value of derivatives	**22,670**	33,005

Credit risk:

Vermilion is exposed to credit risk on accounts receivable and derivative assets in the event that customers, joint operation partners, or counterparties fail to discharge their contractual obligations. As at December 31, 2019, Vermilion's maximum exposure to receivable credit risk was $287.2 million (December 31, 2018 - $357.2 million) which is the value of accounts receivable and derivative assets on the balance sheet.

Vermilion's accounts receivable primarily relates to customers and joint operations partners in the petroleum and natural gas industry. These amounts are subject to normal industry payment terms and credit risks. Vermilion manages these risks by monitoring the creditworthiness of customers and joint operations partners and, where appropriate, obtaining assurances such as parental guarantees and letters of credit. Vermilion determines the lifetime expected credit losses recognized on accounts receivable using a provision matrix. In preparing the provision matrix, the Company takes into account historical credit loss experience based on the aging of accounts receivable, adjusted as necessary for current and future petroleum and natural gas prices to the extent that changes in pricing may negatively impact the Company's customers and joint operations partners. The lifetime expected credit losses on accounts receivable as at December 31, 2019 and 2018 is not material. As at the balance sheet date, approximately 3.6% (2018 - 0.7%) of the accounts receivable balance was outstanding for more than 90 days. Vermilion considers the balance of accounts receivable to be collectible.

Vermilion's derivative assets primarily relates to the fair value of financial instruments used as part of the Company's risk management program to mitigate the effects of changes in commodity prices on future cash flows. Vermilion manages this risk by monitoring the creditworthiness of counterparties, transacting primarily with counterparties that have investment grade third party credit ratings, and by limiting the concentration of financial exposure to individual counterparties. As a result, Vermilion has not obtained collateral or other security to support its financial derivatives.

Vermilion's cash deposited in financial institutions and guaranteed investment certificates are also subject to counterparty credit risk. Vermilion mitigates this risk by transacting with financial institutions with high third party credit ratings.

Liquidity risk:

Liquidity risk is the risk that Vermilion will encounter difficulty in meeting obligations associated with its financial liabilities. Vermilion does not consider this to be a significant risk as its financial position and available committed borrowing facility provide significant financial flexibility and allow Vermilion to meet its obligations as they come due.

The following table summarizes Vermilion's undiscounted non-derivative financial liabilities and their contractual maturities:

($M)	1 month	1 month to 3 months	3 months to 1 year	1 year to 5 years
December 31, 2019	134,502	208,752	5,136	1,608,435
December 31, 2018	167,491	306,927	10,355	1,472,087

18. Related party disclosures

The compensation of directors and management is reviewed annually by the independent Governance and Human Resources Committee against industry practices for oil and gas companies of similar size and scope.

The following table summarizes the compensation of directors and other members of key management personnel during the years ended December 31, 2019 and 2018:

	Year Ended	
	Dec 31, 2019	Dec 31, 2018
Short-term benefits	**8,084**	6,018
Equity based compensation	**16,296**	16,309
	24,380	22,327
Number of individuals included in the above amounts	**19**	18

During the year ended December 31, 2019, Vermilion recorded $0.2 million of office rent recoveries (2018 - $0.2 million) relating to an office sub-lease to a company whose Managing Director is also a member of Vermilion's Board of Directors. This related party transaction is provided in the normal course of business under the same commercial terms and conditions as transactions with unrelated companies and is recorded at the exchange amount.

19. Supplemental information

Changes in non-cash working capital was comprised of the following:

	Year Ended	
	Dec 31, 2019	Dec 31, 2018
Changes in:		
Accounts receivable	**48,913**	(94,562)
Crude oil inventory	**(1,638)**	(10,646)
Prepaid expenses	**(2,882)**	(4,896)
Accounts payable and accrued liabilities	**(137,209)**	230,567
Income taxes payable	**(31,994)**	(1,651)
Working capital assumed in acquisitions	**—**	(58,841)
Initial recognition of IFRS 16 liability	**—**	(10,483)
Foreign exchange	**2,590**	(873)
Changes in non-cash working capital	**(122,220)**	48,615
Changes in non-cash operating working capital	**(65,148)**	(6,876)
Changes in non-cash investing working capital	**(57,072)**	55,491
Changes in non-cash working capital	**(122,220)**	48,615

Cash and cash equivalents was comprised of the following:

	As at	
	Dec 31, 2019	Dec 31, 2018
Cash on deposit with financial institutions	**28,898**	26,604
Guaranteed investment certificates	**130**	205
Cash and cash equivalents	**29,028**	26,809

Wages and benefits included in operating expenses and general and administration expenses were:

	Year Ended	
	Dec 31, 2019	Dec 31, 2018
Operating expense	**77,868**	66,095
General and administration expense	**47,310**	42,496
Wages and benefits	**125,178**	108,591

The following tables summarize Vermilion's outstanding risk management positions as at December 31, 2019:

	Unit	Currency	Bought Put Volume	Weighted Average Bought Put Price	Sold Call Volume	Weighted Average Sold Call Price	Sold Put Volume	Weighted Average Sold Put Price	Swap Volume	Weighted Average Swap Price
Dated Brent										
Q1 2020	bbl	USD	3,000	62.25	3,000	67.39	3,000	55.58	—	—
Q2 2020	bbl	USD	3,000	62.25	3,000	67.39	3,000	55.58	—	—
WTI										
Q1 2020	bbl	USD	9,750	54.18	6,000	60.95	9,750	46.23	1,500	59.17
Q2 2020	bbl	USD	7,250	53.07	4,000	60.23	7,250	44.86	—	—
Q3 2020	bbl	USD	500	57.00	500	61.25	500	52.00	—	—
Q4 2020	bbl	USD	500	57.00	500	61.25	500	52.00	—	—
AECO										
Q1 2020	mcf	CAD	10,426	1.58	10,426	2.56	—	—	—	—
Q2 2020	mcf	CAD	—	—	—	—	—	—	10,426	1.39
Q3 2020	mcf	CAD	—	—	—	—	—	—	10,426	1.39
Q4 2020	mcf	CAD	—	—	—	—	—	—	3,513	1.39
AECO Basis (AECO less NYMEX Henry Hub)										
Q1 2020	mcf	USD	—	—	—	—	—	—	32,500	(0.94)
Q2 2020	mcf	USD	—	—	—	—	—	—	52,500	(1.12)
Q3 2020	mcf	USD	—	—	—	—	—	—	50,000	(1.12)
Q4 2020	mcf	USD	—	—	—	—	—	—	36,739	(1.11)
Q1 2021	mcf	USD	—	—	—	—	—	—	30,000	(1.11)
Q2 2021	mcf	USD	—	—	—	—	—	—	45,000	(1.08)
Q3 2021	mcf	USD	—	—	—	—	—	—	45,000	(1.08)
Q4 2021	mcf	USD	—	—	—	—	—	—	35,054	(1.09)
Q1 2022	mcf	USD	—	—	—	—	—	—	30,000	(1.10)
Q2 2022	mcf	USD	—	—	—	—	—	—	35,000	(1.09)
Q3 2022	mcf	USD	—	—	—	—	—	—	35,000	(1.09)
Q4 2022	mcf	USD	—	—	—	—	—	—	11,793	(1.09)
NYMEX Henry Hub										
Q1 2020	mcf	USD	10,000	2.75	10,000	3.10	10,000	2.25	—	—

	Unit	Currency	Bought Put Volume	Weighted Average Bought Put Price	Sold Call Volume	Weighted Average Sold Call Price	Sold Put Volume	Weighted Average Sold Put Price	Swap Volume	Weighted Average Swap Price
NBP										
Q1 2020	mcf	EUR	49,135	5.27	49,135	5.83	49,135	3.98	—	—
Q2 2020	mcf	EUR	41,765	5.21	41,765	5.53	41,765	3.83	—	—
Q3 2020	mcf	EUR	41,765	5.21	41,765	5.52	41,765	3.83	—	—
Q4 2020	mcf	EUR	61,419	5.28	63,875	5.77	61,419	3.90	—	—
Q1 2021	mcf	EUR	54,048	5.44	56,505	5.85	54,048	3.94	—	—
Q2 2021	mcf	EUR	46,678	5.42	46,678	5.80	46,678	3.92	—	—
Q3 2021	mcf	EUR	46,678	5.42	46,678	5.77	46,678	3.92	—	—
Q4 2021	mcf	EUR	54,048	5.44	54,048	5.72	54,048	3.94	—	—
Q1 2022	mcf	EUR	19,654	5.42	19,654	6.30	19,654	3.79	—	—
Q2 2022	mcf	EUR	12,284	5.33	12,284	6.03	12,284	3.60	—	—
NBP Basis (NBP less NYMEX Henry Hub)										
Q1 2020	mcf	USD	17,500	2.74	17,500	3.99	—	—	—	—
Q2 2020	mcf	USD	15,000	2.61	15,000	3.98	—	—	—	—
Q3 2020	mcf	USD	15,000	2.61	15,000	3.98	—	—	—	—
Q4 2020	mcf	USD	10,000	3.24	10,000	3.98	—	—	—	—
TTF										
Q1 2020	mcf	EUR	7,370	5.37	7,370	6.25	7,370	3.81	—	—
Q2 2020	mcf	EUR	13,512	5.36	9,827	6.15	13,512	3.73	4,913	5.54
Q3 2020	mcf	EUR	13,512	5.36	9,827	6.15	13,512	3.73	3,258	5.45
Q4 2020	mcf	EUR	7,370	5.37	7,370	6.25	7,370	3.81	—	—
TTF Basis (TTF less NYMEX Henry Hub)										
Q2 2020	mcf	USD	2,500	3.50	2,500	4.00	—	—	5,000	3.21
Q3 2020	mcf	USD	2,500	3.50	2,500	4.00	—	—	5,000	3.21

Cross Currency Interest Rate		Receive Notional Amount		Receive Rate	Pay Notional Amount		Pay Rate
Swap	Jan 2020 - Mar 2025	300,000,000	USD	5.625%	265,048,910	EUR	3.275%
Swap	Q1 2020	1,735,895,470	USD	LIBOR + 1.70%	2,304,900,000	CAD	CDOR + 1.25%

VET Equity Swaps		Initial Share Price		Share Volume
Swap	Jan 2020 - Sep 2021	20.9788	CAD	2,250,000
Swap	Jan 2020 - Oct 2021	22.4587	CAD	1,500,000

The following sold option instruments allow the counterparties, at the specified date, to enter into a derivative instrument contract with Vermilion at the detailed terms:

Period if Option Exercised	Unit	Currency	Option Expiration Date	Bought Put Volume	Weighted Average Bought Put Price	Sold Call Volume	Weighted Average Sold Call Price	Sold Put Volume	Weighted Average Sold Put Price	Swap Volume	Weighted Average Swap Price
Dated Brent											
Feb 2020 - Jan 2021	bbl	USD	28-Jan-20	—	—	—	—	—	—	500	63.00
Feb 2020 - Jan 2021	bbl	USD	31-Jan-20	—	—	—	—	—	—	3,000	62.00
Mar 2020 - Feb 2021	bbl	USD	28-Feb-20	—	—	—	—	—	—	4,500	62.71
Apr 2020 - Mar 2021	bbl	USD	31-Mar-20	—	—	—	—	—	—	3,500	63.32
Apr 2020 - Mar 2021	bbl	USD	31-Mar-20	1,000	64.00	1,000	69.00	1,000	59.00	—	—
May 2020 - Apr 2021	bbl	USD	30-Apr-20	—	—	—	—	—	—	4,000	62.63
NBP											
Oct 2020 - Jun 2022	mcf	EUR	30-Jun-20	—	—	—	—	—	—	2,457	5.86
Jan 2021 - Sep 2022	mcf	EUR	30-Jun-20	—	—	—	—	—	—	2,457	5.86
Jan 2021 - Sep 2022	mcf	USD	30-Jun-20	—	—	—	—	—	—	2,457	6.45
Jan 2022 - Dec 2022	mcf	USD	30-Jun-20	—	—	—	—	—	—	9,827	6.45
Oct 2020 - Jun 2022	mcf	EUR	30-Sep-20	—	—	—	—	—	—	2,457	6.15

DIRECTORS

Lorenzo Donadeo [1]
Calgary, Alberta

Larry J. Macdonald [2, 4, 6, 8]
Chairman & CEO, Point Energy Ltd.
Calgary, Alberta

Carin Knickel [6, 8, 12]
Golden, Colorado

Stephen P. Larke [4, 6, 12]
Calgary, Alberta

Loren M. Leiker [10]
McKinney, Texas

Timothy R. Marchant [7, 10, 11]
Calgary, Alberta

Anthony Marino
Calgary, Alberta

Robert Michaleski [4, 5]
Calgary, Alberta

William Roby [8, 9, 12]
Katy, Texas

Catherine L. Williams [3, 6]
Calgary, Alberta

[1] Chairman of the Board
[2] Lead Director
[3] Audit Committee Chair (Independent)
[4] Audit Committee Member
[5] Governance and Human Resources Committee Chair (Independent)
[6] Governance and Human Resources Committee Member
[7] Health, Safety and Environment Committee Chair (Independent)
[8] Health, Safety and Environment Committee Member
[9] Independent Reserves Committee Chair (Independent)
[10] Independent Reserves Committee Member
[11] Sustainability Committee Chair (Independent)
[12] Sustainability Committee Member

OFFICERS AND KEY PERSONNEL

CANADA

Anthony Marino
President & Chief Executive Officer

Lars Glemser
Vice President & Chief Financial Officer

Mona Jasinski
Executive Vice President, People and Culture

Michael Kaluza
Executive Vice President & Chief Operating Officer

Dion Hatcher
Vice President Canada Business Unit

Terry Hergott
Vice President Marketing

Kyle Preston
Vice President Investor Relations

Jenson Tan
Vice President Business Development

Daniel Goulet
Director Corporate HSE

Jeremy Kalanuk
Director Operations Accounting

Bryce Kremnica
Director Field Operations - Canada Business Unit

Steve Reece
Director Information Technology & Information Systems

Tom Rafter
Director Land - Canada Business Unit

Adam Iwanicki
Director Marketing

Robert (Bob) J. Engbloom
Corporate Secretary

UNITED STATES

Scott Seatter
Managing Director - U.S. Business Unit

Timothy R. Morris
Director U.S. Business Development - U.S. Business Unit

EUROPE

Gerard Schut
Vice President European Operations

Sylvain Nothhelfer
Managing Director - France Business Unit

Sven Tummers
Managing Director - Netherlands Business Unit

Bill Liutkus
Managing Director - Germany Business Unit

Darcy Kerwin
Managing Director - Ireland Business Unit

Bryan Sralla
Managing Director - Central & Eastern Europe Business Unit

AUSTRALIA

Bruce D. Lake
Managing Director - Australia Business Unit

AUDITORS

Deloitte LLP
Calgary, Alberta

BANKERS

The Toronto-Dominion Bank

Bank of Montreal

Canadian Imperial Bank of Commerce

Export Development Canada

National Bank of Canada

Royal Bank of Canada

The Bank of Nova Scotia

Wells Fargo Bank N.A., Canadian Branch

HSBC Bank Canada

Bank of America N.A., Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

JPMorgan Chase Bank, N.A., Toronto Branch

La Caisse Centrale Desjardins du Québec

Alberta Treasury Branches

Canadian Western Bank

Goldman Sachs Lending Partners LLC

Barclays Bank PLC

EVALUATION ENGINEERS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL

Norton Rose Fulbright Canada LLP
Calgary, Alberta

TRANSFER AGENT

Computershare Trust Company of Canada

STOCK EXCHANGE LISTINGS

The Toronto Stock Exchange (“VET”)
The New York Stock Exchange (“VET”)

INVESTOR RELATIONS
Kyle Preston
Vice President Investor Relations
403-476-8431 TEL
403-476-8100 FAX
1-866-895-8101 IR TOLL FREE
investor_relations@vermilionenergy.com

EXHIBIT 99.4

Deloitte LLP
700, 850 2 Street SW
Calgary, AB T2P 0R8
Canada

Tel: 403-267-1700
Fax: 587-774-5379
www.deloitte.ca

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the use of our reports dated March 5, 2020 relating to the financial statements of Vermilion Energy Inc. (the "Company") and the effectiveness of the Company's internal control over financial reporting appearing in the Annual Report on Form 40-F of Vermilion Energy Inc. for the year ended December 31, 2019.

/s/ Deloitte LLP

Chartered Professional Accountants
Calgary, Canada
March 5, 2020

EXHIBIT 99.5

CONSENT OF GLJ PETROLEUM CONSULTANTS LTD.

We hereby consent to the use of and reference to our name and our reports, and the inclusion of information derived from our reports, evaluating Vermilion Energy Inc.'s (the "Company") petroleum and natural gas reserves as at December 31, 2019, in the Company's Annual Information Form, news releases and investor presentations.

Yours truly,

GLJ PETROLEUM CONSULTANTS LTD.

"Originally Signed By"

Jodi L. Anhorn, M.Sc., P. Eng.
President & CEO

Calgary, Alberta
February 10, 2020

EXHIBIT 99.6

VERMILION ENERGY INC.
CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER

I, Anthony Marino, President and Chief Executive Officer, certify that:

1. I have reviewed this annual report on Form 40-F of Vermilion Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation;

    d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 5, 2020

/s/ Anthony Marino
[Signature]

Anthony Marino, President and Chief Executive Officer

EXHIBIT 99.6

VERMILION ENERGY INC.
CERTIFICATION OF THE CHIEF FINANCIAL OFFICER

I, Lars Glemser, Vice President and Chief Financial Officer, certify that:

1. I have reviewed this annual report on Form 40-F of Vermilion Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation;

    d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 5, 2020

/s/ Lars Glemser
[Signature]

Lars Glemser, Vice President and Chief Financial Officer

EXHIBIT 99.7

VERMILION ENERGY INC.
CERTIFICATE OF THE CHIEF EXECUTIVE OFFICER

Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 of the United States Code

In connection with the annual report of Vermilion Energy Inc. (the "Corporation") on Form 40-F for the fiscal year ended December 31, 2019, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Anthony Marino, President and Chief Executive Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Dated at Calgary, Alberta, Canada this 5th day of March 2020.

("Anthony Marino")
[Signature]

Anthony Marino, President and Chief Executive Officer

EXHIBIT 99.7

VERMILION ENERGY INC.
CERTIFICATE OF THE CHIEF FINANCIAL OFFICER

Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 of the United States Code

In connection with the annual report of Vermilion Energy Inc. (the "Corporation") on Form 40-F for the fiscal year ended December 31, 2019, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Lars Glemser, Vice President and Chief Financial Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Dated at Calgary, Alberta, Canada this 5th day of March 2020.

("Lars Glemser")
[Signature]

Lars Glemser, Vice President and Chief Financial Officer