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, 2015
Commission file number: No. 0-50832

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:	Common Shares, no par value (together with associated common share purchase rights)	Name of each exchange on which registered:	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: **111,991,466 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.

þ **Yes** ¨ No

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post such files).

¨ **Yes** ¨ No

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, 2015
Exhibit 99.2 - Management's Discussion and Analysis for the fiscal year ended December 31, 2015; and
Exhibit 99.3 - Audited Annual Financial Statements for the fiscal year ended December 31, 2015

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 auditors 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 and internal control over financial reporting 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.

B. Management's Annual Report on Internal Controls.

See page 4 of the 2015 Audited Financial Statements included as Exhibit 99.3 to this report.

C. Auditor Attestation

See page 5 & 6 of the 2015 Audited 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. Joseph F. Killi 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 Joseph F. Killi as an audit committee financial expert does not make him an "expert" for any purpose, impose on him any duties, obligations or liability that are greater than the duties, obligations or liability imposed on him 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. A copy of such code of ethics is available upon request or on the Registrant’s website at www.vermilionenergy.com.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

See page 52 of the Annual Information Form for the year ended December 31, 2015 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, 2015 (Cdn $000’s)

($M)	Less than 1 year	1 - 3 years	3 - 5 years	After 5 years	Total
Long-term debt	226,625	-	1,171,620	-	1,398,245
Operating lease obligations	12,535	22,049	16,617	9,288	60,489
Ship or pay agreement relating to the Corrib project	8,215	8,893	7,292	40,446	64,846
Purchase obligations	17,897	4,071	3,156	-	25,124
Drilling and service agreements	23,205	2,480	-	-	25,685
Total contractual obligations and commitments	288,477	37,493	1,198,685	49,734	1,574,389

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 Joseph F. Killi (Chair), Claudio A. Ghersinich, Kevin J. Reinhart and Cathy L. Williams, 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.

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 4, 2016

By: */s/ ("Curtis W. Hicks")*
Curtis W. Hicks
Executive 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, 2015
99.2	Management's Discussion and Analysis from the 2015 Annual Report to Shareholders
99.3	Audited Annual Financial Statements for the Year Ended December 31, 2015
99.4	Consent of Independent Registered Public Accounting Firm
99.5	Consent of Independent Petroleum Consultants
99.6	Officers' Certifications pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities Exchange Act of 1934
99.7	Officers' Certifications 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

VERMILION ENERGY

EXHIBIT 99.1

2015

ANNUAL INFORMATION FORM

EXCELLENCE. TRUST. RESPECT. RESPONSIBILITY.

DEFINED PRODUCTION GROWTH | RELIABLE & GROWING DIVIDENDS

FOR THE YEAR ENDED DECEMBER 31, 2015
DATED MARCH 4, 2016

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GLOSSARY OF TERMS

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

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

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

"AGCA" means Alberta Gas Cost Allowance;

"AIF" means Annual Information Form;

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

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

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

"common shares" means a common share in the capital of the Company;

"contingent resources" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies;

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

"Conversion Arrangement" means the plan of arrangement effected on September 1, 2010 under section 193 of the ABCA pursuant to which the Trust converted from an income trust to a corporate structure;

"Depletion units" means groups of assets or properties that are within a specific production area and have similar economic lives. Depletion units represent the lowest level of disaggregation for which Vermilion accumulates costs for the purposes of calculating and recording depletion;

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

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

"Dividend Record Date" means the last day of each calendar month or such other date as may be determined from time to time by the Company;

"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 8, 2016 and effective December 31, 2015;

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

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

"Meeting" means the annual meeting of Shareholders of the Company to be held on May 6, 2016 (or, if adjourned, such other date on which the meeting is held);

"NYSE" means New York Stock Exchange;

"PNG" means Petroleum and Natural Gas properties and equipment;

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

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

"Rights Plan" means the Shareholder Rights Plan of the Company;

"Senior Unsecured Notes" means the $225 million aggregate principal amount of five year senior unsecured notes of the Company issued February 10, 2011;

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

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

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

"TSX" means the Toronto Stock Exchange;

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

"Trust Unit" means units in the capital of the Trust;

"Unitholders" means former unitholders of the Trust;

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

"VRL" means Vermilion Resources Ltd., previously a subsidiary of the corporation.

Conventions

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

Abbreviations

Oil and Natural Gas Liquids	
bbl	barrel
Mbbl	thousand barrels
bbl/d	barrels per day
NGLs	natural gas liquids
Natural Gas	
Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMBtu	million British Thermal Units
Other	
API	American Petroleum Institute
°API	An indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28 °API or higher is generally referred to as light crude oil.
boe	barrel of oil equivalent
M$	thousand dollars
MM$	million dollars
Mboe	1,000 barrels of oil equivalent
MMboe	million barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade.
TTF	the day-ahead price for natural gas in the Netherlands, quoted in MWh of natural gas, at the Title Transfer Facility Virtual Trading Point operated by Dutch TSO Gas Transport Services
NBP	the reference price paid for natural gas in the United Kingdom, quoted in pence per therm, at the National Balancing Point Virtual Trading Point operated by National Grid

Conversion

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

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
bbls	Cubic metres	0.159
Cubic metres	bbls oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

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

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

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

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

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

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

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

PRESENTATION OF OIL AND GAS RESERVES AND PRODUCTION INFORMATION

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

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

Contingent Resources

"Contingent resources" are not, and should not be confused with, petroleum and natural gas reserves. "Contingent resources" are defined in COGEH as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resource the estimated discovered recoverable quantities associated with a project in the early evaluation stage.

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

- preparation of firm development plans, including determination of the specific scope and timing of projects;
- project sanction;
- access to capital markets;
- Shareholder and regulatory approvals;
- 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;
- limitations to development based on adverse topography or other surface restrictions; and
- the uncertainty regarding marketing and transportation of petroleum from development areas.

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

NON-GAAP MEASURES

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

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

“Net dividends” is calculated as dividends declared for a given period less proceeds received by Vermilion pursuant to the dividend reinvestment plan. Dividends both before and after the dividend reinvestment plan are reviewed by management and are assessed as a percentage of fund flows from operations to analyze how much of the cash that is generated by Vermilion is being used to fund dividends.

VERMILION ENERGY INC.

General

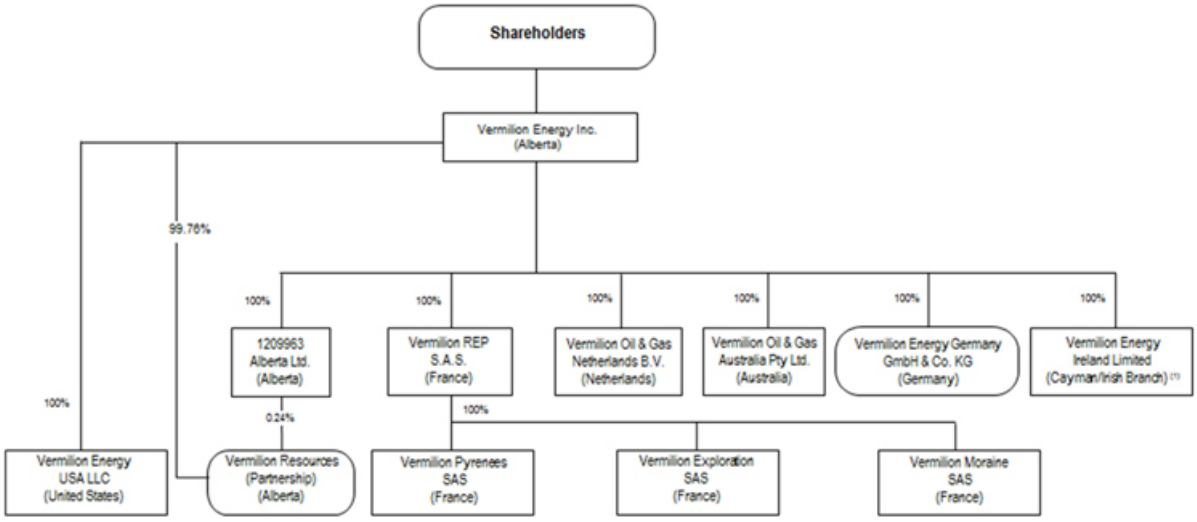
Vermilion Energy Inc. is the successor to the Trust, following the completion of the conversion of the Trust from an income trust to a corporate structure by way of a court approved plan of arrangement under the ABCA on September 1, 2010. Pursuant to the Conversion Arrangement, Unitholders exchanged their Trust Units for common shares of the Company on a one-for-one basis and holders of exchangeable shares of VRL received 1.89344 common shares for each exchangeable share held.

References to "Vermilion" prior to the date of the Conversion Arrangement are generally references to the consolidated business enterprise of the Trust prior to the date of the Conversion Arrangement, whose business the Company is a successor to as a result of the Conversion Arrangement, as accounted for by "continuity-of-interest" accounting.

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

Organizational Structure of the Company

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



Note:

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

Summary Description of the Business

Vermilion Energy Inc.

The Company is actively engaged in the business of oil and natural gas exploitation, development, acquisition and production in Canada, France, Ireland, the Netherlands, Germany, Australia and the United States. The Company's long-term business plan is to expand its portfolio of organic growth opportunities and pursue its strategic plan that targets modest annual average production growth while providing shareholders with a reliable income stream. Vermilion continues to pursue new venture initiatives which target the identification and capture of meaningful conventional and unconventional resource related exploration exposure in North America, Europe and Australia. Where possible, the Company will seek to expand its reserve base through the selective addition of high-quality, long-life conventional reserves with low risk development opportunities.

Shareholders receive monthly dividends of the cash flow generated by Vermilion as declared payable by the board of directors of the Company. The Company currently employs a strategy which: (i) provides Shareholders with a competitive annual cash-on-cash yield through monthly cash dividends, (ii) ensures that Vermilion's existing assets are maintained at a level that provides sustainable ongoing cash flow, and (iii) continues to expand the business of the Company through the development of growth opportunities that are intended to provide long-term stable cash flows and be accretive to the existing Shareholders. The Company intends to finance acquisitions through debt financing and, when necessary, the issuance of additional common shares from treasury, while maintaining prudent leverage.

Three Year History of Vermilion

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

In order to consolidate its Canadian subsidiaries, on January 1, 2013, Vermilion amalgamated with two of its wholly-owned subsidiaries, 1209974 Alberta Ltd. and Vermilion Resources Ltd. Vermilion Energy Inc. was the resulting entity upon completion of the amalgamations. As a result of the forgoing amalgamations, Vermilion Energy Inc. became the managing partner of Vermilion Resources.

On October 11, 2013, Vermilion announced the completion of the acquisition from Northern Petroleum Plc. of 100% of the shares of its subsidiary Northern Petroleum Nederland B.V. ("NPN") for approximately $27.5 million with an effective date of January 1, 2013. The acquisition included interests in nine concessions, including six onshore licences in production or development, three onshore exploration licenses, and one offshore production license ("P12") in the Netherlands (the "Assets"). Four licenses are located in the northeastern region, in close proximity to Vermilion's existing concessions and the remaining five onshore licenses are located in the southwestern region of the Netherlands. Vermilion assumed operatorship of all the acquired Assets following closing of the Acquisition, with the exception of the offshore license P12 in which Vermilion holds a 23.6% non-operated interest. The Assets cover approximately 298,500 net acres, of which approximately 98 percent is undeveloped.

On November 6, 2013, Vermilion announced that it had entered into a purchase and sale agreement with GDF SUEZ E&P Deutschland GmbH ("GDF SUEZ"), (an affiliate of GDF SUEZ S.A., a publicly traded, French multinational utility) whereby Vermilion, through a wholly-owned subsidiary, agreed to acquire GDF SUEZ's 25% interest in four producing natural gas fields and a surrounding exploration license located in northwest Germany. The acquisition from GDF SUEZ was completed in February 2014, and was funded with cash balances on hand.

On November 7, 2013, Vermilion announced that the board of directors approved a 7.5% increase to its monthly dividend to $0.215 per share from $0.20 per share. The increase became effective for the January 2014 dividend payable on February 18, 2014. This marked the third increase to Vermilion's monthly dividend, and the second annual increase.

In Q1 2014, Vermilion was awarded the Ijsselmuiden exploration concession in the Netherlands, which consists of approximately 66,300 net undeveloped acres (60% working interest).

In May 2014, we executed the Battonya South concession in Hungary with the Hungarian Ministry of National Development. The concession consists of 116,000 gross acres located in the southern part of Hungary. The term of the concession is for 20 years, subject to continuation of development in a manner acceptable to both parties.

In early 2014, we informed the Moroccan government of our intention to relinquish our rights to the Haouz block in central Morocco. Based on our evaluation of seismic data we concluded that, due to the structural complexity of the block, we would be unable to pursue a definitive appraisal and exploration program that would fit within the constraints of our predetermined new venture capital and risk parameters. The relinquishment terminates our activities in Morocco after cumulative spending of $0.9 million to evaluate the 2.3 million acre block.

On April 29, 2014, Vermilion announced the completion of the acquisition of Elkhorn Resources Inc., a private S.E. Saskatchewan producer, for total consideration of approximately $427 million. Total consideration comprised $180 million of cash, the assumption of approximately $42 million of debt, and the issuance of 2.8 million common shares of Vermilion valued at approximately $205 million (based on the closing price per Vermilion common share of $72.50 on the Toronto Stock Exchange on April 29, 2014). The assets consist of high netback, light crude oil producing assets in the Northgate region of southeast Saskatchewan and include approximately 57,000 net acres of land (approximately 80% undeveloped), seven oil batteries, and preferential access to 50% or greater capacity at a solution gas facility.

On May 22, 2014, Vermilion announced the completion of tunnel boring operations beneath Sruwaddacon Bay, related to the Corrib project in Ireland. The tunnel will serve as a conduit for the gas pipeline between the Bellanaboy gas processing facility to the offshore pipeline landing valve at Glengad.

On November 10, 2014, Vermilion announced that it had acquired approximately 68,000 acres of land (98% undeveloped) in the Powder River Basin of northeastern Wyoming for approximately $11.1 million.

On June 3, 2015, Vermilion was conditionally awarded four exploration blocks in northeast Croatia near the Hungarian border, by the Croatian Hydrocarbon Agency. This award remains subject to successful execution of a definitive contract acceptable to both Vermilion and the Government of the Republic of Croatia. The four exploration blocks consist of approximately 2.35 million gross acres with a substantial portion of the acreage located near existing crude oil and natural gas fields. The initial 5-year exploration period consists of two phases with an option to relinquish the blocks following the initial 3-year phase.

On July 27, 2015, Vermilion entered into a significant farm-in agreement in northwest Germany. The farm-in provides Vermilion with participating interest in 19 onshore exploration licenses, comprising approximately 850,000 net undeveloped acres in the North German Basin, in exchange for carrying 50% of the costs associated with the drilling and testing of six net exploration wells over the next five years. The agreement also provides for the transfer to Vermilion of operatorship for the exploration phase and data spanning these lands. The farm-in remains subject to customary conditions and regulatory approvals.

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

As at January 31, 2016, Vermilion had 516 full time employees of which 188 employees were located in its Calgary head office, 57 employees in its Canadian field offices, 156 employees in France, 63 employees in the Netherlands, 34 employees in Australia, 9 employees in the United States, 8 employees in Germany and 1 employee in Hungary.

NARRATIVE DESCRIPTION OF THE BUSINESS

Business Objectives

Vermilion is an oil-leveraged energy producer that seeks to create value through the acquisition, exploration, development and optimization of producing properties in North America, Europe and Australia. The Company's long-term business model targets annual organic production growth while providing shareholders with a reliable income stream. Vermilion is targeting growth in production primarily through the exploitation of light crude oil and liquids-rich natural gas conventional resource plays in Western Canada and the United States, the exploration and development of high impact natural gas opportunities in the Netherlands and Germany, and through drilling and workover programs targeting oil in France and Australia. Vermilion also holds an 18.5% working interest in the Corrib gas field in Ireland. In addition, Vermilion continues to pursue new venture initiatives which target the identification and capture of meaningful conventional and unconventional resource related development and exploration exposure in North America, Europe and Australia. Where possible, the Company will seek to expand its reserve base through the selective addition of high-quality, long-life reserves with low risk development opportunities.

In reviewing potential participations or acquisitions, Vermilion will consider a number of factors, including: (a) the present value of the future revenue from such properties from the proved producing, total proved and proved plus probable reserves; (b) the amount of potential for additional reservoir development; (c) whether sufficient infrastructure exists in the prospect to provide for increased activity; (d) the cost of any potential development; (e) investments in properties that exhibit medium to long-life reserves and stable production base; and (f) the ability of Vermilion to enhance the value of acquired properties through additional exploitation efforts and additional development drilling. The board of directors of Vermilion may, in its discretion, approve asset or corporate acquisitions or investments that do not conform to these guidelines based upon the board's consideration of the qualitative aspects of the subject properties including risk profile, technical upside, reserve life, asset quality and the Company's business prospects.

Description of Properties

The following is a description of the oil and natural gas properties, facilities and installations in which Vermilion has an interest and that are material to Vermilion's operations and exploration activities. We manage our business through our Calgary head office and our international business unit offices.

- Canada business unit: Relates to our assets in Alberta and Saskatchewan.
- France business unit: Relates to our operations in France in the Paris and Aquitaine basins.
- Netherlands business unit: Relates to our operations in the Netherlands.
- Germany business unit: Relates to our 25% contractual participation interest in a four-partner consortium in Germany.
- Ireland business unit: Relates to our 18.5% non-operated interest in the offshore Corrib natural gas field.
- Australia business unit: Relates to operations on the Wandoo offshore crude oil field.
- United States business unit: Relates to our operations in Wyoming in the Powder River Basin.
- Corporate: Includes expenditures related to our global hedging program, financing expenses, and general and administration expenses, primarily incurred in Canada and not directly related to the operations of a specific business unit.

The production numbers stated refer to Vermilion's working interest share before deduction of Crown, freehold and other royalties. Reserve amounts are stated, before deduction of royalties, as at December 31, 2015, based on forecast costs and price assumptions as evaluated in the GLJ Report.

Canada Business Unit

Vermilion's production in Canada is located primarily in three areas of Alberta: Drayton Valley, Slave Lake and Central Alberta and the Northgate Region of southeast Saskatchewan. Vermilion's main gas producing areas are Drayton Valley and Central Alberta, while Northgate, Slave Lake and the Cardium light crude oil play in Drayton Valley are the main oil producing areas.

Vermilion holds 71% working interest in 460,400 (326,500 net) acres of developed land, and 88% working interest in 609,100 (537,000 net) acres of undeveloped land. Vermilion had 654 (464 net) producing natural gas wells and 626 (453 net) producing oil wells in Canada as at December 31, 2015.

Vermilion owns and operates three natural gas plants and has an ownership interest in seven additional plants, resulting in combined gross processing capacity of over 80 MMcf/d. In addition, Vermilion has capacity of over 25,000 bbl/d of oil in eleven operated oil batteries including a 15,000 bbl/d oil battery that handles Cardium production (which commenced operations August 1, 2011).

Risks and uncertainties associated with weather conditions can shorten the winter drilling season and can impact the spring and summer drilling programs, potentially resulting in increased costs or reduced production.

For a discussion of the competitive conditions affecting Vermilion's business, refer to "Competition" in the Risk Factors section of this AIF.

For the year ended December 31, 2015, production in Canada averaged approximately 71.6 MMcf/d of natural gas and 13,658 bbl/d of light crude oil, medium crude oil and NGLs. Sales of natural gas in 2015 were approximately $72.7 million (2014 - $92.1 million) and sales from light crude oil, medium crude oil and NGLs were approximately $247.3 million (2014 - $445.7 million).

The GLJ Report assigned 71,163 Mboe of total proved reserves and 121,717 Mboe of proved plus probable reserves to Vermilion's properties located in Canada.

France Business Unit

Vermilion's main producing areas in France are located in the Aquitaine Basin which is southwest of Bordeaux, France and in the Paris Basin, located just east of Paris. Vermilion's assets in France are primarily oil producing properties. The two major fields in the Paris Basin area are Champotran and Chaunoy. The two major fields in the Aquitaine Basin are Parentis and Cazaux. Vermilion operates 13 oil batteries and 12 single well batteries with current throughput of more than 12,000 bbl/d. Given the legacy nature of these assets, the throughput capability of these batteries exceeds any projected future requirements. Vermilion holds 96% working interest in 218,100 (208,900 net) acres of developed land and 100% working interest in 374,600 (374,600 net) acres of undeveloped land in the Aquitaine and Paris Basins. Vermilion had 342 (337 net) producing oil wells and three (three net) producing gas wells in France as at December 31, 2015.

Risks and uncertainties associated with well approvals can impact the drilling programs, potentially resulting in delays or reduced production.
For a discussion of the competitive conditions affecting Vermilion business, refer to "Competition" in the Risk Factors section of this AIF.

For the year ended December 31, 2015, production in France averaged approximately 12,267 bbl/d of light crude oil and medium crude oil and 1.0 MMcf/d of natural gas. Sales from light crude oil and medium crude oil in 2015 were approximately $280.5 million (2014 - $431.3 million) and sales of natural gas were approximately $0.9 million (due to the closure of a third party facility, there were no sales of natural gas in 2014).

The GLJ Report assigned 42,027 Mboe of total proved reserves and 63,612 Mboe of proved plus probable reserves to Vermilion's properties located in France.

Netherlands Business Unit

Vermilion's Netherlands assets consist of 24 onshore concessions and two offshore concessions. Production consists solely of natural gas with a small amount of related condensate. Vermilion's total position in the Netherlands covers 1,492,500 (814,600 net) acres at an average 55% working interest, of which 95% is undeveloped, and 52 (35 net) producing gas wells as at December 31, 2015.

Risks and uncertainties associated with drilling and production permits can impact drilling programs and production timing, potentially resulting in increased costs or reduced production.

For a discussion of the competitive conditions affecting Vermilion's business, refer to "Competition" in the Risk Factors section of this AIF.

For the year ended December 31, 2015, Vermilion's production in the Netherlands averaged 99 bbl/d of NGLs and 44.8 MMcf/d of natural gas. Sales in 2015 of natural gas were approximately $127.3 million (2014 - $121.2 million) and sales from NGLs were approximately $1.8 million (2014 - $2.6 million).

The GLJ Report assigned 8,122 Mboe of total proved reserves and 16,320 Mboe of proved plus probable reserves to Vermilion's properties located in the Netherlands.

Germany Business Unit

Vermilion's Germany assets consist of 25% interest in four producing natural gas fields and a surrounding exploration license located in northwest Germany. Vermilion 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. Vermilion's interest in Germany includes 31,400 (7,800 net) developed acres, 285,300 (153,400 net) undeveloped acres, and 15 (four net) producing gas wells as at December 31, 2015.

For the year ended December 31, 2015, production in Germany averaged approximately 15.8 MMcf/d of natural gas. Sales of natural gas in 2015 were approximately $41.4 million (2014 - $42.0 million).

The GLJ Report assigned 5,250 Mboe of total proved reserves and 8,250 Mboe of proved plus probable reserves to Vermilion's properties located in Germany.

Ireland Business Unit

Vermilion holds an 18.5% non-operating interest in the offshore Corrib gas field located off the northwest coast of Ireland. Vermilion acquired its 18.5% working interest in the project on July 30, 2009, comprised of six offshore wells, both offshore and onshore pipeline segments as well as a natural gas processing facility. At the time of the acquisition most of the key components of the project, with the exception of the onshore pipeline, were either complete or in the latter stages of development. In 2011, approvals and permissions were granted for the onshore gas pipeline and tunneling commenced on December 16, 2012. On May 22, 2014, Vermilion announced the completion of tunnel boring operations. On September 1, 2015, the project operator, Shell E&P Ireland Limited, declared the project operationally ready for service. With the final regulatory consent received on December 29, 2015, gas began to flow from the Corrib project on December 30, 2015. Production from Corrib is expected to rise over a period of approximately six months to a peak rate of approximately 58 MMcf (9,700 boe/d) net to Vermilion.

The GLJ Report assigned 17,637 Mboe of total proved reserves and 25,538 Mboe of proved plus probable reserves to Vermilion's property located in Ireland.

Australia Business Unit

Vermilion's Australia assets consist of a 100% operated interest in an offshore oil field located on Western Australia's northwest shelf. The platform has a current producing capacity of 162,000 bbl/d of total fluid. Vermilion holds a 100% working interest in the Wandoo block, which is comprised of 59,600 acres and 18 (18 net) motherbores as at December 31, 2015.

Western Australia’s northwest shelf is subject to seasonal disruptions caused by cyclones. During cyclone season (December to March) the Company may have to reduce production rates at its offshore facilities as a result of the inability to offload to tankers due to bad weather. Cyclones may also cause production shut-ins due to the evacuation of staff or damage to equipment on the platform.

For a discussion of the competitive conditions affecting Vermilion’s business, refer to "Competition" in the Risk Factors section of this AIF.

For the year ended December 31, 2015, Vermilion's production in Australia averaged 6,454 bbl/d of light crude oil and medium crude oil. Sales in 2015 from light crude oil and medium crude oil were approximately $162.8 million (2014 - $283.5 million).

The GLJ Report assigned 13,765 Mboe of total proved reserves and 17,465 Mboe of proved plus probable reserves to Vermilion's property located in Australia.

United States Business Unit

Vermilion’s assets in the United States include approximately 102,800 (90,700 net) acres of land in the Powder River basin of northeastern Wyoming, of which 98% is undeveloped. Vermilion had five (four net) producing oil wells in the United States as at December 31, 2015.

For the year ended December 31, 2015, Vermilion’s production in the United States averaged approximately 231 bbl/d of light crude oil and medium crude oil. Sales from light crude oil and medium crude oil in 2015 were approximately $4.3 million (2014 - $1.3 million).

The GLJ Report assigned 2,742 Mboe of total proved reserves and 7,988 Mboe of proved plus probable reserves to Vermilion's properties located in the United States.

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 8, 2016 with an effective date of December 31, 2015. 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, 2015 unless otherwise stated.

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

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

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

The following tables may not total due to rounding.

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

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (MMcf)	Net [2] (MMcf)
Proved Developed Producing [3] [5] [6]								
Australia	11,465	11,465	-	-	-	-	-	-
Canada	13,528	11,785	9	9	10	8	98,840	89,253
France	34,866	32,097	-	-	-	-	7,835	7,309
Germany	-	-	-	-	-	-	20,876	18,148
Ireland	-	-	-	-	-	-	94,976	94,976
Netherlands	-	-	-	-	-	-	29,961	27,236
United States	384	314	-	-	-	-	372	304
Total Proved Developed Producing	60,243	55,661	9	9	10	8	252,860	237,226

	Shale Gas		Coal Bed Methane		Natural Gas Liquids			BOE
	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved Developed Producing [3] [5] [6]								
Australia	-	-	-	-	-	-	11,465	11,465
Canada	1,942	1,832	3,100	2,883	7,052	5,383	37,913	32,846
France	-	-	-	-	-	-	36,172	33,315
Germany	-	-	-	-	-	-	3,479	3,025
Ireland	-	-	-	-	-	-	15,829	15,829
Netherlands	-	-	-	-	66	60	5,060	4,599
United States	-	-	-	-	59	49	505	414
	1,942	1,832	3,100	2,883	7,177	5,492	110,423	101,493

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (MMcf)	Net [2] (MMcf)
Proved Developed Non-Producing								
Australia	-	-	-	-	-	-	-	-
Canada	1,032	940	-	-	-	-	17,090	14,633
France	1,914	1,754	-	-	-	-	-	-
Germany	-	-	-	-	-	-	8,263	7,157
Ireland	-	-	-	-	-	-	10,845	10,845
Netherlands	-	-	-	-	-	-	18,238	18,238
United States	313	254	-	-	-	-	318	258
Total Proved Developed Non-Producing	3,259	2,948	-	-	-	-	54,754	51,131

	Shale Gas		Coal Bed Methane		Natural Gas Liquids			BOE
	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved Developed Non-Producing								
Australia	-	-	-	-	-	-	-	-
Canada	-	-	1,743	1,643	692	490	4,863	4,143
France	-	-	-	-	-	-	1,914	1,754
Germany	-	-	-	-	-	-	1,377	1,193
Ireland	-	-	-	-	-	-	1,808	1,808
Netherlands	-	-	-	-	22	22	3,062	3,062
United States	-	-	-	-	51	41	417	338
Total Proved Developed Non-Producing	-	-	1,743	1,643	765	553	13,441	12,298

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (MMcf)	Net [2] (MMcf)
Proved Undeveloped [3] [8]								
Australia	2,300	2,300	-	-	-	-	-	-
Canada	8,411	7,357	-	-	-	-	74,181	68,479
France	3,941	3,693	-	-	-	-	-	-
Germany	-	-	-	-	-	-	2,361	1,684
Ireland	-	-	-	-	-	-	-	-
Netherlands	-	-	-	-	-	-	-	-
United States	1,337	1,087	-	-	-	-	1,480	1,204
Total Proved Undeveloped	15,989	14,437	-	-	-	-	78,022	71,367

	Shale Gas		Coal Bed Methane		Natural Gas Liquids			BOE
	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved Undeveloped								
Australia	-	-	-	-	-	-	2,300	2,300
Canada	-	-	3,367	3,114	7,051	5,955	28,387	25,244
France	-	-	-	-	-	-	3,941	3,693
Germany	-	-	-	-	-	-	394	281
Ireland	-	-	-	-	-	-	-	-
Netherlands	-	-	-	-	-	-	-	-
United States	-	-	-	-	236	192	1,820	1,480
Total Proved Undeveloped	-	-	3,367	3,114	7,287	6,147	36,842	32,998

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (MMcf)	Net [2] (MMcf)
Proved [3]								
Australia	13,765	13,765	-	-	-	-	-	-
Canada	22,971	20,082	9	9	10	8	190,111	172,365
France	40,721	37,544	-	-	-	-	7,835	7,309
Germany	-	-	-	-	-	-	31,500	26,989
Ireland	-	-	-	-	-	-	105,821	105,821
Netherlands	-	-	-	-	-	-	48,199	45,474
United States	2,034	1,655	-	-	-	-	2,170	1,766
Total Proved	79,491	73,046	9	9	10	8	385,637	359,724

	Shale Gas		Coal Bed Methane		Natural Gas Liquids			BOE
	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved								
Australia	-	-	-	-	-	-	13,765	13,765
Canada	1,942	1,832	8,210	7,640	14,795	11,828	71,163	62,233
France	-	-	-	-	-	-	42,027	38,762
Germany	-	-	-	-	-	-	5,250	4,499
Ireland	-	-	-	-	-	-	17,637	17,637
Netherlands	-	-	-	-	88	82	8,122	7,661
United States	-	-	-	-	346	282	2,742	2,232
Total Proved	1,942	1,832	8,210	7,640	15,229	12,192	160,706	146,789

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (MMcf)	Net [2] (MMcf)
Probable [4]								
Australia	3,700	3,700	-	-	-	-	-	-
Canada	14,786	12,565	3	3	3	2	132,676	120,460
France	21,325	19,814	-	-	-	-	1,559	1,505
Germany	-	-	-	-	-	-	17,999	14,999
Ireland	-	-	-	-	-	-	47,405	47,405
Netherlands	-	-	-	-	-	-	48,688	43,700
United States	3,818	3,131	-	-	-	-	4,378	3,590
Total Probable	43,629	39,210	3	3	3	2	252,705	231,659

	Shale Gas		Coal Bed Methane		Natural Gas Liquids			BOE
	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross (Mboe)	Net (Mboe)
Probable								
Australia	-	-	-	-	-	-	3,700	3,700
Canada	475	447	4,917	4,628	12,751	10,144	50,554	43,637
France	-	-	-	-	-	-	21,585	20,065
Germany	-	-	-	-	-	-	3,000	2,500
Ireland	-	-	-	-	-	-	7,901	7,901
Netherlands	-	-	-	-	83	66	8,198	7,349
United States	-	-	-	-	698	572	5,246	4,301
Total Probable	475	447	4,917	4,628	13,532	10,782	100,184	89,453

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (MMcf)	Net [2] (MMcf)
Proved Plus Probable [3] [4]								
Australia	17,465	17,465	-	-	-	-	-	-
Canada	37,757	32,647	12	12	13	10	322,787	292,825
France	62,046	57,358	-	-	-	-	9,394	8,814
Germany	-	-	-	-	-	-	49,499	41,988
Ireland	-	-	-	-	-	-	153,226	153,226
Netherlands	-	-	-	-	-	-	96,887	89,174
United States	5,852	4,786	-	-	-	-	6,548	5,356
Total Proved Plus Probable	123,120	112,256	12	12	13	10	638,342	591,383

	Shale Gas		Coal Bed Methane		Natural Gas Liquids			BOE
	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved Plus Probable [3] [4]								
Australia	-	-	-	-	-	-	17,465	17,465
Canada	2,417	2,279	13,127	12,268	27,546	21,972	121,717	105,870
France	-	-	-	-	-	-	63,612	58,827
Germany	-	-	-	-	-	-	8,250	6,999
Ireland	-	-	-	-	-	-	25,538	25,538
Netherlands	-	-	-	-	171	148	16,320	15,010
United States	-	-	-	-	1,044	854	7,988	6,533
Total Proved Plus Probable	2,417	2,279	13,127	12,268	28,761	22,974	260,890	236,242

Notes:

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

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

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

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

(5) "Developed" reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production.

(6) "Developed Producing" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(7) "Developed Non-Producing" reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

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

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

	Before Deducting Future Income Taxes Discounted At					After Deducting Future Income Taxes Discounted At				
(M$)	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**
Proved Developed Producing [2] [4] [5]										
Australia	2,347	129,206	168,558	175,898	171,717	124,988	173,769	178,900	170,295	158,300
Canada	949,037	750,567	619,559	528,638	462,575	949,037	750,567	619,559	528,638	462,575
France	1,798,973	1,255,682	953,329	767,459	643,532	1,517,541	1,074,705	821,780	664,015	557,940
Germany	43,971	38,938	34,820	31,467	28,720	43,971	38,938	34,820	31,467	28,720
Ireland	552,363	501,468	439,666	387,319	345,603	552,363	501,468	439,666	387,319	345,603
Netherlands	83,154	94,117	99,646	102,200	103,013	64,192	75,617	81,576	84,532	85,720
United States	16,290	12,359	9,959	8,387	7,290	16,290	12,359	9,959	8,387	7,290
Total Proved Developed Producing	3,446,135	2,782,337	2,325,537	2,001,368	1,762,450	3,268,382	2,627,423	2,186,260	1,874,653	1,646,148
Proved Developed Non-Producing [2] [4] [6]										
Australia	-	-	-	-	-	-	-	-	-	-
Canada	104,042	71,099	54,809	45,013	38,420	104,042	71,099	54,809	45,013	38,420
France	90,457	62,628	45,934	35,314	28,159	58,901	40,465	29,248	22,088	17,265
Germany	25,871	19,029	14,433	11,275	9,044	25,871	19,029	14,433	11,275	9,044
Ireland	92,735	62,194	44,189	32,997	25,688	92,735	62,194	44,189	32,997	25,688
Netherlands	49,823	39,122	30,708	24,196	19,156	41,346	30,978	22,865	16,628	11,839
United States	9,355	5,641	3,488	2,150	1,264	9,355	5,641	3,488	2,150	1,264
Total Proved Developed Non-Producing	372,283	259,713	193,561	150,945	121,731	332,250	229,406	169,032	130,151	103,520
Proved Undeveloped [2] [7]										
Australia	90,351	65,761	47,675	34,243	24,141	54,095	38,796	27,698	19,530	13,425
Canada	489,912	322,128	216,629	147,559	100,575	394,990	268,530	185,169	128,464	88,643
France	195,493	141,793	105,874	81,079	63,249	126,807	88,335	62,501	44,867	32,357
Germany	6,456	3,478	1,746	724	117	6,456	3,478	1,746	724	117
Ireland	-	-	-	-	-	-	-	-	-	-
Netherlands	-	-	-	-	-	-	-	-	-	-
United States	33,881	15,244	5,265	(415)	(3,816)	33,881	15,244	5,265	(415)	(3,816)
Total Proved Undeveloped	816,093	548,404	377,189	263,190	184,266	616,229	414,383	282,379	193,170	130,726
Proved [2]										
Australia	92,698	194,967	216,233	210,141	195,858	179,083	212,565	206,598	189,825	171,725
Canada	1,542,991	1,143,794	890,997	721,210	601,570	1,448,069	1,090,196	859,537	702,115	589,638
France	2,084,923	1,460,103	1,105,137	883,852	734,940	1,703,249	1,203,505	913,529	730,970	607,562
Germany	76,298	61,445	50,999	43,466	37,881	76,298	61,445	50,999	43,466	37,881
Ireland	645,098	563,662	483,855	420,316	371,291	645,098	563,662	483,855	420,316	371,291
Netherlands	132,977	133,239	130,354	126,396	122,169	105,538	106,595	104,441	101,160	97,559
United States	59,526	33,244	18,712	10,122	4,738	59,526	33,244	18,712	10,122	4,738
Total Proved	4,634,511	3,590,454	2,896,287	2,415,503	2,068,447	4,216,861	3,271,212	2,637,671	2,197,974	1,880,394
Probable [3]										
Australia	233,918	195,941	160,242	132,868	112,579	131,359	109,293	88,489	72,597	60,886
Canada	1,259,521	782,374	525,575	374,090	277,970	925,820	572,010	383,568	273,386	203,911
France	1,368,130	737,715	464,855	321,653	235,825	898,657	464,533	277,847	181,362	124,539
Germany	58,777	38,397	26,546	19,305	14,655	58,777	38,397	26,546	19,305	14,655
Ireland	444,344	271,776	182,158	131,596	100,818	444,344	271,776	182,158	131,596	100,818
Netherlands	259,073	192,535	149,984	121,255	100,904	213,280	150,798	111,666	85,850	68,004
United States	169,572	89,698	51,373	30,603	18,222	111,879	59,733	33,482	18,708	9,648
Total Probable	3,793,335	2,308,436	1,560,733	1,131,370	860,973	2,784,116	1,666,540	1,103,756	782,804	582,461
Proved Plus Probable [2] [3]										
Australia	326,616	390,908	376,475	343,009	308,437	310,442	321,858	295,087	262,422	232,611
Canada	2,802,512	1,926,168	1,416,572	1,095,300	879,540	2,373,889	1,662,206	1,243,105	975,501	793,549
France	3,453,053	2,197,818	1,569,992	1,205,505	970,765	2,601,906	1,668,038	1,191,376	912,332	732,101
Germany	135,075	99,842	77,545	62,771	52,536	135,075	99,842	77,545	62,771	52,536
Ireland	1,089,442	835,438	666,013	551,912	472,109	1,089,442	835,438	666,013	551,912	472,109
Netherlands	392,050	325,774	280,338	247,651	223,073	318,818	257,393	216,107	187,010	165,563
United States	229,098	122,942	70,085	40,725	22,960	171,405	92,977	52,194	28,830	14,386
Total Proved Plus Probable	8,427,846	5,898,890	4,457,020	3,546,873	2,929,420	7,000,977	4,937,752	3,741,427	2,980,778	2,462,855

Notes:

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

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

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

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

(M$)	Revenue	Royalties	Operating Costs	Capital Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Future Income Taxes	Future Net Revenue After Income Taxes
Proved **(2)**								
Australia	1,279,689	-	765,611	164,897	256,483	92,698	(86,385)	179,083
Canada	3,444,744	430,994	956,472	429,587	84,700	1,542,991	94,922	1,448,069
France	3,739,055	286,952	1,054,237	142,825	170,118	2,084,923	381,674	1,703,249
Germany	243,200	34,472	121,828	7,557	3,045	76,298	-	76,298
Ireland	945,039	-	196,807	29,121	74,013	645,098	-	645,098
Netherlands	419,120	20,930	153,011	38,411	73,791	132,977	27,439	105,538
United States	193,175	53,303	33,559	44,764	2,023	59,526	-	59,526
Total Proved	10,264,022	826,651	3,281,525	857,162	664,173	4,634,511	417,650	4,216,861
Proved Plus Probable **(2) (3)**								
Australia	1,660,324	-	901,981	164,950	266,777	326,616	16,174	310,442
Canada	6,173,958	832,588	1,597,976	830,126	110,756	2,802,512	428,623	2,373,889
France	6,025,272	448,246	1,560,955	340,273	222,745	3,453,053	851,147	2,601,906
Germany	408,139	61,573	199,859	7,594	4,038	135,075	-	135,075
Ireland	1,487,330	-	294,754	29,121	74,013	1,089,442	-	1,089,442
Netherlands	908,049	67,612	274,464	87,472	86,451	392,050	73,232	318,818
United States	596,459	162,300	91,475	109,001	4,585	229,098	57,693	171,405
Total Proved Plus Probable	17,259,531	1,572,319	4,921,464	1,568,537	769,365	8,427,846	1,426,869	7,000,977

Notes:

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

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

Future Net Revenue by Product Type Based on Forecast Prices and Costs [1]

	Future Net Revenue Before Income Taxes [2] (Discounted at 10% Per Year)	Unit Value
Proved Developed Producing	**(M$)**	**($/boe)**
Light crude oil & medium crude oil [3]	1,587,327	25.88
Heavy Oil [3]	216	12.36
Conventional Natural gas [4]	733,875	18.69
Shale Gas	2,860	7.26
Coal Bed Methane	1,259	2.62
Total Proved Developed Producing	2,325,537	22.91
Proved Developed Non-Producing		
Light crude oil & medium crude oil [3]	66,158	20.41
Heavy Oil [3]	-	-
Conventional Natural gas [4]	126,536	14.41
Shale Gas	-	-
Coal Bed Methane	867	3.17
Total Proved Developed Non-Producing	193,561	15.74
Proved Undeveloped		
Light crude oil & medium crude oil [3]	259,816	13.92
Heavy Oil [3]	-	-
Conventional Natural gas [4]	116,627	8.44
Shale Gas	-	-
Coal Bed Methane	746	1.44
Total Proved Undeveloped	377,189	11.43
Proved		
Light crude oil & medium crude oil [3]	1,913,301	22.97
Heavy Oil [3]	216	12.42
Conventional Natural gas [4]	977,038	15.81
Shale Gas	2,860	7.28
Coal Bed Methane	2,872	2.26
Total Proved	2,896,287	19.73
Probable		
Light crude oil & medium crude oil [3]	992,703	20.85
Heavy Oil [3]	87	15.91
Conventional Natural gas [4]	565,389	13.80
Shale Gas	691	7.26
Coal Bed Methane	1,863	2.26
Total Probable	1,560,733	19.73
Proved Plus Probable		
Light crude oil & medium crude oil [3]	2,906,004	22.21
Heavy Oil [3]	303	13.30
Conventional Natural gas [4]	1,542,427	15.00
Shale Gas	3,551	7.33
Coal Bed Methane	4,735	2.31
Total Proved Plus Probable	4,457,020	18.87

Notes:

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

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

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

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

Forecast Prices used in Estimates (1)

Year	WTI Cushing Oklahoma ($US/bbl)	Light Crude Oil and & Medium Crude Oil Edmonton Par Price 40° API ($Cdn/bbl)	Light Crude Oil and & Medium Crude Oil Cromer Medium 29.3° API ($Cdn/bbl)	Crude Oil Brent Blend FOB North Sea ($US/bbl)	Conventional Natural Gas Canada AECO Gas Price ($Cdn/MMBtu)	Conventional Natural Gas Europe National Balancing Point (UK) ($US/MMBtu)	Natural Gas Liquids FOB Field Gate ($Cdn/bbl)	Inflation Rate Percent Per Year	Exchange Rate ($US/$Cdn)	Exchange Rate ($CdnEUR)
2015	48.82	57.23	51.91	53.75	2.70	6.55	34.59	1.1	0.783	1.419
Forecast										
2016	44.00	55.86	50.80	45.00	2.76	5.55	30.27	2.0	0.725	1.517
2017	52.00	64.00	59.52	54.00	3.27	5.68	35.76	2.0	0.750	1.467
2018	58.00	68.39	63.60	61.00	3.45	6.10	39.04	2.0	0.775	1.419
2019	64.00	73.75	68.59	67.00	3.63	6.70	42.96	2.0	0.800	1.375
2020	70.00	78.79	73.27	73.00	3.81	7.30	45.85	2.0	0.825	1.333
2021	75.00	82.35	76.59	78.00	3.90	7.80	47.86	2.0	0.850	1.294
2022	80.00	88.24	82.06	83.00	4.10	8.30	51.23	2.0	0.850	1.294
2023	85.00	94.12	87.53	88.00	4.30	8.80	54.59	2.0	0.850	1.294
2024	87.88	96.48	89.73	91.39	4.50	9.14	57.18	2.0	0.850	1.294
Thereafter	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	0.850	1.294

Note:

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

All forecast prices in the tables above are provided by GLJ. For 2015, the price of Vermilion's natural gas in the Netherlands is based on the TTF day-ahead index, as determined on the Title Transfer Facility Virtual Trading Point operated by Dutch TSO Gas Transport Services, plus various fees. GasTerra, a state owned entity purchases all natural gas produced by Vermilion in the Netherlands. The price of Vermilion's natural gas in Germany is based on the TTF month-ahead index, as determined on the Title Transfer Facility Virtual Trading Point operated by Dutch TSO Gas Transport Services, plus various fees. The benchmark price for Australia and France crude oil is Dated Brent. The benchmark price for Canadian crude oil is Edmonton Par and Canadian natural gas is priced against AECO. For the year ended December 31, 2015, the average realized sales prices before hedging were $70.22 per bbl (Australia), $7.79 per Mcf (Netherlands), $7.18 per Mcf (Germany), $63.31 per bbl (France) for Brent-based crude oil, $49.10 per bbl (United States) for WTI, $49.73 per bbl for Canadian-based crude oil and NGLs and $2.78 per Mcf for Canadian natural gas.

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, shale gas, coal bed methane and NGLs reserves as at December 31, 2015 compared to such reserves as at December 31, 2014 based on the forecast price and cost assumptions set forth in note 3.

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

AUSTRALIA	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2]	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
At December 31, 2014	12,534	5,449	17,983	12,534	5,449	17,983	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	500	50	550	500	50	550	-	-	-	-	-	-
Technical Revisions	3,087	(1,799)	1,288	3,087	(1,799)	1,288	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	(2,356)	-	(2,356)	(2,356)	-	(2,356)	-	-	-	-	-	-
At December 31, 2015	13,765	3,700	17,465	13,765	3,700	17,465	-	-	-	-	-	-

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
Proved Probable P+P [1] [2]	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)
At December 31, 2014	-	-	-	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	-	-	-	-	-	-	-
At December 31, 2015	-	-	-	-	-	-	-	-	-	-	-	-

	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2]	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)	(Mboe)
At December 31, 2014	-	-	-	12,534	5,449	17,983
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	500	50	550
Technical Revisions	-	-	-	3,087	(1,799)	1,288
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-	-	-	(2,356)	-	(2,356)
At December 31, 2015	-	-	-	13,765	3,700	17,465

CANADA	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
At December 31, 2014	27,488	14,799	42,287	27,478	14,797	42,275	10	2	12	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	1,245	2,541	3,786	1,245	2,541	3,786	-	-	-	-	-	-
Technical Revisions	(283)	(825)	(1,108)	(295)	(828)	(1,123)	(1)	1	-	13	3	16
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	(9)	(4)	(13)	(9)	(4)	(13)	-	-	-	-	-	-
Economic Factors	(1,970)	(1,720)	(3,690)	(1,970)	(1,720)	(3,690)	-	-	-	-	-	-
Production	(3,481)	-	(3,481)	(3,478)	-	(3,478)	-	-	-	(3)	-	(3)
At December 31, 2015	22,990	14,792	37,782	22,971	14,786	37,757	9	3	12	10	3	13

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
Proved Probable P+P [1] [2] Factors	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)
At December 31, 2014	177,414	141,032	318,446	153,592	130,581	284,173	22,260	10,031	32,291	1,562	420	1,982
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	56,482	22,244	78,726	56,482	22,244	78,726	-	-	-	-	-	-
Technical Revisions	4,325	(7,773)	(3,448)	3,505	(7,828)	(4,323)	-	-	-	820	55	875
Acquisitions	1,933	10,824	12,757	1,933	10,824	12,757	-	-	-	-	-	-
Dispositions	(39)	(8,944)	(8,983)	(39)	(8,944)	(8,983)	-	-	-	-	-	-
Economic Factors	(13,736)	(19,315)	(33,051)	(2,350)	(14,201)	(16,551)	(11,386)	(5,114)	(16,500)	-	-	-
Production	(26,116)	-	(26,116)	(23,012)	-	(23,012)	(2,664)	-	(2,664)	(440)	-	(440)
At December 31, 2015	200,263	138,068	338,331	190,111	132,676	322,787	8,210	4,917	13,127	1,942	475	2,417

	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
At December 31, 2014	13,550	11,331	24,881	70,608	49,635	120,243
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	3,059	2,749	5,808	13,718	8,997	22,715
Technical Revisions	(410)	(2,077)	(2,487)	28	(4,197)	(4,169)
Acquisitions	187	1,538	1,725	509	3,342	3,851
Dispositions	(2)	(193)	(195)	(18)	(1,688)	(1,705)
Economic Factors	(95)	(597)	(692)	(4,354)	(5,536)	(9,891)
Production	(1,494)	-	(1,494)	(9,328)	-	(9,328)
At December 31, 2015	14,795	12,751	27,546	71,162	50,554	121,717

FRANCE	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
At December 31, 2014	35,602	20,288	55,890	35,602	20,288	55,890	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	4,328	2,466	6,794	4,328	2,466	6,794	-	-	-	-	-	-
Technical Revisions	5,268	(1,429)	3,839	5,268	(1,429)	3,839	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	(4,477)	-	(4,477)	(4,477)	-	(4,477)	-	-	-	-	-	-
At December 31, 2015	40,721	21,325	62,046	40,721	21,325	62,046	-	-	-	-	-	-

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
Proved Probable P+P [1] [2] Factors	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)
At December 31, 2014	9,875	2,582	12,457	9,875	2,582	12,457	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	(1,686)	(1,023)	(2,709)	(1,686)	(1,023)	(2,709)	-	-	-	-	-	-
Production	(354)	-	(354)	(354)	-	(354)	-	-	-	-	-	-
At December 31, 2015	7,835	1,559	9,394	7,835	1,559	9,394	-	-	-	-	-	-

	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
At December 31, 2014	-	-	-	37,249	20,719	57,967
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	4,328	2,465	6,794
Technical Revisions	-	-	-	5,268	(1,429)	3,839
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	(281)	(171)	(452)
Production	-	-	-	(4,537)	-	(4,537)
At December 31, 2015	-	-	-	42,027	21,585	63,612

GERMANY	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
At December 31, 2014	-	-	-	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	-	-	-	-	-	-	-
At December 31, 2015	-	-	-	-	-	-	-	-	-	-	-	-

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
Proved Probable P+P [1] [2] Factors	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)
At December 31, 2014	40,258	21,301	61,559	40,258	21,301	61,559	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	2,546	(2,546)	-	2,546	(2,546)	-	-	-	-	-	-	-
Technical Revisions	(5,543)	(756)	(6,299)	(5,543)	(756)	(6,299)	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	(5,761)	-	(5,761)	(5,761)	-	(5,761)	-	-	-	-	-	-
At December 31, 2015	31,500	17,999	49,499	31,500	17,999	49,499	-	-	-	-	-	-

	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
At December 31, 2014	-	-	-	6,710	3,550	10,260
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	424	(424)	-
Technical Revisions	-	-	-	(924)	(126)	(1,050)
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-	-	-	(960)	-	(960)
At December 31, 2015	-	-	-	5,250	3,000	8,250

IRELAND	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
At December 31, 2014	-	-	-	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	-	-	-	-	-	-	-
At December 31, 2015	-	-	-	-	-	-	-	-	-	-	-	-

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
Proved Probable P+P [1] [2] Factors	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)
At December 31, 2014	105,931	38,707	144,638	105,931	38,707	144,638	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	(99)	8,698	8,599	(99)	8,698	8,599	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	(11)	-	(11)	(11)	-	(11)	-	-	-	-	-	-
At December 31, 2015	105,821	47,405	153,226	105,821	47,405	153,226	-	-	-	-	-	-

	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
At December 31, 2014	-	-	-	17,655	6,451	24,106
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	-	-	-
Technical Revisions	-	-	-	(17)	1,450	1,434
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-	-	-	(2)	-	(2)
At December 31, 2015	-	-	-	17,637	7,901	25,538

NETHERLANDS	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
At December 31, 2014	-	-	-	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	-	-	-	-	-	-	-
At December 31, 2015	-	-	-	-	-	-	-	-	-	-	-	-

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
Proved Probable P+P [1] [2] Factors	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)
At December 31, 2014	37,155	47,076	84,231	37,155	47,076	84,231	-	-	-	-	-	-
Discoveries	17,405	2,880	20,285	17,405	2,880	20,285	-	-	-	-	-	-
Extensions & Improved Recovery	5,736	4,366	10,102	5,736	4,366	10,102	-	-	-	-	-	-
Technical Revisions	4,242	(5,634)	(1,392)	4,242	(5,634)	(1,392)	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	(16,339)	-	(16,339)	(16,339)	-	(16,339)	-	-	-	-	-	-
At December 31, 2015	48,199	48,688	96,887	48,199	48,688	96,887	-	-	-	-	-	-

	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
At December 31, 2014	54	103	157	6,247	7,949	14,196
Discoveries	39	7	46	2,940	487	3,427
Extensions & Improved Recovery	7	6	13	963	734	1,697
Technical Revisions	24	(33)	(9)	731	(972)	(241)
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(36)	-	(36)	(2,759)	-	(2,758)
At December 31, 2015	88	83	171	8,122	8,198	16,320

UNITED STATES	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
At December 31, 2014	449	1,338	1,787	449	1,338	1,787	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	1,367	1,324	2,691	1,367	1,324	2,691	-	-	-	-	-	-
Technical Revisions	106	370	476	106	370	476	-	-	-	-	-	-
Acquisitions	196	786	982	196	786	982	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	(84)	-	(84)	(84)	-	(84)	-	-	-	-	-	-
At December 31, 2015	2,034	3,818	5,852	2,034	3,818	5,852	-	-	-	-	-	-

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
Proved Probable P+P [1] [2] Factors	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)
At December 31, 2014	243	1,402	1,645	243	1,402	1,645	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	1,453	1,569	3,022	1,453	1,569	3,022	-	-	-	-	-	-
Technical Revisions	274	507	781	274	507	781	-	-	-	-	-	-
Acquisitions	220	900	1,120	220	900	1,120	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	(18)	-	(18)	(18)	-	(18)	-	-	-	-	-	-
At December 31, 2015	2,170	4,378	6,548	2,170	4,378	6,548	-	-	-	-	-	-

	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
At December 31, 2014	10	58	68	500	1,630	2,129
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	233	250	483	1,842	1,836	3,678
Technical Revisions	72	247	319	223	702	925
Acquisitions	35	143	178	267	1,079	1,346
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(3)	-	(3)	(90)	-	(90)
At December 31, 2015	346	698	1,044	2,742	5,246	7,988

TOTAL COMPANY	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
At December 31, 2014	76,073	41,874	117,947	76,063	41,872	117,935	10	2	12	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	7,440	6,381	13,821	7,440	6,381	13,821	-	-	-	-	-	-
Technical Revisions	8,178	(3,683)	4,496	8,166	(3,686)	4,480	(1)	1	-	13	3	16
Acquisitions	196	786	982	196	786	982	-	-	-	-	-	-
Dispositions	(9)	(4)	(13)	(9)	(4)	(13)	-	-	-	-	-	-
Economic Factors	(1,970)	(1,720)	(3,690)	(1,970)	(1,720)	(3,690)	-	-	-	-	-	-
Production	(10,398)	-	(10,398)	(10,395)	-	(10,395)	-	-	-	(3)	-	(3)
At December 31, 2015	79,510	43,635	123,145	79,491	43,629	123,120	9	3	12	10	3	13

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
Proved Probable P+P [1] [2] Factors	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)
At December 31, 2014	370,876	252,100	622,976	347,054	241,649	588,703	22,260	10,031	32,291	1,562	420	1,982
Discoveries	17,405	2,880	20,285	17,405	2,880	20,285	-	-	-	-	-	-
Extensions & Improved Recovery	66,217	25,633	91,850	66,218	25,633	91,851	-	-	-	-	-	-
Technical Revisions	3,199	(4,958)	(1,760)	2,379	(5,013)	(2,635)	-	-	-	820	55	875
Acquisitions	2,153	11,724	13,877	2,153	11,724	13,877	-	-	-	-	-	-
Dispositions	(39)	(8,944)	(8,983)	(39)	(8,944)	(8,983)	-	-	-	-	-	-
Economic Factors	(15,422)	(20,338)	(35,760)	(4,036)	(15,224)	(19,260)	(11,386)	(5,114)	(16,500)	-	-	-
Production	(48,599)	-	(48,599)	(45,495)	-	(45,495)	(2,664)	-	(2,664)	(440)	-	(440)
At December 31, 2015	395,788	258,097	653,885	385,637	252,705	638,342	8,210	4,917	13,127	1,942	475	2,417

	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
At December 31, 2014	13,614	11,492	25,106	151,503	95,383	246,884
Discoveries	39	7	46	2,940	487	3,427
Extensions & Improved Recovery	3,299	3,005	6,304	21,775	13,659	35,433
Technical Revisions	(315)	(1,863)	(2,178)	8,397	(6,372)	2,026
Acquisitions	222	1,681	1,903	776	4,421	5,197
Dispositions	(2)	(193)	(195)	(18)	(1,688)	(1,705)
Economic Factors	(95)	(597)	(692)	(4,635)	(5,707)	(10,342)
Production	(1,533)	-	(1,533)	(20,032)	-	(20,031)
At December 31, 2015	15,229	13,532	28,761	160,706	100,184	260,889

Notes:

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

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

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

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

(5) “Coal Bed Methane” and “Shale Gas” were considered “Unconventional Natural Gas” in previous years. NI 51-5101 no longer differentiates between conventional and unconventional activities.

Undeveloped Reserves

Proved undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. These reserves have a 90% probability of being recovered. Vermilion's current plan is to develop these reserves in the following three years. The pace of development of these reserves is influenced by many factors, including but not limited to, the outcomes of yearly drilling and reservoir evaluations, changes in commodity pricing, changes in capital allocations, changing technical conditions, regulatory changes and impact of future acquisitions and dispositions. As new information becomes available these reserves are reviewed and development plans are revised accordingly.

Probable undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. These reserves have a 50% probability of being recovered. Vermilion's current plan is to develop these reserves over the next five years. In general, development of these reserves requires additional evaluation data to increase the probability of success to an acceptable level for Vermilion. This increases the timeline for the development of these reserves. This timetable may be altered depending on outside market forces, changes in capital allocations and impact of future acquisitions and dispositions.

Timing of Initial Undeveloped Reserves Assignment

Undeveloped Reserves Attributed in Current Year

	Light Crude Oil & Medium Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Coal Bed Methane (MMcf)		Natural Gas Liquids (Mbbl)		Total Oil Equivalent (Mboe)	
	First Attributed [1]	Booked	First Attributed [1]	Booked	First Attributed [1]	Booked	First Attributed [1]	Booked	First Attributed [1]	Booked
Proved										
Prior to 2012	7,992	14,715	12,700	222,055	4,943	24,409	424	1,494	11,357	57,287
2012	3,378	9,062	10,998	121,962	-	10,939	415	1,051	5,626	32,263
2013	4,293	13,007	38,720	167,927	8,191	12,389	3,543	4,734	15,655	47,793
2014	5,614	15,434	26,111	170,763	-	11,610	2,175	7,942	12,140	53,772
2015	4,182	15,989	30,963	78,022	333	3,367	2,500	7,287	11,898	36,842
Probable										
Prior to 2012	12,013	28,151	19,297	85,983	2,435	13,827	622	1,868	16,257	46,655
2012	3,910	17,536	8,714	75,358	-	8,340	360	1,276	5,723	32,762
2013	7,967	17,797	53,927	115,066	5,338	7,085	3,742	4,640	21,587	42,795
2014	6,541	22,050	60,779	163,645	-	6,741	3,762	9,615	20,432	60,063
2015	6,118	25,126	50,125	122,802	57	2,949	5,708	10,965	20,190	57,050

Note:

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

Future Development Costs [(1)]

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

(M$)	Total Proved Estimated Using Forecast Prices and Costs	Total Proved Plus Probable Estimated Using Forecast Prices and Costs
Australia		
2016	52,820	52,820
2017	6,701	6,701
2018	51,052	51,052
2019	2,993	2,993
2020	3,052	3,052
Remainder	48,279	48,332
Total for all years undiscounted	164,897	164,950
Canada		
2016	120,559	152,322
2017	98,902	170,944
2018	89,432	189,394
2019	45,342	136,985
2020	51,326	127,236
Remainder	24,026	53,245
Total for all years undiscounted	429,587	830,126
France		
2016	47,099	79,711
2017	41,380	77,270
2018	12,751	76,088
2019	7,300	49,803
2020	15,570	24,985
Remainder	18,725	32,416
Total for all years undiscounted	142,825	340,273
Germany		
2016	210	210
2017	159	159
2018	141	141
2019	6,936	6,936
2020	110	147
Remainder	1	1
Total for all years undiscounted	7,557	7,594
Ireland		
2016	8,862	8,862
2017	1,321	1,321
2018	-	-
2019	1,826	1,826
2020	-	-
Remainder	17,112	17,112
Total for all years undiscounted	29,121	29,121
Netherlands		
2016	1,487	5,150
2017	28,416	48,788
2018	1,076	15,274
2019	424	11,254
2020	433	433
Remainder	6,575	6,573
Total for all years undiscounted	38,411	87,472

United States		
2016	11,034	30,362
2017	24,333	37,820
2018	9,397	40,819
2019	-	-
2020	-	-
Remainder	-	-
Total for all years undiscounted	44,764	109,001
Total Company		
2016	242,071	329,437
2017	201,212	343,003
2018	163,849	372,768
2019	64,821	209,797
2020	70,491	155,853
Remainder	114,718	157,679
Total for all years undiscounted	857,162	1,568,537

Note:

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

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

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

The following table sets forth the number of wells in which Vermilion held a working interest as at December 31, 2015:

	Oil				Gas			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross Wells (3)	Net Wells (4)	Gross Wells (3)	Net Wells (4)	Gross Wells (3)	Net Wells (4)	Gross Wells (3)	Net Wells (4)
Canada								
Alberta	480	328	154	93	654	464	270	189
Saskatchewan	146	125	17	16	-	-	-	-
Total Canada	626	453	171	109	654	464	270	189
Australia	18	18	-	-	-	-	-	-
France	345	339	79	78	3	3	-	-
Germany	-	-	-	-	15	4	-	-
Ireland	-	-	-	-	5	1	1	-
Netherlands	-	-	-	-	52	35	16	13
United States	5	4	1	1	-	-	-	-
Total Vermilion	994	814	251	188	729	507	287	202

Notes:

(1) Well counts are based on wellbores.

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

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

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

Costs Incurred

The following table summarizes the capital expenditures made by Vermilion on oil and gas properties for the year ended December 31, 2015:

	Acquisition Costs				
(M$)	Proved Properties	Unproved Properties	Exploration Costs	Development Costs	Total Costs
Australia	-	-	-	61,741	61,741
Canada	14,650	-	-	201,508	216,158
France	317	-	-	92,265	92,582
Germany	-	-	-	5,363	5,363
Hungary	-	-	1,166	-	1,166
Ireland	-	-	-	66,409	66,409
Netherlands	-	-	-	47,325	47,325
United States	12,764	-	-	12,250	25,014
Total	27,731	-	1,166	486,861	515,758

Acreage

The following table summarizes the acreage for the year ended December 31, 2015:

	Developed [1]		Undeveloped		Total	Total
	Gross [2]	Net [3]	Gross [2]	Net [3]	Gross [2]	Net
Australia	20,164	20,164	39,389	39,389	59,553	59,553
Canada	460,398	326,531	609,129	537,044	1,069,527	863,575
France	218,110	208,858	374,598	374,598	592,708	583,456
Germany	31,363	7,841	285,329	153,378	316,692	161,219
Hungary	-	-	322,142	322,142	322,142	322,142
Ireland	7,200	1,300	-	-	7,200	1,300
Netherlands	80,246	48,121	1,412,224	766,456	1,492,470	814,577
United States	2,408	2,070	100,421	88,672	102,829	90,742
Total	819,889	614,885	3,143,232	2,281,679	3,963,121	2,896,564

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.

Exploration and Development Activities

The following table sets forth the number of development and exploration wells which Vermilion completed during its 2015 financial year:

	Exploration Wells		Development Wells	
	Gross [1]	Net [2]	Gross [1]	Net [2]
Australia				
Oil	-	-	1.0	1.0
Gas	-	-	-	-
Standing	-	-	-	-
Dry Holes	-	-	-	-
Total Completed	-	-	1.0	1.0
Canada				
Oil	-	-	14.0	7.5
Gas	-	-	28.0	18.5
Standing	-	-	-	-
Dry Holes	-	-	-	-
Total Completed	-	-	42.0	26.0
France				
Oil	-	-	3.0	3.0
Gas	-	-	-	-
Service	-	-	1.0	1.0
Standing	-	-	-	-
Dry Holes	-	-	-	-
Total Completed	-	-	4.0	4.0
Germany				
Oil	-	-	-	-
Gas	-	-	1.0	0.3
Standing	-	-	-	-
Dry Holes	-	-	-	-
Total Completed	-	-	1.0	0.3
Ireland				
Oil	-	-	-	-
Gas	-	-	-	-
Standing	-	-	-	-
Dry Holes	-	-	-	-
Total Completed	-	-	-	-
Netherlands				
Oil	-	-	-	-
Gas	-	-	2.0	1.9
Standing	-	-	-	-
Dry Holes	-	-	-	-
Total Completed	-	-	2.0	1.9
United States				
Oil	-	-	3.0	3.0
Gas	-	-	-	-
Standing	-	-	-	-
Dry Holes	-	-	-	-
Total Completed	-	-	3.0	3.0
Total Company				
Oil	-	-	21.0	14.5
Gas	-	-	31.0	20.6
Service	-	-	1.0	1.0
Standing	-	-	-	-
Dry Holes	-	-	-	-
Total Completed	-	-	53.0	36.1

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.

In December 2014, Vermilion had initially announced a $525 million 2015 capital program with activities planned in Australia, Canada, France, Ireland, the Netherlands, Germany and the United States. Subsequently in February 2015, Vermilion announced a reduction in budgeted 2015 capital expenditures to $415 million. That reduction reflected lower planned activity levels, including the deferral of our Australian drilling program. In August 2015, Vermilion announced an increase in our capital expenditure guidance of $70 million to $485 million following the reinstatement of the Australian drilling program as well as additional funding for projects in Canada, France and Ireland.

Properties with No Attributed Reserves

The following table sets out Vermilion's properties with no attributed reserves as at December 31, 2015:

	Properties with No Attributed Reserves	
Country	**Gross Acres (1)**	**Net Acres**
Australia	39,389	39,389
Canada	348,900	307,612
France	374,598	374,598
Germany	285,329	153,378
Hungary	322,142	322,142
Ireland	-	-
Netherlands	1,412,224	766,456
United States	92,768	81,914
Total	2,875,350	2,045,489

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 72,500 (72,500 net) acres in Canada, 1,400 (1,400 net) acres in the United States, and 38,000 (38,000 net) acres in France to expire within one year, unless the Company initiates the capital activity necessary to retain the rights. Work commitments on these lands are categorized as seismic acquisition, geophysical studies or well commitments. No such rights are expected to expire within one year for Australia, Germany, Hungary, Ireland and the Netherlands. Vermilion currently has no material work commitments in Australia, Canada and the United States. Vermilion's work commitments with respect to its European lands held are estimated to be $2.2 million in the next year.

Vermilion's properties with no attributed reserves do not have any significant abandonment and reclamation costs in any country other than Canada, which has a net estimated cost of $14.9 million. All properties with no attributed reserves do not have high expected development or operating costs or contractual sales obligations to produce and sell at substantially lower prices than could be realized.

Tax Information

Vermilion pays current taxes in France, the Netherlands and Australia. Corporate income taxes in France and the Netherlands apply to taxable income after eligible deductions. In France, taxable income is taxed at 34.4%. In 2012, the France government enacted a new 3% tax on dividend distributions made by entities subject to corporate income tax in France. The tax applies to any dividends paid on or after April 17, 2012 and is not recovered by any tax treaties or deductible for French corporate income tax purposes. Vermilion did not pay any dividends from its French entities in 2015. In the Netherlands, taxable income is taxed at a rate of approximately 46%. As a function of the impact of Vermilion's tax pools, the Company does not presently pay current taxes in Canada, Ireland and the United States. The Canadian segment includes holding companies that pay current taxes in foreign jurisdictions.

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

The following table sets forth Vermilion's tax pools as at December 31, 2015:

(M$)	Oil and Gas Assets	Tax Losses (1)	Other	Total
Australia	265,743 (2)	-	-	265,743
Canada	1,176,574 (2)	341,445	2,448	1,520,467
France	430,735 (3)	14,171	-	444,906
Germany	112,038 (4)	43,360	18,977	174,375
Ireland	1,028,986 (1)	429,987	-	1,458,973
Netherlands	54,104 (4)	-	-	54,104
United States	28,950 (2)	15,767	-	44,717
Total	3,097,130	844,730	21,425	3,963,285

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) Deduction for current development expenditures and tax losses at 100% against taxable income

Production Estimates

The following table sets forth the volume of production estimated for the year ended December 31, 2016 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)	Conventional 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	6,403	-	-	-	-	-	-	6,403
Proved Plus Probable	7,213	-	-	-	-	-	-	7,213
Canada								
Proved	8,143	7	6	80,933	940	2,458	5,773	27,983
Proved Plus Probable	8,947	7	7	89,579	1,016	2,665	6,462	30,966
France								
Proved	11,788	-	-	1,433	-	-	-	12,027
Proved Plus Probable	12,877	-	-	1,449	-	-	-	13,119
Germany								
Proved	-	-	-	14,686	-	-	-	2,448
Proved Plus Probable	-	-	-	15,497	-	-	-	2,583
Ireland								
Proved	-	-	-	55,141	-	-	-	9,190
Proved Plus Probable	-	-	-	57,383	-	-	-	9,564
Netherlands								
Proved	-	-	-	47,113	-	-	106	7,958
Proved Plus Probable	-	-	-	54,827	-	-	122	9,260
United States								
Proved	483	-	-	210	-	-	33	551
Proved Plus Probable	917	-	-	438	-	-	70	1,060
Total Proved	26,817	7	6	199,516	940	2,458	5,912	66,560
Total Proved Plus Probable	29,954	7	7	219,173	1,016	2,665	6,654	73,765

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. On December 30, 2015, natural gas began to flow from our Corrib gas project. Light crude oil and medium crude oil average net prices received in the following table also includes immaterial amounts generated by the sale of heavy oil.

	Three Months Ended March 31, 2015	Three Months Ended June 30, 2015	Three Months Ended September 30, 2015	Three Months Ended December 31, 2015
Australia				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	5,672	5,865	6,433	7,824
Conventional Natural Gas (MMcf/d)	-	-	-	-
Natural Gas Liquids (bbl/d)	-	-	-	-
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	83.80	80.87	68.20	58.74
Conventional Natural Gas ($/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 ($/bbl)	25.58	26.02	23.87	17.08
Conventional Natural Gas ($/Mcf)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	58.22	54.85	44.33	41.66
Conventional Natural Gas ($/Mcf)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Canada				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	10,893	10,182	9,195	7,964
Conventional Natural Gas (MMcf/d)	61.78	64.66	71.94	87.90
Natural Gas Liquids (bbl/d)	2,976	3,755	4,513	5,159
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	52.36	67.42	56.59	53.71
Conventional Natural Gas ($/Mcf)	2.97	2.78	2.88	2.57
Natural Gas Liquids ($/bbl)	37.40	36.39	25.52	29.10
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	5.78	5.13	6.81	6.03
Conventional Natural Gas ($/Mcf)	0.23	(0.17)	0.10	0.12
Natural Gas Liquids ($/bbl)	6.21	5.81	0.46	3.78
Transportation				
Light Crude Oil and Medium Crude Oil ($/bbl)	2.26	2.54	2.29	2.16
Conventional Natural Gas ($/Mcf)	0.16	0.18	0.17	0.16
Natural Gas Liquids ($/bbl)	3.04	3.02	2.53	1.86
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	9.34	11.07	12.00	12.56
Conventional Natural Gas ($/Mcf)	1.41	1.39	1.44	1.40
Natural Gas Liquids ($/bbl)	7.87	9.05	10.09	8.53
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	34.98	48.68	35.48	32.95
Conventional Natural Gas ($/Mcf)	1.17	1.38	1.17	0.89
Natural Gas Liquids ($/bbl)	20.28	18.50	12.43	14.93
France				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	11,463	12,746	12,310	12,537
Conventional Natural Gas (MMcf/d)	-	1.03	1.47	1.36
Natural Gas Liquids (bbl/d)	-	-	-	-
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	64.33	72.83	61.75	54.88
Conventional Natural Gas ($/Mcf)	-	1.53	2.93	2.81
Natural Gas Liquids ($/bbl)	-	-	-	-
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	5.48	5.92	6.46	6.23
Conventional Natural Gas ($/Mcf)	-	0.01	0.55	0.32
Natural Gas Liquids ($/bbl)	-	-	-	-

Transportation				
Light Crude Oil and Medium Crude Oil ($/bbl)	3.24	3.15	3.70	3.72
Conventional Natural Gas ($/Mcf)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	11.64	10.72	9.62	13.55
Conventional Natural Gas ($/Mcf)	-	1.16	0.95	1.81
Natural Gas Liquids ($/bbl)	-	-	-	-
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	43.97	53.04	41.97	31.38
Conventional Natural Gas ($/Mcf)	-	0.36	1.43	0.68
Natural Gas Liquids ($/bbl)	-	-	-	-
Germany				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	-	-	-	-
Conventional Natural Gas (MMcf/d)	16.80	16.18	14.00	16.17
Natural Gas Liquids (bbl/d)	-	-	-	-
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	7.53	7.22	7.39	6.61
Natural Gas Liquids ($/bbl)	-	-	-	-
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	1.06	1.52	1.15	0.78
Natural Gas Liquids ($/bbl)	-	-	-	-
Transportation				
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	0.59	0.84	0.49	0.34
Natural Gas Liquids ($/bbl)	-	-	-	-
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	1.32	0.93	2.17	3.22
Natural Gas Liquids ($/bbl)	-	-	-	-
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	4.56	3.93	3.58	2.27
Natural Gas Liquids ($/bbl)	-	-	-	-
Netherlands				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	-	-	-	-
Conventional Natural Gas (MMcf/d)	36.41	32.43	53.56	56.34
Natural Gas Liquids (bbl/d)	63	112	109	110
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	8.09	7.92	8.24	7.09
Natural Gas Liquids ($/bbl)	52.93	53.28	46.65	48.30
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	0.28	0.44	0.13	0.04
Natural Gas Liquids ($/bbl)	-	-	-	-
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	1.78	1.83	1.06	1.21
Natural Gas Liquids ($/bbl)	-	-	-	-
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	6.03	5.65	7.05	5.84
Natural Gas Liquids ($/bbl)	52.93	53.28	46.65	48.30

United States				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	153	123	226	420
Conventional Natural Gas (MMcf/d)	-	-	-	0.20
Natural Gas Liquids (bbl/d)	-	-	-	29
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	48.79	60.57	51.60	47.59
Conventional Natural Gas ($/Mcf)	-	-	-	0.52
Natural Gas Liquids ($/bbl)	-	-	-	5.13
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	14.98	17.08	14.83	13.89
Conventional Natural Gas ($/Mcf)	-	-	-	0.30
Natural Gas Liquids ($/bbl)	-	-	-	3.19
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)	15.61	9.88	6.98	7.02
Conventional Natural Gas ($/Mcf)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	18.20	33.61	29.79	26.68
Conventional Natural Gas ($/Mcf)	-	-	-	0.22
Natural Gas Liquids ($/bbl)	-	-	-	1.94
Total				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	28,181	28,916	28,164	28,745
Conventional Natural Gas (MMcf/d)	115.00	114.29	140.97	162.09
Natural Gas Liquids (bbl/d)	3,039	3,867	4,622	5,298
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	60.86	72.99	61.43	55.61
Conventional Natural Gas ($/Mcf)	5.26	4.86	5.36	4.55
Natural Gas Liquids ($/bbl)	37.72	36.88	26.02	29.36
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	5.09	4.20	5.24	4.43
Conventional Natural Gas ($/Mcf)	0.37	0.25	0.22	0.16
Natural Gas Liquids ($/bbl)	6.08	5.65	0.45	3.70
Transportation Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	2.42	2.14	2.43	2.14
Conventional Natural Gas ($/Mcf)	0.34	0.38	0.27	0.23
Natural Gas Liquids ($/bbl)	2.97	2.93	2.47	1.81
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	12.11	14.70	13.42	14.24
Conventional Natural Gas ($/Mcf)	1.51	1.45	1.36	1.52
Natural Gas Liquids ($/bbl)	7.71	8.79	9.86	8.30
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	41.24	51.95	40.33	34.80
Conventional Natural Gas ($/Mcf)	3.04	2.78	3.51	2.64
Natural Gas Liquids ($/bbl)	20.96	19.51	13.24	15.55

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.

The following tables summarize Vermilion's outstanding risk management positions as at December 31, 2015:

	Note	Volume	Strike Price(s)
Crude Oil			
WTI - Collar			
July 2015 - March 2016	1	250 bbl/d	75.00 - 83.45 CAD $
July 2015 - June 2016	2	500 bbl/d	75.50 - 85.08 CAD $
Dated Brent - Collar			
July 2015 - June 2016	3	1,000 bbl/d	80.50 - 93.49 CAD $
July 2015 - June 2016	4	500 bbl/d	64.50 - 75.48 US $
October 2015 - June 2016	5	250 bbl/d	82.00 - 94.55 CAD $
January 2016 - June 2016	1	250 bbl/d	84.00 - 93.70 CAD $
North American Natural Gas			
AECO - Collar			
November 2015 - March 2016		2,500 GJ/d	2.50 - 3.76 CAD $
November 2015 - October 2016		10,000 GJ/d	2.56 - 3.23 CAD $
January 2016 - December 2016		10,000 GJ/d	2.53 - 3.29 CAD $
April 2016 - October 2016		5,000 GJ/d	2.30 - 2.80 CAD $
AECO Basis - Fixed Price Differential			
November 2015 - March 2016		2,500 mmbtu/d	Nymex HH less 0.47 US $
Nymex HH - Collar			
November 2015 - March 2016	6	5,000 mmbtu/d	3.25 - 3.86 US $

Notes:

(1) The contracted volumes increase to 500 boe/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).

(2) The contracted volumes increase to 1,250 boe/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).

(3) The contracted volumes increase to 2,500 boe/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).

(4) The contracted volumes increase to 1,000 boe/d for any monthly settlement periods above the contracted ceiling price.

(5) The contracted volumes increase to 750 boe/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).

(6) The contracted volumes increase to 10,000 mmbtu/d for any monthly settlement periods above the contracted ceiling price.

	Note	Volume	Strike Price(s)
European Natural Gas			
NBP - Call			
October 2016 - March 2017		2,638 GJ/d	4.64 GBP £
NBP - Collar			
April 2016 - March 2017		2,638 GJ/d	3.79 - 4.53 GBP £
January 2017 - December 2017		2,638 GJ/d	3.22 - 3.75 GBP £
January 2018 - December 2018		2,638 GJ/d	2.99 - 3.63 GBP £
NBP - Put			
April 2016 - September 2016		2,638 GJ/d	3.79 GBP £

NBP - Swap			
July 2015 - March 2016		2,592 GJ/d	6.42 EUR €
October 2015 - March 2016		10,368 GJ/d	6.54 EUR €
January 2016 - June 2016		5,184 GJ/d	6.24 EUR €
January 2016 - June 2016		2,592 GJ/d	6.82 US $
July 2016 - March 2017		2,592 GJ/d	5.43 EUR €
January 2017 - December 2017	1	2,638 GJ/d	4.00 GBP £
January 2018 - December 2018	2	2,638 GJ/d	3.83 GBP £
TTF - Call			
October 2016 - March 2017		2,592 GJ/d	6.03 EUR €
TTF - Collar			
January 2016 - December 2016	3	2,592 GJ/d	5.76 - 6.50 EUR €
April 2016 - December 2016	4	12,960 GJ/d	5.58 - 6.21 EUR €
April 2016 - March 2017	5	5,184 GJ/d	5.28 - 6.35 EUR €
July 2016 - December 2016		2,592 GJ/d	5.00 - 5.63 EUR €
July 2016 - March 2017	3	2,592 GJ/d	5.07 - 6.56 EUR €
July 2016 - March 2018	3	2,592 GJ/d	5.32 - 6.54 EUR €
October 2016 - December 2017		2,592 GJ/d	5.00 - 5.89 EUR €
January 2017 - December 2017	6	7,776 GJ/d	5.00 - 6.15 EUR €
January 2018 - December 2018		5,184 GJ/d	4.17 - 5.03 EUR €
TTF - Put			
April 2016 - September 2016		2,592 GJ/d	5.21 EUR €
TTF - Swap			
January 2015 - March 2016		5,184 GJ/d	6.40 EUR €
January 2015 - June 2016		2,592 GJ/d	6.07 EUR €
February 2015 - March 2016		5,184 GJ/d	6.24 EUR €
April 2015 - March 2016		5,832 GJ/d	6.18 EUR €
October 2015 - March 2016		2,592 GJ/d	6.64 EUR €
January 2016 - June 2016		5,184 GJ/d	5.94 EUR €
April 2016 - December 2016		2,592 GJ/d	5.91 EUR €
July 2016 - June 2018		2,700 GJ/d	5.58 EUR €
October 2016 - December 2016		2,592 GJ/d	5.45 EUR €
January 2017 - December 2017	7	2,592 GJ/d	5.04 EUR €
Electricity			
AESO - Swap			
January 2016 - December 2016		93.6 MWh/d	38.58 CAD $
Interest Rate			
CDOR to fixed - Swap			
September 2015 - September 2019		100,000,000 CAD $/year	1.00 %
October 2015 - October 2019		100,000,000 CAD $/year	1.10 %

Notes:

(1) On the last business day of each month, the counterparty has the option to increase the contracted volumes by an additional 2,638 GJ/d at the contracted price, for the following month.

(2) On the last business day of each month, the counterparty has the option to increase the contracted volumes to 7,913 GJ/d at the contracted price, for the following month.

(3) The contracted volumes increase to 5,184 GJ/d for any monthly settlement periods above the contracted ceiling price.

(4) The contracted volumes increase to 15,552 GJ/d for any monthly settlement periods above the contracted ceiling price.

(5) The contracted volumes increase to 10,368 GJ/d for any monthly settlement periods above the contracted ceiling price.

(6) The contracted volumes increase to 18,144 GJ/d for any monthly settlement periods above the contracted ceiling price.

(7) On the last business day of each month, the counterparty has the option to increase the contracted volumes by an additional 5,184 GJ/d at the contracted price, for the following month.

From time to time Vermilion enters into new risk management positions. Information regarding outstanding risk management positions is available on Vermilion's website at www.vermilionenergy.com/ir/hedging.cfm.

ADDITIONAL INFORMATION RESPECTING VERMILION ENERGY INC.

Management

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 meeting of Shareholders (unless otherwise ceasing to act as a director prior to such meeting). As at February 29, 2016, the directors and officers of Vermilion, as a group, beneficially owned, or controlled or directed, directly or indirectly, 4,150,841 common shares representing approximately 3.7% of the issued and outstanding common shares.

The following table sets forth certain information respecting the current directors and officers of Vermilion. References to Vermilion in the following table for dates prior to the Conversion Arrangement refer to VRL and to the Company following the date of the Conversion Arrangement.

Directors:

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
Claudio A. Ghersinich Calgary, Alberta Canada	(3) (6)	Director	1994	Since 2011, Chairman of ArPetrol Ltd., a public oil and gas company Since 2010, Director of Valeura Energy Inc., a public oil and gas company Since 2005, President of Carrera Investments Corp., a private investment company
Joseph F. Killi Calgary, Alberta Canada	(3) (4)	Director	1999	Since 2011, Director of Network Capital Management Inc., a private investment management company Since 2008, President and Chief Executive Officer and Director of Wilmington Capital Management Inc., a public investment company Since 1993, President of Rosebridge Capital Corp. Inc., a private real estate investment company January 2011 to December 2011, Executive Chairman of Parkbridge Lifestyle Communities Inc., a private real estate company 2005 to 2011, Vice Chairman and Director of Realex Properties Corp., a public real estate company 2004 to 2011, Executive Chairman and Director of Parkbridge Lifestyle Communities Inc., a public real estate company
Loren M. Leiker Houston, Texas USA	(6)	Director	2012	Since 2014, Director of Navitas Midstream Partners LLC Since 2012, Director of SM Energy, a public energy company Since 2012 to 2015, Director of Midstates Petroleum, a public exploration and production company 2008 to 2011, Senior Executive VP Exploration, EOG Resources, a public oil and gas company
Larry J. Macdonald Okotoks, Alberta Canada	(2) (4) (5) (6)	Lead Director	2002	Since March 1, 2016, Lead Director of Vermilion 2012 to March 1, 2016, Chairman of the Board of Vermilion Since 2012, Chairman Northpoint Resources, a private oil and gas company Since 2003, Chairman & Chief Executive Officer and Director of Point Energy Ltd., a private oil and gas company 2006 to 2013, Director of Sure Energy Inc.
William F. Madison Sugar Land, Texas USA	(5) (6)	Director	2004	Since 2011, Director of Montana Tech Foundation, an independent, non-profit organization Since 2007, Director of Canadian Oil Recovery and Remediation Enterprise, Inc., a public oil recovery and remediation company

Timothy R. Marchant Calgary, Alberta Canada	(5) (6)	Director	2010	Since 2015, Director, Valeura Energy Inc., a public oil and gas company Since 2013, Non-Executive Director of Cub Energy Inc., a public oil and gas company Since 2009, Adjunct Professor of Strategy and Energy Geopolitics, Haskayne School of Business 2011 to 2013, Executive Chair of Anatolia Energy Corp., a public oil and gas company
Sarah E. Raiss Calgary, Alberta Canada	(4) (5)	Director	2014	Since 2014, Director, Loblaw Companies Limited, a public food distributor company Since 2011, Director, Commercial Metals Company, a public global, metals recycling, manufacturing, fabricating and trading company 2012 to 2015, Board Chair, Alberta Electric Systems Operator, a not-for-profit entity responsible for the planning and operation of the Alberta Interconnected Electric System 2012 to February 2016, Director, Canadian Oil Sands Limited, a public oil company 2009 to 2014, Director, Shoppers Drug Mart Corporation, a public pharmacy products and services company
Kevin J. Reinhart Calgary, Alberta Canada	(3) (4)	Director	2015	2013 to 2014, President & CEO, Director, Nexen Energy, a CNOOC Limited Company, a public oil and gas company 2012 to 2013, Interim President & CEO, Director, Nexen Inc., a public oil and gas company 2009 to 2012, Executive Vice President & CFO, Nexen Inc., a public oil and gas company 2005 to 2011, Director, Canexus Ltd., a public chemical manufacturing and handling company
Catherine L. Williams Calgary, Alberta Canada	(3) (4)	Director	2015	Since 2015, Director of Enbridge Pipelines Inc., a subsidiary of Enbridge Inc., a public energy transportation company Since 2015, Trustee of Enbridge Commercial Trust, a subsidiary of Enbridge Inc., a public energy transportation company Since 2015, Director of Enbridge Income Partners GP Inc., a subsidiary of Enbridge Inc., a public energy transportation company 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 2009 to 2014, Director, Alberta Investment Management Corporation, an institutional investment fund manager 2009 to 2012, Director, Tim Hortons Inc., a publicly-traded restaurant chain in North America

Committees:

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

Officers:

Name and Municipality of Residence	Office Held	Principal Occupation During the Past Five Years
Anthony (Tony) Marino Calgary, Alberta Canada	President & Chief Executive Officer	Since March 1, 2016, President and Chief Executive Officer March 2014 – March 1, 2016, President and Chief Operating Officer of Vermilion June 2012 – March 2014, Executive Vice President and Chief Operating Officer of Vermilion 2009 to 2012, Director, President & CEO, Baytex Energy Corporation, a public oil and gas company
John D. Donovan Calgary, Alberta Canada	Executive Vice President Business Development	Since 2005, Executive Vice President, Business Development of Vermilion
Curtis W. Hicks Calgary, Alberta Canada	Executive Vice President & Chief Financial Officer	Since 2004, Executive Vice President and Chief Financial Officer of Vermilion
Mona Jasinski Calgary, Alberta Canada	Executive Vice President People & Culture	Since February 2015, Executive Vice President, People and Culture 2011 to 2015, Executive Vice President People of Vermilion 2009 to 2011, Vice President People of Vermilion
Anthony (Dion) Hatcher Calgary, Alberta Canada	Vice President Canada Business Unit	Since March 1, 2016, Vice President Canada Business Unit May 1, 2014 to March 1, 2016, Director Alberta Foothills – Canada Business Unit February 2013 to May 2014, Cardium / LRG Development Manager January 2010 to February 2013 – Cardium Development Manager
Terry Hergott Calgary, Alberta Canada	Vice President Marketing	Since April 2012, Vice President, Marketing of Vermilion 1998 to 2012, Canadian Supply and Trading Manager, Marathon Petroleum Corp.
Michael Kaluza Calgary, Alberta Canada	Executive Vice President & Chief Operating Officer	Since March 1, 2016, Executive Vice President and Chief Operating Officer May 2014 – March 1, 2016, Vice President, Canada Business Unit of Vermilion 2013 to 2014, Director Canadian Business Unit of Vermilion 2012 to 2013, Vice President, Corporate Development and Planning, Baytex Energy Corporation, a public oil and gas company 2011 to 2012, Vice President, Planning, Baytex Energy Corporation, a public oil and gas company 2006 to 2011, Chief Operating Officer, Delphi Energy Corp., a public oil and gas company
Gerard Schut Den Haag The Netherlands	Vice President European Operations	Since July 2012, Vice President European Operations of Vermilion August 2006 to May 2012, General Manager, Chevron Exploration and Production Netherlands, a subsidiary of Chevron Corporation, a public oil and gas company
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 1999 to 2011, partner with Macleod Dixon LLP, a law firm

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.

Cash Dividends

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

Record of Cash Dividends

The following table sets forth the amount of cash distributions per Unit for the specified periods declared by the Trust since the completion of the 2003 Arrangement on January 22, 2003 and the cash dividends per common share for the specified periods declared by the Company since the completion of the Conversion Arrangement on September 1, 2010. Dividends are generally paid on the 15th day of the month following the month of declaration. Until the December 14, 2007 distribution announcement, Vermilion had paid distributions of $0.17 per Trust Unit per month. From the January 15, 2008 payment date and onwards, Vermilion paid distributions of $0.19 per Trust Unit and dividends of $0.19 per common share, in each case per month (as applicable). In January 2013, Vermilion increased its dividend to $0.20 per common share effective for the January 2013 dividend paid on February 15, 2013. In November 2013, Vermilion announced that its board had approved a 7.5% increase in the monthly dividend to $0.215 per common share per month effective for the January 2014 dividend paid on February 18, 2014. The monthly dividend was maintained at $0.215 per common share per month throughout 2015.

Period	Distribution Amount for Period per Trust Unit
As Vermilion Energy Trust	
2003 – January 22 to December 31	$1.87
2004 – January to December	$2.04
2005 – January to December	$2.04
2006 – January to December	$2.04
2007 – January to December	$2.06
2008 – January to December	$2.28
2009 – January to December	$2.28
2010 – January to September [(1)]	$1.71
Period	**Dividend Amount for Period per Common Share**
As Vermilion Energy Inc.	
2010 – September to December [(1)]	$0.57
2011 – January to December	$2.28
2012 – January to December	$2.28
2013 – January to December	$2.40
2014 – January to December	$2.57
2015 – January to December	$2.58
2016 – January to February	$0.43
Total cash dividends since January 22, 2003	$29.43

Note:

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

Premium Dividend™ and Dividend Reinvestment Plan

Under the Premium Dividend™ and Dividend Reinvestment Plan (the “Plan”), Eligible Shareholders who elect to participate in the Dividend Reinvestment Component can continue to reinvest their dividends in common shares at an effective 3% discount to the Average Market Price (with no broker commissions or trading costs), similar to our previous Dividend Reinvestment Plan (Vermilion’s Amended and Restated Dividend Reinvestment Plan dated effective September 1, 2010 as amended effective February 27, 2014 (the “Previous DRIP”).

With the addition of the Premium Dividend™ Component, Eligible Shareholders will also have the option to reinvest their dividends in common shares which will be exchanged for a premium cash payment equal to 101.5% of the reinvested dividends. Under the Premium Dividend™ Component, shares will be issued at a 3.5% discount to the Average Market Price. The shares will be presold at prevailing market prices by the Plan Broker (Canaccord Genuity Corporation), who will then provide participating Shareholders with a premium cash payment equal to 101.5% of their dividends, while the Plan Broker retains the balance of the discount as its fee.

Eligible Shareholders are not required to participate in the Plan. Eligible Shareholders who have not elected to participate in the Plan will continue to receive their regular cash dividends in the usual manner.

The total cost of equity issuance to Vermilion under the Dividend Reinvestment Component and the Premium Dividend™ Component of the Plan will be 3% and 3.5%, respectively. The Premium Dividend™ Component, when combined with the Dividend Reinvestment Component, is expected to increase our access to the lowest cost sources of equity capital available. While the Premium Dividend™ is expected to result in a modest amount of equity issuance (estimated to be less than 2% of shares outstanding in 2015), we believe it represents the most prudent approach to preserving near-term balance sheet strength. We expect the Premium Dividend™ to reduce cash dividends by approximately $89 million during 2016. We view implementation of a Premium Dividend™ as a short term measure to maintain our financial strength. Both components of our program can be suspended or prorated at the company's discretion, offering considerable flexibility. We will actively monitor our ongoing needs and manage our continued use of each component as circumstances dictate.

The amended Dividend Record Dates are published and available on Vermilion's website at www.vermilionenergy.com (under the heading "Investor Relations" subheading "Dividends") and will be included in the applicable news release announcing the approval and declaration of any future dividend payments by Vermilion's Board of Directors.

Each component of 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. Only Canadian-resident Shareholders may participate in the Premium Dividend™ Component of the Plan. The Dividend Reinvestment Component of 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 either component of the Plan. This is 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. We will continue to monitor the relative cost-benefit of such a registration as we go forward.

In order to participate in either the Premium Dividend™ Component or the Dividend Reinvestment Component, an Eligible Shareholder must enroll, or be deemed to have enrolled (in the case of the Dividend Reinvestment Component), in the Plan at least five business days prior to the relevant Dividend Record Date directly (in the case of registered Shareholders) or indirectly through the broker, investment dealer, financial institution or other nominee who holds common shares on the Eligible Shareholder's behalf.

A registered Eligible Shareholder who was enrolled in the Previous DRIP will automatically be deemed to be a participant in the Dividend Reinvestment Component of the Plan, without any further action on their part. A beneficial owner of common shares (i.e., a holder of common shares that are not registered in the beneficial owner's name but are instead held through a broker, investment dealer, financial institution or other nominee) who was validly enrolled, through the nominee holder, in the Previous DRIP should contact such nominee holder to confirm continued participation in the Dividend Reinvestment Component of the Plan.

For more information on the Plan, defined meanings for capitalized terms above, eligibility restrictions and enrollment information among other details of the Plan, please refer to the complete copy of the Plan as well as a related series of Questions and Answers available on Vermilion's website at www.vermilionenergy.com (under the heading "Investor Relations" subheading "DRIP").

Eligible Shareholders may, after electing to participate in the Plan, terminate their participation by written notice to the Plan Agent. That notice, if received by the Plan Agent no later than five (5) business days prior to a Dividend Record Date, will have effect for the dividend to be made on the following Dividend Payment Date. Thereafter, dividends to those Shareholders will be in cash. The Company may amend, suspend or terminate the Plan at any time upon not less than 30 days prior written notice (sent by mail to Plan participants at the most recent address), provided that any amendment to the Plan must be approved by the TSX and no amendment, modification or suspension shall have retroactive effect if it would prejudice the interests of the participants. The Company is not required to issue common shares into any jurisdiction where the issuance would be contrary to applicable laws.

™ denotes trademark of Canaccord Genuity Capital Corporation.

Shareholder Rights Plan

A unitholder Rights Plan was first implemented in 2003 in conjunction with the 2003 Arrangement. At each of the annual and special meetings of holders of Trust Units held in 2006 and 2009, the unitholders Rights Plan was renewed and approved by holders of the Trust Units. In conjunction with the Conversion Arrangement, the Rights Plan for the Company was approved. In 2013, Shareholders approved the amendment and restatement of the Rights Plan and ratified the continuation of the Shareholder Rights Plan Agreement for another three years. The objectives of the Rights Plan are to ensure, to the extent possible, that all Shareholders are treated equally and fairly in connection with any takeover bid for the Company. Takeover bids may be structured to be coercive or may be initiated at a time when the board of directors of Vermilion will have a difficult time preparing an adequate response to the offer. Accordingly, such offers do not always result in Shareholders receiving equal or fair treatment or full or maximum value for their investment. Under current Canadian securities legislation, a takeover bid is required to remain open for 35 days, a period of time which may be insufficient for the directors to:

(a) evaluate a takeover bid (particularly if it includes share or trust unit consideration);

(b) explore, develop and pursue alternatives which are superior to the takeover bid and which could maximize Shareholder value; and

(c) make reasoned recommendations to the Shareholders.

The Rights Plan discourages discriminatory, coercive or unfair takeovers of the Company and gives the board of directors of Vermilion time if, in the circumstances, the board of directors determines it is appropriate to take such time, to pursue alternatives to maximize Shareholder value in the event an unsolicited takeover bid is made for all or a portion of the outstanding common shares of the Company. As set forth in detail below, the Rights Plan discourages coercive hostile takeover bids by creating the potential that any common shares which may be acquired or held by such a bidder will be significantly diluted. The potential for significant dilution to the holdings of such a bidder can occur as the Rights Plan provides that all holders of common shares who are not related to the bidder will be entitled to exercise rights issued to them under the Rights Plan and to acquire common shares at a substantial discount to prevailing market prices. The bidder or the persons related to the bidder will not be entitled to exercise any Rights under the Rights Plan. Accordingly, the Rights Plan will encourage potential bidders to make takeover bids by means of a Permitted Bid (as defined below) or to approach the board of directors of Vermilion to negotiate a mutually acceptable transaction. The Permitted Bid provisions of the Rights Plan are designed to ensure that, in any takeover bid for outstanding common shares of the Company, all Shareholders are treated equally and are given adequate time to properly assess such takeover bid on a fully-informed basis.

The Rights Plan was not proposed in response to, or in anticipation of, any pending, threatened or proposed acquisition or takeover bid. The board of directors did not adopt the Rights Plan to prevent a takeover of the Company, to secure the continuance of management or the directors of the Company in their respective offices or to deter fair offers for the common shares of the Company.

Summary of the Plan

The following summary of terms of the Rights Plan is qualified in its entirety by reference to the text of the Shareholder Rights Plan Agreement. A copy of the Shareholder Rights Plan Agreement is available on SEDAR at www.sedar.com.

Term

The Rights Plan will remain in effect until termination of the annual meeting of Shareholders of the Company in 2016 unless the continuation of the Shareholder Rights Plan Agreement for another three years is ratified by resolution of Shareholders.

As of the date of this annual information form Vermilion is evaluating amendments announced February 25, 2016 to the Canadian regime governing the conduct of take-over bids and the impact on the Rights Plan. Provided all necessary approvals are obtained, the Canadian Securities Administrators expect the take-over bid regime amendments will come into force on May 9, 2016. Further information with respect to the Rights Plan will be set forth in the management proxy circular of the Company for the annual meeting of Shareholders to be held on May 6, 2016, including any recommendations for the continuation (or continuation and amendment) of the Rights Plan beyond the termination of the annual meeting of Shareholders in May, 2016. Vermilion expects the 2016 annual meeting management proxy circular will be mailed and filed on the Company's SEDAR (www.sedar.com) profile by mid-April, 2016.

Issue of Rights

One right (a "Right") has been issued by the Company pursuant to the Shareholder Rights Plan Agreement in respect of each common share of the Company outstanding at the close of business on September 1, 2010 (the "Record Time"). One Right will also be issued for each additional common share issued after the Record Time and prior to the earlier of the Separation Time (as defined below) or the date that a majority of the Shareholders vote against the continued existence of the Shareholder Rights Plan Agreement.

Rights Exercise Privilege

The Rights will separate from the voting common shares to which they are attached and become exercisable at the time (the "Separation Time") which is 10 trading days following the date a person becomes an Acquiring Person (as defined below) or announces an intention to make a takeover bid that is not an acquisition pursuant to a takeover bid permitted by the Rights Plan (a "Permitted Bid").

Any transaction or event in which a person (an "Acquiring Person"), including associates and affiliates and others acting in concert, acquires (other than pursuant to an exemption available under the Rights Plan or a Permitted Bid) Beneficial Ownership (as defined in the Rights Plan) of 20% or more of the voting securities of the Company is referred to as a "Flip-in Event". Any Rights held by an Acquiring Person on or after the earlier of the Separation Time or the first date of public announcement by the Company or an Acquiring Person that an Acquiring Person has become such, will become void and the Rights (other than those held by the Acquiring Person) will permit the holder to purchase common shares at a substantial discount to their prevailing market price at the time.

The issuance of the Rights is not dilutive and will not affect reported earnings or cash flow per common share until the Rights separate from the underlying common shares and become exercisable or until the exercise of the Rights. The issuance of the Rights will not change the manner in which Shareholders currently trade their common shares.

Permitted Lock-Up Agreement

A person will not become an Acquiring Person by virtue of having entered into an agreement (a "Permitted Lock-Up Agreement") with a Shareholder whereby the Shareholder agrees to deposit or tender voting common shares to a takeover bid made by such person, provided that the agreement meets certain requirements including:

(a) the terms of the agreement are publicly disclosed and a copy of the agreement is publicly available;

(b) the Shareholder who has agreed to tender voting common shares to the takeover bid (the "Lock-Up Bid") made by the other party to the agreement is permitted to terminate its obligation under the agreement in order to tender voting common shares to another takeover bid or transaction where: (i) the offer price or value of the consideration payable under the other takeover bid or transaction is greater than the price or value of the consideration per common share at which the Shareholder has agreed to deposit or tender voting common shares to the Lock-Up Bid or is equal to or greater than a specified minimum which is not more than 7% higher than the offer price under the Lock-Up Bid; and (ii) if the number of voting common shares offered to be purchased under the Lock-Up Bid is less than all of the voting common shares held by Shareholders (excluding common shares held by the offeror), the number of voting common shares offered to be purchased under the other takeover bid or transaction (at an offer price not lower than in the Lock-Up Bid) is greater than the number of voting common shares offered to be purchased under the Lock-Up Bid or is equal to or greater than a specified number which is not more than 7% higher than the number of voting common shares offered to be purchased under the Lock-Up Bid; and

(c) no break-up fees or other penalties that exceed in the aggregate the greater of 2.5% of the price or value of the consideration payable under the Lock-Up Bid and 50% of the increase in consideration resulting from another takeover bid or transaction shall be payable by the Shareholder if the Shareholder fails to deposit or tender voting common shares to the Lock-Up Bid.

Certificates and Transferability

Prior to the Separation Time, the Rights will be evidenced by a legend imprinted on certificates for common shares issued from and after the effective date (the "Effective Date") of the Shareholder Rights Plan Agreement (being the later of the date of the Shareholder Rights Plan Agreement and the receipt by the Company of all regulatory approvals with respect to the Shareholder Rights Plan Agreement). Rights are also attached to common shares outstanding on the Effective Date, although certificates issued prior to the Effective Date will not bear such a legend. Shareholders are not required to return their certificates in order to have the benefit of the Rights. Prior to the Separation Time, Rights will trade together with the Company common shares and will not be exercisable or transferable separately from the common shares. From and after the Separation Time, the Rights will become exercisable, will be evidenced by Rights Certificates and will be transferable separately from the common shares.

Permitted Bid Requirements

The requirements of a "Permitted Bid" include the following:

(a) the takeover bid must be made by means of a takeover bid circular;

(b) the takeover bid is made to all holders of voting common shares as registered on the books of the Company, other than the offeror;

(c) the takeover bid contains a provision that no voting common shares will be taken up or paid for pursuant to the takeover bid prior to the close of business on the date that is no earlier than the later of 35 days after the date of the takeover bid and 60 days following the date of the takeover bid and only if at such date more than 50% of the voting common shares held by independent Shareholders shall have been deposited or tendered pursuant to the takeover bid and not withdrawn and have previously been or are taken up at the same time;

(d) the takeover bid contains a provision that unless the takeover bid is withdrawn, voting common shares may be deposited pursuant to such takeover bid at any time during the period of time between the date of the takeover bid and the date on which voting common shares may be taken up and paid for and that any voting common shares deposited pursuant to the takeover bid may be withdrawn until taken up and paid for; and

(e) the takeover bid contains a provision that if, on the date on which voting common shares may be taken up and paid for, more than 50% of the voting common shares held by independent Shareholders have been deposited or tendered pursuant to the takeover bid and not withdrawn, the offeror will make a public announcement of that fact and the takeover bid will be extended to remain open for deposits and tenders of voting common shares for not less than ten business days from the date of such public announcement.

The Rights Plan allows for a competing Permitted Bid (a "Competing Permitted Bid") to be made while a Permitted Bid is in existence. A Competing Permitted Bid must satisfy all of the requirements of a Permitted Bid and include a provision that no voting shares will be taken up or paid for pursuant to the takeover bid prior to the close of business on the date that is earlier than the later of 35 days after the date of the takeover bid constituting the Competing Permitted Bid and 60 days following the date on which the earliest Permitted Bid or Competing Permitted Bid which preceded the Competing Permitted Bid was made.

Waiver and Redemption

If a potential offeror does not desire to make a Permitted Bid, it can negotiate with, and obtain the prior approval of, the board of directors to make a takeover bid by way of a takeover bid circular sent to all holders of voting common shares on terms which the board of directors considers fair to all Shareholders. In such circumstances, the board of directors may waive the application of the Rights Plan thereby allowing such bid to proceed without dilution to the offeror. Any waiver of the application of the Rights Plan in respect of a particular takeover bid shall also constitute a waiver of any other takeover bid which is made by means of a takeover bid circular to all holders of voting common shares while the initial takeover bid is outstanding. The board of directors may also waive the application of the Rights Plan in respect of a particular Flip-in Event that has occurred through inadvertence, provided that the Acquiring Person that inadvertently triggered such Flip-in Event reduces its beneficial holdings to less than 20% of the outstanding voting common shares of the Company within 14 days or such earlier or later date as may be specified by the board. With the prior consent of the holders of voting common shares, the board of directors may, prior to the occurrence of a Flip-in Event that would occur by reason of an acquisition of voting common shares otherwise than pursuant to the foregoing, waive the application of the Rights Plan to such Flip-in Event.

The board of directors may, with the prior consent of the holders of voting common shares, at any time prior to the occurrence of a Flip-in Event, elect to redeem all but not less than all of the then outstanding Rights at a redemption price of $0.00001 per Right. Rights are deemed to be redeemed following completion of a Permitted Bid, a Competing Permitted Bid or a takeover bid in respect of which the board of directors has waived the application of the Rights Plan.

Exemptions for Investment Advisors

Investment advisors (for client accounts), trust companies (acting in their capacity as trustees or administrators), statutory bodies whose business includes the management of funds (for employee benefit plans, pension plans, or insurance plans of various public bodies) and administrators or trustees of registered pension plans or funds acquiring greater than 20% of the voting common shares are exempted from triggering a Flip-in Event, provided they are not making, either alone or jointly or in concert with any other person, a takeover bid.

Board of Directors

The adoption of the Rights Plan does not in any way lessen or affect the duty of the board of directors to act honestly and in good faith with a view to the best interests of the Company. The board of directors, when a takeover bid or similar offer is made, will continue to have the duty and power to take such actions and make such recommendations to Shareholders as are considered appropriate.

Amendment

The Company may, with the prior approval of Shareholders (or the holders of Rights if the Separation Time has occurred), supplement, amend, vary or delete any of the provisions of the Shareholder Rights Plan Agreement. The Company may make amendments to the Shareholder Rights Plan Agreement at any time to correct any clerical or typographical error or, subject to confirmation at the next meeting of Shareholders, make amendments which are required to maintain the validity of the Shareholder Rights Plan Agreement due to changes in any applicable legislation, regulations or rules.

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 "C" 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
Joseph F. Killi (Chair)	Yes	Yes	Mr. Killi holds a Bachelor of Science degree in Biochemistry from Loyola Collage, a Bachelor of Commerce degree from Concordia University and a Chartered Accountant designation. As a Chartered Accountant, Mr. Killi attained experience in preparing, auditing, analyzing and evaluating financial statements including internal controls and procedures for financial reporting. Mr. Killi has an understanding of the accounting principles used by the Company as well as the implications of those accounting principles on the Company's financial results. Mr. Killi has also obtained significant financial experience and exposure to accounting and financial issues in a number of senior positions with Parkbridge Lifestyle Communities Inc., Realex Properties Corp. and Trizec Corporation and in his role as a director and audit committee member of other public and private companies.
Claudio A. Ghersinich	Yes	Yes	Mr. Ghersinich holds a B.Sc. Civil Engineering degree from the University of Manitoba. Mr. Ghersinich has obtained financial experience and exposure to accounting and financial issues in a role as a founder of Vermilion Resources Ltd. in 1994 and as an audit committee member of other public companies.
Kevin J. Reinhart	Yes	Yes	Mr. Reinhart holds a Bachelor of Commerce degree from Saint Mary's University in Halifax. He earned his Chartered Accountant designation in 1985 and is a member of Institute of Chartered Accountants of Alberta. Mr. Reinhart brings 32 years of combined experience in the oil and gas industry and financial services sector, with an extensive background in leadership, strategy and growth, finance, international activities, exploration, sustainability, corporate relations and marketing. In 2012, Mr. Reinhart was named interim President and CEO as well as director of Nexen Inc. Following the sale of Nexen Inc. in 2013, he was promoted to the role of President and CEO (for Nexen Energy, a CNOOC Limited Company), a position he held up until his retirement in 2014. Prior to 2012, Mr. Reinhart had held the roles of Executive Vice President and CFO (2009-2012) and Senior Vice President, Corporate Planning and Business Development (2002-2009). Prior to 2002, Mr. Reinhart served in various capacities as a member of Nexen's executive management team including Controller, Director of Risk Management and Treasurer. From 2005 to 2011, Mr. Reinhart served as a director of Canexus Ltd.
Catherine L. Williams	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 31 years of oil and gas industry experience, with an extensive background in finance, mergers and acquisitions, and business management. Ms. Williams is currently the Owner and Managing Director of Options Canada Ltd. (since 2007) and serves as a Board member of Enbridge Inc. (since 2010) and Chairs their 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).

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, 2015 and 2014, Deloitte LLP, the auditors of the Company, received the following fees from the Company:

Item	2015	2014
Audit fees (1)	$1,560,759	$1,582,647
Audit-related fees (2)	$80,698	$162,000
Tax fees (3)	$55,020	$69,300

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, 2015 and 2014.

(2) Audit-related fees consist of fees for the review of the quarterly financial statements, services provided in connection with statutory and regulatory filings or engagements and fees for review services. Fees also may include services related to review of accounting research and accounting publications.

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

MARKET FOR PRICE RANGE AND TRADING VOLUME OF SECURITIES

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

2015	High	Low	Close	Volume
January	$59.02	$45.66	$55.97	8,638,252
February	$62.80	$53.00	$56.22	8,734,800
March	$56.80	$52.64	$53.25	6,869,845
April	$59.74	$53.14	$58.08	8,647,133
May	$58.27	$52.03	$53.37	5,905,150
June	$56.65	$51.56	$53.95	6,349,618
July	$54.04	$41.61	$44.00	8,331,551
August	$47.91	$37.55	$45.58	8,839,000
September	$45.41	$40.18	$42.97	6,923,709
October	$49.94	$41.26	$46.01	8,341,476
November	$48.83	$38.35	$39.99	9,443,837
December	$40.99	$32.57	$37.61	10,401,924
2016	**High**	**Low**	**Close**	**Volume**
January	$38.18	$29.71	$37.46	10,885,419
February	$37.80	$31.56	$36.80	8,931,986

Awards (entitling the holder thereof to receive common shares) have been issued under the Vermilion Incentive Plan. See the note regarding equity compensation plans in Vermilion's annual financial statements for further details regarding the amount and value of such awards.

CREDIT RATINGS

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

The Senior Unsecured Notes had a rating of BB (low)/Stable trend from DBRS Limited ("DBRS") and BB-/stable outlook from Standard & Poor's Ratings Services, a division of The McGraw-Hill Companies (Canada) Corporation ("S&P"). On February 10, 2016 the Senior Unsecured Notes were fully repaid in accordance with the terms of the indenture and accordingly the ratings have been discontinued as of that date.

DBRS rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". All rating categories other than AAA and D also contain subcategories "(high)" and "(low)". The absence of either a "(high)" or "(low)" designation indicates the rating is in the middle of the category. A rating of "BB" is characterized by DBRS to be speculative, non-investment-grade credit quality. The capacity for the payment of financial obligations is uncertain and vulnerable to future events. The "BB" category is the fifth highest of the ten available categories.

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

Vermilion Rating

DBRS Limited has provided a corporate credit rating of Vermilion of "BB (low") with a stable trend. A rating of "BB" is characterized by DBRS Limited to be speculative, non-investment-grade credit quality. The capacity for the payment of financial obligations is uncertain and vulnerable to future events.

S&P has assigned a corporate credit rating of Vermilion of "BB-" with a stable outlook. 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. The plus (+) or minus (-) modifiers indicate the relative standing within the assigned category. 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).

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.

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, 2015, 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 4, 2016.

MATERIAL CONTRACTS

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

INTERESTS OF EXPERTS

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

TRANSFER AGENT AND REGISTRAR

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

RISK FACTORS

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

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of proved and probable reserves and future net revenues to be derived therefrom, including many factors beyond the Company's control. The reserve and future net revenue information set forth in this annual information form represents estimates only. The reserves and estimated future net cash flow from the Company's properties have been independently evaluated by GLJ with an effective date of December 31, 2015. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of crude oil and natural gas, operating costs, well abandonment and salvage values, royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on prices in use at the date the GLJ Report was prepared, and many of these assumptions are subject to change and are beyond the Company's control. Actual production and cash flow derived therefrom will vary from these evaluations, and such variations could be material.

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

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

The present value of estimated future net revenue referred to in this annual information form should not be construed as the fair market value of estimated crude oil and natural gas reserves attributable to the Company's properties. The estimated discounted future revenue from reserves are based upon price and cost estimates which may vary from actual prices and costs and such variance could be material. Actual future net revenue will also be affected by factors such as the amount and timing of actual production, supply and demand for crude oil and natural gas, curtailments or increases in consumption by purchasers and changes in governmental regulations and taxation.

Uncertainty of Contingent Resource Estimates

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

Volatility of Oil and Natural Gas Prices

The Company's operational results and financial condition are dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated materially during recent years and are determined by supply and demand factors, including weather and general economic conditions as well as conditions in other oil and natural gas regions. Any prolonged decline in oil and natural gas prices could have an adverse effect on Vermilion's cash flow which could have the effect of decreasing dividends.

Changes in Legislation

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

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

The Government of Alberta released its Royalty Review Advisory Panel Report on January 29, 2016 ("RRAP"). The RRAP recommends new rules coming into effect in 2017. These highlights include providing royalty incentives for the efficient development of conventional crude oil, natural gas, and NGL resources, no changes to the royalty structure of wells drilled prior to 2017 for a 10-year period from the royalty program's implementation date, the replacement of royalty credits/holidays on conventional wells by a revenue minus cost framework with a post-payout royalty rate based on commodity prices, the reduction of royalty rates for mature wells, and a neutral internal rate of return for any given play compared to the current royalty framework. The RRAP recommended modernization of Alberta's conventional oil and gas royalty regime, but did not provide detail. The Government of Alberta has accepted the recommendations set out in the RRAP and is expected to adopt those recommendations in spring 2016. It is not anticipated that the new rules will materially impact Vermilion's financial condition; however, the extent and magnitude of any adverse impacts shall be determined once details on the new rules are released.

Government Regulations

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

Competition

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

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

Operational Matters

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

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

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

Environmental Concerns

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

Vermilion expects to incur abandonment and reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2015, expenditures beyond normal compliance with environmental regulations were considered to be in the ordinary course of business. Vermilion does not anticipate material expenditures beyond amounts paid in respect of normal compliance with environmental regulations in 2016.

The Government of Alberta released its Climate Leadership Plan which will impact all consumers and businesses that contribute to carbon emissions in Alberta. This plan includes imposing carbon pricing that is applied across all sectors, starting at $20 per tonne on January 1, 2017 and moving to $30 per tonne on January 1, 2018, the phase-out of coal-fired power generation by 2030, a cap on oil sands emissions production of 100 megatonnes, and a 45 per cent reduction in methane emissions by the oil and gas sector by 2025. Vermilion expects the Climate Leadership Plan to increase the cost of operating its properties located in Alberta and is currently evaluating the expected impact of this plan on its results of operations.

Vermilion was named to the CDP Climate Disclosure Leadership Index (“CDLI”), recognizing the depth and quality of our climate-related disclosure as compared to the 200 largest companies listed on the TSX. CDP (formerly Carbon Disclosure Project), is a global, not-for-profit organization that manages the world’s only global environmental disclosure system. To be named to the CDLI, a company must have a disclosure score within the top 10% of surveyed companies. Vermilion has voluntarily reported to CDP since 2012. We believe that by measuring and understanding our current environmental profile, we can direct our business strategy to operate in an even more environmentally and socially sustainable manner in the future.

Kyoto Protocol

Australia, Canada, France, Ireland, Germany and the Netherlands are signatories to the United Nations Framework Convention on Climate Change and have all ratified the Kyoto Protocol established thereunder. Australia, France, Ireland, Germany and the Netherlands, as Annex B parties to the Kyoto Protocol, and Ireland, France, Germany and Netherlands as members of the European Union, are required to reduce their nation-wide emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases. Canada formally withdrew from the Kyoto Protocol in 2012. The Canadian federal government has indicated an intention to regulate the emissions of greenhouse gases from a range of industries and has stated that it will work with the provinces to develop a portfolio of policies to reduce the greenhouse gas emissions intensity of industrial facilities (the "Federal Plan"). At present, the status of the Federal Plan with respect to the oil and gas industry is unclear. The Canadian federal government has repeatedly stated that it intends to align Canada's greenhouse gas emissions reduction policies with those of the United States. As such, it is unclear when, or in what form, the Federal Plan will be implemented or what impact it may have on Vermilion.

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

Discretionary Nature of Dividends

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

Debt Service

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

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

Changes in Income Tax Laws

Income tax laws and administrative policies may be changed in a manner which adversely affects the Company and/or Shareholders.

Depletion of Reserves

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

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

Net Asset Value

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

Volatility of Market Price of Common Shares

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

Variations in Interest Rates and Foreign Exchange Rates

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

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

Increase in Operating Costs or Decline in Production Level

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

Acquisition Assumptions

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

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

Failure to Realize Anticipated Benefits of Prior Acquisitions

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

Additional Financing

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

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

Potential Conflicts of Interest

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

Accounting Adjustments

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

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

Market Accessibility

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

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

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR at www.sedar.com. 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, 2015.

APPENDIX A
CONTINGENT RESOURCES

Vermilion retained GLJ to conduct an independent resource evaluation to assess contingent resources across all of the Company's key operating regions with an effective date of December 31, 2015 (the "GLJ Resources Assessment"). All contingent resources evaluated in the GLJ Resources Assessment were deemed economic at the effective date of December 31, 2015.

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 contingent resources of 95.1 million boe (low estimate) to 254.7 million boe (high estimate), with a best estimate of 160.7 million boe. Contingent resources are in addition to reserves estimated in the GLJ Report.

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 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.

Summary of Risked Oil and Gas Contingent Resources as at December 31, 2015 **(1) (2)** ***- Forecast Prices and Costs*** **(3) (4)**

Resources	Light Crude Oil & Medium Crude Oil		Conventional Natural Gas		Coal Bed Methane		Natural Gas Liquids		Oil Equivalent			Unrisked Oil Equivalent	
Project Maturity Sub-Class	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Chance of Dev. (%) (9)	Gross (Mbbl)	Net (Mbbl)
Contingent (1C) - Low Estimate													
Development Pending													
Australia(10)	-	-	-	-	-	-	-	-	-	-	-	-	-
Canada(11)	15,733	11,470	216,245	186,486	3,537	3,360	15,457	11,988	67,820	55,099	81.5%	83,218	67,516
France(12)	12,604	11,853	1,020	1,020	-	-	-	-	12,774	12,023	87.8%	14,542	13,687
Germany	-	-	-	-	-	-	-	-	-	-	-	-	-
Ireland(13)	-	-	4,475	4,475	-	-	-	-	746	746	70.0%	1,065	1,065
Netherlands(14)	-	-	215	215	-	-	-	-	36	36	60.0%	60	60
USA(15)	10,099	8,314	11,178	9,202	-	-	1,782	1,467	13,744	11,315	90.0%	15,272	12,571
Total	38,436	31,637	233,133	201,398	3,537	3,360	17,239	13,455	95,120	79,219	83.3%	114,157	94,899
Contingent (2C) - Best Estimate													
Development Pending													
Australia(10)	3,000	3,000	-	-	-	-	-	-	3,000	3,000	80.0%	3,750	3,750
Canada(11)	24,685	17,637	361,733	312,655	6,445	6,009	24,018	18,485	110,066	89,233	79.8%	138,003	111,976
France(12)	25,611	24,007	1,300	1,300	-	-	-	-	25,828	24,224	85.7%	30,138	28,255
Germany	-	-	-	-	-	-	-	-	-	-	-	-	-
Ireland(13)	-	-	6,859	6,859	-	-	-	-	1,143	1,143	70.0%	1,633	1,633
Netherlands(14)	-	-	4,739	4,739	-	-	3	3	793	793	60.0%	1,321	1,321
USA(15)	14,470	11,912	16,449	13,540	-	-	2,622	2,159	19,834	16,328	90.0%	22,038	18,141
Total	67,766	56,556	391,080	339,093	6,445	6,009	26,643	20,647	160,664	134,721	81.6%	196,883	165,076
Contingent (3C) - High Estimate													
Development Pending													
Australia(10)	4,040	4,040	-	-	-	-	-	-	4,040	4,040	80.0%	5,050	5,050
Canada(11)	51,590	36,716	537,685	461,047	8,843	8,270	34,482	25,750	177,160	140,686	78.6%	225,319	179,007
France(12)	41,455	38,784	1,670	1,670	-	-	-	-	41,733	39,062	85.0%	49,114	45,950
Germany	-	-	-	-	-	-	-	-	-	-	-	-	-
Ireland(13)	-	-	10,671	10,671	-	-	-	-	1,779	1,779	70.0%	2,541	2,541
Netherlands(14)	-	-	9,294	9,294	-	-	6	6	1,555	1,555	60.0%	2,592	2,592
USA(15)	20,592	16,951	23,987	19,746	-	-	3,824	3,148	28,414	23,390	90.0%	31,571	25,988
Total	117,677	96,491	583,307	502,428	8,843	8,270	38,312	28,904	254,681	210,512	80.5%	316,187	261,128

Summary of Risked Net Present Value of Future Net Revenues as at December 31, 2015 - Forecast Prices and Costs [3]

Resources Project Maturity Sub-Class	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										
Australia	-	-	-	-	-	-	-	-	-	-
Canada	1,263,475	696,994	404,377	244,496	152,795	917,336	485,559	266,767	150,423	85,918
France	764,172	412,773	234,791	138,408	83,554	500,593	255,152	135,124	72,474	38,285
Germany	-	-	-	-	-	-	-	-	-	-
Ireland	10,759	6,832	3,908	1,827	388	10,759	6,832	3,908	1,827	388
Netherlands	321	288	235	183	139	(111)	(31)	(4)	1	(1)
USA	402,480	183,006	86,860	41,587	19,010	257,913	112,016	47,760	18,068	3,877
Total	2,441,207	1,299,893	730,171	426,501	255,886	1,686,490	859,528	453,555	242,793	128,467
Contingent (2C) -Best Estimate [7]										
Development Pending										
Australia	112,493	76,004	51,782	35,416	24,186	8,804	(933)	(6,457)	(9,465)	(10,961)
Canada	2,320,917	1,231,251	711,661	438,235	283,381	1,690,519	869,129	482,208	282,696	172,627
France	1,596,937	861,198	493,517	295,075	181,775	1,046,955	534,621	286,991	157,949	87,111
Germany	-	-	-	-	-	-	-	-	-	-
Ireland	34,337	24,293	16,560	11,029	7,171	25,752	18,634	12,872	8,618	5,581
Netherlands	17,580	12,005	8,041	5,233	3,236	8,618	5,315	2,916	1,218	28
USA	761,511	347,466	175,611	95,123	53,819	490,733	219,043	105,532	52,935	26,574
Total	4,843,775	2,552,217	1,457,172	880,111	553,568	3,271,381	1,645,809	884,062	493,951	280,960
Contingent (3C) -High Estimate [8]										
Development Pending										
Australia	213,428	151,220	109,414	80,640	60,405	40,896	22,363	11,003	3,988	(347)
Canada	4,528,849	2,254,759	1,249,423	745,486	469,386	3,301,748	1,601,403	857,791	491,549	295,260
France	2,789,003	1,489,072	858,593	521,966	329,664	1,828,488	934,880	512,726	293,550	172,056
Germany	-	-	-	-	-	-	-	-	-	-
Ireland	73,725	48,565	32,219	21,620	14,641	55,100	36,396	24,132	16,127	10,830
Netherlands	54,851	37,676	26,539	19,104	13,995	29,079	19,328	12,926	8,658	5,754
USA	1,306,063	569,626	289,610	162,255	96,886	844,550	363,515	179,660	96,592	54,589
Total	8,965,919	4,550,918	2,565,798	1,551,071	984,977	6,099,861	2,977,885	1,598,238	910,464	538,142

Notes:

(1) The contingent resource assessments were prepared by GLJ in accordance with the definitions, standards and procedures contained in the COGEH and NI 51-101. Contingent resource is defined in the COGEH as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. There is no certainty that it will be commercially viable to produce any portion of the contingent resources or that Vermilion will produce any portion of the volumes currently classified as contingent resources. The estimates of contingent resources involve implied assessment, based on certain estimates and assumptions, that the resources described exists in the quantities predicted or estimated, as at a given date, and that the resources can be profitably produced in the future. The risked net present value of the future net revenue from the contingent resources does not necessarily represent the fair market value of the contingent resources. Actual contingent resources (and any volumes that may be reclassified as reserves) and future production therefrom may be greater than or less than the estimates provided herein.

(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 2015 reserves report were also utilized by GLJ in preparing the contingent resource assessments. See ”GLJ December 31, 2015 Forecast Prices” in Vermilion’s Annual Information Form for the year ended December 31, 2015.

(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 necessarily 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 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 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 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 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.

(10) Contingent resources for Australia have been estimated based on the continued drilling in our active core asset (see “Description of Properties” section of this AIF) using established recovery technologies. The estimated cost to bring these Contingent resources on commercial production is $171 MM and the expected timeline is between two and six years. The specific contingencies for these resources are Corporate Commitment and Development Timing.

(11) Contingent resources for Canada have been estimated based on the continued drilling in our active core assets (see “Description of Properties” section of this AIF) using established recovery technologies. The estimated cost to bring these Contingent resources on commercial production is $1,234 MM and the expected timeline is between one and 10 years. The specific contingencies for these resources are Corporate Commitment and Development Timing.

(12) Contingent resources for France have been estimated based on the continued drilling in our active core assets (see “Description of Properties” section of this AIF) using established recovery technologies. The estimated cost to bring these Contingent resources on commercial production is $542 MM and the expected timeline is between two and 10 years. The specific contingencies for these resources are Corporate Commitment and Development Timing.

(13) Contingent resources for Ireland have been estimated based on the continued drilling in our active core asset (see “Description of Properties” section of this AIF) using established recovery technologies. The estimated cost to bring these Contingent resources on commercial production is $31 MM and the expected timeline is between three and four years. The specific contingencies for these resources are Corporate Commitment and Development Timing.

(14) Contingent resources for Netherlands have been estimated based on the continued drilling in our active core assets (see “Description of Properties” section of this AIF) using established recovery technologies. The estimated cost to bring these Contingent resources on commercial production is $14 MM and the expected timeline is between two and 10 years. The specific contingencies for these resources are Corporate Commitment and Development Timing.

(15) Contingent resources for USA have been estimated based on the continued drilling in our active core asset (see “Description of Properties” section of this AIF) using established recovery technologies. The estimated cost to bring these Contingent resources on commercial production is $278 MM and the expected timeline is between two and 10 years. The specific contingencies for these resources are Corporate Commitment and Development Timing.

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, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2015, 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 2015, 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, 2015	Australia	-	376,474	-	376,474
GLJ Petroleum Consultants	December 31, 2015	Canada	-	1,416,572	-	1,416,572
GLJ Petroleum Consultants	December 31, 2015	France	-	1,569,992	-	1,569,992
GLJ Petroleum Consultants	December 31, 2015	Germany	-	77,544	-	77,544
GLJ Petroleum Consultants	December 31, 2015	Ireland	-	666,013	-	666,013
GLJ Petroleum Consultants	December 31, 2015	Netherlands	-	280,337	-	280,337
GLJ Petroleum Consultants	December 31, 2015	USA	-	70,085	-	70,085
Total			-	4,457,018	-	4,457,018

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

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

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

EXECUTED as to our reports referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 8, 2016

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



APPENDIX B - PART 2
REPORT ON CONTINGENT 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 as at December 31, 2015. The contingent resources data are risked estimates of volume of contingent resources and related risked net present value of future net revenue as at December 31, 2015, estimated using forecast prices and costs.

2. The contingent resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the contingent 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 are free of material misstatement. An evaluation also includes assessing whether the contingent 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 (before deduction of income taxes) attributed to contingent 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 that we have evaluated and reported on to the Company's board of directors:

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, 2015	Australia	3,000	-	51,782	51,782
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2015	Canada	110,076	-	711,661	711,661
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2015	France	25,828	-	493,517	493,517
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2015	Ireland	1,143	-	16,560	16,560
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2015	Netherlands	793	-	8,041	8,041
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2015	USA	19,834	-	175,611	175,611
Total				**160,674**	**-**	**1,457,172**	**1,457,172**

6. In our opinion, the contingent 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 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 are based on judgements regarding future events, actual results will vary and the variations may be material.

EXECUTED as to our reports referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 8, 2016

"*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, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2015, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated the Company's reserves data. The report of the independent qualified reserves evaluators is presented in Schedule A to the Annual Information Form of the Company for the year ended December 31, 2015.

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 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 and other oil and gas information;

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

(c) the content and filing of this report.

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

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

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

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

"Claudio A. Ghersinich"
Claudio A. Ghersinich, Director

March 4, 2016

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.

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

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

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

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

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

III. DUTIES AND RESPONSIBILITIES

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

A. Financial Statements and Other Financial Information

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

i) review and recommend approval of the Company's annual financial statements, MD&A and earnings press release and report to the Board of Directors before the statements are approved by the Board of Directors;
ii) review and recommend approval for release the Company's quarterly financial statements, MD&A and press releases, as well as financial information and earnings guidance provided to analysts and rating agencies;
iii) satisfy itself that adequate procedures are in place for the review of the public disclosure of financial information extracted or derived from the Company's financial statements, other than the public disclosure referred to in items (i) and (ii) above, and periodically assess the adequacy of those procedures; and
iv) review the Annual Information Form and any Prospectus/Private Placement Memorandums.

Review, and where appropriate, discuss:

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

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

B. Risk Management, Internal Control and Information Systems

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

i) review the Company's risk management controls and policies with specific responsibility for Credit & Counterparty, Market & Financial, Political and Strategic & Repatriation risks;

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

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

C. External Audit

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

i) review and recommend to the Board, for Shareholder approval, the appointment of the external auditor;
ii) review and approve the annual external audit plan, including but not limited to the following:
    a) engagement letter between the external auditor and financial management of the Company;
    b) objectives and scope of the external audit work;
    c) procedures for quarterly review of financial statements;
    d) materiality limit;
    e) areas of audit risk;
    f) staffing;
    g) timetable; and
    h) compensation and fees to be paid by the Company to the external auditor.
iii) meet with the external auditor to discuss the Company's quarterly and annual financial statements and the auditor's report including the appropriateness of accounting policies and underlying estimates;
iv) maintain oversight of the external auditor's work and advise the Board, including but not limited to:
    a) the resolution of any disagreements between management and the external auditor regarding financial reporting;
    b) any significant accounting or financial reporting issue;
    c) the auditors' evaluation of the Company's system of internal controls, procedures and documentation;
    d) the post audit or management letter containing any findings or recommendation of the external auditor, including management's response thereto and the subsequent follow-up to any identified internal control weaknesses;
    e) any other matters the external auditor brings to the Committee's attention; and
    f) 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.

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

D. Compliance

The Committee shall:

i) Ensure that the external auditor's fees are disclosed by category in the Annual Information Form in compliance with regulatory requirements;
ii) Disclose any specific policies or procedures adopted for pre-approving non-audit services by the external auditor including affirmation that they meet regulatory requirements;
iii) Assist the Governance and Human Resources Committee with preparing the Company's governance disclosure by ensuring it has current and accurate information on:
    a) the independence of each Committee member relative to regulatory requirements for audit committees;
    b) the state of financial literacy of each Committee member, including the name of any member(s) currently in the process of acquiring financial literacy and when they are expected to attain this status; and
    c) the education and experience of each Committee member relevant to his or her responsibilities as Committee member.
iv) Disclose, if required, if the Company has relied upon any exemptions to the requirements for committees under applicable securities laws and rules of any stock exchange on which the Company's shares are listed for trading.

E. Other

The Committee shall:

i) establish and periodically review procedures for:
    a) the receipt, retention and treatment of complaints received by the Company regarding accounting, internal accounting controls, or auditing matters; and
    b) the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters or other matters that could negatively affect the Company, such as violations of the Code of Business Conduct and Ethics.
ii) review and approve the Company's hiring policies regarding partners, employees and former partners and employees of the present and former external auditor;
iii) review insurance coverage of significant business risks and uncertainties;
iv) review material litigation and its impact on financial reporting;
v) review policies and procedures for the review and approval of officers' expenses and perquisites;
vi) review the policies and practices concerning the expenses and perquisites of the Chairman, including the use of the assets of the Company;
vii) review with external auditors any corporate transactions in which directors or officers of the Company have a personal interest; and
viii) review the terms of reference for the Committee at least annually and otherwise as it deems appropriate, and recommend changes to the Board as required. The Committee shall evaluate its performance with reference to the terms of reference annually.

IV. ACCOUNTABILITY

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

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



EXCELLENCE

We aim for exceptional results in everything we do.

TRUST

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

RESPECT

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

RESPONSIBILITY

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

VERMILION
ENERGY

Vermilion Energy Inc.
3500, 520 3rd Avenue SW
Calgary, Alberta T2P 0R3

Telephone: 1.403.269.4884
Facsimile: 1.403.476.8100
IR Toll Free: 1.866.895.8101
investor_relations@vermilionenergy.com

vermilionenergy.com

Exhibit 99.2


VERMILION
ENERGY
EXHIBIT 99.2
2015
MANAGEMENT'S
DISCUSSION & ANALYSIS
EXCELLENCE. TRUST. RESPECT. RESPONSIBILITY.
DEFINED PRODUCTION GROWTH | RELIABLE & GROWING DIVIDENDS

ABBREVIATIONS

$M	thousand dollars
$MM	million dollars
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
bcf	billion cubic feet
boe	barrel of oil equivalent, including: crude oil, 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
btu	British thermal units
GJ	gigajoules
HH	Henry Hub, a reference price paid for natural gas in US dollars at Erath, Louisiana
mbbls	thousand barrels
mboe	thousand barrel of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmboe	million barrel of oil equivalent
mmbtu	million British thermal units
mmcf	million cubic feet
mmcf/d	million cubic feet per day
MWh	megawatt hour
NBP	the reference price paid for natural gas in the United Kingdom, quoted in pence per therm, at the National Balancing Point Virtual Trading Point operated by National Grid. Our production in Ireland is priced with reference to NBP.
NGLs	natural gas liquids
PRRT	Petroleum Resource Rent Tax, a profit based tax levied on petroleum projects in Australia
TTF	the day-ahead price for natural gas in the Netherlands, quoted in MWh of natural gas, at the Title Transfer Facility Virtual Trading Point operated by Dutch TSO Gas Transport Services
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma
CGU	Cash generating unit, the basis upon which Vermilions assets are evaluated for potential impairments
DRIP	Dividend Reinvestment Plan

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; business strategies and objectives; operational and financial performance; estimated reserve quantities and the discounted net present value of future net revenue from such reserves; petroleum and natural gas sales; future production levels (including the timing thereof) and rates of average annual production growth; estimated contingent resources; exploration and development plans; 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 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 oil and natural gas reserve 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* . The actual crude oil and natural gas reserves and future production will be greater than or less than the estimates provided in this document. The estimated future net revenue from the production of crude 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 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is Management's Discussion and Analysis ("MD&A"), dated February 25, 2016, 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, 2015 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, 2015 and 2014, together with the accompanying notes. Additional information relating to Vermilion, including its Annual Information Form, will be available on or after March 4, 2016 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, 2015 and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with International Financial Reporting Standards ("IFRS" or, alternatively, "GAAP") as issued by the International Accounting Standards Board.

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

- Fund flows from operations: This financial measure is calculated as cash flows from operating activities before changes in non-cash operating working capital and asset retirement obligations settled. 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 cash necessary to pay dividends, repay debt, fund asset retirement obligations and make capital investments.
- Netbacks: These financial measures are per boe and per mcf 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 third party crude oil and natural gas producers.

In addition, this MD&A includes references to certain financial measures which do not have standardized meanings prescribed by IFRS and are not disclosed in our audited financial statements. As such, these financial measures are considered non-GAAP financial measures and therefore are unlikely to be comparable with 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".

VERMILION'S BUSINESS

Vermilion is a Calgary, Alberta based international oil and gas producer focused on the acquisition, 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.

- Canada business unit: Relates to our assets in Alberta and Saskatchewan.
- France business unit: Relates to our operations in France in the Paris and Aquitaine Basins.
- Netherlands business unit: Relates to our operations in the Netherlands.
- Germany business unit: Relates to our operations in Germany.
- Ireland business unit: Relates to our 18.5% non-operated interest in the Corrib offshore natural gas field.
- Australia business unit: Relates to our operations in the Wandoo offshore crude oil field.
- United States business unit: Relates to our operations in Wyoming in the Powder River Basin.
- Corporate: Includes expenditures related to our global hedging program, financing expenses, and general and administration expenses, primarily incurred in Canada and not directly related to the operations of a specific business unit.

2015 REVIEW AND 2016 GUIDANCE

We first issued 2015 capital expenditure guidance of $525 million on December 8, 2014. We subsequently adjusted our 2015 capital expenditure guidance to $415 million on February 27, 2015, in response to the continued weakness in commodity prices. That reduction reflected lower planned activity levels, including the deferral of our Australian drilling program. On August 10, 2015 we announced an increase in our capital expenditure guidance of $70 million to $485 million following the reinstatement of the Australian drilling program as well as additional funding for projects in Canada, France and Ireland. We maintained our previous production guidance of 55,000-57,000 boe/d, albeit towards the lower end of our guidance range due to later-than-originally expected first gas from Corrib. Actual 2015 capital spending of $486.9 million was within 1% of guidance. Production for 2015 proved to be within 0.1% of the guidance range.

On November 9, 2015 we announced preliminary 2016 capital expenditure guidance of $350 million and affirmed production guidance of between 63,000-65,000 boe/d. On January 5, 2016, in response to the continued weakness in commodity prices we adjusted our 2016 capital expenditure guidance to $285 million with corresponding production guidance of 62,500-63,500 boe/d. On February 29, 2016, we further revised our 2016 capital expenditure guidance to $235 million as a result of continued commodity price deterioration. We maintained our production guidance of 62,500-63,500 boe/d. The February 29, 2016 reduction primarily reflects lower expected non-operated drilling activity in Canada, fewer workovers in France, and a deferral of our Netherlands drilling and pipeline twinning programs.

The following table summarizes our 2015 and 2016 guidance:

	Date	Capital Expenditures ($MM)	Production (boe/d)
2015 - Guidance			
2015 Guidance	December 8, 2014	525	55,000 to 57,000
2015 Guidance	February 27, 2015	415	55,000 to 57,000
2015 Guidance	August 10, 2015	485	55,000 to 57,000
2016 - Guidance			
2016 Guidance	November 9, 2015	350	63,000 to 65,000
2016 Guidance	January 5, 2016	285	62,500 to 63,500
2016 Guidance	February 29, 2016	235	62,500 to 63,500

SHAREHOLDER RETURN

Vermilion strives to provide investors with reliable and growing dividends in addition to sustainable, global production growth. The following table, as of December 31, 2015, reflects our trailing one, three, and five year performance:

Total return (1)	Trailing One Year	Trailing Three Year	Trailing Five Year
Dividends per Vermilion share	$2.58	$7.56	$12.12
Capital appreciation per Vermilion share	($19.39)	($14.36)	($8.61)
Total return per Vermilion share	(29.5%)	(13.1%)	7.6%
Annualized total return per Vermilion share	(29.5%)	(4.6%)	1.5%
Annualized total return on the S&P TSX High Income Energy Index	(31.2%)	(13.1%)	(8.5%)

(1) The above table includes non-GAAP financial measures which may not be comparable to other companies. Please see the "NON-GAAP FINANCIAL MEASURES" section of this MD&A.

CONSOLIDATED RESULTS OVERVIEW

	Three Months Ended			% change		Year Ended		% change
	Dec 31, 2015	**Sep 30, 2015**	**Dec 31, 2014**	**Q4/15 vs. Q3/15**	**Q4/15 vs. Q4/14**	**Dec 31, 2015**	**Dec 31, 2014**	**2015 vs. 2014**
Production								
Crude oil (bbls/d)	**28,745**	28,164	28,846	2%	-	**28,502**	28,879	(1%)
NGLs (bbls/d)	**5,298**	4,622	2,822	15%	88%	**4,214**	2,553	65%
Natural gas (mmcf/d)	**162.09**	140.97	107.42	15%	51%	**133.24**	108.85	22%
Total (boe/d)	**61,058**	56,280	49,571	8%	23%	**54,922**	49,573	11%
Build (draw) in inventory (mbbl)	**(93)**	(85)	(238)			**84**	(165)	
Financial metrics								
Fund flows from operations ($M)	**136,441**	129,435	185,528	5%	(26%)	**516,167**	804,865	(36%)
Per share ($/basic share)	**1.22**	1.17	1.73	4%	(29%)	**4.71**	7.63	(38%)
Net earnings (loss)	**(142,080)**	(83,310)	58,642	71%	(342%)	**(217,302)**	269,326	(181%)
Per share ($/basic share)	**(1.28)**	(0.76)	0.55	68%	(333%)	**(1.98)**	2.55	(178%)
Cash flows from operating activities ($M)	**164,863**	122,230	229,146	35%	(28%)	**444,408**	791,986	(44%)
Net debt ($M)	**1,381,951**	1,363,043	1,265,650	1%	9%	**1,381,951**	1,265,650	9%
Cash dividends ($/share)	**0.645**	0.645	0.645	-	-	**2.580**	2.580	-
Activity								
Capital expenditures ($M)	**128,996**	93,381	166,243	38%	(22%)	**486,861**	687,724	(29%)
Acquisitions ($M)	**6,227**	22,155	1,652	(72%)	277%	**28,897**	601,865	(95%)
Gross wells drilled	**8.00**	11.00	26.00			**53.00**	89.00	
Net wells drilled	**5.56**	6.91	16.58			**36.12**	62.43	

Operational review

- Recorded consolidated average production of 61,058 boe/d in Q4 2015, which was an 8% increase over Q3 2015. This quarter-over-quarter increase was the result of production growth in all of our business units, including a 2,075 boe/d increase in Canada, largely attributable to growth in our Mannville condensate-rich gas play, and a 1,391 boe/d increase from Australia driven by our sidetrack well drilled in Q4 2015.
- Increased consolidated average production for the three months and year ended December 31, 2015 by 23% and 11%, respectively, versus the comparable periods in 2014, primarily due to growth in Canada, the Netherlands, and France.
- Activity during the quarter included capital expenditures totalling $129.0 million, incurred primarily in Australia, Canada, and France. In Australia, capital expenditures totalling $40.9 million related to the horizontal sidetrack drilling program. In Canada, capital expenditures totalling $27.6 million were 26% lower than the $37.2 million incurred during Q3 2015 and related to the drilling of 2.6 net wells (6.9 net wells in Q3 2015). In France, capital expenditures of $24.1 million were 39% higher than the $17.4 million incurred in Q3 2015 and related primarily to facility maintenance, accretive workovers, and subsurface activity.

Financial review

Net earnings (loss)

- The net loss for Q4 2015 was $142.1 million ($1.28/basic share) as compared to a net loss of $83.3 million ($0.76/basic share) in Q3 2015. The increase in the net loss was primarily attributable to unfavourable foreign exchange variances and the impact of a valuation allowance recorded on deferred tax assets. The valuation allowance relates to certain non-capital losses for which there is uncertainty as to the Company's ability to fully utilize such losses when applying forecasted commodity prices in effect as at December 31, 2015.
- The net loss for the three months and year ended December 31, 2015 represented decreases of $200.7 million and $486.6 million, respectively, versus the comparative periods in 2014. These decreases were driven primarily by lower petroleum and natural gas sales as a result of lower commodity prices, as well as impairment charges recognized in Canada and a valuation allowance recorded on deferred tax assets due to declines in commodity price forecasts. The impacts of weakened commodity prices were partially offset by significant production growth and global cost reductions, including an 8% and 11% reduction in per unit operating expense for the three months and year ended December 31, 2015, respectively. The year ended December 31, 2015 was also positively impacted by the recovery of $31.8 million (before taxes) recognized in Q1 2015 following a judgment in favour of Vermilion for costs incurred as a result of a 2007 oil spill at the Ambès oil terminal in France that occurred shortly after Vermilion acquired the asset.

Cash flows from operating activities

- Absent changes in working capital, cash flows from operating activities increased by 3% quarter-over-quarter, despite significantly lower commodity prices, due to production growth in every business unit, coupled with increased realized gains from our commodity hedges.
- Cash flows from operating activities decreased by 28% and 44% for the three months and year ended December 31, 2015, respectively, versus the comparable periods in 2014. These decreases were primarily related to lower revenue due to lower commodity prices, as well as timing differences pertaining to working capital, partially offset by lower royalties and current taxes.

Fund flows from operations

- Generated fund flows from operations of $136.4 million during Q4 2015, an increase of 5% over Q3 2015. This quarter-over-quarter increase occurred despite lower commodity pricing, driven primarily by production growth in all business units, lower current taxes, and higher receipts from commodity hedges.
- Fund flows from operations decreased by 26% and 36% for the three months and year ended December 31, 2015, respectively, versus the comparable periods in 2014. These decreases were primarily driven by lower crude oil pricing, partially offset by higher sold volumes resulting from significant production growth, global cost reductions, and favourable current tax and royalty variances. The decrease in fund flows from operations for the year ended December 31, 2015 was also partially offset by the previously mentioned recovery of costs in France.

Net debt

- Net debt increased by $116.3 million to $1.38 billion for the year ended December 31, 2015 due to capital expenditures in Canada, France, and Ireland, partially offset by fund flows from operations.

Dividends

- Declared dividends of $0.215 per common share per month during the fourth quarter of 2015, totalling $2.58 per common share for the year ended December 31, 2015.

COMMODITY PRICES

	Three Months Ended			% change		Year Ended		% change
	Dec 31, 2015	Sep 30, 2015	Dec 31, 2014	Q4/15 vs. Q3/15	Q4/15 vs. Q4/14	Dec 31, 2015	Dec 31, 2014	2015 vs. 2014
Average reference prices								
Crude oil								
WTI (US $/bbl)	**42.18**	46.43	73.15	(9%)	(42%)	**48.80**	93.00	(48%)
Edmonton Sweet index (US $/bbl)	**39.72**	43.01	66.79	(8%)	(41%)	**44.91**	85.83	(48%)
Dated Brent (US $/bbl)	**43.69**	50.26	76.27	(13%)	(43%)	**52.46**	98.99	(47%)
Natural gas								
AECO ($/mmbtu)	**2.46**	2.90	3.60	(15%)	(32%)	**2.69**	4.50	(40%)
TTF ($/mmbtu)	**7.28**	8.48	9.16	(14%)	(21%)	**8.23**	8.96	(8%)
TTF (€/mmbtu)	**4.98**	5.82	6.46	(14%)	(23%)	**5.80**	6.11	(5%)
NBP ($/mmbtu)	**7.41**	8.40	9.52	(12%)	(22%)	**8.33**	9.10	(8%)
NBP (€/mmbtu)	**5.07**	5.77	6.71	(12%)	(24%)	**5.87**	6.20	(5%)
Henry Hub ($/mmbtu)	**3.03**	3.62	4.54	(16%)	(33%)	**3.41**	4.88	(30%)
Henry Hub (US $/mmbtu)	**2.27**	2.77	4.00	(18%)	(43%)	**2.66**	4.41	(40%)
Average foreign currency exchange rates								
CDN $/US $	**1.34**	1.31	1.14	2%	18%	**1.28**	1.10	16%
CDN $/Euro	**1.46**	1.46	1.42	-	3%	**1.42**	1.47	(3%)
Average realized prices ($/boe)								
Canada	**28.94**	32.78	51.27	(12%)	(44%)	**34.32**	64.06	(46%)
France	**54.20**	60.96	79.25	(11%)	(32%)	**62.67**	105.43	(41%)
Netherlands	**42.61**	49.42	52.07	(14%)	(18%)	**46.77**	52.65	(11%)
Germany	**39.68**	44.36	49.19	(11%)	(19%)	**43.10**	46.03	(6%)
Australia	**58.74**	68.20	90.37	(14%)	(35%)	**70.22**	113.80	(38%)
United States	**41.94**	51.60	74.08	(19%)	(43%)	**47.53**	74.08	(36%)
Consolidated	**41.04**	46.56	63.79	(12%)	(36%)	**47.07**	77.75	(39%)
Production mix (% of production)								
% priced with reference to WTI	**22%**	24%	28%			**25%**	28%	
% priced with reference to AECO	**24%**	22%	20%			**22%**	18%	
% priced with reference to TTF	**20%**	20%	16%			**19%**	18%	
% priced with reference to Dated Brent	**34%**	34%	36%			**34%**	36%	

Reference prices

- Oil benchmarks faced strong headwinds throughout the fourth quarter, causing both WTI and Dated Brent to average the quarter at US $42.18/bbl and US $43.69/bbl respectively. Compared to the previous quarter, WTI was down an additional 9% whereas Dated Brent averaged 13% lower versus the previous quarter. On a year-over-year basis, WTI was down 48% and Dated Brent was down 47%.
- Crude oil prices set at Edmonton were less volatile during the fourth quarter, but still tracked lower to average the quarter at US $39.72/bbl, or 8% lower quarter-over-quarter, and 41% lower year-over-year.
- AECO natural gas suffered a 15% quarter-over-quarter decline as high levels of gas-in-storage, strong field receipts, and below-normal demand weighed on the market. Averaging $2.46/mmbtu for the three months ending December 31, 2015, AECO was down 32% versus the same quarter in 2014.
- Despite having lower gas-in-storage, a mild start to winter and the anticipation of increasing LNG supply reduced European natural gas prices in Q4 2015, driving similar movements in TTF and NBP reference prices. For the fourth quarter, TTF averaged $7.28/mmbtu, which was 14% lower versus the previous quarter and 21% lower versus the same quarter in the prior year. In Euro terms, TTF averaged the quarter at €4.98/mmbtu, which was a 14% decrease versus Q3 2015, and 23% lower year-over-year.
- Weakness in the price of oil and a rate hike by the US Federal Reserve in December kept the Canadian dollar on its declining path against the US dollar; however, a similar impact was felt by the Euro versus the US dollar, causing CDN $/Euro to remain flat quarter-over-quarter.

Realized prices

- Consolidated realized price decreased by 12% for Q4 2015 as compared to Q3 2015. This decrease was primarily the result of weakening crude oil and natural gas pricing.
- Consolidated realized price for the three months and year ended December 31, 2015 decreased by 36% and 39%, respectively, as compared to the comparable periods in 2014. These decreases were due to weakening commodity prices, primarily driven by a weakening of crude oil and North American natural gas prices, as well as changes in production mix, which included increased relative NGL and natural gas volumes in Canada.

FUND FLOWS FROM OPERATIONS

	Three Months Ended						Year Ended			
	Dec 31, 2015		Sep 30, 2015		Dec 31, 2014		Dec 31, 2015		Dec 31, 2014	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Petroleum and natural gas sales	**234,319**	**41.04**	245,051	46.56	306,073	63.79	**939,586**	**47.07**	1,419,628	77.75
Royalties	**(16,285)**	**(2.85)**	(17,100)	(3.25)	(25,963)	(5.41)	**(65,920)**	**(3.30)**	(108,000)	(5.92)
Petroleum and natural gas revenues	**218,034**	**38.19**	227,951	43.31	280,110	58.38	**873,666**	**43.77**	1,311,628	71.83
Transportation expense	**(10,147)**	**(1.78)**	(11,090)	(2.11)	(9,489)	(1.98)	**(41,660)**	**(2.09)**	(42,361)	(2.32)
Operating expense	**(65,645)**	**(11.50)**	(57,826)	(10.99)	(59,881)	(12.48)	**(225,938)**	**(11.32)**	(232,307)	(12.72)
General and administration	**(12,431)**	**(2.18)**	(13,088)	(2.49)	(13,236)	(2.76)	**(53,584)**	**(2.68)**	(61,727)	(3.38)
PRRT	**(1,054)**	**(0.18)**	(99)	(0.02)	(13,568)	(2.83)	**(6,878)**	**(0.34)**	(60,340)	(3.30)
Corporate income taxes	**3,113**	**0.55**	(12,383)	(2.35)	(8,304)	(1.73)	**(44,237)**	**(2.22)**	(96,996)	(5.31)
Interest expense	**(16,584)**	**(2.90)**	(15,420)	(2.93)	(12,943)	(2.70)	**(59,852)**	**(3.00)**	(49,655)	(2.72)
Realized gain on derivative instruments	**21,164**	**3.71**	10,854	2.06	22,816	4.76	**41,356**	**2.07**	36,712	2.01
Realized foreign exchange (loss) gain	**(252)**	**(0.04)**	309	0.06	(179)	(0.03)	**623**	**0.03**	(821)	(0.04)
Realized other income	**243**	**0.04**	227	0.04	202	0.04	**32,671**	**1.64**	732	0.04
Fund flows from operations	**136,441**	**23.91**	129,435	24.58	185,528	38.67	**516,167**	**25.86**	804,865	44.09

The following table shows a reconciliation of the change in fund flows from operations:

($M)	**Q4/15 vs. Q3/15**	**Q4/15 vs. Q4/14**	**2015 vs. 2014**
Fund flows from operations – Comparative period	**129,435**	**185,528**	**804,865**
Sales volume variance:			
Canada	1,779	3,636	24,239
France	(5,232)	8,916	36,817
Netherlands	2,104	20,038	21,601
Germany	1,478	(1,153)	2,245
Ireland	57	57	57
Australia	16,350	2,802	(19,697)
United States	1,051	524	2,948
Pricing variance on sold volumes:			
WTI	(3,075)	(32,707)	(195,644)
AECO	(2,507)	(9,461)	(45,760)
Dated Brent	(15,632)	(53,825)	(287,666)
TTF	(7,105)	(10,581)	(19,182)
Changes in:			
Royalties	815	9,678	42,080
Transportation	943	(658)	701
Operating expense	(7,819)	(5,764)	6,369
General and administration	657	805	8,143
PRRT	(955)	12,514	53,462
Corporate income taxes	15,496	11,417	52,759
Interest	(1,164)	(3,641)	(10,197)
Realized derivatives	10,310	(1,652)	4,644
Realized foreign exchange	(561)	(73)	1,444
Realized other income	16	41	31,939
Fund flows from operations – Current period	**136,441**	**136,441**	**516,167**

Fund flows from operations of $136.4 million during Q4 2015 represented an increase of 5% versus Q3 2015. Quarter-over-quarter, the increase was achieved, despite significant commodity price declines, as a result of higher sold volumes driven by production growth in every business unit, lower current taxes, and increased receipts from commodity hedges.

Fund flows from operations decreased 26% and 36% for the three months and year ended December 31, 2015, respectively, versus the comparable periods in 2014. The 2015 decreases were primarily driven by unfavourable crude oil and natural gas price variances, partially offset by higher sold volumes resulting from significant production growth and global cost reductions, most notably in per unit operating expense which decreased 8% and 11% for the quarter and full year, respectively. The full year decrease in fund flows from operations was partially offset by the previously mentioned recovery of costs in France.

Fluctuations in fund flows from operations (and correspondingly net earnings (loss) and cash flows from operating activities) may occur as a result of changes in commodity prices and costs to produce petroleum and natural gas. In addition, fund flows from operations may be highly 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 in income.

CANADA BUSINESS UNIT

Overview

- Production and assets focused in West Pembina near Drayton Valley, Alberta and Northgate in southeast Saskatchewan.
  - Potential for three significant resource plays sharing the same surface infrastructure in the West Pembina region:
  - Cardium light oil (1,800m depth) – in development phase
  - Mannville condensate-rich gas (2,400 – 2,700m depth) – in development phase
- Duvernay condensate-rich gas (3,200 – 3,400m depth) – in appraisal phase
- Canadian cash flows are fully tax-sheltered for the foreseeable future.

Operational review

	Three Months Ended			% change		Year Ended		% change
Canada business unit	Dec 31, 2015	Sep 30, 2015	Dec 31, 2014	Q4/15 vs. Q3/15	Q4/15 vs. Q4/14	Dec 31, 2015	Dec 31, 2014	2015 vs. 2014
Production								
Crude oil (bbls/d)	**7,964**	9,195	11,384	(13%)	(30%)	**9,550**	11,248	(15%)
NGLs (bbls/d)	**5,159**	4,513	2,741	14%	88%	**4,108**	2,476	66%
Natural gas (mmcf/d)	**87.90**	71.94	58.36	22%	51%	**71.65**	55.67	29%
Total (boe/d)	**27,773**	25,698	23,851	8%	16%	**25,598**	23,001	11%
Production mix (% of total)								
Crude oil	**29%**	36%	48%			**37%**	49%	
NGLs	**19%**	18%	11%			**16%**	11%	
Natural gas	**52%**	46%	41%			**47%**	40%	
Activity								
Capital expenditures ($M)	**27,554**	37,224	85,442	(26%)	(68%)	**201,508**	334,742	(40%)
Acquisitions ($M)	**6,169**	8,062	1,671			**14,650**	415,648	
Gross wells drilled	**5.00**	11.00	23.00			**42.00**	74.00	
Net wells drilled	**2.56**	6.91	15.16			**26.01**	50.27	

Production

- Q4 2015 average production in Canada increased by 8% quarter-over-quarter and 16% year-over-year. Full year average production increased 11% versus 2014. Quarterly and annual increases were primarily due to strong organic production growth in our Mannville condensate-rich gas resource play.
- In early December 2015, some transportation restrictions were lifted, resulting in approximately 1,000 boe/d of non-operated volumes being brought online. At the end of Q4 2015, approximately 1,600 boe/d of production was shut-in due to a lack of field compression capacity, but the majority of these volumes are expected to be brought online in Q1 2016.
- Cardium production averaged approximately 8,000 boe/d in Q4 2015, a 14% decrease quarter-over-quarter. Full year 2015 average production of approximately 9,100 boe/d represented a decrease of 16% versus 2014.
- Mannville production averaged approximately 11,000 boe/d in Q4 2015, a 57% increase quarter-over-quarter and more than 2.5 times Q4 2014 production of approximately 4,300 boe/d. Full year 2015 production averaged more than 7,100 boe/d, representing an 82% increase versus 2014.
- Production from our southeast Saskatchewan assets averaged approximately 2,500 boe/d in Q4 2015, a decrease of 17% quarter-over-quarter. The North Portal Gas Plant was commissioned late in Q1 2015. The plant enables the processing of approximately 5,500 mcf/d (920 boe/d net) of natural gas which was previously being flared.

Activity review

· Vermilion drilled two (2.0 net) operated wells and participated in the drilling of three (0.6 net) non-operated wells during Q4 2015. During 2015, Vermilion drilled 20 (17.6 net) operated wells and participated in the drilling of 22 (8.4 net) non-operated wells in Canada.

Cardium

- During Q4 2015, we participated in the drilling of two (0.3 net) non-operated wells; no wells were placed on production.
- In 2015, we drilled one (1.0 net) operated well and brought ten (9.3 net) operated wells on production. We also participated in the drilling of eight (2.4 net) non-operated wells and six (2.1 net) non-operated wells were brought on production.
- 2016 activity will focus on the optimization of existing assets.

Mannville

- During Q4 2015, we drilled two (2.0 net) operated wells and brought one (1.0 net) operated well on production. We also participated in the drilling of one (0.3 net) non-operated well and one (0.4 net) non-operated well was placed on production.
- In 2015, we drilled 14 (12.5 net) operated wells and brought 11 (9.5 net) operated wells on production. We also participated in the drilling of 14 (6.0 net) non-operated wells, and ten (3.8 net) non-operated wells were placed on production.
- In 2016, we plan to drill or participate in approximately six (4.0 net) wells.

Saskatchewan

- We drilled and brought on production five (4.1 net) operated Midale wells during Q1 2015, completing our 2015 drilling activity in Saskatchewan.
- In 2016, we plan to drill or participate in six (5.5 net) wells.

Financial review

Canada business unit ($M except as indicated)	Three Months Ended Dec 31, 2015	Sep 30, 2015	Dec 31, 2014	% change Q4/15 vs. Q3/15	Q4/15 vs. Q4/14	Year Ended Dec 31, 2015	Dec 31, 2014	% change 2015 vs. 2014
Sales	**73,952**	77,493	112,494	(5%)	(34%)	**320,613**	537,788	(40%)
Royalties	**(7,146)**	(6,638)	(15,626)	8%	(54%)	**(28,144)**	(65,563)	(57%)
Transportation expense	**(3,784)**	(4,131)	(3,455)	(8%)	10%	**(16,326)**	(14,625)	12%
Operating expense	**(24,575)**	(23,877)	(19,315)	3%	27%	**(89,085)**	(76,178)	17%
General and administration	**(3,669)**	(3,694)	(2,840)	(1%)	29%	**(16,888)**	(16,791)	1%
Fund flows from operations	**34,778**	39,153	71,258	(11%)	(51%)	**170,170**	364,631	(53%)
Netbacks ($/boe)								
Sales	**28.94**	32.78	51.27	(12%)	(44%)	**34.32**	64.06	(46%)
Royalties	**(2.80)**	(2.81)	(7.12)	-	(61%)	**(3.01)**	(7.81)	(61%)
Transportation expense	**(1.48)**	(1.75)	(1.57)	(15%)	(6%)	**(1.75)**	(1.74)	1%
Operating expense	**(9.62)**	(10.10)	(8.80)	(5%)	9%	**(9.54)**	(9.07)	5%
General and administration	**(1.44)**	(1.56)	(1.29)	(8%)	12%	**(1.81)**	(2.00)	(10%)
Fund flows from operations netback	**13.60**	16.56	32.49	(18%)	(58%)	**18.21**	43.44	(58%)
Reference prices								
WTI (US $/bbl)	**42.18**	46.43	73.15	(9%)	(42%)	**48.80**	93.00	(48%)
Edmonton Sweet index (US $/bbl)	**39.72**	43.01	66.79	(8%)	(41%)	**44.91**	85.83	(48%)
Edmonton Sweet index ($/bbl)	**53.04**	56.32	75.85	(6%)	(30%)	**57.43**	94.82	(39%)
AECO ($/mcf)	**2.46**	2.90	3.60	(15%)	(32%)	**2.69**	4.50	(40%)

Sales

- The realized price for our crude oil production in Canada is directly linked to WTI, but is also subject to market conditions in Western Canada. These market conditions can result in fluctuations in the pricing differential to WTI, as reflected by the Edmonton Sweet index price. The realized price of our NGLs in Canada is based on product specific differentials pertaining to trading hubs in the United States. The realized price of our natural gas in Canada is based on the AECO spot price in Canada.
- Q4 2015 and full year 2015 sales per boe decreased versus all comparable periods, largely as the result of weakening crude oil and natural gas pricing.

Royalties

- Royalties as a percentage of sales for Q4 2015 of 9.7% was slightly higher than the 8.6% for Q3 2015 due to the absence of certain royalty credits recorded in the third quarter.
- Royalties as a percentage of sales for the three months and year ended December 31, 2015 decreased to 9.7% and 8.8% versus the same periods in 2014 (13.9% and 12.2%, respectively) due to the impact of lower reference prices on the sliding scale used to determine crude oil royalty rates.

Transportation

- Transportation expense relates to the delivery of crude oil and natural gas production to major pipelines where legal title transfers.
- Transportation expense for the three months and year ended December 31, 2015 was higher than the comparable periods in 2014 due to increased natural gas and natural gas liquids volumes produced in 2015. In addition, full year 2015 expense includes incremental trucking costs from Vermilion's Saskatchewan properties, which were acquired in April 2014.

Operating expense

- Operating expense was higher in Q4 2015 versus Q4 2014 due to higher gas gathering and processing expenditures following significantly increased natural gas and natural gas liquids production. For Q4 2015 versus Q3 2015, this increase was largely offset by cost reduction initiatives including reduced major project, transportation and other costs, resulting in a 5% reduction in per unit costs.
- Full year operating expense increased on a spend basis by approximately 17% due to incremental operating expense associated with Vermilion's Saskatchewan properties acquired in Q2 2014 and higher gas gathering and processing fees following increased natural gas and natural gas liquids production in Alberta. This increase in spending was partially offset by increased production volumes, resulting in a 5% increase in operating expense per boe.

General and administration

- General and administration expense increased from Q4 2014 primarily due to a decrease in recoveries, which more than offset lower gross costs.
- Year-over-year, 2015 general and administrative expense were essentially flat due to lower current year recoveries more than offsetting a decrease in gross costs.

Impairment

- For the three months and year ended December 31, 2015, Vermilion recorded an impairment charge of $131.6 million and $274.6 million, respectively, related to the light crude oil play in Saskatchewan, Canada ($267.9 million in 2015) and the shallow coal bed methane gas properties in Alberta, Canada ($6.7 million in 2015). These impairment charges were a result of declines in the price forecasts for crude oil and natural gas in Canada which decreased the expected future cash flows from the respective cash generating units.

FRANCE BUSINESS UNIT

Overview

- Entered France in 1997 and completed three subsequent acquisitions, including two in 2012.
- Largest oil producer in France, constituting approximately three-quarters of domestic oil production.
- Producing assets include large conventional fields with high working interests located in the Aquitaine and Paris Basins with an identified inventory of workover, infill drilling, and secondary recovery opportunities.
- Production is characterized by Brent-based crude pricing and low base decline rates.

Operational review

	Three Months Ended			% change		Year Ended		% change
France business unit	**Dec 31, 2015**	**Sep 30, 2015**	**Dec 31, 2014**	**Q4/15 vs. Q3/15**	**Q4/15 vs. Q4/14**	**Dec 31, 2015**	**Dec 31, 2014**	**2015 vs. 2014**
Production								
Crude oil (bbls/d)	**12,537**	12,310	11,133	2%	13%	**12,267**	11,011	11%
Natural gas (mmcf/d)	**1.36**	1.47	-	(7%)	100%	**0.97**	-	100%
Total (boe/d)	**12,763**	12,555	11,133	2%	15%	**12,429**	11,011	13%
Inventory (mbbls)								
Opening crude oil inventory	**239**	340	214			**197**	269	
Crude oil production	**1,153**	1,133	1,024			**4,477**	4,019	
Crude oil sales	**(1,149)**	(1,234)	(1,041)			**(4,431)**	(4,091)	
Closing crude oil inventory	**243**	239	197			**243**	197	
Production mix (% of total)								
Crude oil	**98%**	98%	100%			**99%**	100%	
Natural gas	**2%**	2%	-			**1%**	-	
Activity								
Capital expenditures ($M)	**24,085**	17,369	37,189	39%	(35%)	**92,265**	147,852	(38%)
Acquisitions ($M)	**79**	142	-			**317**	-	
Gross wells drilled	**-**	-	1.00			**4.00**	8.00	
Net wells drilled	**-**	-	0.50			**4.00**	7.50	

Production

- Ongoing workover and optimization activities in Q4 2015 resulted in stable quarter-over-quarter production. Production increased versus 2014, for both the quarter and full year periods, due to production additions from our 2015 Champotran drilling program and workovers.

Activity review

- Vermilion drilled four (4.0 net) wells in the Champotran field in the Paris Basin in Q1 2015, completing our planned France drilling program for 2015.
- In 2015, additional activity included workover and optimization programs in the Aquitaine and Paris Basins, and the resumption of sales from a portion of our shut-in natural gas at Vic Bilh, which was brought back on-line in Q2 2015.
- In 2016, our planned capital activity includes a program of approximately 15 well workovers.

Financial review

France business unit ($M except as indicated)	Three Months Ended Dec 31, 2015	Sep 30, 2015	Dec 31, 2014	% change Q4/15 vs. Q3/15	Q4/15 vs. Q4/14	Year Ended Dec 31, 2015	Dec 31, 2014	% change 2015 vs. 2014
Sales	**63,411**	76,552	82,499	(17%)	(23%)	**281,422**	431,252	(35%)
Royalties	**(7,198)**	(8,038)	(6,319)	(10%)	14%	**(26,958)**	(28,444)	(5%)
Transportation expense	**(4,275)**	(4,566)	(4,096)	(6%)	4%	**(15,378)**	(18,975)	(19%)
Operating expense	**(15,792)**	(11,998)	(13,544)	32%	17%	**(50,718)**	(61,729)	(18%)
General and administration	**(4,894)**	(5,338)	(3,765)	(8%)	30%	**(20,217)**	(20,929)	(3%)
Other income	**-**	-	-	-	-	**31,775**	-	100%
Current income taxes	**4,529**	(4,696)	(6,132)	(196%)	(174%)	**(23,764)**	(66,901)	(64%)
Fund flows from operations	**35,781**	41,916	48,643	(15%)	(26%)	**176,162**	234,274	(25%)
Netbacks ($/boe)								
Sales	**54.20**	60.96	79.25	(11%)	(32%)	**62.67**	105.43	(41%)
Royalties	**(6.15)**	(6.40)	(6.07)	(4%)	1%	**(6.00)**	(6.95)	(14%)
Transportation expense	**(3.65)**	(3.64)	(3.94)	-	(7%)	**(3.42)**	(4.64)	(26%)
Operating expense	**(13.50)**	(9.55)	(13.01)	41%	4%	**(11.30)**	(15.09)	(25%)
General and administration	**(4.18)**	(4.25)	(3.62)	(2%)	15%	**(4.50)**	(5.12)	(12%)
Other income	**-**	-	-	-	-	**7.08**	-	100%
Current income taxes	**3.87**	(3.74)	(5.89)	(203%)	(166%)	**(5.29)**	(16.36)	(68%)
Fund flows from operations netback	**30.59**	33.38	46.72	(8%)	(35%)	**39.24**	57.27	(31%)
Reference prices								
Dated Brent (US $/bbl)	**43.69**	50.26	76.27	(13%)	(43%)	**52.46**	98.99	(47%)
Dated Brent ($/bbl)	**58.34**	65.81	86.62	(11%)	(33%)	**67.09**	109.36	(39%)

Sales

- Crude oil in France is priced with reference to Dated Brent.
- Sales per boe decreased quarter-over-quarter, consistent with a decrease in the Dated Brent reference price. This decrease in price was combined with decreased sales volumes due to a slight build in inventory of 4,000 bbls in Q4 (versus a draw in Q3 2015).
- On a year-over-year basis, sales decreased for the three months and year ended December 31, 2015, consistent with a decline in the Dated Brent reference price, and was partially offset by increased sales volumes driven by production growth.

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).
- Royalties as a percentage of sales of 11.4% and 9.6% for the three months and year ended December 31, 2015 was higher than Q3 2015 (10.5%) and the 2014 periods (7.7% and 6.6%, respectively) as a result of the impact of fixed RCDM royalties coupled with lower realized pricing.

Transportation

- Transportation expense for Q4 2015 was relatively consistent with both Q3 2015 and Q4 2014.
- Transportation expense decreased by 19% for 2015 versus 2014 due to a lower level of maintenance and project activity at the Ambès terminal coupled with the favourable foreign exchange impact of the strengthening of the Canadian dollar versus the Euro.

Operating expense

- Operating expense on a dollar and per boe basis increased in Q4 2015 versus both Q3 2015 and Q4 2014 due to increased electricity usage and costs coupled with a higher level of project activity in the current quarter.
- Operating expense on a dollar and per boe basis decreased in 2015 versus 2014 due largely to the successful implementation of cost reduction initiatives undertaken in response to commodity price weakness. These cost reduction initiatives included lower costs on downhole and other maintenance activities, lower labour usage and costs and savings from service contract renegotiations. These cost cutting initiatives were delivered while growing production during the year by 13%, resulting in a 25% decrease in unit costs.

General and administration

- General and administration expense for Q4 2015 was 8% lower than Q3 2015 and 30% higher than Q4 2014. These fluctuations in general and administration expense for the quarters presented primarily result from variances in the timing of spending, including the timing of allocations from our Corporate segment.
- Year-over-year, 2015 general and administration expense was 3% lower than 2014 due to the impact of a number of cost reduction initiatives undertaken in response to commodity price weakness, including a reduction in third party consultant expenditures.

Other income

- Included in the results for the year ended December 31, 2015 is a judgment award pertaining to costs incurred as a result of an oil spill at the Ambès oil terminal in France that occurred in 2007. As a result of the award, $31.8 million (before taxes) was recognized as other income.

Current income taxes

- Current income taxes in France are applied to taxable income, after eligible deductions, at a statutory rate of 34.4% for 2015. France is not expected to incur any current income taxes for 2016. This is subject to change in response to commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.
- Q4 2015 current income taxes decreased compared to Q3 2015 and Q4 2014 due to decreased revenues and additional tax deductions taken for depletion.
- Current income taxes for the full year ended December 31, 2015 decreased versus the comparative period in 2014 mainly due to lower fund flows from operations as a result of the decline in the Dated Brent reference price and additional tax deductions taken for depletion.

NETHERLANDS BUSINESS UNIT

Overview

- Entered the Netherlands in 2004.
- Second largest onshore gas producer.
- Interests include 24 onshore licenses and two offshore licenses.
- Licenses include more than 800,000 net acres of undeveloped land.
- Natural gas drilling and development.
- Natural gas produced in the Netherlands is priced off the TTF index, which receives a significant premium over North American gas prices.

Operational review

	Three Months Ended			% change		Year Ended		% change
Netherlands business unit	**Dec 31, 2015**	**Sep 30, 2015**	**Dec 31, 2014**	**Q4/15 vs. Q3/15**	**Q4/15 vs. Q4/14**	**Dec 31, 2015**	**Dec 31, 2014**	**2015 vs. 2014**
Production								
NGLs (bbls/d)	**110**	109	81	1%	36%	**99**	77	29%
Natural gas (mmcf/d)	**56.34**	53.56	31.35	5%	80%	**44.76**	38.20	17%
Total (boe/d)	**9,500**	9,035	5,306	5%	79%	**7,559**	6,443	17%
Activity								
Capital expenditures ($M)	**18,810**	5,297	10,022	255%	88%	**47,325**	61,740	(23%)
Gross wells drilled	**-**	-	2.00			**2.00**	7.00	
Net wells drilled	**-**	-	0.92			**1.86**	4.66	

Production

- Q4 2015 production represented a new record for our Netherlands Business Unit at 9,500 boe/d, which is an increase of 5% from the prior quarter. This increase is primarily attributable to production from the Diever-02 exploration well (45% working interest), coming on an extended production test in late October. Diever-02 is currently producing approximately 13.2 mmcf/d (2,200 boe/d) net to Vermilion.
- Q4 2015 production increased 79% year-over-year, mainly driven by the extended production test of three wells: Slootdorp-06/07 (92.8% working interest) and Diever-02 (45% working interest). Slootdorp-06/07 were drilled in Q2 2015 and placed on an extended production test in the following quarter. Slootdorp-06/07 are currently producing approximately 25.8 mmcf/d (4,300 boe/d) net to Vermilion.
- 2015 average production increased 17% versus 2014. Production additions from the Slootdorp-06/07 and Diever-02 wells later in the year were partially offset by the loss of production from our Middenmeer-3 well, which was fully depleted and taken offline in February 2015. The depletion of this well occurred as expected. The turnaround at the Garijp Treatment Centre during Q2 2015 further impacted current year production.
- Production in the Netherlands is actively managed to optimize facility use and regulate declines.

Activity review

- During Q2 2015, Vermilion drilled two (1.9 net) wells, Slootdorp-06 and Slootdorp-07. These wells are currently on sales during an extended production test to size additional production equipment.
- The Diever-02 exploration well (45% working interest), drilled in 2014, came on production in late October for an extended production test
- During the year, we executed numerous debottlenecking activities to enhance deliverability from the Slootdorp wells as well as a turnaround at the Garijp Treatment Centre.
- Activity in 2016 will focus on permitting and optimization initiatives.

Financial review

Netherlands business unit ($M except as indicated)	Three Months Ended Dec 31, 2015	Sep 30, 2015	Dec 31, 2014	% change Q4/15 vs. Q3/15	Q4/15 vs. Q4/14	Year Ended Dec 31, 2015	Dec 31, 2014	% change 2015 vs. 2014
Sales	**37,243**	41,083	25,420	(9%)	47%	**129,057**	123,815	4%
Royalties	**(224)**	(638)	(1,171)	(65%)	(81%)	**(3,082)**	(5,014)	(39%)
Operating expense	**(6,263)**	(5,243)	(6,200)	19%	1%	**(22,746)**	(24,041)	(5%)
General and administration	**(813)**	(2,154)	(2,489)	(62%)	(67%)	**(4,158)**	(3,617)	15%
Current income taxes	**(2,930)**	(4,487)	2,124	(35%)	(238%)	**(12,152)**	(4,154)	193%
Fund flows from operations	**27,013**	28,561	17,684	(5%)	53%	**86,919**	86,989	-
Netbacks ($/boe)								
Sales	**42.61**	49.42	52.07	(14%)	(18%)	**46.77**	52.65	(11%)
Royalties	**(0.26)**	(0.77)	(2.40)	(66%)	(89%)	**(1.12)**	(2.13)	(47%)
Operating expense	**(7.17)**	(6.31)	(12.70)	14%	(44%)	**(8.24)**	(10.22)	(19%)
General and administration	**(0.93)**	(2.59)	(5.10)	(64%)	(82%)	**(1.51)**	(1.54)	(2%)
Current income taxes	**(3.35)**	(5.40)	4.35	(38%)	(177%)	**(4.40)**	(1.77)	149%
Fund flows from operations netback	**30.90**	34.35	36.22	(10%)	(15%)	**31.50**	36.99	(15%)
Reference prices								
TTF ($/mmbtu)	**7.28**	8.48	9.16	(14%)	(21%)	**8.23**	8.96	(8%)
TTF (€/mmbtu)	**4.98**	5.82	6.46	(14%)	(23%)	**5.80**	6.11	(5%)

Sales

- The price of our natural gas in the Netherlands is based on the TTF day-ahead index, as determined on the Title Transfer Facility Virtual Trading Point operated by Dutch TSO Gas Transport Services, plus various fees. GasTerra, a state owned entity, continues to purchase all of the natural gas we produce in the Netherlands.
- Sales per boe decreased 14% quarter-over-quarter, consistent with a decrease in the TTF reference price. The decrease in price was partially offset by a 5% increase in production, resulting in a 9% decrease in sales.
- On a year-over-year basis, sales per boe decreased, consistent with declines in the TTF reference price for the respective periods. For the three months ended December 31, 2015, the decrease in price was more than offset by a 79% increase in production. For the year ended December 31, 2015, the decrease in price was offset by a 17% increase in production.

Royalties

- In the Netherlands, we pay overriding royalties on certain wells associated with an acquisition completed by the Netherlands business unit in October 2013. As such, fluctuations in royalty expense in the periods presented relate to the amount of production from those wells subject to overriding royalties.

Transportation expense

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

Operating expense

- Q4 2015 operating expenses on a dollar and per boe basis increased versus Q3 2015 as a result of higher power usage and gas processing tariffs associated with our Diever-02 exploration well, which came on production in late October 2015.
- 2015 operating expenses decreased by 5% on a dollar basis compared to 2014 due in equal parts to the favourable foreign exchange impact of a stronger Canadian dollar coupled with reduced facility operation expenditures following cost reduction initiatives undertaken in response to commodity price weakness. These cost reduction initiatives were executed while growing production 17%, resulting in a 19% reduction in per unit costs.

General and administration

- Variances in general and administration expense generally relate to timing of expenditures, including the timing of allocations from Vermilion's Corporate segment.

Current income taxes

- Current income taxes in the Netherlands apply to taxable income after eligible deductions at an implied tax rate of approximately 46%. For 2016, the effective rate on current taxes is expected to be between approximately 13% and 15%. This rate is subject to change in response to commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.
- Current income taxes in Q4 2015 were lower compared to Q3 2015 due to decreased revenues. Current income taxes in Q4 2015 compared to Q4 2014 were higher due to increased revenues.
- Current income taxes for the full year ended December 31, 2015 were higher compared to 2014 as increased revenues in 2015 were combined with comparatively lower tax depletion due to accelerated tax deductions recognized in 2014.

GERMANY BUSINESS UNIT

Overview

- Vermilion entered Germany in February 2014.
- Holds a 25% interest in a four partner consortium. Associated assets include four gas producing fields spanning 11 production licenses as well as an exploration license in surrounding fields. Total license area comprises 204,000 gross acres, of which 85% is in the exploration license.
- Entered into a farm-in agreement in July 2015 that provides Vermilion with participating interest in 19 onshore exploration licenses in northwest Germany, comprising approximately 850,000 net undeveloped acres of oil and natural gas rights. Vermilion will assume operatorship for 11 of the 19 licenses during the exploration phase.
- Awarded 110,000 net acres (100% working interest) across two exploration licenses in Lower Saxony.

Operational review

	Three Months Ended			% change		Year Ended		% change
Germany business unit	**Dec 31, 2015**	**Sep 30, 2015**	**Dec 31, 2014**	**Q4/15 vs. Q3/15**	**Q4/15 vs. Q4/14**	**Dec 31, 2015**	**Dec 31, 2014**	**2015 vs. 2014**
Production								
Natural gas (mmcf/d)	**16.17**	14.00	17.71	16%	(9%)	**15.78**	14.99	5%
Total (boe/d)	**2,695**	2,333	2,952	16%	(9%)	**2,630**	2,498	5%
Activity								
Capital expenditures ($M)	**(441)**	1,605	563	(127%)	(178%)	**5,363**	2,747	95%
Acquisitions ($M)	**-**	-	-			**-**	172,871	
Gross wells drilled	**-**	-	-			**1.00**	-	
Net wells drilled	**-**	-	-			**0.25**	-	

Production

- Q4 2015 production increased by 16% quarter-over-quarter due to a planned maintenance shutdown in Q3 2015 and decreased 9% year-over-year due to additions from the Deblinghausen Z7a well that was brought on production in Q4 2014. Full year production increased 5% versus prior year, due to 2014 volumes only reflecting production from the acquisition's effective date of February 1, 2014.

Activity review

- The Burgmoor Z3a sidetrack well (25% working interest), was completed in Q2 2015 and was tied-in and placed on production in Q3 2015.
- In 2016, the majority of activity will be associated with permitting and pre-drill activities for Burgmoor Z5 and two farm-in prospects. In addition, we will continue our ongoing analysis of the proprietary geologic data associated with the farm-in assets.

Financial review

Germany business unit ($M except as indicated)	Three Months Ended Dec 31, 2015	Sep 30, 2015	Dec 31, 2014	% change Q4/15 vs. Q3/15	Q4/15 vs. Q4/14	Year Ended Dec 31, 2015	Dec 31, 2014	% change 2015 vs. 2014
Sales	**9,840**	9,523	13,359	3%	(26%)	**41,384**	41,962	(1%)
Royalties	**(1,166)**	(1,477)	(2,481)	(21%)	(53%)	**(6,479)**	(8,613)	(25%)
Transportation expense	**(508)**	(627)	(218)	(19%)	133%	**(3,269)**	(2,367)	38%
Operating expense	**(4,788)**	(2,796)	(2,862)	71%	67%	**(10,956)**	(8,686)	26%
General and administration	**(3,032)**	(1,311)	(2,200)	131%	38%	**(7,386)**	(4,688)	58%
Current income taxes	**-**	-	1,145	-	(100%)	**-**	(44)	(100%)
Fund flows from operations	**346**	3,312	6,743	(90%)	(95%)	**13,294**	17,564	(24%)
Netbacks ($/boe)								
Sales	**39.68**	44.36	49.19	(11%)	(19%)	**43.10**	46.03	(6%)
Royalties	**(4.70)**	(6.88)	(9.13)	(32%)	(49%)	**(6.75)**	(9.45)	(29%)
Transportation expense	**(2.05)**	(2.92)	(0.80)	(30%)	156%	**(3.41)**	(2.60)	31%
Operating expense	**(19.31)**	(13.03)	(10.54)	48%	83%	**(11.41)**	(9.53)	20%
General and administration	**(12.22)**	(6.11)	(8.10)	100%	51%	**(7.69)**	(5.14)	50%
Current income taxes	**-**	-	4.21	-	(100%)	**-**	(0.05)	(100%)
Fund flows from operations netback	**1.40**	15.42	24.83	(91%)	(94%)	**13.84**	19.26	(28%)
Reference prices								
TTF ($/mmbtu)	**7.28**	8.48	9.16	(14%)	(21%)	**8.23**	8.96	(8%)
TTF (€/mmbtu)	**4.98**	5.82	6.46	(14%)	(23%)	**5.80**	6.11	(5%)

Sales

- The price of our natural gas in Germany is based on the TTF month-ahead index, as determined on the Title Transfer Facility Virtual Trading Point operated by Dutch TSO Gas Transport Services, plus various fees.
- The 3% increase in sales quarter-over-quarter is due to an increase in production, partially offset by decreases in the TTF reference price.
- On a year-over-year basis, sales per boe decreased for the three months and year ended December 31, 2015 consistent with movements in the TTF reference price. For the three months ended December 31, 2015, this pricing decline was combined with a decrease in production. For the year ended December 31, 2015, the decrease in price was almost entirely offset by an increase in production.

Royalties

- Our production in Germany is subject to state and private royalties on sales after certain eligible deductions.
- In Q4 2015, royalties as a percentage of sales was 11.8%, a decrease versus both the 15.5% for Q3 2015 and 18.6% for Q4 2014. The decrease in Q4 2015 versus both comparable quarters was a result of adjustments to Q3 2015 royalties following preliminary royalty submissions recorded in the current quarter.
- Full year 2015 royalties as a percentage of sales was 15.7% versus 20.5% for 2014 as a result of lower state royalty rates in the current year.

Transportation expense

- Transportation expense in Germany relates to costs incurred to deliver natural gas from the processing facility to the customer.
- Q4 2015 transportation expense was lower than Q3 2015 due to seasonal changes in levels of transportation facility maintenance, which are typically higher at the beginning of the year. Q4 2015 transportation expense was higher than Q4 2014 due to the impact of prior period adjustments recorded in the 2014 period.
- Year-over-year, transportation expense has increased as 2014 included only eleven months of expense due to the timing of our Germany acquisition. In addition, 2015 included a prior period adjustment payment related to 2014.

Operating expense

- Operating expenses for Germany are billed monthly by the joint venture operator and primarily relate to tariffs charged for facility operations and gas processing.
- Q4 2015 operating expense was higher than both Q3 2015 and Q4 2014 due in equal parts to charges for prior period maintenance expenditures and the inclusion of a full year gas processing tariff adjustment recorded in the current quarter.
- Full year operating expense was higher on a dollar basis versus 2014 due to the inclusion of only eleven months of expense in 2014 due to the timing of our Germany acquisition and additional charges from the operator relating to 2014.

General and administration

- Q4 2015 general and administration expenses were higher than both Q3 2015 and Q4 2014 due largely to increased allocations from our Corporate segment in addition to higher staffing levels and office extension costs incurred to support our farm-in agreement.
- Full year 2015 general and administration expense increased in 2015 versus 2014 due to the aforementioned increased allocations coupled with higher staffing levels and expenditures relating to our farm-in agreement.

Current income taxes

- Current income taxes in Germany apply to taxable income after eligible deductions at a statutory tax rate of approximately 24.2%. As a function of tax pools in Germany, Vermilion does not presently pay taxes in Germany.

IRELAND BUSINESS UNIT

Overview

- 18.5% non-operating interest in the offshore Corrib gas field located approximately 83 km off the northwest coast of Ireland.
- Project comprises six offshore wells, offshore and onshore sales and transportation pipeline segments as well as a natural gas processing facility.
- Corrib is expected to produce approximately 58 mmcf/d (9,700 boe/d) net to Vermilion at peak production rates.

Operational and financial review

	Three Months Ended			% change		Year Ended		% change
Ireland business unit ($M except as indicated)	**Dec 31, 2015**	**Sep 30, 2015**	**Dec 31, 2014**	**Q4/15 vs. Q3/15**	**Q4/15 vs. Q4/14**	**Dec 31, 2015**	**Dec 31, 2014**	**2015 vs. 2014**
Sales	**57**	-	-	100%	100%	**57**	-	100%
Transportation expense	**(1,580)**	(1,766)	(1,720)	(11%)	(8%)	**(6,687)**	(6,394)	5%
Operating expense	**(15)**	-	-	100%	100%	**(15)**	-	100%
General and administration	**(714)**	(663)	(579)	8%	23%	**(2,517)**	(1,447)	74%
Fund flows from operations	**(2,252)**	(2,429)	(2,299)	(7%)	(2%)	**(9,162)**	(7,841)	17%
Reference prices								
NBP ($/mmbtu)	**7.41**	8.40	9.52	(12%)	(22%)	**8.33**	9.10	(8%)
NBP (€/mmbtu)	**5.07**	5.77	6.71	(12%)	(24%)	**5.87**	6.20	(5%)
Activity								
Capital expenditures	**12,493**	20,694	20,932	(40%)	(40%)	**66,409**	94,439	(30%)

Activity review

- On December 29, 2015, the operator, Shell E&P Ireland Limited received consent from the office of Ireland's Minister for Communication, Energy and Natural Resources.
- On December 30, 2015, natural gas began to flow from our Corrib gas project.
- Production volumes at Corrib are expected to rise over a period of approximately six months to a peak rate of approximately 58 mmcf/d (9,700 boe/d) net to Vermilion.

Transportation expense

- Transportation expense in Ireland relates to payments under a ship or pay agreement related to the Corrib project.
- Q4 2015 transportation expense is lower than Q3 2015 due to lower tariffs for the current gas year, which began in October of 2015, under the ship or pay agreement.

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 21 producing well bores.
- Wells that utilize horizontal legs (ranging in length from 500 to 3,000 plus metres) are located 600 metres below the seabed in approximately 55 metres of water depth.
- Contracted crude oil production is priced with reference to Dated Brent.

Operational review

	Three Months Ended			% change		Year Ended		% change
Australia business unit	**Dec 31, 2015**	**Sep 30, 2015**	**Dec 31, 2014**	**Q4/15 vs. Q3/15**	**Q4/15 vs. Q4/14**	**Dec 31, 2015**	**Dec 31, 2014**	**2015 vs. 2014**
Production								
Crude oil (bbls/d)	**7,824**	6,433	6,134	22%	28%	**6,454**	6,571	(2%)
Inventory (mbbls)								
Opening crude oil inventory	**172**	156	258			**37**	130	
Crude oil production	**720**	592	564			**2,356**	2,398	
Crude oil sales	**(817)**	(576)	(785)			**(2,318)**	(2,491)	
Closing crude oil inventory	**75**	172	37			**75**	37	
Activity								
Capital expenditures ($M)	**40,852**	7,966	11,616	413%	252%	**61,741**	44,283	39%
Gross wells drilled	**1.00**	-	-			**1.00**	-	
Net wells drilled	**1.00**	-	-			**1.00**	-	

Production

- Q4 2015 quarterly production increased 22% quarter-over-quarter and 28% year-over-year, due to production additions from the horizontal sidetrack well drilled in the quarter. The well was brought on production in mid-November and exhibited strong well performance, producing approximately 3,900 bbls/d through the end of Q4. Full year 2015 production decreased 2% versus the prior year.
- Production volumes are managed within corporate targets while meeting customer demands and the requirements of long-term supply agreements.
- We continue to plan for long-term production levels of between 6,000 and 8,000 bbls/d.

Activity review

- In Q4 2015, we completed a horizontal sidetrack drilling program and placed the well on production.
- Additional 2015 activities included ongoing facilities maintenance, enhancement, and refurbishment.
- We plan to drill a two-well sidetrack program in Q2 2016.

Financial review

Australia business unit ($M except as indicated)	Three Months Ended			% change		Year Ended		% change
	Dec 31, 2015	Sep 30, 2015	Dec 31, 2014	Q4/15 vs. Q3/15	Q4/15 vs. Q4/14	Dec 31, 2015	Dec 31, 2014	2015 vs. 2014
Sales	**47,952**	39,325	70,971	22%	(32%)	**162,765**	283,481	(43%)
Operating expense	**(13,941)**	(13,766)	(17,719)	1%	(21%)	**(51,676)**	(61,432)	(16%)
General and administration	**(1,768)**	(1,391)	(1,628)	27%	9%	**(5,754)**	(5,873)	(2%)
PRRT	**(1,054)**	(99)	(13,568)	965%	(92%)	**(6,878)**	(60,340)	(89%)
Corporate income taxes	**1,201**	(2,720)	(4,799)	(144%)	(125%)	**(7,230)**	(24,477)	(70%)
Fund flows from operations	**32,390**	21,349	33,257	52%	(3%)	**91,227**	131,359	(31%)
Netbacks ($/boe)								
Sales	**58.74**	68.20	90.37	(14%)	(35%)	**70.22**	113.80	(38%)
Operating expense	**(17.08)**	(23.87)	(22.56)	(28%)	(24%)	**(22.29)**	(24.66)	(10%)
General and administration	**(2.17)**	(2.41)	(2.07)	(10%)	5%	**(2.48)**	(2.36)	5%
PRRT	**(1.29)**	(0.17)	(17.28)	659%	(93%)	**(2.97)**	(24.22)	(88%)
Corporate income taxes	**1.47**	(4.72)	(6.11)	(131%)	(124%)	**(3.12)**	(9.83)	(68%)
Fund flows from operations netback	**39.67**	37.03	42.35	7%	(6%)	**39.36**	52.73	(25%)
Reference prices								
Dated Brent (US $/bbl)	**43.69**	50.26	76.27	(13%)	(43%)	**52.46**	98.99	(47%)
Dated Brent ($/bbl)	**58.34**	65.81	86.62	(11%)	(33%)	**67.09**	109.36	(39%)

Sales

- Crude oil in Australia is priced with reference to Dated Brent.
- Sales per boe decreased 14% in Q4 2015 versus Q3 2015, consistent with a decrease in the Dated Brent reference price. This decrease in sales per boe was more than offset by an increase in sold volumes, resulting in a 22% increase in sales
- Year-over-year, sales on a dollar and on a per boe basis decreased for the three months and year ended December 31, 2015, consistent with decreases in Dated Brent reference price.

Royalties and transportation expense

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

Operating expense

- Operating expense on a dollar basis remained relatively consistent between Q3 and Q4 2015. The flat cost profile was achieved while crude volumes sold increased by 42% as a result of strong production growth and a 97,000 bbl inventory draw, which led to increase recognition of deferred operating expense. A continued focus on cost reduction initiatives resulted in reduced helicopter and vessel costs, contributing to a 28% decrease in per unit costs.
- Operating expense on a dollar basis decreased for the three months and year ended December 31, 2015 versus 2014 due to cost-cutting initiatives, favourable foreign exchange from a weaker Australian dollar during 2015, and inventory variances. On a per boe basis, operating expense decreased by 24% and 10% during the three months and year ended 2015 versus 2014 as a result of savings from cost reduction initiatives undertaken in response to commodity price weakness – these initiatives included reduced vessel usage, lower diesel consumption, and reduced staffing costs.

General and administration

- Fluctuations in general and administration expense for Q4 2015 versus the comparable quarters is largely the result of the timing of expenditures. Full year 2015 general and administration expense was relatively consistent with 2014.

PRRT and corporate income taxes

- In Australia, current income taxes include both 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 include PRRT.
- Australia is not expected to incur any corporate income tax or PRRT for 2016. This is subject to change in response to commodity price fluctuations, the timing of capital expenditures and other eligible in-country adjustments.
- Combined corporate income taxes and PRRT for the three months and full year ended December 31, 2015 were lower than the comparable periods as a result of decreased revenues and increased capital spending in the 2015 periods. Q4 2015 combined taxes were lower compared to Q3 2015 as increased sales were offset by increased capital spending.

UNITED STATES BUSINESS UNIT

Overview

- Entered the United States in September 2014.
- Interests include approximately 90,700 acres of land (98% undeveloped) in the Powder River Basin of northeastern Wyoming.
- Tight oil development targeting the Turner Sand at a depth of approximately 1,500 metres.

Operational and financial review

	Three Months Ended			% change		Year Ended		% change
United States business unit ($M except as indicated)	**Dec 31, 2015**	**Sep 30, 2015**	**Dec 31, 2014**	**Q4/15 vs. Q3/15**	**Q4/15 vs. Q4/14**	**Dec 31, 2015**	**Dec 31, 2014**	**2015 vs. 2014**
Production								
Crude oil (bbls/d)	**420**	226	195	86%	115%	**231**	49	371%
NGLs (bbls/d)	**29**	-	-	100%	100%	**7**	-	100%
Natural gas (mmcf/d)	**0.20**	-	-	100%	100%	**0.05**	-	100%
Total (boe/d)	**483**	226	195	114%	148%	**247**	49	404%
Activity								
Capital expenditures	**5,643**	3,226	460	75%	1,127%	**12,250**	460	2,563%
Acquisitions	**(21)**	12,785	-			**12,764**	11,175	
Gross wells drilled	**2.00**	-	-			**3.00**	-	
Net wells drilled	**2.00**	-	-			**3.00**	-	
Sales	**1,864**	1,075	1,330	73%	40%	**4,288**	1,330	222%
Royalties	**(551)**	(309)	(366)	78%	51%	**(1,257)**	(366)	243%
Operating expense	**(271)**	(146)	(241)	86%	12%	**(742)**	(241)	208%
General and administration	**(897)**	(896)	(959)	-	(6%)	**(3,836)**	(959)	300%
Fund flows from operations	**145**	(276)	(236)	153%	161%	**(1,547)**	(236)	556%
Netbacks ($/boe)								
Sales	**41.94**	51.60	74.08	(19%)	(43%)	**47.53**	74.08	(36%)
Royalties	**(12.40)**	(14.83)	(20.38)	(16%)	(39%)	**(13.93)**	(20.38)	(32%)
Operating expense	**(6.11)**	(6.98)	(13.44)	(12%)	(55%)	**(8.23)**	(13.44)	(39%)
General and administration	**(20.18)**	(43.03)	(53.44)	(53%)	(62%)	**(42.51)**	(53.44)	(20%)
Fund flows from operations netback	**3.25**	(13.24)	(13.18)	125%	125%	**(17.14)**	(13.18)	30%
Reference prices								
WTI (US $/bbl)	**42.18**	46.43	73.15	(9%)	(42%)	**48.80**	93.00	(48%)
WTI ($/bbl)	**56.32**	60.80	83.08	(7%)	(32%)	**62.41**	102.75	(39%)
Henry Hub (US $/mmbtu)	**2.27**	2.77	4.00	(18%)	(43%)	**2.66**	4.41	(40%)
Henry Hub ($/mmbtu)	**3.03**	3.62	4.54	(16%)	(33%)	**3.41**	4.88	(30%)

Activity review

- Vermilion drilled two (2.0 net) wells in the East Finn prospect area in Q4 2015 with well completions planned for Q1 2016.
- In Q4 2015, we initiated sales of associated natural gas from our East Finn wells, enabled by the completion of construction of a gas gathering system in the area.
- During the year, we consolidated our ownership interest in the eastern Powder River Basin of Wyoming to a 100% working interest through the US $9.6 million acquisition of the remaining 30% interest that was previously outstanding. The acquisition encompassed an estimated 0.9 mmboe of 2P reserves and an additional 22,000 net acres.
- In 2016, we plan to drill one (1.0 net) well and tie-in an additional two (2.0 net) wells drilled in Q4 2015.

Sales

- The price of crude oil in the United States is directly linked to WTI, subject to market conditions in the United States.

Royalties

- Our production in the United States is subject to federal and private royalties, severance tax, and ad valorem tax.
- Royalties as a percentage of sales for the three months and year ended December 31, 2015 of approximately 29.6% was slightly higher than Q3 2015 (28.7%) and the 2014 periods (27.5%) due to nominally higher royalty rates on the well we brought online in August 2015.

Operating expense

- Operating expense decreased quarter-over-quarter by 12% from $6.98/boe to $6.11/boe.

General and administration

- General and administration expense was relatively consistent quarter-over-quarter. Full year 2015 expenditures were higher than 2014 due to the timing of the formation of the US business unit in Q4 2014.

CORPORATE

Overview

- Our Corporate segment includes costs related to our global hedging program, financing expenses, and general and administration expenses, primarily incurred in Canada and not directly related to the operations of our business units.

Financial review

	Three Months Ended			Year Ended	
($M)	**Dec 31, 2015**	**Sep 30, 2015**	**Dec 31, 2014**	**Dec 31, 2015**	**Dec 31, 2014**
General and administration recovery (expense)	**3,356**	2,359	1,224	**7,172**	(7,423)
Current income taxes	**313**	(480)	(642)	**(1,091)**	(1,420)
Interest expense	**(16,584)**	(15,420)	(12,943)	**(59,852)**	(49,655)
Realized gain on derivatives	**21,164**	10,854	22,816	**41,356**	36,712
Realized foreign exchange (loss) gain	**(252)**	309	(179)	**623**	(821)
Realized other income	**243**	227	202	**896**	732
Fund flows from operations	**8,240**	(2,151)	10,478	**(10,896)**	(21,875)

General and administration

- The increase in the recovery of general and administration costs for the three months and year ended December 31, 2015 versus the comparable periods in the prior year is due to a decrease in staff-related expenditures, general cost saving initiatives in response to declining crude oil prices, and increased salary 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

- The increase in interest expense in Q4 2015 versus all comparable periods is primarily due to increased average borrowings under our revolving credit facility. In addition, interest expense for the three months and year ended December 31, 2015 versus the comparable periods in 2014 was higher due to interest expense related to a finance lease recognized in Q1 2015.

Hedging

- The nature of our operations results in exposure to fluctuations in commodity prices, interest rates and foreign currency exchange rates. We monitor and, when appropriate, use derivative financial instruments to manage our exposure to these fluctuations. All transactions of this nature entered into are related to an underlying financial position or to future crude oil and natural gas production. We do not use derivative financial instruments for speculative purposes. We have elected not to designate any of our derivative financial instruments as accounting hedges and thus account for changes in fair value in net earnings (loss) at each reporting period. We have not obtained collateral or other security to support our financial derivatives as we review the creditworthiness of our counterparties prior to entering into derivative contracts.
- Our hedging philosophy is to hedge solely for the purposes of risk mitigation. Our approach is to hedge centrally to manage our global risk (typically with an outlook of 12 to 18 months) up to 50% of net of royalty volumes through a portfolio of forward collars, swaps, and physical fixed price arrangements.
- We believe that our hedging philosophy and approach increases the stability of revenues, cash flows and future dividends while also assisting us in the execution of our capital and development plans.
- The realized gain in Q4 2015 related primarily to amounts received on our TTF, WTI, and Dated Brent derivatives, partially offset by payments made on our foreign exchange derivatives.
- A listing of derivative positions as at December 31, 2015 is included in "Supplemental Table 2" of this MD&A.

FINANCIAL PERFORMANCE REVIEW

	Year Ended		
($M except per share)	**Dec 31, 2015**	**Dec 31, 2014**	**Dec 31, 2013**
Total assets	**4,209,220**	4,386,091	3,708,719
Long-term debt	**1,162,998**	1,238,080	990,024
Petroleum and natural gas sales	**939,586**	1,419,628	1,273,835
Net earnings (loss)	**(217,302)**	269,326	327,641
Net earnings (loss) per share			
Basic	**(1.98)**	2.55	3.24
Diluted	**(1.98)**	2.51	3.20
Cash dividends ($/share)	**2.58**	2.58	2.40

	Three Months Ended							
($M except per share)	**Dec 31, 2015**	**Sep 30, 2015**	**Jun 30, 2015**	**Mar 31, 2015**	**Dec 31, 2014**	**Sep 30, 2014**	**Jun 30, 2014**	**Mar 31, 2014**
Petroleum and natural gas sales	**234,319**	245,051	264,331	195,885	306,073	344,688	387,684	381,183
Net earnings (loss)	**(142,080)**	(83,310)	6,813	1,275	58,642	53,903	53,993	102,788
Net earnings (loss) per share								
Basic	**(1.28)**	(0.76)	0.06	0.01	0.55	0.50	0.51	1.00
Diluted	**(1.28)**	(0.76)	0.06	0.01	0.54	0.50	0.50	0.99

The following table shows a reconciliation of the change in net earnings (loss):

($M)	**Q4/15 vs. Q3/15**	**Q4/15 vs. Q4/14**	**2015 vs. 2014**
Net earnings (loss) - Comparative period	(83,310)	58,642	269,326
Changes in:			
Fund flows from operations	7,006	(49,087)	(288,698)
Equity based compensation	(4,760)	(3,140)	(7,430)
Unrealized gain or loss on derivative instruments	(4,627)	10,236	16,177
Unrealized foreign exchange gain or loss	(21,315)	(2,371)	26,386
Unrealized other expense	75	511	484
Accretion	(125)	(137)	2
Depletion and depreciation	41,031	9,369	(33,064)
Deferred tax	(87,432)	(34,480)	74,138
Impairment	11,377	(131,623)	(274,623)
Net loss - Current period	**(142,080)**	**(142,080)**	**(217,302)**

The fluctuations in net earnings (loss) from quarter-to-quarter and from year-to-year are caused by changes in both cash and non-cash based income and charges. Cash based items are reflected in fund flows from operations and include: sales, royalties, operating expenses, transportation, general and administration expense, current tax expense, interest expense, realized gains and losses on derivative instruments, and realized foreign exchange gains and losses. 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 amounts resulting from acquisitions or charges resulting from impairment or impairment recoveries.

Equity based compensation

Equity based compensation expense relates to non-cash compensation expense attributable to long-term incentives granted to directors, officers, and employees under the Vermilion Incentive Plan ("VIP"). The expense is recognized over the vesting period based on the grant date fair value of awards, adjusted for the ultimate number of awards that actually vest as determined by the Company's achievement of performance conditions.

Equity based compensation expense for the three months and year ended December 31, 2015 was higher versus the comparable periods in 2014 due to a higher average number of awards outstanding and higher grant value.

Unrealized gain or loss on derivative instruments
Unrealized gain or loss on derivative instruments arise as a result of changes in forecasted future commodity prices. 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 forecasted future commodity prices decline and vice-versa.

For the year ended December 31, 2015, we recognized an unrealized gain on derivative instruments of $43.5 million, relating primarily to our TTF, Dated Brent, and WTI swaps and collars. As at December 31, 2015, we have a net derivative asset position of $68.3 million.

Unrealized foreign exchange gain or loss
As a result of Vermilion's international operations, Vermilion conducts business in currencies other than the Canadian dollar and has monetary assets and liabilities (including cash, receivables, payables, derivative assets and liabilities, and intercompany loans) denominated in such currencies. Vermilion's exposure to foreign currencies includes the US dollar, the Euro and the Australian dollar.

Unrealized foreign exchange gains and losses are the result of translating monetary assets and liabilities held in non-functional currencies to the respective functional currencies of Vermilion and its subsidiaries. Unrealized foreign exchange primarily results from the translation of Euro denominated financial assets and US dollar denominated financial liabilities. As such, an appreciation in the Euro against the Canadian dollar will result in an unrealized foreign exchange gain while an appreciation in the US dollar against the Canadian dollar will result in an unrealized foreign exchange loss (and vice-versa).

For the three months ended December 31, 2015, the Canadian dollar weakened against the US dollar and remained relatively flat against the Euro, leading to an unrealized foreign exchange loss of $6.4 million. During the year ended December 31, 2015, the Canadian dollar weakened significantly versus the US dollar, but was offset by a strengthening in the Canadian dollar against the Euro resulting in an unrealized foreign exchange gain of $8.8 million.

Accretion
Fluctuations in accretion expense are primarily the result of changes in discount rates applicable to the balance of asset retirement obligations and additions resulting from drilling and acquisitions.

Q4 2015 accretion expense was relatively consistent with all comparative periods.

Depletion and depreciation
Fluctuations in depletion and depreciation expense are primarily the result of changes in produced crude oil and natural gas volumes.

Depletion and depreciation on a per boe basis for Q4 2015 of $18.88 was lower as compared to $28.28 in Q3 2015 and $24.42 for Q4 2014. This decrease is primarily due to increased production natural gas properties in Drayton Valley, Canada which have a lower per boe depletion expense. For the year ended December 31, 2015, depletion and depreciation on a per boe basis of $22.98 was relatively consistent with $23.31 for the comparable period in 2014 as increased production from natural gas properties in the Netherlands and light crude oil properties in Saskatchewan, Canada, which both have relatively higher per boe depletion expense, was offset with higher production from natural gas properties in Drayton Valley, Canada, which have a relatively lower per boe depletion expense.

Deferred tax
Deferred tax expense (recovery) arises primarily as a result of changes in the accounting basis and tax basis for capital assets and asset retirement obligations and changes in available tax losses. The increase in deferred tax recovery largely pertains to the tax effect on the $274.6 million impairment charge recorded in 2015, increased accounting basis depletion primarily associated with higher global production, partially offset by a valuation allowance recorded on deferred tax assets. The valuation allowance relates to certain non-capital losses for which there is uncertainty as to the Company's ability to fully utilize such losses when applying forecasted commodity prices in effect as at December 31, 2015.

Impairment
For the three months and year ended December 31, 2015, Vermilion recorded impairment charges of $131.6 million and $274.6 million, respectively, related to the light crude oil play in Saskatchewan, Canada ($267.9 million in 2015) and the shallow coal bed methane gas properties in Alberta, Canada ($6.7 million in 2015). These impairment charges were a result of declines in the price forecasts for crude oil and natural gas in Canada which decreased the expected future cash flows from the CGU.

TAXES

Corporate income tax rates

Vermilion pays corporate income taxes in France, the Netherlands, and Australia. In addition, Vermilion pays PRRT in Australia. PRRT 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.

Taxable income was subject to corporate income tax at the following rates:

Jurisdiction	2015	2014
Canada [1]	25.5% / 27.0%	25.5%
France	34.4%	34.4%
Netherlands	46.0%	46.0%
Germany	24.2%	22.8%
Ireland	25.0%	25.0%
Australia	30.0%	30.0%
United States	35.0%	35.0%

(1) Alberta corporate income tax rates increased from 10% to 12% effective July 1, 2015.

In 2012, the France government enacted a new 3% tax on dividend distributions made by entities subject to corporate income tax in France. The tax applies to any dividends paid on or after April 17, 2012 and is not recovered by any tax treaties or deductible for French corporate income tax purposes. Vermilion did not pay any dividends from its French entities in 2015.

Tax pools

As at December 31, 2015, we had the following tax pools:

($M)	Oil & Gas Assets	Tax Losses [4]	Other	Total
Canada	1,176,574 [1]	341,445	2,448	1,520,467
France	430,735 [2]	14,171	-	444,906
Netherlands	54,104 [3]	-	-	54,104
Germany	112,038 [3]	43,360	18,977	174,375
Ireland	1,028,986 [4]	429,987	-	1,458,973
Australia	265,743 [1]	-	-	265,743
United States	28,950 [1]	15,767	-	44,717
Total	3,097,130	844,730	21,425	3,963,285

(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) Deduction for current development expenditures and tax losses at 100% against taxable income

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 forecasted fund flows from operations is sufficient to finance planned capital expenditures, dividends, and abandonment and reclamation expenditures. To the extent that forecasted fund flows from operations is not expected to be sufficient to fulfill such expenditures, we will evaluate our ability to finance any excess with debt (including borrowing using the unutilized capacity of our existing revolving credit facility) or issue equity.

To ensure that we maintain a conservative balance sheet, we monitor the ratio of net debt to fund flows from operations and typically strive to maintain an internally targeted ratio of approximately 1.0 to 1.3 in a normalized commodity price environment. When prices trend higher, we may target a lower ratio and conversely, in a lower commodity price environment, the debt ratio may prove to be higher. At times, we will use our balance sheet to finance acquisitions and, in these situations, we are prepared to accept a higher ratio in the short term but will implement a strategy to reduce the ratio to acceptable levels within a reasonable period of time, usually considered to be no more than 12 to 24 months. This plan could potentially include an increase in hedging activities, a reduction in capital expenditures, an issuance of equity or the utilization of excess fund flows from operations to reduce outstanding indebtedness.

In the current low commodity price environment, Vermilion's net debt to fund flows ratio is expected to be higher than the longer term target ratio. During this period, Vermilion will remain focused on maintaining a strong balance sheet by aligning capital expenditures within forecasted fund flows from operations, which is continually monitored for revised forward price estimates, as well as by hedging additional European natural gas volumes to maintain a diversified commodity portfolio.

Long-term debt

Our long-term debt consists of our revolving credit facility and our senior unsecured notes. The applicable annual interest rates and the balances recognized on our balance sheet are as follows:

	Annual Interest Rate		As at	
($M)	**Dec 31, 2015**	**Dec 31, 2014**	**Dec 31, 2015**	**Dec 31, 2014**
Revolving credit facility	**3.1%**	**3.1%**	**1,162,998**	1,014,067
Senior unsecured notes [(1)]	**6.5%**	**6.5%**	**224,901**	224,013
Long-term debt	**3.7%**	**3.8%**	**1,387,899**	1,238,080

(1) The senior unsecured notes, which matured on February 10, 2016, are included in the current portion of long-term debt as at December 31, 2015.

Revolving Credit Facility

On January 30, 2015, Vermilion increased its credit facility from $1.5 billion to $1.75 billion. During Q2 2015, we negotiated a further expansion and extension of our existing revolving credit facilities from $1.75 billion to $2 billion with a maturity of May 2019. This allowed Vermilion to redeem the senior unsecured notes, which matured on February 10, 2016, with a portion of the credit facility. The facility bears interest at rates applicable to demand loans plus applicable margins. The following table outlines the terms of our revolving credit facility:

	As at	
	Dec 31, 2015	**Dec 31, 2014**
Total facility amount	**$2.0 billion**	$1.5 billion
Amount drawn	**$1.2 billion**	$1.0 billion
Letters of credit outstanding	**$25.2 million**	$8.6 million
Facility maturity date	**31-May-19**	31-May-17

In addition, the revolving credit facility is subject to the following covenants:

		As at	
Financial covenant	**Limit**	**Dec 31, 2015**	**Dec 31, 2014**
Consolidated total debt to consolidated EBITDA	4.0	**2.23**	1.21
Consolidated total senior debt to consolidated EBITDA	3.0	**1.83**	0.99
Consolidated total senior debt to total capitalization	50%	**36%**	31%

Our covenants include financial measures defined within our revolving credit facility agreement that are not defined under GAAP. 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 "Finance lease obligation" 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.
- Total capitalization: Includes all amounts on our balance sheet classified as "Shareholders' equity" plus consolidated total debt as defined above.

Vermilion was in compliance with its financial covenants for all periods presented.

Senior Unsecured Notes

As at December 31, 2015, we had outstanding senior unsecured notes that were senior unsecured obligations and ranked pari passu with all our unsecured and unsubordinated indebtedness. The following table outlines the terms of these notes:

Total issued and outstanding amount	$225.0 million
Interest rate	6.5% per annum
Issued date	February 10, 2011
Maturity date	February 10, 2016

Vermilion redeemed the full principal outstanding of the notes on February 10, 2016 using available capacity under the revolving credit facility. The notes were initially recognized at fair value net of transaction costs and were subsequently measured at amortized cost using an effective interest rate of 7.1%.

Net debt

Net debt is reconciled to its most directly comparable GAAP measure, long-term debt, as follows:

	As at	
($M)	**Dec 31, 2015**	**Dec 31, 2014**
Long-term debt	**1,162,998**	1,238,080
Current liabilities [(1)]	**503,731**	365,729
Current assets	**(284,778)**	(338,159)
Net debt	**1,381,951**	1,265,650
Ratio of net debt to fund flows from operations	**2.7**	1.6

(1) Includes the current portion of long-term debt, which, as at December 31, 2015, represented the senior unsecured notes that matured on February 10, 2016.

Long term debt, including the current portion, as at December 31, 2015, increased to $1.39 billion from $1.24 billion as at December 31, 2014 as a result of draws on the revolving credit facility during the current year to fund capital expenditures, particularly relating to development expenditures in Canada, France, Ireland, and Australia. The increase in long-term debt resulted in an increase to net debt from $1.27 billion to $1.38 billion. As a result of this increase to long-term debt coupled with weak commodity prices, the ratio of net debt to fund flows from operations increased from 1.6 times as at December 31, 2014 to 2.7 times for the year ended December 31, 2015.

Shareholders' capital

During the year ended December 31, 2015, we maintained monthly dividends at $0.215 per share and declared dividends which totalled $283.6 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 31, 2013	$0.200
January 2014 to Present	$0.215

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. As a further step to preserve our financial flexibility and conservatively exercise our access to capital, we amended our existing DRIP to include a Premium Dividend™ Component in February 2015. The Premium Dividend™ Component, when combined with our continuing Dividend Reinvestment Component, increases our access to the lowest cost sources of equity capital available. While the Premium Dividend™ results in a modest amount of equity issuance, we believe it represents the most prudent approach to preserving near-term balance sheet strength. We view implementation of a Premium Dividend™ as a short-term measure to maintain our financial flexibility while we continue to lower our unit costs and await further clarity on the direction of commodity prices. Both components of our program can be reduced or eliminated at the company's discretion, offering considerable flexibility. We will actively monitor our ongoing needs and manage our continued use of each component as circumstances dictate.

Although we currently expect to be able to maintain our current dividend, fund flows from operations may not be sufficient during this period to fund cash dividends, capital expenditures and asset retirement obligations. We will evaluate our ability to finance any shortfalls 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 as at December 31, 2014	107,303	1,959,021
Issuance of shares pursuant to the dividend reinvestment and Premium Dividend™ plans	3,338	155,033
Vesting of equity based awards	1,158	56,855
Share-settled dividends on vested equity based awards	135	7,561
Shares issued pursuant to the employee savings and bonus plans	57	2,619
Balance as at December 31, 2015	111,991	2,181,089

As at December 31, 2015, there were approximately 1.7 million VIP awards outstanding. As at February 25, 2016, there were approximately 113.0 million common shares issued and outstanding.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

As at December 31, 2015, 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	226,625	-	1,171,620	-	1,398,245
Operating lease obligations	12,535	22,049	16,617	9,288	60,489
Ship or pay agreement relating to the Corrib project	8,215	8,893	7,292	40,446	64,846
Purchase obligations	17,897	4,071	3,156	-	25,124
Drilling and service agreements	23,205	2,480	-	-	25,685
Total contractual obligations and commitments	288,477	37,493	1,198,685	49,734	1,574,389

ASSET RETIREMENT OBLIGATIONS

As at December 31, 2015, asset retirement obligations were $305.6 million compared to $350.8 million as at December 31, 2014.

The decrease in asset retirement obligations is largely attributable to an overall increase in the discount rates applied to the abandonment obligations.

RISKS AND UNCERTAINTIES

Crude oil and natural gas exploration, production, acquisition and marketing operations involve a number of risks and uncertainties including financial risks and uncertainties. These include fluctuations in commodity prices, exchange rates and interest rates as well as uncertainties associated with reserve and resource volumes, sales volumes and government regulatory and income tax regime changes. These and other related risks and uncertainties are discussed in additional detail below.

Commodity prices
Our operational results and financial condition is dependent on the prices received for crude oil and natural gas production. Crude oil and natural gas prices have fluctuated significantly during recent years and are determined by supply and demand factors, including weather and general economic conditions as well as conditions in other crude oil and natural gas producing regions.

Exchange rates
Much of our revenue stream is priced in U.S. dollars and as such an increase in the strength of the Canadian dollar relative to the U.S. dollar may result in the receipt of fewer Canadian dollars with respect to our production. In addition, we incur expenses and capital costs in U.S. dollars, Euros and Australian dollars and accordingly, the Canadian dollar equivalent of these expenditures as reported in our financial results is impacted by the prevailing exchange rates at the time the transaction occurs. We monitor risks associated with exchange rates and, when appropriate, use derivative financial instruments to manage our exposure to these risks.

Production and sales volumes
The operation of crude oil and natural gas wells and facilities involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to us and possible liability to third parties. We maintain 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. We may become liable for damages arising from such events against which we cannot insure or against which we may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities may materially impact our financial results.

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

An increase in operating costs or a decline in our production level could have an adverse effect on our financial results. The level of production may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond our control. A significant decline in production could result in materially lower revenues.

Interest rates
An increase in interest rates could result in a significant increase in the amount we pay to service debt.

Reserve volumes
Our reserve volumes and related reserve values support the carrying value of our crude oil and natural gas assets on the consolidated balance sheets and provide the basis to calculate the depletion of those assets. There are numerous uncertainties inherent in estimating quantities of reserves and future net revenues to be derived therefrom, including many factors beyond our control. These include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of crude oil, NGLs and natural gas, operating expenses, well abandonment and salvage values, royalties and any government levies that may be imposed over the producing life of the reserves. These assumptions were based on estimated prices in use at the date the evaluation was prepared, and many of these assumptions are subject to change and are beyond our control. Actual production and income derived therefrom will vary from these evaluations, and such variations could be material.

Asset retirement obligations
Our asset retirement obligations are based on environmental regulations and estimates of future costs and the timing of expenditures. Changes in environmental regulations, the estimated costs associated with reclamation activities and the related timing may impact our financial position and results of operations.

Government regulation and income tax regime
Our operations are governed by many levels of government, including municipal, state, provincial and federal governments, in Canada, France, the Netherlands, Australia, Germany, Ireland and the United States. We are 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 licences. The regulatory process involved in each of the countries in which we operate is not uniform and regulatory regimes vary as to complexity, timeliness of access to, and response from, regulatory bodies and other matters specific to each jurisdiction. If regulatory approvals or permits are delayed or not obtained, there can also be delays or abandonment of projects and decreases in production and increases in costs, potentially resulting in us being unable to fully execute our strategy. Governments may also amend or create new legislation and regulatory bodies may also amend regulations or impose additional requirements which could result in increased capital, operating and compliance costs.

There can be no assurance that income tax laws and government incentive programs relating to the crude oil and natural gas industry in Canada and the foreign jurisdictions in which we operate, will not be changed in a manner which adversely affects the results of our operations.

A change in the royalty regime resulting in an increase in royalties would reduce our net earnings and could make future capital expenditures or our operations uneconomic and could, in the event of a material increase in royalties, make it more difficult to service and repay outstanding debt. Any material increase in royalties would also significantly reduce the value of the associated assets.

FINANCIAL RISK MANAGEMENT

To mitigate the aforementioned risks 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 highly 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/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 management to make estimates, judgments and assumptions that affect reported assets, liabilities, revenues and expenses, gains and losses, and disclosures of any possible contingencies. These estimates and assumptions are developed based on the best available information which management believed to be reasonable at the time such estimates and assumptions were made. As such, these assumptions are uncertain at the time estimates are made and could change, resulting in a material impact on our consolidated financial statements or financial performance. Estimates are reviewed by management on an ongoing basis, and as a result, certain estimates may change from period to period due to the availability of new information or changes in circumstances. Additionally, as a result of the unique circumstances of each jurisdiction in which we operate, the critical accounting estimates may affect one or more jurisdictions.

The following discussion outlines what management believes to be the most critical accounting policies involving the use of estimates and assumptions.

Depletion and depreciation
We classify our assets into depletion units, which are groups of assets or properties that are within a specific production area and have similar economic lives. The depletion units represent the lowest level of disaggregation for which we accumulate costs for the purposes of calculating and recording 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 proven and probable reserves, taking into account the future development costs necessary to bring the applicable reserves into production. As a result, depletion and depreciation charges are based on estimates of total proven and probable reserves that we expect to recover in the future. The reserve estimates are reviewed annually by management or when material changes occur to the underlying assumptions.

Asset retirement obligations
Our estimate of asset retirement obligations are based on past experience and current economic factors which management believes are reasonable. The estimates include assumptions of environmental regulations, legal requirements, technological advances, inflation and the timing of expenditures, all of which impact our measurement of the present value of the obligations. Due to these estimates, the actual cost of the obligation may change from period to period due to new information being available. Several or all of these estimates are subject to change and such changes could have a material impact on our financial position and net earnings.

Assessment of impairments
Impairment tests are performed at the level of the cash generating unit ("CGU"), which are determined based on management's judgment of the lowest level at which there are identifiable cash inflows which are largely independent of the cash inflows of other groups of assets or properties. The factors used to determine CGUs vary by country due to the unique operating and geographic circumstances in each jurisdiction. However, in general, we will assess the following factors in determining whether a group of assets generate largely independent cash inflows: 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 or transport production.

The calculation of the recoverable amount of CGUs is based on market factors as well as estimates of reserves and resources and future costs required to develop reserves and resources. Our reserve and resource estimates and the related future cash flows are subject to measurement uncertainty, and the impact on the consolidated financial statements in future periods could be material. Considerable judgment is used in determining the recoverable amount of petroleum and natural gas assets as well as exploration and evaluation assets, including determining the quantity of reserves and resources, the time horizon to develop and produce such reserves and resources, and the estimated revenues and expenditures from such production.

Taxes
Tax interpretations, regulations and legislation in the various jurisdictions in which we operate are subject to change. Such changes can affect the timing of the reversal of temporary tax differences, the tax rates in effect when such differences reverse and our ability to use tax losses and other credits in the future. The determination of deferred tax amounts recognized in the consolidated financial statements was based on management's assessment of the tax positions, including consideration of their technical merits and communications with tax authorities. The effect of a change in income tax rates or legislation on tax assets and liabilities is recognized in net earnings in the period in which the change is enacted.

OFF BALANCE SHEET ARRANGEMENTS

We have certain lease agreements that are entered into in the normal course of operations, including operating leases for which no asset or liability value has been assigned to the consolidated balance sheet as at December 31, 2015.
We have not entered into any guarantee or off balance sheet arrangements that would materially impact our financial position or results of operations.

ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

The impacts of the adoption of the following pronouncements are currently being evaluated.

IFRS 9 "Financial Instruments"
On July 24, 2014, the IASB issued the final element of its comprehensive response to the financial crisis by issuing IFRS 9 "Financial Instruments". The improvements introduced by IFRS 9 includes a model for classification and measurement, a single, forward-looking 'expected loss' impairment model and a substantially-reformed approach to hedge accounting. Vermilion will adopt the standard for reporting periods beginning January 1, 2018.

IFRS 15 "Revenue from Contracts with Customers"
On May 28, 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers", a new standard that specifies recognition requirements for revenue as well as requiring entities to provide the users of financial statements with more informative and relevant disclosures. The standard replaces IAS 11 "Construction Contracts" and IAS 18 "Revenue" as well as a number of revenue-related interpretations. Vermilion will adopt the standard for reporting periods beginning January 1, 2018.

IFRS 16 "Leases"
On January 13, 2016, the IASB issued IFRS 16, "Leases", a new standard which will replace IAS 17, "Leases". Under IFRS 16, a single recognition and measurement model will apply for lessees which will require recognition of assets and liabilities for most leases. Vermilion will adopt the standard for reporting periods beginning January 1, 2019.

HEALTH, SAFETY AND ENVIRONMENT

We are committed to ensuring we conduct our activities 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 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 workplace free of incidents. Our mantra is HSE: Everywhere. Everyday. Everyone.

We maintain health, safety and environmental practices and procedures that comply with or exceed regulatory requirements and industry standards. It is a condition of employment that our personnel work safely and in accordance with established regulations and procedures.

In 2015, we remained committed to the principles of the Responsible Canadian Energy™ program set out by the Canadian Association of Petroleum Producers. Responsible Canadian Energy™ is an association-wide performance reporting program to demonstrate progress in environmental, health, safety, and social performance.

We uphold our commitment to keep our people safe and to reduce impacts to land, water and air, as policies and procedures demonstrating leadership in these areas, were maintained and further developed in 2015. Examples of our accomplishments during the year included:

- Maintained clear priorities around 5 key focus areas of HSE Culture, Communication and Knowledge Management, Technical Safety Management, Incident Prevention and Operational Stewardship & Sustainability;
- Completed and published our Corporate Sustainability Report;
- Reported our CO_2e emissions to the Carbon Disclosure Project, achieving a 100% score and a CDLI ranking;
- Emphasized improving energy efficiency, greenhouse gas emissions reduction and water efficiency optimization;
- Further refined and expanded our enterprise wide corporate risk register;
- Developed a robust organizational wide HSE leadership training program to improve hazard identification and risk reduction;
- Implemented a fair culture policy to ensure transparency in our processes;
- Developed a robust risk mitigation program around our top fatal risk and energy type exposures;
- Developed a robust hazard identification and risk mitigation program specific to environmentally sensitive areas;
- Audited our HSE and asset integrity management systems;
- Updated various key Corporate HSE Standards such as our process hazards analysis;
- Reduced long-term environmental liabilities through decommissioning, abandoning and reclaiming well leases and facilities;
- Performed continuous auditing, management inspections and workforce observations to identify potential hazards and apply risk reduction measures;
- Developed, communicated and measured against leading and lagging HSE key performance indicators;
- Further enhanced of our competency and training programs;
- Managed our waste products by reducing, recycling and recovering; and
- Continued risk management efforts in addition to detailed emergency-response planning.

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.

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. 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 will be provided in our Management Proxy Circular, which will be filed on SEDAR (www.sedar.com) and mailed to all shareholders on April 6, 2016.

A summary of the significant differences between the governance practices of the Company and those required of U.S. domestic companies under the New York Stock Exchange listing standards can be found in the Governance section of the Company's website at *http://www.vermilionenergy.com/about/governance.cfm*.

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, 2015, 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, 2015. The effectiveness of Vermilion's internal control over financial reporting as of December 31, 2015 has been audited by Deloitte LLP, as reflected in their report included in the 2015 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, 2015, 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. Natural gas sales volumes have been converted on a basis of six thousand cubic feet of natural gas to one barrel of oil equivalent.

	Three Months Ended December 31, 2015			Year Ended December 31, 2015			Three Months Ended December 31, 2014	Year Ended December 31, 2014
	Oil & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Oil & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Total $/boe	Total $/boe
Canada								
Sales	44.03	2.57	**28.94**	49.73	2.78	**34.32**	51.27	64.06
Royalties	(5.15)	(0.12)	**(2.80)**	(5.26)	(0.07)	**(3.01)**	(7.12)	(7.81)
Transportation	(2.04)	(0.16)	**(1.48)**	(2.38)	(0.17)	**(1.75)**	(1.57)	(1.74)
Operating	(10.97)	(1.40)	**(9.62)**	(10.47)	(1.41)	**(9.54)**	(8.80)	(9.07)
Operating netback	25.87	0.89	**15.04**	31.62	1.13	**20.02**	33.78	45.44
General and administration			**(1.44)**			**(1.81)**	(1.29)	(2.00)
Fund flows from operations netback			**13.60**			**18.21**	32.49	43.44
France								
Sales	54.88	2.81	**54.20**	63.31	2.52	**62.67**	79.25	105.43
Royalties	(6.23)	(0.32)	**(6.15)**	(6.06)	(0.33)	**(6.00)**	(6.07)	(6.95)
Transportation	(3.72)	-	**(3.65)**	(3.47)	-	**(3.42)**	(3.94)	(4.64)
Operating	(13.55)	(1.81)	**(13.50)**	(11.34)	(1.31)	**(11.30)**	(13.01)	(15.09)
Operating netback	31.38	0.68	**30.90**	42.44	0.88	**41.95**	56.23	78.75
General and administration			**(4.18)**			**(4.50)**	(3.62)	(5.12)
Other income			**-**			**7.08**	-	-
Current income taxes			**3.87**			**(5.29)**	(5.89)	(16.36)
Fund flows from operations netback			**30.59**			**39.24**	46.72	57.27
Netherlands								
Sales	48.30	7.09	**42.61**	49.98	7.79	**46.77**	52.07	52.65
Royalties	-	(0.04)	**(0.26)**	-	(0.19)	**(1.12)**	(2.40)	(2.13)
Operating	-	(1.21)	**(7.17)**	-	(1.39)	**(8.24)**	(12.70)	(10.22)
Operating netback	48.30	5.84	**35.18**	49.98	6.21	**37.41**	36.97	40.30
General and administration			**(0.93)**			**(1.51)**	(5.10)	(1.54)
Current income taxes			**(3.35)**			**(4.40)**	4.35	(1.77)
Fund flows from operations netback			**30.90**			**31.50**	36.22	36.99
Germany								
Sales	-	6.61	**39.68**	-	7.18	**43.10**	49.19	46.03
Royalties	-	(0.78)	**(4.70)**	-	(1.12)	**(6.75)**	(9.13)	(9.45)
Transportation	-	(0.34)	**(2.05)**	-	(0.57)	**(3.41)**	(0.80)	(2.60)
Operating	-	(3.22)	**(19.31)**	-	(1.90)	**(11.41)**	(10.54)	(9.53)
Operating netback	-	2.27	**13.62**	-	3.59	**21.53**	28.72	24.45
General and administration			**(12.22)**			**(7.69)**	(8.10)	(5.14)
Current income taxes			**-**			**-**	4.21	(0.05)
Fund flows from operations netback			**1.40**			**13.84**	24.83	19.26
Australia								
Sales	58.74	-	**58.74**	70.22	-	**70.22**	90.37	113.80
Operating	(17.08)	-	**(17.08)**	(22.29)	-	**(22.29)**	(22.56)	(24.66)
PRRT [(1)]	(1.29)	-	**(1.29)**	(2.97)	-	**(2.97)**	(17.28)	(24.22)
Operating netback	40.37	-	**40.37**	44.96	-	**44.96**	50.53	64.92
General and administration			**(2.17)**			**(2.48)**	(2.07)	(2.36)
Corporate income taxes			**1.47**			**(3.12)**	(6.11)	(9.83)
Fund flows from operations netback			**39.67**			**39.36**	42.35	52.73
United States								
Sales	44.83	0.52	**41.94**	49.10	0.52	**47.53**	74.08	74.08
Royalties	(13.19)	(0.30)	**(12.40)**	(14.36)	(0.30)	**(13.93)**	(20.38)	(20.38)
Operating	(6.56)	-	**(6.11)**	(8.52)	-	**(8.23)**	(13.44)	(13.44)
Operating netback	25.08	0.22	**23.43**	26.22	0.22	**25.37**	40.26	40.26
General and administration			**(20.18)**			**(42.51)**	(53.44)	(53.44)
Fund flows from operations netback			**3.25**			**(17.14)**	(13.18)	(13.18)
Total Company								
Sales	51.64	4.55	**41.04**	58.80	4.98	**47.07**	63.79	77.75
Realized hedging gain	2.69	0.84	**3.71**	1.32	0.53	**2.07**	4.76	2.01
Royalties	(4.32)	(0.16)	**(2.85)**	(4.58)	(0.24)	**(3.30)**	(5.41)	(5.92)
Transportation	(2.09)	(0.23)	**(1.78)**	(2.30)	(0.30)	**(2.09)**	(1.98)	(2.32)
Operating	(13.35)	(1.52)	**(11.50)**	(13.06)	(1.46)	**(11.32)**	(12.48)	(12.72)
PRRT [(1)]	(0.33)	-	**(0.18)**	(0.58)	-	**(0.34)**	(2.83)	(3.30)
Operating netback	34.24	3.48	**28.44**	39.60	3.51	**32.09**	- 45.85 -	55.50
General and administration			**(2.18)**			**(2.68)**	(2.76)	(3.38)
Interest expense			**(2.90)**			**(3.00)**	(2.70)	(2.72)
Realized foreign exchange (loss) gain			**(0.04)**			**0.03**	(0.03)	(0.04)
Other income			**0.04**			**1.64**	0.04	0.04
Corporate income taxes [(1)]			**0.55**			**(2.22)**	(1.73)	(5.31)
Fund flows from operations netback			**23.91**			**25.86**	38.67	44.09

(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 following tables outline Vermilion's outstanding risk management positions as at December 31, 2015:

	Note	Volume	Strike Price(s)
Crude Oil			
WTI - Collar			
July 2015 - March 2016	1	250 bbl/d	75.00 - 83.45 CAD $
July 2015 - June 2016	2	500 bbl/d	75.50 - 85.08 CAD $
Dated Brent - Collar			
July 2015 - June 2016	3	1,000 bbl/d	80.50 - 93.49 CAD $
July 2015 - June 2016	4	500 bbl/d	64.50 - 75.48 US $
October 2015 - June 2016	5	250 bbl/d	82.00 - 94.55 CAD $
January 2016 - June 2016	1	250 bbl/d	84.00 - 93.70 CAD $
North American Natural Gas			
AECO - Collar			
November 2015 - March 2016		2,500 GJ/d	2.50 - 3.76 CAD $
November 2015 - October 2016		10,000 GJ/d	2.56 - 3.23 CAD $
January 2016 - December 2016		10,000 GJ/d	2.53 - 3.29 CAD $
April 2016 - October 2016		5,000 GJ/d	2.30 - 2.80 CAD $
AECO Basis - Fixed Price Differential			
November 2015 - March 2016		2,500 mmbtu/d	Nymex HH less 0.47 US $
Nymex HH - Collar			
November 2015 - March 2016	6	5,000 mmbtu/d	3.25 - 3.86 US $

(1) The contracted volumes increase to 500 boe/d for any monthly settlement periods above the contracted ceiling price and are settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).
(2) The contracted volumes increase to 1,250 boe/d for any monthly settlement periods above the contracted ceiling price and are settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).
(3) The contracted volumes increase to 2,500 boe/d for any monthly settlement periods above the contracted ceiling price and are settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).
(4) The contracted volumes increase to 1,000 boe/d for any monthly settlement periods above the contracted ceiling price.
(5) The contracted volumes increase to 750 boe/d for any monthly settlement periods above the contracted ceiling price and are settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).
(6) The contracted volumes increase to 10,000 mmbtu/d for any monthly settlement periods above the contracted ceiling price.

Supplemental Table 2: Hedges (Continued)

	Note	Volume	Strike Price(s)
European Natural Gas			
NBP - Call			
October 2016 - March 2017		2,638 GJ/d	4.64 GBP £
NBP - Collar			
April 2016 - March 2017		2,638 GJ/d	3.79 - 4.53 GBP £
January 2017 - December 2017		2,638 GJ/d	3.22 - 3.75 GBP £
January 2018 - December 2018		2,638 GJ/d	2.99 - 3.63 GBP £
NBP - Put			
April 2016 - September 2016		2,638 GJ/d	3.79 GBP £
NBP - Swap			
July 2015 - March 2016		2,592 GJ/d	6.42 EUR €
October 2015 - March 2016		10,368 GJ/d	6.54 EUR €
January 2016 - June 2016		5,184 GJ/d	6.24 EUR €
January 2016 - June 2016		2,592 GJ/d	6.82 US $
July 2016 - March 2017		2,592 GJ/d	5.43 EUR €
January 2017 - December 2017	1	2,638 GJ/d	4.00 GBP £
January 2018 - December 2018	2	2,638 GJ/d	3.83 GBP £
TTF - Call			
October 2016 - March 2017		2,592 GJ/d	6.03 EUR €
TTF - Collar			
January 2016 - December 2016	3	2,592 GJ/d	5.76 - 6.50 EUR €
April 2016 - December 2016	4	12,960 GJ/d	5.58 - 6.21 EUR €
April 2016 - March 2017	5	5,184 GJ/d	5.28 - 6.35 EUR €
July 2016 - December 2016		2,592 GJ/d	5.00 - 5.63 EUR €
July 2016 - March 2017	3	2,592 GJ/d	5.07 - 6.56 EUR €
July 2016 - March 2018	3	2,592 GJ/d	5.32 - 6.54 EUR €
October 2016 - December 2017		2,592 GJ/d	5.00 - 5.89 EUR €
January 2017 - December 2017	6	7,776 GJ/d	5.00 - 6.15 EUR €
January 2018 - December 2018		5,184 GJ/d	4.17 - 5.03 EUR €
TTF - Put			
April 2016 - September 2016		2,592 GJ/d	5.21 EUR €
TTF - Swap			
January 2015 - March 2016		5,184 GJ/d	6.40 EUR €
January 2015 - June 2016		2,592 GJ/d	6.07 EUR €
February 2015 - March 2016		5,184 GJ/d	6.24 EUR €
April 2015 - March 2016		5,832 GJ/d	6.18 EUR €
October 2015 - March 2016		2,592 GJ/d	6.64 EUR €
January 2016 - June 2016		5,184 GJ/d	5.94 EUR €
April 2016 - December 2016		2,592 GJ/d	5.91 EUR €
July 2016 - June 2018		2,700 GJ/d	5.58 EUR €
October 2016 - December 2016		2,592 GJ/d	5.45 EUR €
January 2017 - December 2017	7	2,592 GJ/d	5.04 EUR €
Electricity			
AESO - Swap			
January 2016 - December 2016		93.6 MWh/d	38.58 CAD $
Interest Rate			
CDOR to fixed - Swap			
September 2015 - September 2019		100,000,000 CAD $/year	1.00 %
October 2015 - October 2019		100,000,000 CAD $/year	1.10 %

(1) On the last business day of each month, the counterparty has the option to increase the contracted volumes by an additional 2,638 GJ/d at the contracted price, for the following month.
(2) On the last business day of each month, the counterparty has the option to increase the contracted volumes to 7,913 GJ/d at the contracted price, for the following month.
(3) The contracted volumes increase to 5,184 GJ/d for any monthly settlement periods above the contracted ceiling price.
(4) The contracted volumes increase to 15,552 GJ/d for any monthly settlement periods above the contracted ceiling price.
(5) The contracted volumes increase to 10,368 GJ/d for any monthly settlement periods above the contracted ceiling price.
(6) The contracted volumes increase to 18,144 GJ/d for any monthly settlement periods above the contracted ceiling price.
(7) On the last business day of each month, the counterparty has the option to increase the contracted volumes by an additional 5,184 GJ/d at the contracted price, for the following month.

Supplemental Table 3: Capital Expenditures

By classification ($M)	Three Months Ended Dec 31, 2015	Sep 30, 2015	Dec 31, 2014	Year Ended Dec 31, 2015	Dec 31, 2014
Drilling and development	**128,996**	93,381	151,395	**486,861**	618,689
Exploration and evaluation	**-**	-	14,848	**-**	69,035
Capital expenditures	**128,996**	93,381	166,243	**486,861**	687,724
Property acquisition	**6,227**	22,155	1,652	**28,897**	220,726
Corporate acquisition	**-**	-	-	**-**	381,139
Acquisitions	**6,227**	22,155	1,652	**28,897**	601,865

By category ($M)	Three Months Ended Dec 31, 2015	Sep 30, 2015	Dec 31, 2014	Year Ended Dec 31, 2015	Dec 31, 2014
Land	**819**	763	1,457	**3,793**	9,506
Seismic	**4,217**	810	7,598	**8,243**	19,034
Drilling and completion	**58,327**	39,712	69,691	**212,358**	311,696
Production equipment and facilities	**55,662**	44,589	77,272	**218,963**	275,538
Recompletions	**6,338**	3,948	7,696	**26,689**	36,234
Other	**3,633**	3,559	2,529	**16,815**	35,716
Capital expenditures	**128,996**	93,381	166,243	**486,861**	687,724
Acquisitions	**6,227**	22,155	1,652	**28,897**	601,865
Total capital expenditures and acquisitions	**135,223**	115,536	167,895	**515,758**	1,289,589

By country ($M)	Three Months Ended Dec 31, 2015	Sep 30, 2015	Dec 31, 2014	Year Ended Dec 31, 2015	Dec 31, 2014
Canada	**33,723**	45,286	87,113	**216,158**	750,390
France	**24,164**	17,511	37,189	**92,582**	147,852
Netherlands	**18,810**	5,297	10,022	**47,325**	61,740
Germany	**(441)**	1,605	563	**5,363**	175,618
Ireland	**12,493**	20,694	20,932	**66,409**	94,439
Australia	**40,852**	7,966	11,616	**61,741**	44,283
United States	**5,622**	16,011	460	**25,014**	11,635
Corporate	**-**	1,166	-	**1,166**	3,632
Total capital expenditures and acquisitions	**135,223**	115,536	167,895	**515,758**	1,289,589

Supplemental Table 4: Production

	Q4/15	Q3/15	Q2/15	Q1/15	Q4/14	Q3/14	Q2/14	Q1/14	Q4/13	Q3/13	Q2/13	Q1/13
Canada												
Crude oil (bbls/d)	**7,964**	9,195	10,182	10,893	11,384	11,469	12,676	9,437	8,719	7,969	8,885	7,966
NGLs (bbls/d)	**5,159**	4,513	3,755	2,976	2,741	2,291	2,796	2,071	1,699	1,897	1,725	1,335
Natural gas (mmcf/d)	**87.90**	71.94	64.66	61.78	58.36	57.07	57.59	49.53	41.43	43.40	43.69	41.04
Total (boe/d)	**27,773**	25,698	24,713	24,165	23,851	23,272	25,070	19,763	17,322	17,099	17,892	16,140
% of consolidated	**45%**	47%	48%	48%	49%	47%	49%	42%	43%	41%	42%	41%
France												
Crude oil (bbls/d)	**12,537**	12,310	12,746	11,463	11,133	11,111	11,025	10,771	11,131	11,625	10,390	10,330
Natural gas (mmcf/d)	**1.36**	1.47	1.03	-	-	-	-	-	-	5.23	4.19	4.21
Total (boe/d)	**12,763**	12,555	12,917	11,463	11,133	11,111	11,025	10,771	11,131	12,496	11,088	11,032
% of consolidated	**21%**	22%	25%	23%	22%	22%	21%	23%	27%	30%	26%	29%
Netherlands												
NGLs (bbls/d)	**110**	109	112	63	81	63	96	69	62	48	50	96
Natural gas (mmcf/d)	**56.34**	53.56	32.43	36.41	31.35	38.07	40.35	43.15	37.53	28.78	38.52	36.91
Total (boe/d)	**9,500**	9,035	5,517	6,132	5,306	6,407	6,822	7,260	6,318	4,845	6,470	6,248
% of consolidated	**16%**	16%	11%	12%	11%	13%	13%	16%	15%	12%	15%	16%
Germany												
Natural gas (mmcf/d)	**16.17**	14.00	16.18	16.80	17.71	15.38	16.13	10.64	-	-	-	-
Total (boe/d)	**2,695**	2,333	2,696	2,801	2,952	2,563	2,689	1,773	-	-	-	-
% of consolidated	**4%**	4%	5%	6%	6%	5%	5%	4%	-	-	-	-
Ireland												
Natural gas (mmcf/d)	**0.12**	-	-	-	-	-	-	-	-	-	-	-
Total (boe/d)	**20**	-	-	-	-	-	-	-	-	-	-	-
% of consolidated	**-**	-	-	-	-	-	-	-	-	-	-	-
Australia												
Crude oil (bbls/d)	**7,824**	6,433	5,865	5,672	6,134	6,567	6,483	7,110	6,189	7,070	7,363	5,287
% of consolidated	**13%**	11%	11%	11%	12%	13%	12%	15%	15%	17%	17%	14%
United States												
Crude oil (bbls/d)	**420**	226	123	153	195	-	-	-	-	-	-	-
NGLs (bbls/d)	**29**	-	-	-	-	-	-	-	-	-	-	-
Natural gas (mmcf/d)	**0.20**	-	-	-	-	-	-	-	-	-	-	-
Total (boe/d)	**483**	226	123	153	195	-	-	-	-	-	-	-
% of consolidated	**1%**	-	-	-	-	-	-	-	-	-	-	-
Consolidated												
Crude oil & NGLs (bbls/d)	**34,043**	32,786	32,783	31,220	31,668	31,501	33,076	29,458	27,800	28,609	28,413	25,014
% of consolidated	**56%**	58%	63%	62%	64%	63%	63%	63%	68%	69%	66%	65%
Natural gas (mmcf/d)	**162.09**	140.97	114.29	115.00	107.42	110.52	114.08	103.32	78.96	77.41	86.40	82.16
% of consolidated	**44%**	42%	37%	38%	36%	37%	37%	37%	32%	31%	34%	35%
Total (boe/d)	**61,058**	56,280	51,831	50,386	49,571	49,920	52,089	46,677	40,960	41,510	42,813	38,707

Supplemental Table 4: Production (Continued)

	2015	2014	2013	2012	2011	2010
Canada						
Crude oil (bbls/d)	**9,550**	11,248	8,387	7,659	4,701	2,778
NGLs (bbls/d)	**4,108**	2,476	1,666	1,232	1,297	1,427
Natural gas (mmcf/d)	**71.65**	55.67	42.39	37.50	43.38	43.91
Total (boe/d)	**25,598**	23,001	17,117	15,142	13,227	11,524
% of consolidated	**46%**	47%	41%	40%	38%	36%
France						
Crude oil (bbls/d)	**12,267**	11,011	10,873	9,952	8,110	8,347
Natural gas (mmcf/d)	**0.97**	-	3.40	3.59	0.95	0.92
Total (boe/d)	**12,429**	11,011	11,440	10,550	8,269	8,501
% of consolidated	**23%**	22%	28%	28%	23%	26%
Netherlands						
NGLs (bbls/d)	**99**	77	64	67	58	35
Natural gas (mmcf/d)	**44.76**	38.20	35.42	34.11	32.88	28.31
Total (boe/d)	**7,559**	6,443	5,967	5,751	5,538	4,753
% of consolidated	**14%**	13%	15%	15%	16%	15%
Germany						
Natural gas (mmcf/d)	**15.78**	14.99	-	-	-	-
Total (boe/d)	**2,630**	2,498	-	-	-	-
% of consolidated	**5%**	5%	-	-	-	-
Ireland						
Natural gas (mmcf/d)	**0.03**	-	-	-	-	-
Total (boe/d)	**5**	-	-	-	-	-
% of consolidated	**-**	-	-	-	-	-
Australia						
Crude oil (bbls/d)	**6,454**	6,571	6,481	6,360	8,168	7,354
% of consolidated	**12%**	13%	16%	17%	23%	23%
United States						
Crude oil (bbls/d)	**231**	49	-	-	-	-
NGLs (bbls/d)	**7**	-				
Natural gas (mmcf/d)	**0.05**	-	-	-	-	-
Total (boe/d)	**247**	49	-	-	-	-
% of consolidated	**-**	-	-	-	-	-
Consolidated						
Crude oil & NGLs (bbls/d)	**32,716**	31,432	27,471	25,270	22,334	19,941
% of consolidated	**60%**	63%	67%	67%	63%	62%
Natural gas (mmcf/d)	**133.24**	108.85	81.21	75.20	77.21	73.14
% of consolidated	**40%**	37%	33%	33%	37%	38%
Total (boe/d)	**54,922**	49,573	41,005	37,803	35,202	32,132

Supplemental Table 5: Segmented Financial Results

	Three Months Ended December 31, 2015								
($M)	**Canada**	**France**	**Netherlands**	**Germany**	**Ireland**	**Australia**	**United States**	**Corporate**	**Total**
Drilling and development	27,554	24,085	18,810	(441)	12,493	40,852	5,643	-	128,996
Oil and gas sales to external customers	73,952	63,411	37,243	9,840	57	47,952	1,864	-	234,319
Royalties	(7,146)	(7,198)	(224)	(1,166)	-	-	(551)	-	(16,285)
Revenue from external customers	66,806	56,213	37,019	8,674	57	47,952	1,313	-	218,034
Transportation expense	(3,784)	(4,275)	-	(508)	(1,580)	-	-	-	(10,147)
Operating expense	(24,575)	(15,792)	(6,263)	(4,788)	(15)	(13,941)	(271)	-	(65,645)
General and administration	(3,669)	(4,894)	(813)	(3,032)	(714)	(1,768)	(897)	3,356	(12,431)
PRRT	-	-	-	-	-	(1,054)	-	-	(1,054)
Corporate income taxes	-	4,529	(2,930)	-	-	1,201	-	313	3,113
Interest expense	-	-	-	-	-	-	-	(16,584)	(16,584)
Realized gain on derivative instruments	-	-	-	-	-	-	-	21,164	21,164
Realized foreign exchange loss	-	-	-	-	-	-	-	(252)	(252)
Realized other income	-	-	-	-	-	-	-	243	243
Fund flows from operations	34,778	35,781	27,013	346	(2,252)	32,390	145	8,240	136,441

	Year Ended December 31, 2015								
($M)	**Canada**	**France**	**Netherlands**	**Germany**	**Ireland**	**Australia**	**United States**	**Corporate**	**Total**
Total assets	1,609,180	863,304	212,749	167,908	908,453	235,139	42,927	169,560	4,209,220
Drilling and development	201,508	92,265	47,325	5,363	66,409	61,741	12,250	-	486,861
Oil and gas sales to external customers	320,613	281,422	129,057	41,384	57	162,765	4,288	-	939,586
Royalties	(28,144)	(26,958)	(3,082)	(6,479)	-	-	(1,257)	-	(65,920)
Revenue from external customers	292,469	254,464	125,975	34,905	57	162,765	3,031	-	873,666
Transportation expense	(16,326)	(15,378)	-	(3,269)	(6,687)	-	-	-	(41,660)
Operating expense	(89,085)	(50,718)	(22,746)	(10,956)	(15)	(51,676)	(742)	-	(225,938)
General and administration	(16,888)	(20,217)	(4,158)	(7,386)	(2,517)	(5,754)	(3,836)	7,172	(53,584)
PRRT	-	-	-	-	-	(6,878)	-	-	(6,878)
Corporate income taxes	-	(23,764)	(12,152)	-	-	(7,230)	-	(1,091)	(44,237)
Interest expense	-	-	-	-	-	-	-	(59,852)	(59,852)
Realized gain on derivative instruments	-	-	-	-	-	-	-	41,356	41,356
Realized foreign exchange gain	-	-	-	-	-	-	-	623	623
Realized other income	-	31,775	-	-	-	-	-	896	32,671
Fund flows from operations	170,170	176,162	86,919	13,294	(9,162)	91,227	(1,547)	(10,896)	516,167

NON-GAAP FINANCIAL MEASURES

This MD&A includes references to certain financial measures which do not have standardized meanings prescribed by IFRS and are not disclosed in our audited consolidated financial statements. As such, these financial measures are considered non-GAAP financial measures and therefore may not be comparable with similar measures presented by other issuers.

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 our equity based compensation plans as determined using the treasury stock method.

Free cash flow: Represents fund flows from operations in excess of capital expenditures. We consider free cash flow to be a key measure as it is used 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.

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.

Payout: We define payout as net dividends plus drilling and development, exploration and evaluation, dispositions and asset retirement obligations settled. Management uses payout to assess the amount of cash distributed back to shareholders and re-invested in the business for maintaining production and organic growth.

Fund flows from operations (excluding Corrib) and Payout (excluding Corrib): Management excludes expenditures relating to the Corrib project in assessing fund flows from operations (a non-GAAP financial measure) and payout in order to assess our ability to generate cash and finance organic growth from our current producing assets.

Diluted shares outstanding: Is 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.

Cash dividends per share: Represents cash dividends declared per share.

Total returns: Includes cash dividends per share and the change in Vermilion's share price on the Toronto Stock Exchange.

The following tables reconcile fund flows from operations (excluding Corrib), net dividends, payout, and diluted shares outstanding to their most directly comparable GAAP measures as presented in our financial statements:

	Three Months Ended			Year Ended	
($M)	**Dec 31, 2015**	**Sep 30, 2015**	**Dec 31, 2014**	**Dec 31, 2015**	**Dec 31, 2014**
Cash flows from operating activities	**164,863**	122,230	229,146	**444,408**	791,986
Changes in non-cash operating working capital	**(33,343)**	5,082	(49,865)	**60,390**	(3,077)
Asset retirement obligations settled	**4,921**	2,123	6,247	**11,369**	15,956
Fund flows from operations	**136,441**	129,435	185,528	**516,167**	804,865
Expenses related to Corrib	**2,252**	2,429	2,299	**9,162**	7,841
Fund flows from operations (excluding Corrib)	**138,693**	131,864	187,827	**525,329**	812,706

	Three Months Ended			Year Ended	
($M)	**Dec 31, 2015**	**Sep 30, 2015**	**Dec 31, 2014**	**Dec 31, 2015**	**Dec 31, 2014**
Dividends declared	**71,965**	71,244	69,119	**283,575**	272,732
Issuance of shares pursuant to the dividend reinvestment and Premium Dividend ^{TM} plans	**(46,764)**	(44,590)	(20,980)	**(155,033)**	(79,430)
Net dividends	**25,201**	26,654	48,139	**128,542**	193,302
Drilling and development	**128,996**	93,381	151,395	**486,861**	618,689
Exploration and evaluation	**-**	-	14,848	**-**	69,035
Asset retirement obligations settled	**4,921**	2,123	6,247	**11,369**	15,956
Payout	**159,118**	122,158	220,629	**626,772**	896,982
Corrib drilling and development	**(12,493)**	(20,694)	(20,932)	**(66,409)**	(94,439)
Payout (excluding Corrib)	**146,625**	101,464	199,697	**560,363**	802,543

	As at		
('000s of shares)	**Dec 31, 2015**	**Sep 30, 2015**	**Dec 31, 2014**
Shares outstanding	**111,991**	110,818	107,303
Potential shares issuable pursuant to the VIP	**3,033**	2,825	3,031
Diluted shares outstanding	**115,024**	113,643	110,334

CORPORATE INFORMATION

DIRECTORS

Lorenzo Donadeo [1]
Calgary, Alberta

Larry J. Macdonald [2, 4, 5, 6]
Chairman & CEO, Point Energy Ltd.
Calgary, Alberta

Claudio A. Ghersinich [3, 6]
Executive Director, Carrera Investments Corp.
Calgary, Alberta

Joseph F. Killi [3, 4]
Chairman, Parkbridge Lifestyle Communities Inc.
Vice Chairman, Realex Properties Corp.
Calgary, Alberta

Loren M. Leiker [6]
Houston, Texas

William F. Madison [5, 6]
Sugar Land, Texas

Timothy R. Marchant [5, 6]
Calgary, Alberta

Sarah E. Raiss [4, 5]
Calgary, Alberta

Kevin J. Reinhart [3, 4]
Calgary, Alberta

Catherine L. Williams [3, 4]
Calgary, Alberta

[1] Chairman of the Board
[2] Lead Director
[3] Audit Committee
[4] Governance and Human Resources Committee
[5] Health, Safety and Environment Committee
[6] Independent Reserves Committee

ANNUAL GENERAL MEETING

May 6, 2016
10:00 AM MST
The Ballroom
Metropolitan Centre
333 – 4th Avenue S.W.
Calgary, Alberta

OFFICERS AND KEY PERSONNEL

CANADA
Anthony Marino, P.Eng.
President & Chief Executive Officer

John D. Donovan, FCA
Executive Vice President Business Development

Curtis W. Hicks, CA
Executive Vice President & Chief Financial Officer

Mona Jasinski, M.B.A., ICD.D., C.H.R.P.
Executive Vice President, People and Culture

Michael Kaluza, P.Eng.
Executive Vice President & Chief Operating Officer

Dion Hatcher, P.Eng.
Vice President Canada Business Unit

Terry Hergott, CMA
Vice President Marketing

Daniel Goulet, P.Eng.
Director Corporate HSE

Bryce Kremnica, P.Eng.
Director Field Operations – Canada Business Unit

Dean N. Morrison, CFA
Director Investor Relations

Mike Prinz
Director Information Technology & Information Systems

Jenson Tan, P.Eng.
Director New Ventures

Robert (Bob) J. Engbloom, LL.B
Corporate Secretary

UNITED STATES
Daniel G. Anderson
Managing Director – U.S. Business Unit

Timothy R. Morris
Director, U.S. Business Development – U.S. Business Unit

EUROPE
Gerard Schut, P.Eng.
Vice President European Operations

Darcy Kerwin, P.Eng.
Managing Director - France Business Unit

Scott Seatter, P.Eng.
Managing Director - Netherlands Business Unit

Albrecht Moehring
Managing Director - Germany Business Unit

Bryan Sralla
Managing Director - Central & Eastern Europe Business Unit

AUSTRALIA
Bruce D. Lake, P.Eng.
Managing Director - Australia Business Unit

AUDITORS

Deloitte LLP
Calgary, Alberta

BANKERS

The Toronto-Dominion Bank

Bank of Montreal

Canadian Imperial Bank of Commerce

Royal Bank of Canada

The Bank of Nova Scotia

National Bank of Canada

Alberta Treasury Branches

HSBC Bank Canada

La Caisse Centrale Desjardins du Québec

Wells Fargo Bank N.A., Canadian Branch

Bank of America N.A., Canada Branch

BNP Paribas, Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

JPMorgan Chase Bank, N.A., Toronto Branch

Union Bank, Canada Branch

Canadian Western Bank

Goldman Sachs Lending Partners LLC

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 CONTACT

Dean Morrison, CFA
Director Investor Relations
403-269-4884 TEL
403-476-8100 FAX
1-866-895-8101 IR TOLL FREE
investor_relations@vermilionenergy.com



EXCELLENCE

We aim for exceptional results in everything we do.

TRUST

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

RESPECT

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

RESPONSIBILITY

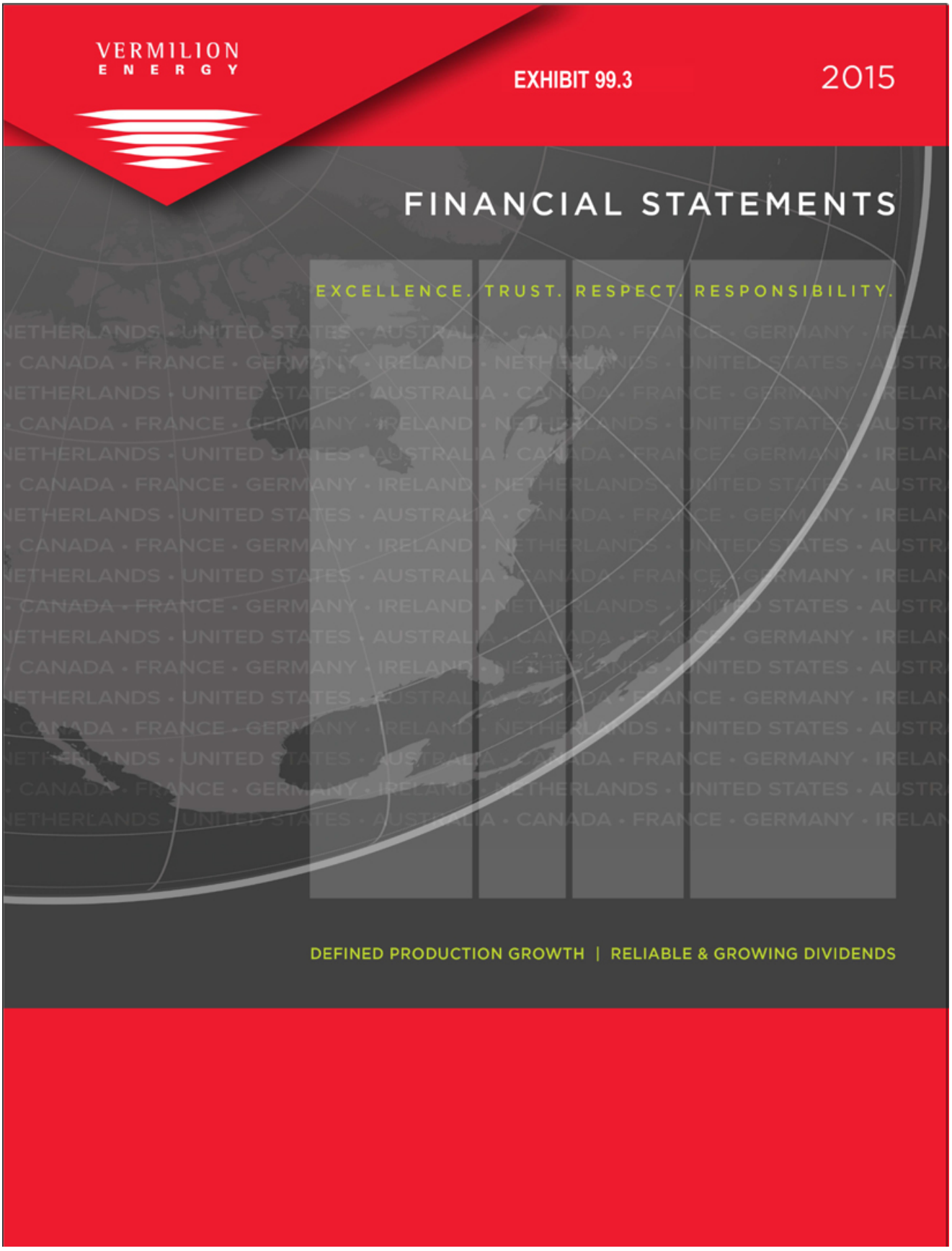
Vermilion continually shows its commitment to the care of our people and environment, and enrichment of the communities in which we live and work.

VERMILION ENERGY

Vermilion Energy Inc.
3500, 520 3rd Avenue SW
Calgary, Alberta T2P 0R3

Telephone: 1.403.269.4884
Facsimile: 1.403.476.8100
IR Toll Free: 1.866.895.8101
investor_relations@vermilionenergy.com

vermilionenergy.com


VERMILION
ENERGY
EXHIBIT 99.3
2015
FINANCIAL STATEMENTS
EXCELLENCE. TRUST. RESPECT. RESPONSIBILITY.
DEFINED PRODUCTION GROWTH | RELIABLE & GROWING DIVIDENDS

ABBREVIATIONS

$M	thousand dollars
$MM	million dollars
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
bcf	billion cubic feet
boe	barrel of oil equivalent, including: crude oil, 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
btu	British thermal units
GJ	gigajoules
HH	Henry Hub, a reference price paid for natural gas in US dollars at Erath, Louisiana
mbbls	thousand barrels
mboe	thousand barrel of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmboe	million barrel of oil equivalent
mmbtu	million British thermal units
mmcf	million cubic feet
mmcf/d	million cubic feet per day
MWh	megawatt hour
NBP	the reference price paid for natural gas in the United Kingdom, quoted in pence per therm, at the National Balancing Point Virtual Trading Point operated by National Grid. Our production in Ireland is priced with reference to NBP.
NGLs	natural gas liquids
PRRT	Petroleum Resource Rent Tax, a profit based tax levied on petroleum projects in Australia
TTF	the day-ahead price for natural gas in the Netherlands, quoted in MWh of natural gas, at the Title Transfer Facility Virtual Trading Point operated by Dutch TSO Gas Transport Services
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma
CGU	Cash generating unit, the basis upon which Vermilions assets are evaluated for potential impairments
DRIP	Dividend Reinvestment Plan

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; business strategies and objectives; operational and financial performance; estimated reserve quantities and the discounted net present value of future net revenue from such reserves; petroleum and natural gas sales; future production levels (including the timing thereof) and rates of average annual production growth; estimated contingent resources; exploration and development plans; 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 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 oil and natural gas reserve 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* . The actual crude oil and natural gas reserves and future production will be greater than or less than the estimates provided in this document. The estimated future net revenue from the production of crude 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 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.

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 external auditors, have conducted an audit of the consolidated financial statements in accordance with Canadian generally accepted auditing standards and 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, the Management's Discussion and Analysis and the external Auditor's Report 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 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 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, 2015. The effectiveness of Vermilion's internal control over financial reporting as of December 31, 2015 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, 2015.

("Lorenzo Donadeo")

Lorenzo Donadeo
Chief Executive Officer
February 25, 2016

("Curtis W. Hicks")

Curtis W. Hicks
Executive Vice President & Chief Financial Officer

Report of Independent Registered Public Accounting Firm

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

We have audited the internal control over financial reporting of Vermilion Energy Inc. and subsidiaries (the "Company") as of December 31, 2015, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. 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 on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. 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 International Financial Reporting Standards as issued by the International Accounting Standards Board, 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2015 of the Company and our report dated February 26, 2016 expressed an unqualified opinion on those financial statements.

("/s/Deloitte LLP")

Chartered Professional Accountants, Chartered Accountants
February 26, 2016
Calgary, Canada

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated financial statements of Vermilion Energy Inc. and subsidiaries (the "Company"), which comprise the consolidated balance sheets as at December 31, 2015 and December 31, 2014, and the consolidated statements of net earnings (loss) and comprehensive income (loss), cash flows, and changes in shareholders' equity for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Vermilion Energy Inc. and subsidiaries as at December 31, 2015 and December 31, 2014, and their financial performance and their cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Other Matter

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2016 expressed an unmodified opinion on the Company's internal control over financial reporting.

("/s/Deloitte LLP")

Chartered Professional Accountants, Chartered Accountants
February 26, 2016
Calgary, Canada

CONSOLIDATED BALANCE SHEETS
(THOUSANDS OF CANADIAN DOLLARS)

	Note	December 31, 2015	December 31, 2014
ASSETS			
Current			
Cash and cash equivalents	17	**41,676**	120,405
Accounts receivable		**160,499**	171,820
Crude oil inventory		**13,079**	9,510
Derivative instruments	13	**55,214**	23,391
Prepaid expenses		**14,310**	13,033
		284,778	338,159
Derivative instruments	13	**13,128**	1,403
Deferred taxes	9	**135,753**	154,816
Exploration and evaluation assets	6	**308,192**	380,621
Capital assets	5	**3,467,369**	3,511,092
		4,209,220	4,386,091
LIABILITIES			
Current			
Accounts payable and accrued liabilities		**248,747**	298,196
Current portion of long-term debt	8	**224,901**	-
Dividends payable	10	**24,077**	23,070
Income taxes payable	9	**6,006**	44,463
		503,731	365,729
Long-term debt	8	**1,162,998**	1,238,080
Finance lease obligation	16	**23,565**	-
Asset retirement obligations	7	**305,613**	350,753
Deferred taxes	9	**354,654**	410,183
		2,350,561	2,364,745
SHAREHOLDERS' EQUITY			
Shareholders' capital	10	**2,181,089**	1,959,021
Contributed surplus		**107,946**	92,188
Accumulated other comprehensive income		**113,647**	5,722
Deficit		**(544,023)**	(35,585)
		1,858,659	2,021,346
		4,209,220	4,386,091

APPROVED BY THE BOARD

(Signed "Joseph F. Killi")

Joseph F. Killi, Director

(Signed "Lorenzo Donadeo")

Lorenzo Donadeo, Director

CONSOLIDATED STATEMENTS OF NET EARNINGS (LOSS) AND COMPREHENSIVE INCOME (LOSS)
(THOUSANDS OF CANADIAN DOLLARS, EXCEPT SHARE AND PER SHARE AMOUNTS)

	Note	Year Ended December 31, 2015	Year Ended December 31, 2014
REVENUE			
Petroleum and natural gas sales		**939,586**	1,419,628
Royalties		**(65,920)**	(108,000)
Petroleum and natural gas revenue		**873,666**	1,311,628
EXPENSES			
Operating	21	**225,938**	232,307
Transportation		**41,660**	42,361
Equity based compensation	11	**75,232**	67,802
Gain on derivative instruments	13	**(84,904)**	(64,083)
Interest expense		**59,852**	49,655
General and administration	21	**53,584**	61,727
Foreign exchange (gain) loss		**(9,410)**	18,420
Other (income) expense		**(31,663)**	760
Accretion	7	**23,911**	23,913
Depletion and depreciation	5, 6	**458,758**	425,694
Impairment	5, 6	**274,623**	-
		1,087,581	858,556
EARNINGS (LOSS) BEFORE INCOME TAXES		**(213,915)**	453,072
INCOME TAXES	9		
Deferred		**(47,728)**	26,410
Current		**51,115**	157,336
		3,387	183,746
NET EARNINGS (LOSS)		**(217,302)**	269,326
OTHER COMPREHENSIVE (LOSS) INCOME			
Currency translation adjustments		**107,925**	(41,420)
COMPREHENSIVE (LOSS) INCOME		**(109,377)**	227,906
NET EARNINGS (LOSS) PER SHARE	12		
Basic		**(1.98)**	2.55
Diluted		**(1.98)**	2.51
WEIGHTED AVERAGE SHARES OUTSTANDING ('000s)	12		
Basic		**109,642**	105,448
Diluted		**109,642**	107,187

CONSOLIDATED STATEMENTS OF CASH FLOWS
(THOUSANDS OF CANADIAN DOLLARS)

	Note	Year Ended December 31, 2015	Year Ended December 31, 2014
OPERATING			
Net earnings (loss)		**(217,302)**	269,326
Adjustments:			
Accretion	7	**23,911**	23,913
Depletion and depreciation	5, 6	**458,758**	425,694
Impairment	5, 6	**274,623**	-
Unrealized gain on derivative instruments	13	**(43,548)**	(27,371)
Equity based compensation	11	**75,232**	67,802
Unrealized foreign exchange (gain) loss		**(8,787)**	17,599
Unrealized other expense		**1,008**	1,492
Deferred taxes	9	**(47,728)**	26,410
Asset retirement obligations settled	7	**(11,369)**	(15,956)
Changes in non-cash operating working capital	14	**(60,390)**	3,077
Cash flows from operating activities		**444,408**	791,986
INVESTING			
Drilling and development	5	**(486,861)**	(618,689)
Exploration and evaluation	6	**-**	(69,035)
Property acquisitions	4, 5, 6	**(28,897)**	(220,726)
Corporate acquisitions, net of cash acquired	4	**-**	(176,179)
Changes in non-cash investing working capital	14	**(25,980)**	12,365
Cash flows used in investing activities		**(541,738)**	(1,072,264)
FINANCING			
Increase in long-term debt	8	**138,341**	196,387
Decrease in finance lease obligation	16	**(2,246)**	-
Cash dividends	10	**(127,535)**	(190,657)
Cash flows from financing activities		**8,560**	5,730
Foreign exchange gain on cash held in foreign currencies		**10,041**	5,394
Net change in cash and cash equivalents		**(78,729)**	(269,154)
Cash and cash equivalents, beginning of year		**120,405**	389,559
Cash and cash equivalents, end of year	17	**41,676**	120,405
Supplementary information for operating activities - cash payments			
Interest paid		**62,911**	50,801
Income taxes paid		**92,907**	166,993

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(THOUSANDS OF CANADIAN DOLLARS)

	Note	Shareholders' Capital	Contributed Surplus	Accumulated Other Comprehensive Income	Deficit	Total Shareholders' Equity
Balances as at January 1, 2014		1,618,443	75,427	47,142	(24,637)	1,716,375
Net earnings		-	-	-	269,326	269,326
Currency translation adjustments		-	-	(41,420)	-	(41,420)
Equity based compensation expense	11	-	67,081	-	-	67,081
Dividends declared	10	-	-	-	(272,732)	(272,732)
Shares issued pursuant to the dividend reinvestment plan	10	79,430	-	-	-	79,430
Shares issued pursuant to corporate acquisition	4, 10	204,960	-	-	-	204,960
Modification of equity based awards	11	-	(2,395)	-	-	(2,395)
Vesting of equity based awards	10, 11	47,925	(47,925)	-	-	-
Share-settled dividends on vested equity based awards	10, 11	7,542	-	-	(7,542)	-
Shares issued pursuant to the bonus plan	10	721	-	-	-	721
Balances as at December 31, 2014		1,959,021	92,188	5,722	(35,585)	2,021,346

	Note	Shareholders' Capital	Contributed Surplus	Accumulated Other Comprehensive Income	Deficit	Total Shareholders' Equity
Balances as at January 1, 2015		1,959,021	92,188	5,722	(35,585)	2,021,346
Net loss		-	-	-	(217,302)	(217,302)
Currency translation adjustments		-	-	107,925	-	107,925
Equity based compensation expense	11	-	72,613	-	-	72,613
Dividends declared	10	-	-	-	(283,575)	(283,575)
Shares issued pursuant to the dividend reinvestment and Premium Dividend™ plans	10	155,033	-	-	-	155,033
Vesting of equity based awards	10, 11	56,855	(56,855)	-	-	-
Share-settled dividends on vested equity based awards	10, 11	7,561	-	-	(7,561)	-
Shares issued pursuant to the employee savings and bonus plans	10	2,619	-	-	-	2,619
Balances as at December 31, 2015		2,181,089	107,946	113,647	(544,023)	1,858,659

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 employee awards which are settled in shares. Once vested, the value of the awards is transferred to shareholders' capital.

Accumulated other comprehensive income
Represents the cumulative income and expenses which are not recorded immediately in net earnings (loss) and are accumulated until an event triggers recognition in net earnings (loss). The current balance consists of currency translation adjustments resulting from translating financial statements of subsidiaries with a foreign functional currency to Canadian dollars at period-end rates.

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2015 AND 2014
(TABULAR AMOUNTS IN THOUSANDS OF CANADIAN DOLLARS, EXCEPT SHARE AND PER SHARE AMOUNTS)

1. BASIS OF PRESENTATION

Vermilion Energy Inc. (the "Company" or "Vermilion") is a corporation governed by the laws of the Province of Alberta and is actively engaged in the business of crude oil and natural gas exploration, development, acquisition and production.

These consolidated financial statements were approved and authorized for issuance by the Board of Directors of Vermilion on February 25, 2016.

2. SIGNIFICANT ACCOUNTING POLICIES

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

Principles of Consolidation
Subsidiaries that are directly controlled by the parent company or indirectly controlled through other consolidated subsidiaries are fully consolidated. Vermilion accounts for joint operations by recognizing its share of assets, liabilities, income and expenses. All significant intercompany balances, transactions, income and expenses are eliminated upon consolidation.

Vermilion currently has no special purpose entities of which it retains control and accordingly the consolidated financial statements do not include the accounts of any such entities.

Exploration and Evaluation Assets
Vermilion accounts for exploration and evaluation of petroleum and natural gas property ("E&E") costs in accordance with IFRS 6 "Exploration for and Evaluation of Mineral Resources". Costs incurred are classified as E&E costs when they relate to exploring and evaluating a property for which the Company has the licence or right to explore and extract resources.

E&E costs related to each license or prospect area are initially capitalized within E&E assets. E&E costs that are capitalized may include costs of licence acquisitions, technical services and studies, seismic acquisitions, exploration drilling and testing, directly attributable overhead and administration expenses and, if applicable, the estimated costs of retiring the assets. Any costs incurred prior to the acquisition of the legal rights to explore an area are expensed as incurred.

E&E assets are not initially depleted and are carried at cost until technical feasibility and commercial viability of the area can be determined. The technical feasibility and commercial viability of extracting the reserves is considered to be determinable when proven and probable reserves are identified. If proven and probable reserves are identified as recoverable, the related E&E costs are reclassified to Petroleum and Natural Gas ("PNG") assets pending an impairment test. If reserves are not found within the license area or the area is abandoned, the related E&E costs are amortized over a period not greater than five years.

Petroleum and Natural Gas Assets
Vermilion recognizes PNG assets at cost less accumulated depletion, depreciation and impairment losses. Directly attributable costs incurred for the drilling of development wells and for the construction of production facilities are capitalized together with the discounted value of estimated future costs of asset retirement obligations. When components of PNG assets are replaced, disposed of, or no longer in use, they are derecognized.

Gains and losses on disposal of a component of PNG assets, including oil and gas interests, are determined by comparing the proceeds of disposal with the carrying amount of the component, and are recognized in net earnings (loss).

Depletion and Depreciation
Vermilion classifies its assets into PNG depletion units, which are groups of assets or properties that are within a specific production area and have similar economic lives. The PNG depletion units represent the lowest level of disaggregation for which Vermilion accumulates costs for the purposes of calculating and recording depletion and depreciation.

The net carrying value of each PNG depletion unit is depleted using the unit of production method by reference to the ratio of production in the period to the total proven and probable reserves, taking into account the future development costs necessary to bring the applicable reserves into production. The reserve estimates are reviewed annually by management or when material changes occur to the underlying assumptions.

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.

2. SIGNIFICANT ACCOUNTING POLICIES (Continued)

Furniture and office equipment are recorded at cost and are depreciated on a declining-balance basis.

Impairment of Long-Lived Assets
E&E assets are tested for impairment when reclassified to PNG assets or when indicators of impairment are identified. If indicators of impairment are identified, E&E assets are tested for impairment as part of the group of Cash Generating Units ("CGUs") attributable to the jurisdiction in which the exploration area resides.

PNG depletion units are aggregated into CGUs for impairment testing. The determination of CGUs is based on management's judgment and represents the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets or properties. CGUs are reviewed for indicators that the carrying value of the CGU may exceed its recoverable amount. If an indication of impairment exists, the CGU's recoverable amount is then estimated. A CGU's recoverable amount is defined as the higher of the fair value less costs to sell and its value in use. If the carrying amount exceeds its recoverable amount, an impairment loss is recorded to net earnings (loss) in the period to reduce the carrying value of the CGU to its recoverable amount.

For PNG assets and E&E assets, when there has been an impairment loss recognized, at each reporting date an assessment is performed as to whether the circumstances which led to the impairment loss have reversed. If the change in circumstances leads to the recoverable amount being higher than the carrying value after recognition of an impairment, that impairment loss is reversed, with such reversal not to exceed the depreciated value of the asset had no impairment loss been previously recognized.

Finance leases
Finance leases, which transfer substantially all the risks and rewards incidental to legal ownership, are recognized at the commencement of the least term. The lease obligation and corresponding capitalized lease asset are measured at the lower of fair value of the leased property or the present value of the minimum lease payments, which are determined at the inception of the lease. Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term.

Cash and Cash Equivalents
Cash and cash equivalents include monies on deposit and short-term investments, which are comprised primarily of guaranteed investment certificates.

Crude Oil Inventory
Inventories of crude oil, consisting of production for which title has not yet transferred to the customer, are valued at the lower of cost or net realizable value. Cost is determined on a weighted-average basis and includes related operating expenses, royalties, and depletion.

Provisions and Asset Retirement Obligations
Vermilion recognizes a provision or asset retirement obligation in the consolidated financial statements when an event gives rise to an obligation of uncertain timing or amount.

The estimated present value of the asset retirement obligation is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset. This increase is depleted with the related depletion unit and is allocated to a CGU for impairment testing. The liability recorded is increased each reporting period due to the passage of time and this change is charged to net earnings (loss) in the period as accretion expense. The asset retirement obligation can also increase or decrease due to changes in the estimated timing of cash flows, changes in the discount rate and/or changes in the original estimated undiscounted costs. Increases or decreases in the obligation will result in a corresponding change in the carrying amount of the related asset. Actual costs incurred upon settlement of the asset retirement obligation are charged against the asset retirement obligation to the extent of the liability recorded. Vermilion discounts the costs related to asset retirement obligations using the discount rate that reflects 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. Vermilion applies discount rates applicable to each of the jurisdictions in which it has future asset retirement obligations. Asset retirement obligations are remeasured at each reporting period in order to reflect the discount rates in effect at that time.

A provision for onerous contracts is recognized when the expected benefits to be derived by Vermilion from a contract are lower than the unavoidable cost of meeting the obligations under the contract. The provision is measured at the lower of the expected cost of terminating the contract and the present value of the expected net cost of the remaining term of the contract. Before a provision is established, Vermilion first recognizes any impairment loss on assets associated with the onerous contract. For the periods presented in the consolidated financial statements, there were no onerous contracts recognized.

Revenue Recognition
Revenues associated with the sale of crude oil, natural gas and natural gas liquids are recorded when title passes to the customer. For the majority of Canadian oil and natural gas production, legal title transfers upon delivery to major pipelines. In Australia, oil is sold at the Wandoo B Platform. In the Netherlands, natural gas is sold at the plant gate. In Germany, natural gas is sold upon delivery to major pipelines. In France, oil is sold either when delivered to the refinery by pipeline or when delivered to the refinery via tanker. In the United States, oil is sold when transferred to the truck from the tank and natural gas is sold at a custody transfer meter on location.

2. SIGNIFICANT ACCOUNTING POLICIES (Continued)

Financial Instruments
Cash and cash equivalents are classified as held for trading and are measured at fair value. A gain or loss arising from a change in the fair value is recognized in net earnings (loss) in the period in which it occurs.

Accounts receivable are classified as loans and receivables and are initially measured at fair value and are then subsequently measured at amortized cost. The carrying value of accounts receivable approximates the fair value due to the short-term nature of these instruments.

Accounts payable and accrued liabilities, dividends payable, finance lease, and long-term debt have been classified as other financial liabilities and are initially recognized at fair value and are subsequently measured at amortized cost. Transaction costs and discounts are recorded against the fair value of long-term debt on initial recognition.

All derivative instruments have been classified as held for trading and are measured at fair value. A gain or loss arising from a change in the fair value is recognized in net earnings (loss) in the period in which it occurs.

Equity Based Compensation
Vermilion has long-term equity based compensation plans for directors, officers and employees of Vermilion and its subsidiaries. Equity based compensation expense is recognized in net earnings (loss) over the vesting period of the awards with a corresponding adjustment to contributed surplus. Upon vesting, the amount previously recognized in contributed surplus is reclassified to shareholders' capital.

The expense recognized is based on the grant date fair value of the awards and incorporates an estimate of the forfeiture rate based on historical vesting data. The grant date fair value of the awards is determined as the grant date closing price of Vermilion's common shares on the Toronto Stock Exchange, adjusted by the Company's estimate of the performance factor that will ultimately be achieved.

Per Share Amounts
Net earnings (loss) per share is calculated using the weighted-average number of shares outstanding during the period. Diluted net earnings per share is calculated using the diluted weighted-average number of shares outstanding during the period. The diluted weighted-average number of shares is determined by considering whether equity based compensation plans, if converted during the year, would result in reduced net earnings per share.

The treasury stock method is used to determine the dilutive effect of equity based compensation plans. The treasury stock method assumes that the deemed proceeds related to unrecognized equity based compensation expense are used to repurchase shares at the average market price during the period. Equity based awards outstanding are included in the calculation of diluted net earnings per share based on estimated performance factors.

Foreign Currency Translation
The consolidated financial statements are presented in Canadian dollars, which is Vermilion's reporting currency. As several of Vermilion's subsidiaries transact and operate primarily in countries other than Canada, they accordingly have functional currencies other than the Canadian dollar.

Transactions denominated in currencies other than the functional currency of the subsidiary are translated to the functional currency at the prevailing rates on the date of the transaction. Non-monetary assets or liabilities that result from such transactions are held at the prevailing rate on the date of the transaction. Monetary items denominated in non-functional currencies are translated to the functional currency of the subsidiary at the prevailing rate at the balance sheet date. All translations associated with currencies other than the respective functional currencies are recorded in net earnings (loss).

Translation of all assets and liabilities from the respective functional currencies to the reporting currency are performed using the rates prevailing at the balance sheet date. The differences arising upon translation from the functional currency to the reporting currency are recorded as currency translation adjustments in other comprehensive income (loss) and are held within accumulated other comprehensive income (loss) until a disposal or partial disposal of a subsidiary. A disposal or partial disposal may give rise to a realized gain or loss, which is recorded in net earnings (loss).

Within the consolidated group there are outstanding intercompany loans which in substance represent investments in certain subsidiaries. When these loans are identified as part of the net investment in a foreign subsidiary, any exchange differences arising on those loans are recorded to currency translation adjustments within other comprehensive income (loss) until the disposal or partial disposal of the subsidiary.

Income Taxes
Deferred taxes are calculated using the liability method of accounting. Under this method, deferred tax is recognized for the estimated effect of any temporary differences between the amounts recognized on Vermilion's consolidated balance sheets and respective tax basis. This calculation uses enacted or substantively enacted tax rates that will 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 net earnings (loss) in the period in which the related legislation is substantively enacted.

2. SIGNIFICANT ACCOUNTING POLICIES (Continued)

Deferred tax assets are reviewed each reporting period and a valuation allowance is recognized if available evidence indicates that it is not probable that all or a part of a deferred tax asset will be utilized in future periods. A previously recognized valuation allowance is removed when available evidence indicates that all or a part of the valuation allowance is no longer required.

Vermilion is subject to current income taxes based on the tax legislation of each respective country in which Vermilion conducts business.

Borrowing Costs
Borrowing costs that are directly attributable to the acquisition or construction of an asset that necessarily takes a substantial period of time to prepare for its intended use are capitalized as part of the cost of that asset. Borrowing costs are capitalized by applying interest rates attributable to the project being financed and could include both general and/or specific borrowings. Interest rates applied from general borrowings are computed using the weighted average borrowing rate for the period.

Measurement Uncertainty
The preparation of the consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses for the periods presented.

Key areas where management has made complex or subjective judgments include asset retirement obligations, assessment of impairment or recovery of impairment of long-lived assets and income taxes. Actual results could differ significantly from these and other estimates.

Asset Retirement Obligations
Vermilion's asset retirement obligations are based on the expected cost of adherence to environmental regulations and estimates of the amount and timing of future expenditures. Changes in environmental regulations, the estimated costs associated with reclamation activities, the discount rate applied and the timing of expenditures could materially impact Vermilion's measurement of the obligations and, correspondingly, impact Vermilion's financial position and net earnings (loss).

Assessment of Impairments or Recovery of Previous Impairments
Impairment tests are performed at a CGU level. CGUs are determined based on management's judgment of the lowest level at which there is identifiable cash inflows that are largely independent of the cash inflows of other groups of assets or properties. The factors used by Vermilion to determine CGUs may vary by country due to the unique operating and geographic circumstances in each country. However, in general, Vermilion will assess the following factors in determining whether a group of assets generate largely independent cash inflows: 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.

The calculation of the recoverable amount of the CGUs is based on market factors, estimates of PNG reserves and future costs required to develop reserves. Vermilion's reserve estimates and the related future cash flows are subject to measurement uncertainty, and the impact on the consolidated financial statements of future periods could be material. Considerable management judgment is used in determining the recoverable amount of PNG assets, including determining the quantity of reserves, the time horizon to develop and produce such reserves and the estimated revenues and expenditures of such production.

Income Taxes
Tax interpretations, regulations, and legislation in the various jurisdictions in which Vermilion and its subsidiaries operate are subject to change and interpretation. Such changes 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 current and deferred 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.

3. CHANGES TO ACCOUNTING PRONOUNCEMENTS

Accounting pronouncements not yet adopted

The impacts of the adoption of the following pronouncements are currently being evaluated.

IFRS 9 "Financial Instruments"
On July 24, 2014, the IASB issued the final element of its comprehensive response to the financial crisis by issuing IFRS 9 "Financial Instruments". The improvements introduced by IFRS 9 includes a model for classification and measurement, a single, forward-looking 'expected loss' impairment model and a substantially-reformed approach to hedge accounting. Vermilion will adopt the standard for reporting periods beginning January 1, 2018.

IFRS 15 "Revenue from Contracts with Customers"
On May 28, 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers", a new standard that specifies recognition requirements for revenue as well as requiring entities to provide the users of financial statements with more informative and relevant disclosures. The standard replaces IAS 11 "Construction Contracts" and IAS 18 "Revenue" as well as a number of revenue-related interpretations. Vermilion will adopt the standard for reporting periods beginning January 1, 2018.

IFRS 16 "Leases"
On January 13, 2016, the IASB issued IFRS 16, "Leases", a new standard which will replace IAS 17, "Leases". Under IFRS 16, a single recognition and measurement model will apply for lessees which will require recognition of assets and liabilities for most leases. Vermilion will adopt the standard for reporting periods beginning January 1, 2019.

4. BUSINESS COMBINATIONS

Property acquisition:

Germany

In February of 2014, Vermilion acquired, through a wholly-owned subsidiary, GDF's 25% interest in four producing natural gas fields and a surrounding exploration license located in northwest Germany. GDF is an affiliate of GDF Suez S.A., a publicly traded, French multinational utility. The acquisition represented Vermilion's entry into the German E&P business, a producing region with a long history of oil and gas development activity, low political risk and strong marketing fundamentals. The acquisition was well aligned with Vermilion's European focus, and has increased the company's exposure to the strong fundamentals and pricing of the European natural gas markets. The acquisition closed in February of 2014 for cash proceeds of $172.9 million. Vermilion funded this acquisition with existing credit facilities.

The acquired assets were comprised of four gas producing fields across eleven production licenses and included both exploration and production licenses that comprised a total of 207,000 gross acres, of which 85% was in the exploration license.

The acquisition was accounted for as a business combination with the fair value of the assets acquired and liabilities assumed at the date of acquisition summarized as follows:

($M)	**Consideration**
Cash paid to vendor	172,871
Total consideration	172,871

($M)	**Allocation of Consideration**
Petroleum and natural gas assets	158,840
Exploration and evaluation	16,065
Asset retirement obligations assumed	(2,030)
Deferred tax liabilities	(4)
Net assets acquired	172,871

The results of operations from the assets acquired were included in Vermilion's consolidated financial statements beginning February of 2014 and had contributed net revenues of $33.3 million and a net loss of $0.3 million for the year ended December 31, 2014.

Had the acquisition occurred on January 1, 2014, management estimates that consolidated revenues would have increased by an additional $4.6 million and consolidated net earnings would have increased by $0.9 million for the year ended December 31, 2014.

4. BUSINESS COMBINATIONS (Continued)

Corporate acquisitions:

a) Elkhorn Resources Inc.

On April 29, 2014, Vermilion acquired Elkhorn Resources Inc., a private southeast Saskatchewan producer. The acquisition created a new core area for Vermilion in the Williston Basin.

The acquired assets included approximately 57,000 net acres of land (approximately 80% undeveloped), seven oil batteries, and preferential access to a minimum of 50% of capacity at a solution gas facility.

Total consideration was comprised of $180.4 million of cash, which was funded with existing credit facilities, and the issuance of 2.8 million Vermilion common shares valued at approximately $205.0 million (based on the closing price per Vermilion common share of $72.50 on the Toronto Stock Exchange on April 29, 2014).

The acquisition was accounted for as a business combination with the fair value of the assets acquired and liabilities assumed at the date of acquisition summarized as follows:

($M)	**Consideration**
Cash paid to shareholders of Elkhorn Resources Inc.	180,353
Shares issued pursuant to corporate acquisition	204,960
Total consideration	385,313

($M)	**Allocation of Consideration**
Petroleum and natural gas assets	390,523
Exploration and evaluation	138,264
Asset retirement obligations assumed	(5,974)
Deferred tax liabilities	(89,437)
Long-term debt assumed	(47,526)
Cash acquired	4,174
Acquired non-cash working capital deficiency	(4,711)
Net assets acquired	385,313

The results of operations from the assets acquired were included in Vermilion's consolidated financial statements beginning April 29, 2014 and contributed revenues of $50.6 million and operating income of $39.8 million for the year ended December 31, 2014.

Had the acquisition occurred on January 1, 2014, management estimates that consolidated revenues would have increased by an additional $8.8 million and consolidated operating income would have increased by $7.0 million for the year ended December 31, 2014. In determining the pro-forma amounts, management had assumed that the fair value adjustments, determined provisionally, that arose at the date of acquisition would have been the same if the acquisition had occurred on January 1, 2014. It is impracticable to derive all amounts necessary to determine the impact on net earnings from the acquisition as the acquired company was immediately merged with Vermilion’s operations.

5. CAPITAL ASSETS

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

($M)	Petroleum and Natural Gas Assets	Furniture and Office Equipment	Total Capital Assets
Balance at January 1, 2014	2,784,634	15,211	2,799,845
Additions	608,709	9,980	618,689
Property acquisitions	176,625	-	176,625
Corporate acquisitions	390,523	-	390,523
Changes in estimate for asset retirement obligations	19,107	-	19,107
Depletion and depreciation	(412,768)	(5,072)	(417,840)
Effect of movements in foreign exchange rates	(75,635)	(222)	(75,857)
Balance at December 31, 2014	3,491,195	19,897	3,511,092
Additions	482,574	4,287	486,861
Property acquisitions	27,731	-	27,731
Changes in estimate for asset retirement obligations	(78,429)	-	(78,429)
Depletion and depreciation	(431,889)	(6,453)	(438,342)
Recognition of finance lease asset (1)	31,028	-	31,028
Impairment (2)	(219,808)	-	(219,808)
Effect of movements in foreign exchange rates	146,641	595	147,236
Balance at December 31, 2015	3,449,043	18,326	3,467,369
Cost	5,114,188	54,723	5,168,911
Accumulated depletion and depreciation	(1,622,993)	(34,826)	(1,657,819)
Carrying amount at December 31, 2014	3,491,195	19,897	3,511,092
Cost	5,624,809	57,652	5,682,461
Accumulated depletion and depreciation	(2,175,766)	(39,326)	(2,215,092)
Carrying amount at December 31, 2015	3,449,043	18,326	3,467,369

(1) Refer to Financial Statement Note 16 – Leases
(2) Refer to Financial Statement Note 6 – Exploration and Evaluation Assets

Depletion and depreciation rates
PNG assets (unit of production method)
Furniture and office equipment (declining balance at rates of 5% to 25%)

Capitalized overhead
During the year ended December 31, 2015, Vermilion capitalized $5.1 million (2014 - $7.7 million) of overhead costs directly attributable to PNG activities.

Impairments
On a quarterly basis, Vermilion performs an assessment as to whether any CGUs have indicators of impairment. When indicators of impairment are identified, Vermilion assesses the recoverable amount of the applicable CGU based on the higher of the estimated fair value less costs to sell and value in use as at the reporting date. The estimated recoverable amount takes into account commodity price forecasts, expected production, estimated costs and timing of development, and undeveloped land values.

As a result of declines in commodity price forecasts, which decreased expected cash flows, Vermilion recorded a non-cash impairment charge of $131.6 million in the Canada segment for the three months ended December 31, 2015 ($274.6 million for the year ended December 31, 2015, of which $219.8 million related to PNG assets and $54.8 million related to E&E assets). The recoverable amount of each CGU was determined using a value in use approach based on 2015 year end reserves and resource data, an after-tax discount rate of 9% for proved and probable reserves, and an after-tax discount rate of 15% on resources carried within exploration and evaluation assets.

This impairment charge in the year ended December 31, 2015 related to the light crude oil play in Saskatchewan, Canada ($267.9 million based on a recoverable amount of $266.8 million) and the shallow coal bed methane properties in Alberta, Canada ($6.7 million based on a recoverable amount of $19.7 million). The determination of impairment is sensitive to changes in key judgments, including reserve or resource revisions, changes in forward commodity prices and exchange rates, and changes in costs and timing of development. Changes in these key judgments would impact the recoverable amount of CGUs, therefore resulting in additional impairment charges or recoveries. For the year ended December 31, 2015, a one percent increase in the assumed discount rate on expected cash flows of the Saskatchewan light crude oil and Alberta shallow coal bed methane CGUs would result in an additional impairment of $19.5 million, and a five percent decrease in commodity prices would result in an additional impairment of $33.3 million.

5. CAPITAL ASSETS (Continued)

Vermilion also identified indicators of impairment on the Ireland CGU which consists of Vermilion's non-operating interest in offshore Corrib natural gas field, but determined that the recoverable amount exceeded its carrying value and accordingly, no impairment charge was recorded. For the year ended December 31, 2015, a one percent increase in the assumed discount rate on expected cash flows of the Ireland CGU would have resulted in impairment of $21.9 million, and a five percent decrease in commodity prices would result in an impairment of $33.6 million.

The following table outlines the forward commodity price estimates that were used in the calculation of recoverable amounts:

Forward Commodity Price Assumptions [1]					
	WTI Oil (US $/bbl)	AECO Gas (CDN $/mmbtu)	Blended NGLs [2] (CDN $/bbl)	NBP Gas (US $/mmbtu)	CDN $/US $ Exchange Rate
2016	44.00	2.76	30.27	5.55	0.73
2017	52.00	3.27	35.76	5.68	0.75
2018	58.00	3.45	39.04	6.10	0.78
2019	64.00	3.63	42.96	6.70	0.80
2020	70.00	3.81	45.85	7.30	0.83
2021	75.00	3.90	47.86	7.80	0.85
2022	80.00	4.10	51.23	8.30	0.85
2023	85.00	4.30	54.59	8.80	0.85
2024	87.88	4.50	56.05	9.14	0.85
2025	89.63	4.60	57.18	9.32	0.85
Thereafter	+2.0% per year	+2.0% per year	+2.0% per year	+2.0% per year	0.85

(1) Source: GLJ Petroleum Consultants price forecast, effective January 1, 2016.
(2) The price of blended NGLs shown above is determined used a simple average for Ethane, Propane, Butane, and C5+.

6. EXPLORATION AND EVALUATION ASSETS

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

($M)	Exploration and Evaluation Assets
Balance at January 1, 2014	136,259
Additions	69,035
Changes in estimate for asset retirement obligations	22
Property acquisitions	46,135
Corporate acquisitions	138,264
Depreciation	(5,038)
Effect of movements in foreign exchange rates	(4,056)
Balance at December 31, 2014	380,621
Changes in estimate for asset retirement obligations	(130)
Property acquisitions	1,166
Depreciation	(21,893)
Impairment [1]	(54,815)
Effect of movements in foreign exchange rates	3,243
Balance at December 31, 2015	308,192
Cost	399,348
Accumulated depreciation	(18,727)
Carrying amount at December 31, 2014	380,621
Cost	362,919
Accumulated depreciation	(54,727)
Carrying amount at December 31, 2015	308,192

(1) Refer to Financial Statement Note 5 – Capital Assets

7. ASSET RETIREMENT OBLIGATIONS

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

($M)	Asset Retirement Obligations
Balance at January 1, 2014	326,162
Additional obligations recognized	22,565
Changes in estimates for asset retirement obligations	(3,434)
Obligations settled	(15,956)
Accretion	23,913
Changes in discount rates	9,404
Effect of movements in foreign exchange rates	(11,901)
Balance at December 31, 2014	350,753
Additional obligations recognized	3,550
Changes in estimates for asset retirement obligations	1,117
Obligations settled	(11,369)
Accretion	23,911
Changes in discount rates	(83,226)
Effect of movements in foreign exchange rates	20,877
Balance at December 31, 2015	305,613

Vermilion has estimated the net present value of its asset retirement obligations to be $305.6 million as at December 31, 2015 (2014 - $350.8 million) based on a total undiscounted future liability, after inflation adjustment, of $1.3 billion (2014 - $1.3 billion). These payments are expected to be made between 2016 and 2064. Vermilion calculated the present value of the obligations using discount rates between 7.1% and 10.3% (2014 - between 5.7% and 7.9%) to reflect the market assessment of the time value of money as well as risks specific to the liabilities that have not been included in the cash flow estimates. Inflation rates used in determining the cash flow estimates were between 0.6% and 2.4% (2014 - between 0.8% and 2.4%).

Vermilion reviews annually its estimates of the expected costs to reclaim the net interest in its wells and facilities. The resulting changes are categorized as changes in estimates for existing obligations in the preceding table. The decrease in the liability for the year ended December 31, 2015 primarily resulted from an overall increase in the discount rates applied to the abandonment obligations.

8. LONG-TERM DEBT

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

	As at	
($M)	Dec 31, 2015	Dec 31, 2014
Revolving credit facility	**1,162,998**	1,014,067
Senior unsecured notes [(1)]	**224,901**	224,013
Long-term debt	**1,387,899**	1,238,080

(1) The senior unsecured notes, which matured on February 10, 2016, are included in the current portion of long-term debt as at December 31, 2015.

Revolving Credit Facility

At December 31, 2015, Vermilion had in place a bank revolving credit facility totalling $2 billion, of which approximately $1.16 billion was drawn. The facility, which matures on May 31, 2019, is fully revolving up to the date of maturity.

The facility is extendable from time to time, but not more than once per year, for a period not longer than four years, 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. This facility bears interest at a rate applicable to demand loans plus applicable margins. For the year ended December 31, 2015, the interest rate on the revolving credit facility was approximately 3.1% (2014 – 3.1%).

The amount available to Vermilion under this facility is reduced by certain outstanding letters of credit associated with Vermilion's operations totalling $25.2 million as at December 31, 2015 (December 31, 2014 - $8.6 million).

8. LONG-TERM DEBT (Continued)

The facility is secured by various fixed and floating charges against the subsidiaries of Vermilion. Under the terms of the facility, Vermilion must maintain:

- A ratio of total borrowings (defined as amounts classified as "Long-term debt", "Current portion of long term debt", and "Finance lease obligation" on the balance sheet and referred to collectively as consolidated total debt), to consolidated net earnings before interest, income taxes, depreciation, accretion and other certain non-cash items (defined as consolidated EBITDA) of not greater than 4.0.
- A ratio of consolidated total senior debt (defined as consolidated total debt excluding unsecured and subordinated debt) to consolidated EBITDA of not greater than 3.0.
- A ratio of consolidated total senior debt to total capitalization (defined as amounts classified as "Shareholders' equity" on the balance sheet plus consolidated total senior debt as defined above) of not greater than 50%.

As at December 31, 2015, Vermilion was in compliance with all financial covenants.

Senior Unsecured Notes

On February 10, 2011, Vermilion issued $225.0 million of senior unsecured notes at par. The notes bear interest at a rate of 6.5% per annum and matured on February 10, 2016. As direct senior unsecured obligations of Vermilion, the notes ranked pari passu with all other present and future unsecured and unsubordinated indebtedness of the Company. The notes were initially recognized at fair value net of transaction costs and were subsequently measured at amortized cost using an effective interest rate of 7.1%.

Subsequent to December 31, 2015, Vermilion repaid the senior unsecured notes using funds from the revolving credit facility.

9. INCOME TAXES

Deferred taxes

The net deferred income tax liability at December 31, 2015 and 2014 is comprised of the following:

	Year Ended	
($M)	**Dec 31, 2015**	**Dec 31, 2014**
Deferred income tax liabilities:		
Derivative contracts	**(18,452)**	(5,965)
Capital assets	**(349,664)**	(445,457)
Asset retirement obligations	**(130,904)**	(96,616)
Unrealized foreign exchange	**(16,300)**	(14,507)
Other	**(10,767)**	(13,164)
Deferred income tax assets:		
Capital assets	**77,343**	72,821
Non-capital losses	**175,477**	178,222
Asset retirement obligations	**51,958**	65,760
Unrealized foreign exchange	**-**	720
Other	**2,408**	2,819
Net deferred income tax liability	**(218,901)**	(255,367)
Comprised of:		
Deferred income tax assets	**135,753**	154,816
Deferred income tax liability	**(354,654)**	(410,183)
Net deferred income tax liability	**(218,901)**	(255,367)

9. INCOME TAXES (Continued)

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 of 26.2% (2014 - 25.5%), as follows:

	Year Ended	
($M)	**Dec 31, 2015**	**Dec 31, 2014**
Earnings (loss) before income taxes	**(213,915)**	453,072
Canadian corporate tax rate	**26.2%** (1)	25.5%
Expected tax expense (recovery)	**(56,046)**	115,533
Increase (decrease) in taxes resulting from:		
Petroleum resource rent tax rate (PRRT) differential (2)	**8,310**	37,035
Foreign tax rate differentials (2), (3)	**(8,096)**	3,492
Equity based compensation expense	**14,000**	17,290
Amended returns and changes to estimated tax pools and tax positions	**(6,856)**	(7,512)
Changes in statutory tax rates and the estimated reversal rates associated with temporary differences	**1,733**	16,429
Valuation allowance	**51,736**	-
Other non-deductible items	**(1,394)**	1,479
Provision for income taxes	**3,387**	183,746

(1) The corporate tax rate increased to 26.2% in 2015 from 25.5% in 2014 due to the Alberta corporate tax rate increase of 2.0% effective July 1, 2015.
(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 combined tax rate was 34.4% in France, 46.0% in the Netherlands, 24.2% in Germany, 25% in Ireland, and 35% in the United States. The corporate tax rate for Germany increased to 24.2% (2014 - 22.8%) due to a trade tax increase of 1.4% effective January 2015.

10. SHAREHOLDERS' CAPITAL

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

Shareholders' Capital	**Number of Shares ('000s)**	**Amount ($M)**
Balance as at January 1, 2014	102,123	1,618,443
Shares issued pursuant to corporate acquisition	2,827	204,960
Shares issued pursuant to the dividend reinvestment plan	1,279	79,430
Vesting of equity based awards	955	47,925
Share-settled dividends on vested equity based awards	108	7,542
Shares issued pursuant to the bonus plan	11	721
Balance as at December 31, 2014	107,303	1,959,021
Shares issued pursuant to the dividend reinvestment and Premium Dividend ™ plans	3,338	155,033
Vesting of equity based awards	1,158	56,855
Share-settled dividends on vested equity based awards	135	7,561
Shares issued pursuant to the employee savings and bonus plans	57	2,619
Balance as at December 31, 2015	111,991	2,181,089

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

Dividends

Dividends declared to shareholders for the year ended December 31, 2015 were $283.6 million (2014 - $272.7 million). Dividends are approved by the Board of Directors and are paid monthly. Vermilion has a dividend reinvestment plan ("DRIP") which allows eligible holders of common shares to purchase additional common shares at a 3% discount to market by reinvesting their cash dividends. Additionally, an amendment to the existing DRIP to include a Premium Dividend™ Component was announced in February 2015. With the addition of the Premium Dividend™ Component eligible shareholders have the option to reinvest their dividends in new common shares which are exchanged for a premium cash payment equal to 101.5% of the reinvested dividends.

Subsequent to the end of year-end and prior to the consolidated financial statements being authorized for issue on February 25, 2016, Vermilion declared dividends totalling $48.5 million or $0.215 per share for each of January and February of 2016.

11. EQUITY BASED COMPENSATION

The following table summarizes the number of awards outstanding under the Vermilion Incentive Plan ("VIP"):

Number of Awards ('000s)	2015	2014
Opening balance	**1,775**	1,665
Granted	**609**	707
Vested	**(587)**	(515)
Modified	**-**	(21)
Forfeited	**(86)**	(61)
Closing balance	**1,711**	1,775

The fair value of a VIP award is determined on the grant date at the closing price of Vermilion's common shares on the Toronto Stock Exchange, adjusted by the estimated performance factor that will ultimately be achieved. Dividends, which notionally accrue to the awards during the vesting period, are not included in the determination of grant date fair values. For the year ended December 31, 2015, the awards granted had a weighted average fair value of $80.70 (2014 - $101.63).

The performance factor is determined by the Board of Directors after consideration of Company performance using Vermilion's balanced scorecard metrics including, but not limited to, relative total shareholder return, financial and operational performance, and performance on strategic objectives.

The expense recognized is based on the grant date fair value of the awards and incorporates an estimate of forfeiture rate based on historical vesting data. For the year ended December 31, 2015, Vermilion incorporated an estimated forfeiture rate of 4.8% (2014 - 5.8%). Equity based compensation expense of $72.6 million was recorded during the year ended December 31, 2015 (2014 - $67.1 million) related to the VIP.

12. PER SHARE AMOUNTS

Basic and diluted net earnings (loss) per share have been determined based on the following:

	Year Ended	
($M except per share amounts)	**Dec 31, 2015**	**Dec 31, 2014**
Net (loss) earnings [1]	**(217,302)**	269,326
Basic weighted average shares outstanding [2]	**109,642**	105,448
Dilutive impact of equity based awards	**-**	1,739
Diluted weighted average shares outstanding [3]	**109,642**	107,187
Basic (loss) earnings per share ([1] ÷ [2])	**(1.98)**	2.55
Diluted (loss) earnings per share ([1] ÷ [3])	**(1.98)**	2.51

13. DERIVATIVE INSTRUMENTS

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 elected not to designate any of its derivative financial instruments as accounting hedges and thus accounts for changes in fair value in net earnings at each reporting period. 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 enter into fixed price arrangements to sell a portion of its production or purchase commodities for operational use. Vermilion does not apply fair value accounting on these contracts as they were entered into and continue to be held for the sale of production or operational use in accordance with the Company's expected requirements.

13. DERIVATIVE INSTRUMENTS (Continued)

The following tables summarize Vermilion's outstanding risk management positions as at December 31, 2015:

	Note	Volume	Strike Price(s)
Crude Oil			
WTI - Collar			
July 2015 - March 2016	1	250 bbl/d	75.00 - 83.45 CAD $
July 2015 - June 2016	2	500 bbl/d	75.50 - 85.08 CAD $
Dated Brent - Collar			
July 2015 - June 2016	3	1,000 bbl/d	80.50 - 93.49 CAD $
July 2015 - June 2016	4	500 bbl/d	64.50 - 75.48 US $
October 2015 - June 2016	5	250 bbl/d	82.00 - 94.55 CAD $
January 2016 - June 2016	1	250 bbl/d	84.00 - 93.70 CAD $
North American Natural Gas			
AECO - Collar			
November 2015 - March 2016		2,500 GJ/d	2.50 - 3.76 CAD $
November 2015 - October 2016		10,000 GJ/d	2.56 - 3.23 CAD $
January 2016 - December 2016		10,000 GJ/d	2.53 - 3.29 CAD $
April 2016 - October 2016		5,000 GJ/d	2.30 - 2.80 CAD $
AECO Basis - Fixed Price Differential			
November 2015 - March 2016		2,500 mmbtu/d	Nymex HH less 0.47 US $
Nymex HH - Collar			
November 2015 - March 2016	6	5,000 mmbtu/d	3.25 - 3.86 US $

(1) The contracted volumes increase to 500 boe/d for any monthly settlement periods above the contracted ceiling price and are settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).
(2) The contracted volumes increase to 1,250 boe/d for any monthly settlement periods above the contracted ceiling price and are settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).
(3) The contracted volumes increase to 2,500 boe/d for any monthly settlement periods above the contracted ceiling price and are settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).
(4) The contracted volumes increase to 1,000 boe/d for any monthly settlement periods above the contracted ceiling price.
(5) The contracted volumes increase to 750 boe/d for any monthly settlement periods above the contracted ceiling price and are settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).
(6) The contracted volumes increase to 10,000 mmbtu/d for any monthly settlement periods above the contracted ceiling price.

13. DERIVATIVE INSTRUMENTS (Continued)

	Note	Volume	Strike Price(s)
European Natural Gas			
NBP - Call			
October 2016 - March 2017		2,638 GJ/d	4.64 GBP £
NBP - Collar			
April 2016 - March 2017		2,638 GJ/d	3.79 - 4.53 GBP £
January 2017 - December 2017		2,638 GJ/d	3.22 - 3.75 GBP £
January 2018 - December 2018		2,638 GJ/d	2.99 - 3.63 GBP £
NBP - Put			
April 2016 - September 2016		2,638 GJ/d	3.79 GBP £
NBP - Swap			
July 2015 - March 2016		2,592 GJ/d	6.42 EUR €
October 2015 - March 2016		10,368 GJ/d	6.54 EUR €
January 2016 - June 2016		5,184 GJ/d	6.24 EUR €
January 2016 - June 2016		2,592 GJ/d	6.82 US $
July 2016 - March 2017		2,592 GJ/d	5.43 EUR €
January 2017 - December 2017	1	2,638 GJ/d	4.00 GBP £
January 2018 - December 2018	2	2,638 GJ/d	3.83 GBP £
TTF - Call			
October 2016 - March 2017		2,592 GJ/d	6.03 EUR €
TTF - Collar			
January 2016 - December 2016	3	2,592 GJ/d	5.76 - 6.50 EUR €
April 2016 - December 2016	4	12,960 GJ/d	5.58 - 6.21 EUR €
April 2016 - March 2017	5	5,184 GJ/d	5.28 - 6.35 EUR €
July 2016 - December 2016		2,592 GJ/d	5.00 - 5.63 EUR €
July 2016 - March 2017	3	2,592 GJ/d	5.07 - 6.56 EUR €
July 2016 - March 2018	3	2,592 GJ/d	5.32 - 6.54 EUR €
October 2016 - December 2017		2,592 GJ/d	5.00 - 5.89 EUR €
January 2017 - December 2017	6	7,776 GJ/d	5.00 - 6.15 EUR €
January 2018 - December 2018		5,184 GJ/d	4.17 - 5.03 EUR €
TTF - Put			
April 2016 - September 2016		2,592 GJ/d	5.21 EUR €
TTF - Swap			
January 2015 - March 2016		5,184 GJ/d	6.40 EUR €
January 2015 - June 2016		2,592 GJ/d	6.07 EUR €
February 2015 - March 2016		5,184 GJ/d	6.24 EUR €
April 2015 - March 2016		5,832 GJ/d	6.18 EUR €
October 2015 - March 2016		2,592 GJ/d	6.64 EUR €
January 2016 - June 2016		5,184 GJ/d	5.94 EUR €
April 2016 - December 2016		2,592 GJ/d	5.91 EUR €
July 2016 - June 2018		2,700 GJ/d	5.58 EUR €
October 2016 - December 2016		2,592 GJ/d	5.45 EUR €
January 2017 - December 2017	7	2,592 GJ/d	5.04 EUR €
Electricity			
AESO - Swap			
January 2016 - December 2016		93.6 MWh/d	38.58 CAD $
Interest Rate			
CDOR to fixed - Swap			
September 2015 - September 2019		100,000,000 CAD $/year	1.00 %
October 2015 - October 2019		100,000,000 CAD $/year	1.10 %

(1) On the last business day of each month, the counterparty has the option to increase the contracted volumes by an additional 2,638 GJ/d at the contracted price, for the following month.
(2) On the last business day of each month, the counterparty has the option to increase the contracted volumes to 7,913 GJ/d at the contracted price, for the following month.
(3) The contracted volumes increase to 5,184 GJ/d for any monthly settlement periods above the contracted ceiling price.
(4) The contracted volumes increase to 15,552 GJ/d for any monthly settlement periods above the contracted ceiling price.
(5) The contracted volumes increase to 10,368 GJ/d for any monthly settlement periods above the contracted ceiling price.
(6) The contracted volumes increase to 18,144 GJ/d for any monthly settlement periods above the contracted ceiling price.
(7) On the last business day of each month, the counterparty has the option to increase the contracted volumes by an additional 5,184 GJ/d at the contracted price, for the following month.

13. DERIVATIVE INSTRUMENTS (Continued)

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

	Year Ended	
($M)	**Dec 31, 2015**	**Dec 31, 2014**
Fair value of contracts, beginning of year	**24,794**	(1,287)
Reversal of opening contracts settled during the year	**(23,391)**	1,287
Acquired derivative contracts	**-**	(1,290)
Realized gain on contracts settled during the year	**41,356**	36,712
Unrealized gain during the year on contracts outstanding at the end of the year	**66,939**	26,084
Net receipt from counterparties on contract settlements during the year	**(41,356)**	(36,712)
Fair value of contracts, end of year	**68,342**	24,794
Comprised of:		
Current derivative asset	**55,214**	23,391
Non-current derivative asset	**13,128**	1,403
Fair value of contracts, end of year	**68,342**	24,794

The gain on derivative instruments for 2015 and 2014 were comprised of the following:

	Year Ended	
($M)	**Dec 31, 2015**	**Dec 31, 2014**
Realized gain on contracts settled during the year	**(41,356)**	(36,712)
Reversal of opening contracts settled during the year	**23,391**	(1,287)
Unrealized gain during the year on contracts outstanding at the end of the year	**(66,939)**	(26,084)
Gain on derivative instruments	**(84,904)**	(64,083)

14. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital is comprised of the following:

	Year Ended	
($M)	**Dec 31, 2015**	**Dec 31, 2014**
Changes in:		
Accounts receivable	**11,321**	(4,202)
Crude oil inventory	**(3,569)**	7,633
Prepaid expenses	**2,577**	1,400
Accounts payable and accrued liabilities	**(49,449)**	30,364
Income taxes payable	**(38,457)**	(11,152)
Movements in foreign exchange rates	**(8,793)**	(8,601)
Changes in non-cash working capital	**(86,370)**	15,442
Changes in non-cash operating working capital	**(60,390)**	3,077
Changes in non-cash investing working capital	**(25,980)**	12,365
Changes in non-cash working capital	**(86,370)**	15,442

15. SEGMENTED INFORMATION

Vermilion has operations in three core areas: North America, Europe, and Australia. Vermilion's operating activities in each country relate solely to the exploration, development and production of petroleum and natural gas. Vermilion has a Corporate head office located in Calgary, Alberta. Costs incurred in the Corporate segment relate to Vermilion's global hedging program and expenses incurred in financing and managing our operating business units.

Vermilion's chief operating decision maker reviews the financial performance of the Company by assessing the fund flows from operations of each country individually. Fund flows from operations provides a measure of each business unit's ability to generate cash (that is not subject to short-term movements in non-cash operating working capital) necessary to pay dividends, fund asset retirement obligations, and make capital investments.

	Year Ended December 31, 2015								
($M)	**Canada**	**France**	**Netherlands**	**Germany**	**Ireland**	**Australia**	**United States**	**Corporate**	**Total**
Total assets	1,609,180	863,304	212,749	167,908	908,453	235,139	42,927	169,560	4,209,220
Drilling and development	201,508	92,265	47,325	5,363	66,409	61,741	12,250	-	486,861
Oil and gas sales to external customers	320,613	281,422	129,057	41,384	57	162,765	4,288	-	939,586
Royalties	(28,144)	(26,958)	(3,082)	(6,479)	-	-	(1,257)	-	(65,920)
Revenue from external customers	292,469	254,464	125,975	34,905	57	162,765	3,031	-	873,666
Transportation expense	(16,326)	(15,378)	-	(3,269)	(6,687)	-	-	-	(41,660)
Operating expense	(89,085)	(50,718)	(22,746)	(10,956)	(15)	(51,676)	(742)	-	(225,938)
General and administration	(16,888)	(20,217)	(4,158)	(7,386)	(2,517)	(5,754)	(3,836)	7,172	(53,584)
PRRT	-	-	-	-	-	(6,878)	-	-	(6,878)
Corporate income taxes	-	(23,764)	(12,152)	-	-	(7,230)	-	(1,091)	(44,237)
Interest expense	-	-	-	-	-	-	-	(59,852)	(59,852)
Realized gain on derivative instruments	-	-	-	-	-	-	-	41,356	41,356
Realized foreign exchange gain	-	-	-	-	-	-	-	623	623
Realized other income	-	31,775	-	-	-	-	-	896	32,671
Fund flows from operations	170,170	176,162	86,919	13,294	(9,162)	91,227	(1,547)	(10,896)	516,167

	Year Ended December 31, 2014								
($M)	**Canada**	**France**	**Netherlands**	**Germany**	**Ireland**	**Australia**	**United States**	**Corporate**	**Total**
Total assets	1,865,942	874,163	220,100	170,237	822,756	240,614	14,731	177,548	4,386,091
Drilling and development	291,046	136,019	49,695	2,747	94,439	44,283	460	-	618,689
Exploration and evaluation	43,696	11,833	12,045	-	-	-	-	1,461	69,035
Oil and gas sales to external customers	537,788	431,252	123,815	41,962	-	283,481	1,330	-	1,419,628
Royalties	(65,563)	(28,444)	(5,014)	(8,613)	-	-	(366)	-	(108,000)
Revenue from external customers	472,225	402,808	118,801	33,349	-	283,481	964	-	1,311,628
Transportation expense	(14,625)	(18,975)	-	(2,367)	(6,394)	-	-	-	(42,361)
Operating expense	(76,178)	(61,729)	(24,041)	(8,686)	-	(61,432)	(241)	-	(232,307)
General and administration	(16,791)	(20,929)	(3,617)	(4,688)	(1,447)	(5,873)	(959)	(7,423)	(61,727)
PRRT	-	-	-	-	-	(60,340)	-	-	(60,340)
Corporate income taxes	-	(66,901)	(4,154)	(44)	-	(24,477)	-	(1,420)	(96,996)
Interest expense	-	-	-	-	-	-	-	(49,655)	(49,655)
Realized gain on derivative instruments	-	-	-	-	-	-	-	36,712	36,712
Realized foreign exchange loss	-	-	-	-	-	-	-	(821)	(821)
Realized other income	-	-	-	-	-	-	-	732	732
Fund flows from operations	364,631	234,274	86,989	17,564	(7,841)	131,359	(236)	(21,875)	804,865

15. SEGMENTED INFORMATION (Continued)

Reconciliation of fund flows from operations to net earnings (loss)

	Year Ended	
($M)	**Dec 31, 2015**	**Dec 31, 2014**
Fund flows from operations	**516,167**	804,865
Equity based compensation	**(75,232)**	(67,802)
Unrealized gain on derivative instruments	**43,548**	27,371
Unrealized foreign exchange loss	**8,787**	(17,599)
Unrealized other expense	**(1,008)**	(1,492)
Accretion	**(23,911)**	(23,913)
Depletion and depreciation	**(458,758)**	(425,694)
Deferred taxes	**47,728**	(26,410)
Impairment	**(274,623)**	-
Net earnings (loss)	**(217,302)**	269,326

Vermilion has two major customers with revenues in excess of 10% within the France and Netherlands segments. Substantially all sales in the France and Netherlands segments for the years ended December 31, 2015 and 2014 were to one customer in each respective segment.

16. LEASES

Vermilion had the following future commitments associated with its operating and finance leases as at December 31, 2015:

($M)	**Less than 1 year**	**1 - 3 years**	**4 - 5 years**	**After 5 years**	**Total**
Operating lease payments by period	20,750	30,942	23,909	49,734	125,335
Finance lease minimum lease payments by period	6,285	12,571	9,515	6,984	35,355
Interest	2,079	3,077	1,521	907	7,584
Present value of minimum lease payments	6,029	10,746	7,069	4,148	27,992

In addition, Vermilion has various other commitments associated with its business operations; none of which, in management's view, are significant in relation to Vermilion's financial position.

As part of an acquisition in April of 2014, Vermilion assumed an agreement for the use of a solution gas facility. The substance of the arrangement was determined to be a lease and has been classified as a finance lease. The assets are to be used for a minimum period of 10 years, with an option to renew. As at December 31, 2015, the carrying amount of the asset included in capital assets is $28.4 million, and the current portion of the finance lease obligation included in accrued liabilities in $5.9 million.

17. CASH AND CASH EQUIVALENTS

Cash and cash equivalents was comprised of the following:

($M)	**Dec 31, 2015**	**Dec 31, 2014**
Money on deposit with financial institutions	**31,175**	116,643
Short-term investments	**10,501**	3,762
Cash and cash equivalents	**41,676**	120,405

18. CAPITAL DISCLOSURES

Vermilion defines capital as net debt (a non-standardized measure, which is defined by management as long-term debt as shown on the consolidated balance sheets plus net working capital) and shareholders' capital.

In managing capital, Vermilion reviews whether fund flows from operations (a non-standardized measure, defined by management as cash flows from operating activities before changes in non-cash operating working capital and asset retirement obligations settled), is sufficient to pay for all capital expenditures, dividends and abandonment and reclamation expenditures. To the extent that the forecasted fund flows from operations is not expected to be sufficient in relation to these expenditures, Vermilion will evaluate its ability to finance any excess with debt, an issuance of equity or by reducing some or all categories of expenditures to ensure that total expenditures do not exceed available funds.

Additionally, Vermilion monitors the ratio of net debt to fund flows from operations. Vermilion typically strives to maintain an internally targeted ratio of net debt to fund flows from operations of 1.0 to 1.3 in a normalized commodity price environment. Where prices trend higher, Vermilion may target a lower ratio and conversely, in a lower commodity price environment, the acceptable ratio may be higher. At times, Vermilion will use its balance sheet to finance acquisitions and, in these situations, Vermilion is prepared to accept a higher ratio in the short term but will implement a plan to reduce the ratio to acceptable levels within a reasonable period of time, usually considered to be no more than 12 to 18 months. This plan could potentially include an increase in hedging activities, a reduction in capital expenditures, an issuance of equity or the utilization of excess fund flows from operations to reduce outstanding indebtedness.

In the current low commodity price environment, the net debt to fund flows ratio is expected to be higher than the longer term ratio. During this period, Vermilion is managing the higher debt level by aligning capital expenditures within forecasted fund flows from operations, which is continually monitored for revised forward price estimates, as well as by hedging additional European natural gas volumes to maintain a diversified commodity portfolio.

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

	Year Ended	
($M except as indicated)	**Dec 31, 2015**	**Dec 31, 2014**
Long-term debt	**1,162,998**	1,238,080
Current liabilities[(1)]	**503,731**	365,729
Current assets	**(284,778)**	(338,159)
Net debt [1]	**1,381,951**	1,265,650
Cash flows from operating activities	**444,408**	791,986
Changes in non-cash operating working capital	**60,390**	(3,077)
Asset retirement obligations settled	**11,369**	15,956
Fund flows from operations [2]	**516,167**	804,865
Ratio of net debt to fund flows from operations ([1] ÷ [2])	**2.7**	1.6

(1) Includes the current portion of long-term debt, which, as at December 31, 2015, represents the senior unsecured notes that matured on February 10, 2016.

Long-term debt, including the current portion, as at December 31, 2015 increased to $1.39 billion from $1.24 billion as at December 31, 2014, primarily as a result of draws on the revolving credit facility to fund capital expenditures as fund flows from operations for the year ended December 31, 2015 were lower due to weakening crude oil and natural gas prices. The increase in long-term debt resulted in an increase in net debt from $1.27 billion as at December 31, 2014 to $1.38 billion as at December 31, 2015.

Driven primarily by the weakness in crude oil prices, the ratio of net debt to fund flows from operations increased to 2.7 times for the year ended December 31, 2015.

19. FINANCIAL INSTRUMENTS

Classification of Financial Instruments

The following table summarizes information relating to Vermilion's financial instruments as at December 31, 2015 and December 31, 2014:

				As at Dec 31, 2015		As at Dec 31, 2014		
Class of financial instrument	**Consolidated balance sheet caption**	**Accounting designation**	**Related caption on Statement of Net Earnings (Loss)**	**Carrying value ($M)**	**Fair value ($M)**	**Carrying value ($M)**	**Fair value ($M)**	**Fair value measurement hierarchy**
Cash	Cash and cash equivalents	HFT	Gains and losses on foreign exchange are included in foreign exchange (gain) loss	**41,676**	**41,676**	120,405	120,405	Level 1
Receivables	Accounts receivable	LAR	Gains and losses on foreign exchange are included in foreign exchange (gain) loss and impairments are recognized as general and administration expense	**160,499**	**160,499**	171,820	171,820	Not applicable
Derivative assets	Derivative instruments	HFT	Gain on derivative instruments	**68,342**	**68,342**	24,794	24,794	Level 2
Payables	Accounts payable and accrued liabilities Dividends payable	OTH	Gains and losses on foreign exchange are included in foreign exchange (gain) loss	**(272,824)**	**(272,824)**	(321,266)	(321,266)	Not applicable
Long-term debt	Long-term debt	OTH	Interest expense	**(1,387,899)**	**(1,387,998)**	(1,238,080)	(1,238,505)	Level 2

The accounting designations used in the above table refer to the following:

HFT – Classified as "Held for trading" in accordance with International Accounting Standard 39 "Financial Instruments: Recognition and Measurement". These financial assets and liabilities are carried at fair value on the consolidated balance sheets with associated gains and losses reflected in net earnings (loss).

LAR – "Loans and receivables" are initially recognized at fair value and are subsequently measured at amortized cost. Impairments and foreign exchange gains and losses are recognized in net earnings (loss).

OTH – "Other financial liabilities" are initially recognized at fair value net of transaction costs directly attributable to the issuance of the instrument and subsequently are measured at amortized cost. Interest is recognized in net earnings (loss) using the effective interest method. Foreign exchange gains and losses are recognized in net earnings (loss).

Level 1 – Fair value measurement is determined by reference to unadjusted quoted prices in active markets for identical assets or liabilities.

Level 2 – Fair value measurement is determined based on inputs other than unadjusted quoted prices that are observable, either directly or indirectly.

Level 3 – Fair value measurement is based on inputs for the asset or liability that are not based on observable market data.

Determination of Fair Values

The level in the fair value hierarchy into which the fair value measurements are categorized is determined on the basis of the lowest level input that is significant to the fair value measurement. Transfers between levels on the fair value hierarchy are deemed to have occurred at the end of the reporting period.

Fair values for derivative assets and derivative liabilities are determined using pricing models incorporating future prices that are based on assumptions which are supported by prices from observable market transactions and are adjusted for credit risk.

The carrying value of receivables approximate their fair value due to their short maturities.

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.

The fair value of the senior unsecured notes changes in response to changes in the market rates of interest payable on similar instruments and was determined with reference to prevailing market rates for such instruments.

19. FINANCIAL INSTRUMENTS (Continued)

Nature and Extent of Risks Arising from Financial Instruments

Vermilion is exposed to the following types of risks in relation to its financial instruments:

Credit risk:
Vermilion extends credit to customers and is due amounts from counterparties in relation to derivative instruments. Accordingly, there is a risk of financial loss in the event that a counterparty fails to discharge its obligation. For transactions that are financially significant, Vermilion reviews third-party credit ratings and may require additional forms of security. Cash held on behalf of the Company by financial institutions is also subject to credit risk.

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.

Currency risk:
Vermilion conducts business in foreign currencies in addition to Canadian dollars and accordingly is subject to currency risk associated with changes in foreign exchange rates in relation to cash and cash equivalents, receivables, payables and derivative assets and liabilities. The impact related to working capital is somewhat mitigated as a result of the offsetting effects of foreign exchange fluctuations on assets and liabilities. 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.

Commodity price risk:
Vermilion uses derivative financial instruments as part of its risk management program to mitigate the effects of changes in commodity prices on future cash flows. Changes in the underlying commodity prices impact the fair value and future cash flows related to these derivatives.

Interest rate risk:
Vermilion's long-term debt is comprised of borrowings under the revolving credit facility and the Company's senior unsecured notes. Borrowings under the revolving credit facility bear interest at market rates plus applicable margins and as such changes in interest rates could result in an increase or decrease in the amount Vermilion pays to service this debt. In 2015, Vermilion had interest rate swaps to mitigate the effects of changes in variable interest rates. The senior unsecured notes bear interest at a fixed 6.5% interest rate and as such, changes in prevailing interest rates would affect the fair value of these notes. However, as Vermilion does not intend to settle this debt prior to maturity, the notes are carried at amortized cost and changes in fair value do not affect net earnings.

Summarized Quantitative Data Associated with the Risks Arising from Financial Instruments

Credit risk:
As at December 31, 2015, Vermilion's maximum exposure to receivable credit risk was $228.8 million (December 31, 2014 - $196.6 million) which is the aggregate value of receivables and derivative assets at the balance sheet date. Vermilion's receivables are primarily due from counterparties that have investment grade third party credit ratings or, in the absence of the availability of such ratings, have been satisfactorily reviewed by Vermilion for creditworthiness. Additionally, cash and cash equivalents consist of moneys on deposit and short-term investments which may be subject to counterparty credit risk. Vermilion mitigates this risk by transacting with North American institutions with high third party credit ratings.

As at the balance sheet date the amount of financial assets that were past due or impaired was not material.

Liquidity risk:
Vermilion's derivative financial instruments settle on a monthly basis.

19. FINANCIAL INSTRUMENTS (Continued)

The following table summarizes Vermilion's undiscounted non-derivative financial liabilities and their contractual maturities as at December 31, 2015 and December 31, 2014:

($M)	Due in one month	Later than one month and not later than three months	Later than three months and not later than one year	Later than one year and not later than five years
December 31, 2015	112,890	353,934	33,663	1,180,486
December 31, 2014	162,127	138,823	20,314	1,239,067

Market risk:
Vermilion's financial instruments are exposed to currency risk related to changes in foreign currency denominated financial instruments and commodity price risk related to outstanding derivative positions. The following table summarizes what the impact on comprehensive income before tax would be for the year ended December 31, 2015 given changes in the relevant risk variables that Vermilion considers were reasonably possible at the balance sheet date. The impact on comprehensive income before tax associated with changes in these risk variables for assets and liabilities that are not considered financial instruments are excluded from this analysis. This analysis does not attempt to reflect any interdependencies between the relevant risk variables.

Risk ($M)	Description of change in risk variable	Before tax effect on comprehensive income - increase (decrease) December 31, 2015	December 31, 2014
Currency risk - Euro to Canadian	**Increase** in strength of the Canadian dollar against the Euro by 5% over the relevant closing rates	(1,986)	(4,030)
	Decrease in strength of the Canadian dollar against the Euro by 5% over the relevant closing rates	1,986	4,030
Currency risk - US $ to Canadian	**Increase** in strength of the Canadian dollar against the US $ by 5% over the relevant closing rates	3,423	(5,739)
	Decrease in strength of the Canadian dollar against the US $ by 5% over the relevant closing rates	(3,423)	5,739
Commodity price risk	**Increase** in relevant oil reference price within option pricing models used to determine the fair value of financial derivatives by US $5.00/bbl at the relevant valuation dates	(3,262)	(1,072)
	Decrease in relevant oil reference price within option pricing models used to determine the fair value of financial derivatives by US $5.00/bbl at the relevant valuation dates	3,263	1,048
	Increase in relevant European natural gas reference price within option pricing models used to determine the fair value of financial derivatives by € 0.5/GJ at the relevant valuation dates	(23,813)	(10,279)
	Decrease in relevant European natural gas reference price within option pricing models used to determine the fair value of financial derivatives by € 0.5/GJ at the relevant valuation dates	21,754	10,085
Interest rate risk	**Increase** in average Canadian prime interest rate by 100 basis points during the relevant periods	(10,543)	(9,032)
	Decrease in average Canadian prime interest rate by 100 basis points during the relevant periods	10,543	9,032

Reasonably possible changes in North American natural gas prices would not have had a material impact on comprehensive income for the years ended December 31, 2015 and 2014.

20. RELATED PARTY DISCLOSURES

The compensation of directors and management are 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, 2015 and December 31, 2014:

	Year Ended	
($M)	**Dec 31. 2015**	**Dec 31, 2014**
Short-term benefits	5,460	5,684
Share-based payments	20,310	16,414
	25,770	22,098
Number of individuals included in the above amounts	20	18

21. WAGES AND BENEFITS

Included in operating expenses and general and administrative expenses for the year ended December 31, 2015 were $47.7 million and $40.4 million of wages and benefits, respectively (2014 – $56.2 million and $47.2 million, respectively).

22. SIGNIFICANT TRANSACTIONS

During Q1 2015, Vermilion was awarded a recovery of costs resulting from an oil spill at the Ambès oil terminal in France that occurred in 2007. The French court awarded Vermilion approximately €25 million (before taxes), of which 50% was due immediately to Vermilion upon posting a surety bond. The payment was received in Q2 2015, with the remainder due upon conclusion of the appeal process. Based on the recent court decision and the conclusions of the expert engaged by the French court, Vermilion is virtually certain that the award will be upheld.

CORPORATE INFORMATION

DIRECTORS

Lorenzo Donadeo [1]
Calgary, Alberta

Larry J. Macdonald [2, 4, 5, 6]
Chairman & CEO, Point Energy Ltd.
Calgary, Alberta

Claudio A. Ghersinich [3, 6]
Executive Director, Carrera Investments Corp.
Calgary, Alberta

Joseph F. Killi [3, 4]
Chairman, Parkbridge Lifestyle Communities Inc.
Vice Chairman, Realex Properties Corp.
Calgary, Alberta

Loren M. Leiker [6]
Houston, Texas

William F. Madison [5, 6]
Sugar Land, Texas

Timothy R. Marchant [5, 6]
Calgary, Alberta

Sarah E. Raiss [4, 5]
Calgary, Alberta

Kevin J. Reinhart [3, 4]
Calgary, Alberta

Catherine L. Williams [3, 4]
Calgary, Alberta

[1] Chairman of the Board
[2] Lead Director
[3] Audit Committee
[4] Governance and Human Resources Committee
[5] Health, Safety and Environment Committee
[6] Independent Reserves Committee

ANNUAL GENERAL MEETING

May 6, 2016
10:00 AM MST
The Ballroom
Metropolitan Centre
333 – 4th Avenue S.W.
Calgary, Alberta

OFFICERS AND KEY PERSONNEL

CANADA
Anthony Marino, P.Eng.
President & Chief Executive Officer

John D. Donovan, FCA
Executive Vice President Business Development

Curtis W. Hicks, CA
Executive Vice President & Chief Financial Officer

Mona Jasinski, M.B.A., ICD.D., C.H.R.P.
Executive Vice President, People and Culture

Michael Kaluza, P.Eng.
Executive Vice President & Chief Operating Officer

Dion Hatcher, P.Eng.
Vice President Canada Business Unit

Terry Hergott, CMA
Vice President Marketing

Daniel Goulet, P.Eng.
Director Corporate HSE

Bryce Kremnica, P.Eng.
Director Field Operations – Canada Business Unit

Dean N. Morrison, CFA
Director Investor Relations

Mike Prinz
Director Information Technology & Information Systems

Jenson Tan, P.Eng.
Director New Ventures

Robert (Bob) J. Engbloom, LL.B
Corporate Secretary

UNITED STATES
Daniel G. Anderson
Managing Director – U.S. Business Unit

Timothy R. Morris
Director, U.S. Business Development – U.S. Business Unit

EUROPE
Gerard Schut, P.Eng.
Vice President European Operations

Darcy Kerwin, P.Eng.
Managing Director - France Business Unit

Scott Seatter, P.Eng.
Managing Director - Netherlands Business Unit

Albrecht Moehring
Managing Director - Germany Business Unit

Bryan Sralla
Managing Director - Central & Eastern Europe Business Unit

AUSTRALIA
Bruce D. Lake, P.Eng.
Managing Director - Australia Business Unit

AUDITORS

Deloitte LLP
Calgary, Alberta

BANKERS

The Toronto-Dominion Bank

Bank of Montreal

Canadian Imperial Bank of Commerce

Royal Bank of Canada

The Bank of Nova Scotia

National Bank of Canada

Alberta Treasury Branches

HSBC Bank Canada

La Caisse Centrale Desjardins du Québec

Wells Fargo Bank N.A., Canadian Branch

Bank of America N.A., Canada Branch

BNP Paribas, Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

JPMorgan Chase Bank, N.A., Toronto Branch

Union Bank, Canada Branch

Canadian Western Bank

Goldman Sachs Lending Partners LLC

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 CONTACT

Dean Morrison, CFA
Director Investor Relations
403-269-4884 TEL
403-476-8100 FAX
1-866-895-8101 IR TOLL FREE
investor_relations@vermilionenergy.com



EXCELLENCE

We aim for exceptional results in everything we do.

TRUST

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

RESPECT

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

RESPONSIBILITY

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

VERMILION ENERGY

Vermilion Energy Inc.
3500, 520 3rd Avenue SW
Calgary, Alberta T2P 0R3

Telephone: 1.403.269.4884
Facsimile: 1.403.476.8100
IR Toll Free: 1.866.895.8101
investor_relations@vermilionenergy.com

vermilionenergy.com

EXHIBIT 99.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the use of our reports dated February 26, 2016 relating to the consolidated financial statements of Vermilion Energy Inc. and the effectiveness of Vermilion Energy Inc.'s internal control over financial reporting appearing in this Annual Report on Form 40-F of Vermilion Energy Inc. for the year ended December 31, 2015.

/s/ Deloitte LLP

Chartered Professional Accountants, Chartered Accountants
Calgary, Canada
March 4, 2016

EXHIBIT 99.5

CONSENT OF INDEPENDENT ENGINEERS

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 petroleum and natural gas reserves and resources as at December 31, 2015, in this Annual Report on Form 40-F of Vermilion Energy Inc.

Yours truly,

("GLJ Petroleum Consultants Ltd.")

GLJ Petroleum Consultants Ltd.
4100, 400 - 3rd Avenue S.W.,
Calgary, Alberta, Canada T2P 4H2
(403) 266-9500 Fax (403) 262-1855

March 4, 2016

EXHIBIT 99.6

VERMILION ENERGY INC.
CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER

I, Anthony Marino, 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(s) 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; and

   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(s) 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 4, 2016

("Anthony Marino")
[Signature]

Anthony Marino, Chief Executive Officer

EXHIBIT 99.6

VERMILION ENERGY INC.
CERTIFICATION OF THE CHIEF FINANCIAL OFFICER

I, Curtis Hicks, 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(s) 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; and

   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(s) 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 4, 2016

("Curtis Hicks")
[Signature]

Curtis Hicks, 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, 2015, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Anthony Marino, 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 4th day of March 2016.

("Anthony Marino")
[Signature]

Anthony Marino, 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, 2015, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Curtis Hicks, 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 4th day of March 2016.

("Curtis Hicks")
[Signature]

Curtis Hicks, Chief Financial Officer