VERMILION
ENERGY

Vermilion Energy Inc.

2014 Management's Discussion & Analysis

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
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
mmcf	million cubic feet
mmcf/d	million cubic feet per day
MWh	megawatt hour
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

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 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 and prospective 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; the timing of regulatory proceedings and approvals; and the timing of first commercial natural gas 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 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. The actual 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 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 27, 2015, 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, 2014 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, 2014 and 2013, together with the accompanying notes. Additional information relating to Vermilion, including its Annual Information Form, is available on SEDAR at www.sedar.com or on Vermilion's website at www.vermilionenergy.com.

The audited consolidated financial statements for the year ended December 31, 2014 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. As such, these financial measures are considered additional GAAP or non-GAAP financial measures and therefore are unlikely to be comparable with similar financial measures presented by other issuers. These additional GAAP and non-GAAP financial measures include:

- Fund flows from operations: This additional GAAP 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 non-GAAP 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.

For a full description of these and other non-GAAP financial measures and a reconciliation of these measures to their most directly comparable GAAP measures, please refer to "ADDITIONAL AND 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 25% contractual participation interest in a four-partner consortium 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.

NEW COUNTRY ENTRIES

In February 2014, we acquired a 25% contractual participation interest in a four-partner consortium in Germany from GDF Suez S.A. The acquisition enables us to participate in the exploration and development, production and transportation of natural gas from the assets held by the consortium. The assets are comprised of four gas producing fields across eleven production licenses and are characterized by a low effective decline rate of approximately 11% annually. The acquired assets include both exploration and production licenses that comprise a total of 204,000 gross acres, of which 85% is in the exploration license. The acquisition represented Vermilion's entry into the German exploration and production business, a producing region with a long history of oil and gas development activity, low political risk, and strong marketing fundamentals. The acquisition provides us with entry into this sizable market, in the form of free cash flow generating, low-decline assets with near-term development inventory in addition to longer-term, low-permeability gas prospectivity. Entry into Germany is in keeping with our European focus, and increases our exposure to the strong fundamentals and pricing of European natural gas markets. We believe that our conventional and unconventional expertise, coupled with new access to proprietary technical data, will position us strongly for future development and expansion opportunities in both Germany and the greater European region.

On November 10, 2014, we announced an acquisition of assets in the Powder River Basin of northeastern Wyoming for $11.1 million. The assets cover approximately 68,000 acres of land (98% undeveloped) with current working interest production of approximately 200 bbls/d (100% crude oil). The land base includes 53,000 net acres at an average operated working interest of 70% in a promising tight oil project in the Turner Sand at a depth of approximately 1,500 metres. The acquisition represented a low-cost entry into the prolific Powder River Basin and Vermilion's entry into the sizable United States exploration and production market. Looking ahead we see continued opportunity for expansion, with an active asset market in North America where technology continues to unlock new opportunities for development. We have established an office in Denver, Colorado as the operating headquarters for our new United States business unit and have hired to staff this subsidiary.

2014 REVIEW AND 2015 GUIDANCE

We first issued 2014 capital expenditure guidance of $555 million on November 7, 2013. We subsequently increased our 2014 capital expenditure guidance to $590 million on March 18, 2014, to reflect an additional $35 million of 2014 development capital expected to be incurred in association with our acquisition of Elkhorn Resources Inc.

Concurrent with the release of our first quarter 2014 financial and operating results on May 2, 2014, we further updated our 2014 capital expenditure guidance to $635 million, reflecting the expected full-year rise in the cost to Vermilion, in Canadian dollar terms, of both actual and anticipated international capital expenditures as a result of the devaluation of the Canadian dollar against both the U.S. dollar and the Euro, and the addition of approximately $15 million of anticipated spending associated with drilling activities. We also increased our original production guidance from 47,500-48,500 boe/d to 48,000-49,000 boe/d.

Based on the continued strength of our operations during the second quarter of 2014, we further increased our full-year 2014 production and capital expenditure guidance to 48,500-49,500 boe/d and $650 million, respectively. The increase in capital expenditures was attributed to increased Mannville development drilling and higher than anticipated costs associated with the Duvernay development program.

Concurrent with the release of our third quarter 2014 financial and operating results on November 10, 2014, we further revised our 2014 full year production guidance from the previous range of 48,500-49,500 boe/d to a range of 49,000-49,500 boe/d and announced the expectation of achieving production near the upper end of the range for 2014.

We provided updated 2014 capital expenditure guidance concurrent with the release of our initial 2015 production and capital expenditure guidance on December 8, 2014. The increase in 2014 capital expenditures resulted from a shift in capital priorities, previously unplanned spending and foreign exchange movements.

The following table summarizes our 2014 actual results compared to guidance and our 2015 guidance:

	Date	Capital Expenditures ($MM)	Production (boe/d)
2014 - Guidance			
2014 Guidance	November 7, 2013	555	45,000 to 46,000
2014 - Guidance Updates			
2014 Guidance - Update	March 18, 2014	590	47,500 to 48,500
2014 Guidance - Update	May 2, 2014	635	48,000 to 49,000
2014 Guidance - Update	July 31, 2014	650	48,500 to 49,500
2014 Guidance - Update	November 10, 2014	650	49,000 to 49,500
2014 Guidance - Update	December 8, 2014	675	49,000 to 49,500
2014 - Actual Production			
2014 Actual	February 27, 2015	688	49,573
2015 - Guidance			
2015 Guidance	December 8, 2014	525	55,000 to 57,000
2015 Guidance	February 27, 2015	415	55,000 to 57,000

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, 2014, 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	$7.26	$11.82
Capital appreciation per Vermilion share	-$5.35	$11.63	$24.58
Total return per Vermilion share	-4.4%	41.6%	112.3%
Annualized total return per Vermilion share	-4.4%	12.3%	16.2%
Annualized total return on the S&P TSX High Income Energy Index	-13.6%	-3.3%	1.3%

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

CONSOLIDATED RESULTS OVERVIEW

	Three Months Ended			% change		Year Ended		% change
	Dec 31, 2014	Sep 30, 2014	Dec 31, 2013	Q4/14 vs. Q3/14	Q4/14 vs. Q4/13	Dec 31, 2014	Dec 31, 2013	2014 vs. 2013
Production								
Crude oil (bbls/d)	28,846	29,147	26,039	(1%)	11%	28,879	25,741	12%
NGLs (bbls/d)	2,822	2,354	1,761	20%	60%	2,553	1,730	48%
Natural gas (mmcf/d)	107.42	110.52	78.96	(3%)	36%	108.85	81.21	34%
Total (boe/d)	49,571	49,920	40,960	(1%)	21%	49,573	41,005	21%
Build (draw) in inventory (mbbl)	(238)	104	(10)			(164)	(229)	
Financial metrics								
Fund flows from operations ($M)	185,528	197,898	163,660	(6%)	13%	804,865	667,526	21%
Per share ($/basic share)	1.73	1.85	1.61	(6%)	7%	7.63	6.61	15%
Net earnings ($M)	58,642	53,903	101,510	9%	(42%)	269,326	327,641	(18%)
Per share ($/basic share)	0.55	0.50	1.00	10%	(45%)	2.55	3.24	(21%)
Cash flows from operating activities ($M)	229,146	235,010	177,003	(2%)	29%	791,986	705,025	12%
Net debt ($M)	1,265,650	1,243,438	749,685	2%	69%	1,265,650	749,685	69%
Cash dividends ($/share)	0.645	0.645	0.600	-	8%	2.580	2.400	8%
Activity								
Capital expenditures ($M)	166,243	190,033	148,478	(13%)	12%	687,724	542,726	27%
Acquisitions ($M)	1,652	40,847	29,103	(96%)	(94%)	601,865	36,689	1,540%
Gross wells drilled	26.00	26.00	21.00			89.00	76.00	
Net wells drilled	16.58	20.31	16.65			62.43	64.21	

Operational review

- Recorded consolidated average production of 49,571 boe/d during Q4 2014, which was consistent with Q3 2014.
- Increased consolidated average production for the three months and year ended December 31, 2014 by 21% versus the comparable periods in 2013, primarily due to growth in Canada, the Netherlands, and incremental production from our acquisitions in Germany, southeast Saskatchewan and the United States. In Canada, production growth of 38% and 34% for the three months and year ended December 31, 2014, respectively, versus the comparable periods in 2013, resulted from our continued development of the Cardium and Mannville plays in Alberta coupled with incremental production from southeast Saskatchewan following our acquisition in April 2014 of Elkhorn Resources Inc. In the Netherlands, production growth of 8% for the year ended December 31, 2014 versus the comparable period in 2013 resulted from incremental production from our acquisition in the Netherlands in Q4 2013, increased volumes following completion of the Middenmeer Treatment Centre retrofit in the latter part of 2013, and ongoing recompletion and production optimization activities. These production increases were partially offset by decreased production in France due primarily to the temporary shut-in of natural gas production from the Vic Bilh field for the entirety of 2014.
- Activity during the quarter included capital expenditures totalling $166.2 million, incurred primarily in Canada, France, and Ireland. In Canada, capital expenditures totalling $85.4 million were 12% lower than the $97.4 million incurred in Q3 2014 and related to the drilling of 15.16 net wells compared to 16.86 net wells in Q3 2014. In France, capital expenditures of $37.2 million related to workovers, seismic activity, various facility projects, and the drilling of one (0.5 net) well in the Tamaris field. In Ireland, $20.9 million of capital expenditures were incurred related to offshore workover and pipeline operations, as well as outfitting the 4.9 km tunnel.
- Acquisition expenditures for the quarter totalling $1.7 million related to crown land sales, primarily in southeast Saskatchewan.

Financial review

Net earnings

- Net earnings for Q4 2014 were $58.6 million ($0.55/basic share) as compared to $53.9 million ($0.50/basic share) for Q3 2014. Quarter-over-quarter net earnings were relatively consistent as lower petroleum and natural gas sales ("sales") and operating income were offset by gains on derivative instruments (including $17.2 million of unrealized gains due to lower forecasted pricing for 2015 and the impact on the valuation of our crude oil and natural gas derivative positions).
- Net earnings for the three months and year ended December 31, 2014 were 42% and 18% lower versus the respective comparable periods in 2013 due to a decrease in realized prices and foreign exchange losses, partially offset by the aforementioned gains on derivative instruments. For the three months ended December 31, 2014, revenue decreased by 6% driven by lower commodity prices. Revenue increased by 11% for the year ended December 31, 2014 as the decrease in realized prices was offset by incremental production and a decrease in crude inventory as compared to the same periods in 2013. Unrealized foreign exchange losses of $4.0 million and $17.6 million for the three months and year ended December 31, 2014 were the result of the Euro weakening versus the Canadian dollar and the resulting impact on our Euro denominated financial assets. In addition, both periods were affected by the absence of the $47.4 million impairment recovery recognized in 2013.

Cash flows from operating activities

- Cash flows from operations decreased 2% as compared to Q3 2014 as lower sales were offset by higher realized gains on derivative instruments and timing differences pertaining to working capital.
- Cash flow from operations increased by 29% and 12% for the three months and year ended December 31, 2014 compared to the same periods in 2013. For the three months ended December 31, 2014, the increase primarily related to timing differences pertaining to working capital, partially offset by lower revenues due to lower commodity prices. For the year ended December 31, 2014, the increase primarily related to increased revenues driven by incremental production related to our Germany and Saskatchewan acquisitions, partially offset by timing differences pertaining to working capital.

Fund flows from operations

- Generated fund flows from operations of $185.5 million during Q4 2014, a decrease of $12.4 million (6%) versus Q3 2014. This quarter-over-quarter decrease was the result of lower sales partially offset by increased realized derivative gains and decreases in corporate income taxes and general and administration expenses. Lower sales were driven by weaker commodity pricing coupled with a decrease in Netherlands production, as production in that country is managed to optimize facility use and regulate declines.
- Fund flows from operations increased by 13% and 21% for the three months and year ended December 31, 2014, respectively, versus the comparable periods in 2013. These increases were primarily the result of increased sales volumes in Canada coupled with incremental production following our Q1 2014 acquisition in Germany, our Q2 2014 acquisition in southeast Saskatchewan, and a draw in Australia inventory in both periods.

Net debt

- As a result of funding our 2014 acquisitions in Germany, Canada, and the United States, net debt increased to $1.27 billion or 1.6 times fund flows from operations for the year ended December 31, 2014.

Dividends

- Declared dividends of $0.215 per common share per month during 2014, totalling $0.645 per common share for the quarter and $2.58 per common share for the year ended December 31, 2014. Dividends were higher in the 2014 periods versus the comparable periods in 2013 due to our increase in dividends per share starting with the January 31, 2014 dividend paid on February 18, 2014.

COMMODITY PRICES

	Three Months Ended			% change		Year Ended		% change
	Dec 31, 2014	Sep 30, 2014	Dec 31, 2013	Q4/14 vs. Q3/14	Q4/14 vs. Q4/13	Dec 31, 2014	Dec 31, 2013	2014 vs. 2013
Average reference prices								
WTI (US $/bbl)	73.15	97.17	97.46	(25%)	(25%)	93.00	97.97	(5%)
Edmonton Sweet index (US $/bbl)	66.79	89.24	82.53	(25%)	(19%)	85.83	90.40	(5%)
Dated Brent (US $/bbl)	76.27	101.85	109.27	(25%)	(30%)	98.99	108.66	(9%)
AECO ($/GJ)	3.41	3.81	3.35	(10%)	2%	4.27	3.01	42%
TTF ($/GJ)	8.69	7.26	10.65	20%	(18%)	8.50	10.29	(17%)
TTF (€/GJ)	6.12	5.04	7.45	21%	(18%)	5.79	7.51	(23%)
Average foreign currency exchange rates								
CDN $/US $	1.14	1.09	1.05	5%	9%	1.10	1.03	7%
CDN $/Euro	1.42	1.44	1.43	(1%)	(1%)	1.47	1.37	7%
Average realized prices ($/boe)								
Canada	51.27	64.85	61.10	(21%)	(16%)	64.06	61.14	5%
France	79.25	107.99	112.84	(27%)	(30%)	105.43	106.26	(1%)
Netherlands	52.07	45.73	67.88	14%	(23%)	52.65	64.08	(18%)
Germany	49.19	36.43	-	35%	100%	46.03	-	100%
Australia	90.37	119.07	124.63	(24%)	(27%)	113.80	119.38	(5%)
United States	74.08	-	-	100%	100%	74.08	-	100%
Consolidated	63.79	76.80	86.04	(17%)	(26%)	77.75	83.83	(7%)
Production mix (% of production)								
% priced with reference to WTI	28%	28%	25%			28%	25%	
% priced with reference to AECO	20%	18%	17%			18%	16%	
% priced with reference to TTF	16%	18%	15%			18%	16%	
% priced with reference to Dated Brent	36%	36%	43%			36%	43%	

Reference prices

- The growing global surplus of crude oil put considerable downside pressure on global crude oil prices in the fourth quarter of 2014, with Dated Brent falling 25% quarter-over-quarter and 9% year-over-year.
- North American crude oil prices were not immune to the global oversupply situation as both WTI and Edmonton Sweet index declined by 25% quarter-over-quarter and 5% year-over-year.
- Natural gas prices at AECO suffered a 10% quarter-over-quarter decline as weather-driven demand was not sufficient to tighten the fundamental balance; however, on a year-over-year basis, AECO increased by 42%.
- European natural gas prices recovered from a weaker summer. Aided by both seasonality and concerns over winter supplies from Russia, TTF saw a 20% quarter-over-quarter gain, but with ample gas-in-storage and little weather demand during the early stages of the winter season, the TTF price was down 17% year-over-year.
- A weak crude oil market and general strengthening of the US dollar saw the Canadian dollar weaken throughout the quarter, but against the Euro, the Canadian dollar was relatively unchanged.

Realized prices

- Consolidated realized price decreased by 17% for Q4 2014 as compared to Q3 2014 and 26% as compared to Q4 2013. These decreases were primarily the result of weaker crude oil prices, partially offset by stronger TTF pricing and a weaker Canadian dollar versus the US dollar during Q4 2014 versus the comparable quarters.
- Consolidated realized price for the year ended December 31, 2014 decreased by 7% as compared to the prior year. This decrease was driven by weaker crude oil and TTF pricing, partially offset by stronger AECO pricing and a weaker Canadian dollar.

FUND FLOWS FROM OPERATIONS

	Three Months Ended						Year Ended			
	Dec 31, 2014		Sep 30, 2014		Dec 31, 2013		Dec 31, 2014		Dec 31, 2013	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Petroleum and natural gas sales	306,073	63.79	344,688	76.80	325,108	86.04	1,419,628	77.75	1,273,835	83.83
Royalties	(25,963)	(5.41)	(29,000)	(6.46)	(17,616)	(4.66)	(108,000)	(5.92)	(67,936)	(4.47)
Petroleum and natural gas revenues	280,110	58.38	315,688	70.34	307,492	81.38	1,311,628	71.83	1,205,899	79.36
Transportation expense	(9,489)	(1.98)	(10,979)	(2.45)	(9,081)	(2.40)	(42,361)	(2.32)	(28,924)	(1.90)
Operating expense	(59,881)	(12.48)	(56,227)	(12.53)	(48,140)	(12.74)	(232,307)	(12.72)	(195,043)	(12.84)
General and administration	(13,236)	(2.76)	(16,262)	(3.62)	(13,954)	(3.69)	(61,727)	(3.38)	(49,910)	(3.28)
PRRT	(13,568)	(2.83)	(13,834)	(3.08)	(17,173)	(4.55)	(60,340)	(3.30)	(56,565)	(3.72)
Corporate income taxes	(8,304)	(1.73)	(17,454)	(3.89)	(43,065)	(11.40)	(96,996)	(5.31)	(161,794)	(10.65)
Interest expense	(12,943)	(2.70)	(12,918)	(2.88)	(10,049)	(2.66)	(49,655)	(2.72)	(38,183)	(2.51)
Realized gain (loss) on derivative instruments	22,816	4.76	8,837	1.97	(1,300)	(0.34)	36,712	2.01	(7,082)	(0.47)
Realized foreign exchange (loss) gain	(179)	(0.03)	812	0.17	(1,294)	(0.34)	(821)	(0.04)	(1,866)	(0.12)
Realized other income	202	0.04	235	0.05	224	0.06	732	0.04	994	0.07
Fund flows from operations	185,528	38.67	197,898	44.08	163,660	43.32	804,865	44.09	667,526	43.94

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

($M)	Q4/14 vs. Q3/14	Q4/14 vs. Q4/13	2014 vs. 2013
Fund flows from operations – Comparative period	197,898	163,660	667,526
Sales volume variance:			
Canada	3,545	35,366	136,832
France	5,839	6,706	(9,302)
Netherlands	(4,524)	(6,216)	11,132
Germany	1,297	13,359	41,962
Australia	29,803	20,345	(1,564)
United States	1,330	1,330	1,330
Pricing variance on sold volumes:			
WTI	(26,146)	(20,454)	(4,007)
AECO	(3,758)	215	22,959
Dated Brent	(52,457)	(61,872)	(26,662)
TTF	6,456	(7,814)	(26,887)
Changes in:			
Royalties	3,037	(8,347)	(40,064)
Transportation	1,490	(408)	(13,437)
Operating expense	(3,654)	(11,741)	(37,264)
General and administration	3,026	718	(11,817)
PRRT	266	3,605	(3,775)
Corporate income taxes	9,150	34,761	64,798
Interest	(25)	(2,894)	(11,472)
Realized derivatives	13,979	24,116	43,794
Realized foreign exchange	(991)	1,115	1,045
Realized other income	(33)	(22)	(262)
Fund flows from operations – Current Period	185,528	185,528	804,865

Fund flows from operations of $185.5 million during Q4 2014 represented a decrease of $12.4 million (6%) versus Q3 2014. This quarter-over-quarter decrease was the result of a $38.6 million decrease in sales, partially offset by a $14.0 million increase in hedging proceeds (following weaker commodity prices during the quarter) and a $9.2 million decrease in corporate income taxes. The decrease in sales included $75.9 million of pricing variance primarily due to a decrease in crude oil prices, partially offset by $37.3 million of sales volume variance primarily due to higher volumes in Australia (due to inventory draws in the period). The decrease in corporate income taxes was due to lower taxable income resulting from decreased sales.

On a year-over-year basis, fund flows from operations increased 13% and 21% for the three months and year ended December 31, 2014, respectively, versus the comparable periods in 2013. These increases were primarily the result of favorable sales volume variances in Canada coupled with incremental production following our Q1 2014 acquisition in Germany. The impact of increased AECO pricing, hedging proceeds and lower income taxes also contributed favorably to fund flows from operations. These favorable increases were partially offset by weaker crude oil and TTF pricing.

Fluctuations in fund flows from operations (and correspondingly net earnings 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 balance sheet. When the crude oil inventory is subsequently drawn down, the related expenses are recognized in fund flows from operations.

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, 2014	Sep 30, 2014	Dec 31, 2013	Q4/14 vs. Q3/14	Q4/14 vs. Q4/13	Dec 31, 2014	Dec 31, 2013	2014 vs. 2013
Production								
Crude oil (bbls/d)	11,384	11,469	8,719	(1%)	31%	11,248	8,387	34%
NGLs (bbls/d)	2,741	2,291	1,699	20%	61%	2,476	1,666	49%
Natural gas (mmcf/d)	58.36	57.07	41.43	2%	41%	55.67	42.39	31%
Total (boe/d)	23,851	23,272	17,322	2%	38%	23,001	17,117	34%
Production mix (% of total)								
Crude oil	48%	49%	50%			49%	49%	
NGLs	11%	10%	10%			11%	10%	
Natural gas	41%	41%	40%			40%	41%	
Activity								
Capital expenditures ($M)	85,442	97,393	77,245	(12%)	11%	334,742	241,197	39%
Acquisitions ($M)	1,671	27,883	1,603			415,648	9,189	
Gross wells drilled	23.00	22.00	21.00			74.00	69.00	
Net wells drilled	15.16	16.86	16.65			50.27	57.21	

Production

- The year-over-year increase in full year average production volumes was primarily attributable to strong organic production growth in each of our Cardium light crude oil resource play and Mannville condensate-rich gas play as well as incremental production volumes from our southeast Saskatchewan assets acquired in April 2014.
- Cardium production averaged more than 10,000 boe/d in Q4 2014 and more than 10,800 boe/d in 2014. The 20% increase in average annual production volumes was driven by better-than-forecasted production from long-reach wells and improved completion design.
- Mannville production averaged more than 4,300 boe/d in Q4 2014, a 17% increase quarter-over-quarter. Full year 2014 production averaged in excess of 3,900 boe/d.
- Production from our southeast Saskatchewan assets averaged approximately 3,000 boe/d in Q4 2014, an increase of 15% over Q3 2014. Full year 2014 production averaged approximately 1,900 boe/d taking into account a closing date for the acquisition of April 29, 2014.

Activity review

- Vermilion drilled a total of 18 (13.6 net) operated wells during Q4 2014 and 53 (44.8 net) operated wells during 2014.

  Cardium
  - We drilled 13 (9.9 net) operated wells and brought 10 (7.0 net) operated wells on production during Q4 2014. During 2014, we drilled 30 (25.9 net) operated wells and brought 30 (27.0 net) operated wells on production, of which 17 were long-reach wells with horizontal lengths greater than one mile.
  - Since 2009, we have drilled or participated in 278 (198.8 net) wells.
  - Operating netbacks averaged approximately $62.50/boe in 2014.
  - In 2015, we plan to drill or participate in approximately eight (3.0 net) wells and complete, equip and tie-in an additional 8.2 net wells which were drilled in 2014.

  Mannville
  - During Q4 2014, we drilled four (3.0 net) operated wells and brought three (2.5 net) operated wells on production. In 2014, we drilled 10 (7.7 net) operated wells and brought eight (6.2 net) operated wells on production.
  - In 2015, we expect to drill or participate in approximately 28 (16.0 net) wells and complete, equip and tie-in an additional 1.0 net well which was drilled in 2014.

  Duvernay
  - During the second half of 2014 we drilled two (1.3 net) horizontal wells. One (0.3 net) well was completed and brought on production during Q3 2014. The second well was completed and brought on production during Q4 2014.

  Saskatchewan
  - We drilled one (0.7 net) operated Midale well and brought three (2.6 net) operated wells on production during Q4 2014.
  - In 2014, we drilled or participated in 12 (10.4 net) Midale wells.
  - In 2015, we plan to drill or participate in five (4.1 net) wells in Saskatchewan.

Financial review

Canada business unit ($M except as indicated)	Three Months Ended Dec 31, 2014	Sep 30, 2014	Dec 31, 2013	% change Q4/14 vs. Q3/14	Q4/14 vs. Q4/13	Year Ended Dec 31, 2014	Dec 31, 2013	% change 2014 vs. 2013
Sales	112,494	138,853	97,367	(19%)	16%	537,788	382,005	41%
Royalties	(15,626)	(19,034)	(11,039)	(18%)	42%	(65,563)	(40,891)	60%
Transportation expense	(3,455)	(4,048)	(4,102)	(15%)	(16%)	(14,625)	(12,254)	19%
Operating expense	(19,315)	(19,074)	(13,218)	1%	46%	(76,178)	(55,804)	37%
General and administration	(2,840)	(4,523)	(2,478)	(37%)	15%	(16,791)	(12,979)	29%
Fund flows from operations	71,258	92,174	66,530	(23%)	7%	364,631	260,077	40%
Netbacks ($/boe)								
Sales	51.27	64.85	61.10	(21%)	(16%)	64.06	61.14	5%
Royalties	(7.12)	(8.89)	(6.93)	(20%)	3%	(7.81)	(6.55)	19%
Transportation expense	(1.57)	(1.89)	(2.57)	(17%)	(39%)	(1.74)	(1.96)	(11%)
Operating expense	(8.80)	(8.91)	(8.29)	(1%)	6%	(9.07)	(8.93)	2%
General and administration	(1.29)	(2.11)	(1.60)	(39%)	(19%)	(2.00)	(2.24)	(11%)
Fund flows from operations netback	32.49	43.05	41.71	(25%)	(22%)	43.44	41.46	5%
Reference prices								
WTI (US $/bbl)	73.15	97.17	97.46	(25%)	(25%)	93.00	97.97	(5%)
Edmonton Sweet index (US $/bbl)	66.79	89.24	82.53	(25%)	(19%)	85.83	90.40	(5%)
Edmonton Sweet index ($/bbl)	75.85	97.21	86.64	(22%)	(12%)	94.82	93.12	2%
AECO ($/GJ)	3.41	3.81	3.35	(10%)	2%	4.27	3.01	42%

Sales

- The realized price for our crude oil production in Canada is directly linked to WTI but is subject to market conditions in Western Canada. These market conditions can result in fluctuations in the pricing differential, 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.
- Sales per boe decreased by 21% quarter-over-quarter as a result of a 25% decrease in Edmonton Sweet index pricing and a 10% decrease in AECO pricing. This decrease coupled with relatively consistent production volumes resulted in a 19% decrease in sales.
- On a year-over-year basis, sales per boe decreased by 16% for the three months ended December 31, 2014 and increased by 5% for the year ended December 31, 2014 versus the same periods in 2013. Sales increased for the current year periods despite the decline in the Edmonton Sweet index price that occurred in the latter half of 2014 due to higher production, including incremental production from our Saskatchewan acquisition and production growth in the Cardium and Mannville resource plays, and higher AECO pricing.

Royalties

- Royalty expense as a percentage of sales increased to 13.9% and 12.2% for the three months and year ended December 31, 2014 (versus 11.3% and 10.7% for the comparable periods in 2013). The increase is associated with wells coming off of incentive royalty rates after reaching specified production thresholds, increased natural gas prices, and slightly higher average royalty rates associated with Vermilion's Saskatchewan production.
- On a quarter-over-quarter basis, royalties as a percentage of sales for Q4 2014 was unchanged versus Q3 2014.

Transportation

- Transportation expense relates to the delivery of crude oil and natural gas production to major pipelines where legal title transfers.
- Transportation expense for Q4 2014 was lower than Q3 2014 and Q4 2013 as a result of lower crude oil production subject to transportation costs.
- Transportation expense increased for 2014 as compared to 2013 due to incremental trucking costs from Vermilion's Saskatchewan properties, which were acquired in Q2 2014.

Operating expense

- On a per boe basis, operating expenses were relatively unchanged quarter-over-quarter and year-over-year. In dollar terms, the year-over-year increase is a result of increased facilities maintenance expenditures and gas processing costs coupled with incremental operating expenses associated with Vermilion's Saskatchewan properties.

General and administration

- Year-over-year, the increase in general and administration expense is associated with incremental expense associated with the Saskatchewan acquisition and higher staffing levels. The quarter-over-quarter decrease relates to the timing of expenditures.

FRANCE BUSINESS UNIT

Overview

- Entered France in 1997 and completed three subsequent acquisitions, including two in 2012.
- Largest oil producer in France.
- 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, 2014	Sep 30, 2014	Dec 31, 2013	Q4/14 vs. Q3/14	Q4/14 vs. Q4/13	Dec 31, 2014	Dec 31, 2013	2014 vs. 2013
Production								
Crude oil (bbls/d)	11,133	11,111	11,131	-	-	11,011	10,873	1%
Natural gas (mmcf/d)	-	-	-	-	-	-	3.40	(100%)
Total (boe/d)	11,133	11,111	11,131	-	-	11,011	11,440	(4%)
Inventory (mbbls)								
Opening crude oil inventory	214	179	226			269	354	
Adjustments	-	-	-			-	5	
Crude oil production	1,024	1,022	1,024			4,019	3,969	
Crude oil sales	(1,041)	(987)	(981)			(4,091)	(4,059)	
Closing crude oil inventory	197	214	269			197	269	
Production mix (% of total)								
Crude oil	100%	100%	100%			100%	95%	
Natural gas	-	-	-			-	5%	
Activity								
Capital expenditures ($M)	37,189	35,082	31,899	6%	17%	147,852	100,378	47%
Gross wells drilled	1.00	3.00	-			8.00	5.00	
Net wells drilled	0.50	3.00	-			7.50	5.00	

Production

- Q4 production was essentially flat quarter-over-quarter and year-over-year. Full year 2014 average production was 4% lower versus full year average production in 2013 due to the shut-in of produced gas volumes at Vic Bilh.
- In late September 2013, the third party Lacq processing facility that processed our Vic Bilh gas production was permanently closed. As a result, our Vic Bilh gas production has been temporarily shut-in while preparations to transfer to an alternative facility are completed. We currently expect a portion of the Vic Bilh production (approximately 850 mcf/d) will be back on-stream in mid-2015. As a result of the shut-in, current production volumes remain 100% weighted to Brent-based crude.

Activity review

- Vermilion drilled one (0.5 net) well in the Tamaris field in the Aquitaine Basin in Q4 2014.
- During Q4 2014, the 160 km^2 Champotran 3D seismic project was completed ahead of schedule and under budget. The final processing of the data is expected to be completed in Q1 2015.
- During 2014, we drilled eight (7.5 net) wells in France, including the completion of a five-well drilling program in the Champotran field. Additional activities in 2014 included a number of workovers, as well as seismic and facility integrity projects.
- In 2015, we are planning a four-well drilling program in the Champotran field, an 18-well workover program and the resumption of sales of approximately 850 mcf/d of solution gas at Vic Bilh.

Financial review

France business unit ($M except as indicated)	Three Months Ended Dec 31, 2014	Sep 30, 2014	Dec 31, 2013	% change Q4/14 vs. Q3/14	Q4/14 vs. Q4/13	Year Ended Dec 31, 2014	Dec 31, 2013	% change 2014 vs. 2013
Sales	82,499	106,576	110,757	(23%)	(26%)	431,252	453,315	(5%)
Royalties	(6,319)	(6,978)	(6,577)	(9%)	(4%)	(28,444)	(27,045)	5%
Transportation expense	(4,096)	(4,741)	(4,622)	(14%)	(11%)	(18,975)	(12,505)	52%
Operating expense	(13,544)	(15,215)	(15,524)	(11%)	(13%)	(61,729)	(66,997)	(8%)
General and administration	(3,765)	(6,411)	(5,080)	(41%)	(26%)	(20,929)	(19,657)	6%
Current income taxes	(6,132)	(10,744)	(28,024)	(43%)	(78%)	(66,901)	(94,524)	(29%)
Fund flows from operations	48,643	62,487	50,930	(22%)	(4%)	234,274	232,587	1%
Netbacks ($/boe)								
Sales	79.25	107.99	112.84	(27%)	(30%)	105.43	106.26	(1%)
Royalties	(6.07)	(7.07)	(6.70)	(14%)	(9%)	(6.95)	(6.34)	10%
Transportation expense	(3.94)	(4.80)	(4.71)	(18%)	(16%)	(4.64)	(2.93)	58%
Operating expense	(13.01)	(15.42)	(15.82)	(16%)	(18%)	(15.09)	(15.70)	(4%)
General and administration	(3.62)	(6.50)	(5.18)	(44%)	(30%)	(5.12)	(4.61)	11%
Current income taxes	(5.89)	(10.89)	(28.55)	(46%)	(79%)	(16.36)	(22.16)	(26%)
Fund flows from operations netback	46.72	63.31	51.88	(26%)	(10%)	57.27	54.52	5%
Reference prices								
Dated Brent (US $/bbl)	76.27	101.85	109.27	(25%)	(30%)	98.99	108.66	(9%)
Dated Brent ($/bbl)	86.62	110.95	114.71	(22%)	(24%)	109.36	111.93	(2%)

Sales

- Crude oil production in France is priced with reference to Dated Brent.
- Sales per boe decreased by 27% quarter-over-quarter, consistent with the 25% decrease in the Dated Brent reference price. This decrease, partially offset by a decrease in inventory, resulted in a 23% decrease in sales.
- On a year-over-year basis, sales per boe decreased by 30% and 1% for the three months and year ended December 31, 2014, respectively, as compared to the same periods in 2013. This decrease was primarily driven by 30% and 9% decreases in the Dated Brent reference price for the three months and year ended December 31, 2014, respectively. For the three months ended December 31, 2014, this was partially offset by a 6% increase in sales volumes, resulting in a 26% decrease in sales. On a yearly basis, the decrease in crude pricing coupled with consistent sales volumes resulted in a 5% decrease in sales.

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 revenue).
- As a percentage of sales, royalties remained relatively consistent at 6.6% in 2014 (2013 – 6.0%). As a percentage of sales, royalties increased from 6.5% in Q3 2014 to 7.7% in Q4 2014 due to the impact of fixed RCDM royalties coupled with lower realized pricing.

Transportation

- Historically, transportation expense in France related to shipments of crude oil by tanker from the Aquitaine Basin to third party refineries. As a result of the closure of the Lacq processing facility in Q3 2013, Vermilion began incurring additional transportation charges to ship Vic Bilh crude oil production to market. Accordingly, transportation expense for the year ended December 31, 2014 is higher than the prior year.

Operating expense

- Operating expense was lower in Q4 2014 as compared to both Q3 2014 and Q4 2013 on both a spend and on a per boe basis due to reduced facilities maintenance and repairs costs in the current quarter. For the year ended December 31, 2014, operating expense per boe remained consistent with the prior year.

General and administration

- General and administration expense for 2014 was 6% higher than in 2013 as a result of increased staffing costs and the weaker Canadian dollar relative to the Euro. On a quarterly basis, general and administration expense fluctuates as a result of timing of expenditures and allocations from Vermilion's Corporate segment.

Current income taxes

- Current income taxes in France are applied to taxable income after eligible deductions at a statutory rate of 34.4% for 2014. In addition, a 10.7% temporary surtax is applicable for tax year 2014 and 2015 if annual revenue exceeds €250 million. The France business unit is not subject to the 10.7% surtax for 2014.
- Current income taxes for the three months and year ended December 31, 2014 were lower than the comparable periods in 2013 due to accelerated depletion on certain assets as a result of the impact of the declining Dated Brent reference price.

NETHERLANDS BUSINESS UNIT

Overview

- Entered the Netherlands in 2004.
- Second largest onshore gas producer.
- Interests include 16 licenses in the northeast region, five licenses in the central region, and two offshore licenses.
- Licenses include more than 800,000 net acres of undeveloped land.
- High impact 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, 2014	Sep 30, 2014	Dec 31, 2013	Q4/14 vs. Q3/14	Q4/14 vs. Q4/13	Dec 31, 2014	Dec 31, 2013	2014 vs. 2013
Production								
NGLs (bbls/d)	81	63	62	29%	31%	77	64	20%
Natural gas (mmcf/d)	31.35	38.07	37.53	(18%)	(16%)	38.20	35.42	8%
Total (boe/d)	5,306	6,407	6,318	(17%)	(16%)	6,443	5,967	8%
Activity								
Capital expenditures ($M)	10,022	10,087	15,698	(1%)	(36%)	61,740	28,543	116%
Acquisitions ($M)	-	-	27,500			-	27,500	
Gross wells drilled	2.00	1.00	-			7.00	-	
Net wells drilled	0.92	0.45	-			4.66	-	

Production

- Achieved record annual production of 6,443 boe/d.
- Production was 17% lower quarter-over-quarter while full year 2014 average production grew 8% versus 2013. Production volumes in 2014 benefited from the addition of production from the DeHoeve-01 well during Q2 2014 and increased throughput capacity following a retrofit at our Middenmeer Treatment Centre completed in late 2013.
- Production in the Netherlands is actively managed to optimize facility use and regulate declines.

Activity review

- Vermilion drilled the Langezwaag-02 well (42% working interest), in the Gorredijk concession, during Q4 2014. The primary targets were the Vlieland (Cretaceous sandstone) and the Zechstein 2 (Permian carbonate) formations. A ten hour clean-up test conducted on the Zechstein 2 formation delivered a stabilized flow rate of 14 mmcf/d of gas on a 48/64 inch choke with a flowing wellhead pressure of 1,378 psi(1). This well was drilled from an existing lease site (Langezwaag-01) and is expected to be tied into existing facilities and on production in Q1 2015.
- The final well of our seven-well 2014 drilling program, Sonnega-2, was drilled in the Steenwijk concession in Q4 2014. A seven hour clean-up test conducted on the Vlieland formation delivered a stabilized flow rate of 15.8 mmcf/d on a 52/64 inch choke with a flowing wellhead pressure of 1,059 psi(1). This well was drilled from an existing lease site and is expected to be tied into existing facilities and on production in Q2 2015.
- In 2015, we are planning a three-well development drilling program and expect to equip and tie-in four previous discovery wells.

(1) Test results are not necessarily indicative of long-term performance or of ultimate recovery.

Financial review

Netherlands business unit ($M except as indicated)	Three Months Ended Dec 31, 2014	Sep 30, 2014	Dec 31, 2013	% change Q4/14 vs. Q3/14	Q4/14 vs. Q4/13	Year Ended Dec 31, 2014	Dec 31, 2013	% change 2014 vs. 2013
Sales	25,420	26,960	39,451	(6%)	(36%)	123,815	139,570	(11%)
Royalties	(1,171)	(942)	-	24%	100%	(5,014)	-	100%
Operating expense	(6,200)	(5,409)	(6,179)	15%	-	(24,041)	(20,617)	17%
General and administration	(2,489)	(204)	(1,553)	1,120%	60%	(3,617)	(2,724)	33%
Current income taxes	2,124	(1,189)	(8,267)	(279%)	(126%)	(4,154)	(34,132)	(88%)
Fund flows from operations	17,684	19,216	23,452	(8%)	(25%)	86,989	82,097	6%
Netbacks ($/boe)								
Sales	52.07	45.73	67.88	14%	(23%)	52.65	64.08	(18%)
Royalties	(2.40)	(1.60)	-	50%	100%	(2.13)	-	100%
Operating expense	(12.70)	(9.18)	(10.63)	38%	19%	(10.22)	(9.47)	8%
General and administration	(5.10)	(0.35)	(2.67)	1,357%	91%	(1.54)	(1.25)	23%
Current income taxes	4.35	(2.02)	(14.22)	(315%)	(131%)	(1.77)	(15.67)	(89%)
Fund flows from operations netback	36.22	32.58	40.36	11%	(10%)	36.99	37.69	(2%)
Reference prices								
TTF ($/GJ)	8.69	7.26	10.65	20%	(18%)	8.50	10.29	(17%)
TTF (€/GJ)	6.12	5.04	7.45	21%	(18%)	5.79	7.51	(23%)

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.
- The 6% decrease in sales quarter-over-quarter is primarily related to a 17% decrease in production, partially offset by a 14% increase in sales per boe consistent with the 20% increase in the Canadian dollar equivalent of the TTF reference price.
- On a year-over-year basis, sales per boe declined by 23% and 18% for the three months and year ended December 31, 2014, respectively. This was consistent with the decrease in the TTF reference price over the same periods in 2013. On a quarterly basis, lower pricing coupled with a 16% decrease in production volumes resulted in a 36% decrease in sales. On a yearly basis, weaker pricing was partially offset by an 8% increase in production volumes, resulting in an 11% decrease in sales.

Royalties

- Historically, we have not paid royalties in the Netherlands, however, certain wells associated with an acquisition completed by Vermilion's Netherlands business unit in October 2013 have reached payout and are now subject to an overriding royalty.

Transportation expense

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

Operating expense

- Operating expense per boe increased in Q4 2014 from Q3 2014 as additional project work was performed in Q4 2014.
- Operating expense per boe for 2014 increased as compared to the prior year due to the strengthening of the Euro versus the Canadian dollar, as well as higher salary costs associated with increased staffing levels supporting the continued organic growth in the Netherlands business unit.

General and administration

- On a year-over-year basis, general and administration expenses increased as a result of additional staffing and administration costs associated with Vermilion's continued organic growth in the Netherlands. In addition, on a quarter-over-quarter basis, Q4 2014 general and administration expenses were higher than the comparable quarters due to 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 a statutory tax rate of approximately 46%.
- Current income taxes decreased for the year ended December 31, 2014 as compared to the same period in 2013 as a result of decreased revenues from lower TTF reference prices, and an increase in tax deductions for depletion on two unsuccessful wells during the current year.
- The effective rate is lower compared to the statutory rate due to accelerated tax deductions from certain capital expenditures and other eligible in-country tax adjustments resulting from the corporate acquisition completed in Q4 2013.

GERMANY BUSINESS UNIT

Overview

- Vermilion entered Germany in February 2014 with the purchase of a 25% participation interest in a four-partner consortium.
- The assets include four gas producing fields across 11 production licenses and an exploration license in surrounding fields.
- Production licenses comprise 207,000 gross acres, of which 85% is in the exploration license.

Operational review

Germany business unit	Three Months Ended Dec 31, 2014	Three Months Ended Sep 30, 2014	% change Q4/14 vs. Q3/14	Year Ended Dec 31, 2014
Production				
Natural gas (mmcf/d)	17.71	15.38	15%	14.99
Total (boe/d)	2,952	2,563	15%	2,498
Activity				
Capital expenditures ($M)	563	1,358	(59%)	2,747
Acquisitions ($M)	-	-		172,871

Production

- Achieved Q4 2014 production of 2,952 boe/d, an increase of 15% as compared to 2,563 boe/d in the prior quarter, largely attributable to the Deblinghausen Z7a well being brought on production. Full year 2014 production averaged 2,498 boe/d taking into account an effective date for production of February 1, 2014.

Activity review

- During the first quarter of 2014, we participated in the drilling of the Deblinghausen Z7a development well (25% working interest).
- Continued the integration of the German business unit and commenced planning with our working interest partners for future drilling operations.
- Hired a Managing Director for the German business unit and opened an office outside of Berlin.
- In 2015, we are participating in the Burgmoor Z3a sidetrack well which spud in Q1 2015.

Financial review

Germany business unit ($M except as indicated)	Three Months Ended Dec 31, 2014	Three Months Ended Sep 30, 2014	% change Q4/14 vs. Q3/14	Year Ended Dec 31, 2014
Sales	13,359	8,591	55%	41,962
Royalties	(2,481)	(2,046)	21%	(8,613)
Transportation expense	(218)	(675)	(68%)	(2,367)
Operating expense	(2,862)	(2,227)	29%	(8,686)
General and administration	(2,200)	(1,090)	102%	(4,688)
Current income taxes	1,145	(146)	(884%)	(44)
Fund flows from operations	6,743	2,407	180%	17,564
Netbacks ($/boe)				
Sales	49.19	36.43	35%	46.03
Royalties	(9.13)	(8.68)	5%	(9.45)
Transportation expense	(0.80)	(2.86)	(72%)	(2.60)
Operating expense	(10.54)	(9.44)	12%	(9.53)
General and administration	(8.10)	(4.62)	75%	(5.14)
Current income taxes	4.21	(0.62)	(779%)	(0.05)
Fund flows from operations netback	24.83	10.21	143%	19.26
Reference prices				
TTF ($/GJ)	8.69	7.26	20%	8.50
TTF (€/GJ)	6.12	5.04	21%	5.79

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.
- Sales per boe increased by 35% from Q3 2014 due to an increase in the TTF reference price. This increase, coupled with higher production volumes, resulted in a 55% increase in sales quarter-over-quarter.

Royalties expense

- Our production in Germany is subject to royalties at a rate of approximately 20% of natural gas sales revenue.

Transportation expense

- Transportation expense relates to costs incurred to deliver natural gas from the processing facility to the customer.
- Transportation expense decreased for Q4 2014 as compared to Q3 2014 as a result of prior period adjustments recorded in the current quarter.

Operating expense

- Operating expenses for Germany are billed monthly by the joint venture operator and are similar on a per boe basis to our Netherlands business unit.

General and administration

- General and administration expense increased quarter-over-quarter as a result of increased allocations from Vermilion's Corporate segment.

Current income taxes

- Current income taxes in Germany apply to taxable income after eligible deductions at a statutory tax rate of approximately 23%.
- Current income taxes for Q4 2014 were lower compared to Q3 2014 due to the finalization of tax deductions related to the acquisition.

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

Ireland business unit ($M)	Three Months Ended Dec 31, 2014	Sep 30, 2014	Dec 31, 2013	% change Q4/14 vs. Q3/14	Q4/14 vs. Q4/13	Year Ended Dec 31, 2014	Dec 31, 2013	% change 2014 vs. 2013
Transportation expense	(1,720)	(1,515)	(357)	14%	382%	(6,394)	(4,165)	54%
General and administration	(579)	(334)	(482)	73%	20%	(1,447)	(1,442)	0%
Fund flows from operations	(2,299)	(1,849)	(839)	24%	174%	(7,841)	(5,607)	40%
Activity								
Capital expenditures	20,932	30,050	14,472	(30%)	45%	94,439	90,898	4%

Activity review

- Our Corrib project in Ireland has continued to progress on schedule following the completion of tunnel boring operations in May 2014. During the remainder of 2014, project operator Shell Exploration & Production Ireland Ltd. (SEPIL) successfully completed offshore workover and pipeline operations as well as outfitting of the 4.9 km tunnel including installation of flow and umbilical lines, hydro-testing and dewatering with the final weld completed in December. The grouting of the tunnel was completed subsequent to year end 2014. Natural gas from the sales grid was safely introduced into the processing facility in Q4 2014 as part of the commencement of operations at the plant. Remaining work includes the testing of all systems and processes required for the safe operation of the Bellanaboy gas processing terminal and the finalization of operating permits.
- Based on the current schedule for remaining commissioning activities, we anticipate first gas in approximately mid-2015 with peak production 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.

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 sea bed 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, 2014	Sep 30, 2014	Dec 31, 2013	Q4/14 vs. Q3/14	Q4/14 vs. Q4/13	Dec 31, 2014	Dec 31, 2013	2014 vs. 2013
Production								
Crude oil (bbls/d)	6,134	6,567	6,189	(7%)	(1%)	6,571	6,481	1%
Inventory (mbbls)								
Opening crude oil inventory	258	189	183			130	268	
Crude oil production	564	604	569			2,398	2,366	
Crude oil sales	(785)	(535)	(622)			(2,491)	(2,504)	
Closing crude oil inventory	37	258	130			37	130	
Activity								
Capital expenditures ($M)	11,616	15,985	8,420	(27%)	38%	44,283	77,931	(43%)
Gross wells drilled	-	-	-			-	2.00	
Net wells drilled	-	-	-			-	2.00	

Production

- Quarterly production decreased 7% quarter-over-quarter. Full year 2014 production increased 1% versus full year 2013.
- Production volumes are managed within corporate targets while meeting customer demands and the requirements of long-term supply agreements. We continue to plan for production levels of between 6,000 and 8,000 bbls/d.

Activity review

- In Q4 2014, efforts were largely focused on facilities enhancement and engineering studies, including the expansion of accommodation quarters on the Wandoo B platform, as well as pre-drill activities for a two-well drilling program that was initially planned for Q1 2015 but which was subsequently deferred. With the deferral of the drilling program, 2015 planned activities include ongoing facilities maintenance, enhancement, and refurbishment, as well as preparation and permitting activities in advance of our next drilling program.

Financial review

	Three Months Ended			% change		Year Ended		% change
Australia business unit ($M except as indicated)	Dec 31, 2014	Sep 30, 2014	Dec 31, 2013	Q4/14 vs. Q3/14	Q4/14 vs. Q4/13	Dec 31, 2014	Dec 31, 2013	2014 vs. 2013
Sales	70,971	63,708	77,533	11%	(8%)	283,481	298,945	(5%)
Operating expense	(17,719)	(14,302)	(13,219)	24%	34%	(61,432)	(51,625)	19%
General and administration	(1,628)	(1,378)	(1,442)	18%	13%	(5,873)	(5,752)	2%
PRRT	(13,568)	(13,834)	(17,173)	(2%)	(21%)	(60,340)	(56,565)	7%
Corporate income taxes	(4,799)	(5,148)	(6,210)	(7%)	(23%)	(24,477)	(31,735)	(23%)
Fund flows from operations	33,257	29,046	39,489	14%	(16%)	131,359	153,268	(14%)
Netbacks ($/boe)								
Sales	90.37	119.07	124.63	(24%)	(27%)	113.80	119.38	(5%)
Operating expense	(22.56)	(26.73)	(21.25)	(16%)	6%	(24.66)	(20.62)	20%
General and administration	(2.07)	(2.58)	(2.32)	(20%)	(11%)	(2.36)	(2.30)	3%
PRRT	(17.28)	(25.86)	(27.60)	(33%)	(37%)	(24.22)	(22.59)	7%
Corporate income taxes	(6.11)	(9.62)	(9.98)	(36%)	(39%)	(9.83)	(12.67)	(22%)
Fund flows from operations netback	42.35	54.28	63.48	(22%)	(33%)	52.73	61.20	(14%)
Reference prices								
Dated Brent (US $/bbl)	76.27	101.85	109.27	(25%)	(30%)	98.99	108.66	(9%)
Dated Brent ($/bbl)	86.62	110.95	114.71	(22%)	(24%)	109.36	111.93	(2%)

Sales
- Our production in Australia currently receives a premium to Dated Brent.
- Sales per boe for Q4 2014 decreased by 24% versus Q3 2014 as a result of a decrease in the Dated Brent reference price. This decrease was offset by higher sales volumes, resulting in an 11% increase in sales.
- Sales per boe for the three months and year ended December 31, 2014 versus the same periods in 2013 reflect the decrease in the Dated Brent reference price by 30% and 9%, respectively, partially offset by the weakening of the Canadian dollar versus the US dollar. On a quarterly basis, this was partially offset by an increase in sales volumes, resulting in an 8% decrease in sales. On a yearly basis, the weaker pricing was coupled with consistent sales volumes, resulting in a 5% decrease in sales.

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
- On a quarter-over-quarter basis, operating expense for Q4 2014 was higher than Q3 2014 as a result of a large draw in inventory during the current quarter (221,000 bbls) versus a build in the previous quarter (69,000 bbls). On a per barrel basis, operating expense decreased quarter-over-quarter as a result of lower diesel usage in the current quarter.
- On a year-over-year basis, the three months and year ended December 31, 2014 had higher operating expense on a dollar and barrel basis as a result of increased diesel usage.

General and administration
- General and administration expense for 2014 was relatively unchanged versus 2013. The timing of expenditures resulted in variances from quarter-to-quarter.

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.
- Combined corporate income taxes and PRRT movements for the three months and year ended December 31, 2014 versus the comparable periods in 2013 were largely consistent with the fluctuations in sales. On a year-over-year basis, PRRT for 2014 increased versus the 2013 periods as a result of the lower capital spending in 2014.

UNITED STATES BUSINESS UNIT

Overview

- Entered the United States in September 2014 with $11.1 million acquisition.
- Interests include approximately 68,000 acres of land (98% undeveloped) in the Powder River Basin of northeastern Wyoming.
- Promising tight oil development targeting the Turner Sand at a depth of approximately 1,500 metres.

Operational and financial review

United States business unit ($M except as indicated)	Three Months Ended Dec 31, 2014
Sales	1,330
Royalties	(366)
Operating expense	(241)
General and administration	(959)
Fund flows from operations	(236)
Netbacks ($/boe)	
Sales	74.08
Royalties	(20.38)
Operating Expense	(13.44)
General and administration	(53.44)
Fund flows from operations netback	(13.18)
Production	
Crude oil (bbls/d)	195
Total (boe/d)	195
Activity	
Capital expenditures	460
Reference prices	
WTI (US $/bbl)	73.15
WTI ($/bbl)	83.08

Activity review

- The most recently completed well on this land block (70% working interest) is currently producing approximately 150 bbls/d of oil in its seventh month of production, from an approximately 1,100 metre hydraulically-fractured horizontal lateral.
- We plan to drill one well in the East Finn prospect in 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 expense

- Our production in the United States is subject to federal and private royalties, severance tax, and ad valorem tax at a combined rate of approximately 27.5% of sales.

Operating expense

- Operating expense represents costs incurred by the contract operators of our current wells in the United States.

General and administration

- General and administration expense for Q4 2014 relate to the initial costs incurred to establish an office in Denver, Colorado.

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, 2014	Sep 30, 2014	Dec 31, 2013	Dec 31, 2014	Dec 31, 2013
General and administration	1,224	(2,322)	(2,919)	(7,423)	(7,356)
Current income taxes	(642)	(227)	(564)	(1,420)	(1,403)
Interest expense	(12,943)	(12,918)	(10,049)	(49,655)	(38,183)
Realized gain (loss) on derivatives	22,816	8,837	(1,300)	36,712	(7,082)
Realized foreign exchange (loss) gain	(179)	812	(1,294)	(821)	(1,866)
Realized other income	202	235	224	732	994
Fund flows from operations	10,478	(5,583)	(15,902)	(21,875)	(54,896)

General and administration

- The decrease in general and administration costs in Q4 2014 as compared to Q3 2014 and Q4 2013 is largely due to a decrease in staff-related expenditures, general cost saving initiatives in response to declining crude prices, and increased salary allocations to the various segments.
- On a year-over-year basis, general and administration costs for the year ended December 31, 2014 as compared to 2013 remained relatively consistent. The change is primarily due to cost saving initiatives and increased salary allocations to the various segments, partially offset by certain outstanding Vermilion Incentive Plan ("VIP") awards to be settled partially in cash.

Current income taxes

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

Interest expense

- Interest expense is incurred on our senior unsecured notes and on borrowings under our revolving credit facility. As compared to Q3 2014, Q4 2014 interest expense remained consistent. The increase in the three months and year ended December 31, 2014 versus the comparable periods in 2013 is due to increased borrowings under our revolving credit facility.

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 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) for 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 2014 related primarily to amounts received on our TTF and Dated Brent derivatives, partially offset by payments made on our AECO derivatives.
- A listing of derivative positions as at December 31, 2014 is included in "Supplemental Table 2" in this MD&A.

FINANCIAL PERFORMANCE REVIEW

	Year Ended		
($M except per share)	Dec 31, 2014	Dec 31, 2013	Dec 31, 2012
Total assets	4,386,091	3,708,719	3,076,257
Long-term debt	1,238,080	990,024	642,022
Petroleum and natural gas sales	1,419,628	1,273,835	1,083,103
Net earnings	269,326	327,641	190,622
Net earnings per share			
Basic	2.55	3.24	1.94
Diluted	2.51	3.20	1.92
Cash dividends ($/share)	2.58	2.40	2.28

	Three Months Ended							
($M except per share)	Dec 31, 2014	Sep 30, 2014	Jun 30, 2014	Mar 31, 2014	Dec 31, 2013	Sep 30, 2013	Jun 30, 2013	Mar 31, 2013
Petroleum and natural gas sales	306,073	344,688	387,684	381,183	325,108	327,185	311,966	309,576
Net earnings	58,642	53,903	53,993	102,788	101,510	67,796	106,198	52,137
Net earnings per share								
Basic	0.55	0.50	0.51	1.00	1.00	0.67	1.05	0.53
Diluted	0.54	0.50	0.50	0.99	0.98	0.66	1.04	0.51

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

($M)	Q4/14 vs. Q3/14	Q4/14 vs. Q4/13	2014 vs. 2013
Net earnings – Comparative period	53,903	101,510	327,641
Changes in:			
Fund flows from operations	(12,370)	21,868	137,339
Equity based compensation	(3,673)	2,813	(6,957)
Unrealized gain or loss on derivative instruments	9,357	15,885	22,260
Unrealized foreign exchange gain or loss	7,881	(26,276)	(69,627)
Unrealized other expense	(148)	(323)	(41)
Accretion	(123)	340	652
Depletion and depreciation	(13,022)	(33,487)	(103,308)
Deferred tax	16,837	23,712	8,767
Impairment recovery	-	(47,400)	(47,400)
Net earnings – Current Period	58,642	58,642	269,326

The fluctuations in net earnings 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.

For the year ended December 31, 2014, equity based compensation expense was higher than the same period in 2013 as a result of an upward revision of future performance condition assumptions during Q2 2014. Equity based compensation expense was higher for Q4 2014 as compared to Q3 2014 due to a higher number of VIP awards outstanding. Equity based compensation expense in Q4 2014 was lower than Q4 2013 as the 2013 period included an upward revision of future performance condition assumptions.

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.

In the year ended December 31, 2014, we recognized an unrealized gain on derivative instruments of $27.4 million, relating primarily to our TTF and crude oil swaps and collars. As at December 31, 2014, we have a net derivative asset position of $24.8 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. As such, an appreciation in the Euro against the Canadian dollar will result in an unrealized foreign exchange gain, and vice-versa.

For the three months and year ended December 31, 2014, the Canadian dollar strengthened versus the Euro resulting in unrealized foreign exchange losses of $4.0 million and $17.6 million, respectively.

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 2014 accretion expense was relatively consistent as compared to Q3 2014 and the comparable periods in 2013.

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 of $24.42 in Q4 2014 was higher as compared to $23.21 in Q3 2014. Depletion and depreciation on a per boe basis increased for the three months and year ended December 31, 2014 to $24.42/boe and $23.31/boe, respectively, as compared to the same periods in 2013 of $22.15/boe and $21.22/boe, respectively. The increase on a per boe basis was largely due to Vermilion's increased capital and acquisition activity which resulted in higher per boe amounts when compared to legacy producing assets.

Deferred tax

Deferred tax expense 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.

TAXES

Corporate income tax rates

Vermilion pays corporate income taxes in France, the Netherlands, Germany, 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	2014	2013
Canada	25.5%	25.0%
France	34.4%	38.0%
Netherlands	46.0%	46.0%
Germany	22.8%	-
Ireland	25.0%	25.0%
Australia	30.0%	30.0%
United States	35.0%	-

France tax legislation

In December 2013, the France government enacted corporate tax legislation that will lead to increases in current tax for companies operating in France, including a temporary surtax of 10.7% (with the surtax levied as a percent of base corporate income tax payable). The new surtax rate is applicable for companies which have annual revenue in excess of €250 million and if applicable to Vermilion's France Operations would effectively increase the statutory rate applicable to our French operations to 38.1% for applicable years. The surtax has been extended to tax years ending up to December 31, 2016. The French operations were not subject to the surcharge in 2014 and are not expected to be subject to the surcharge for 2015 at current commodity prices.

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 2014.

Tax pools

As at December 31, 2014, we had the following tax pools:

($M)	Oil & Gas Assets	Tax Losses [4]	Other	Total
Canada	1,128,614 (1)	326,300	6,299	1,461,213
France	403,201 (2)	-	-	403,201
Netherlands	59,032 (3)	-	-	59,032
Germany	134,550 (2)	17,348	17,004	168,902
Ireland	897,528 (4)	332,140	-	1,229,668
Australia	219,273 (1)	-	-	219,273
United States	12,072 (1)	395	-	12,467
Total	2,854,270	676,183	23,303	3,553,756

(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) Development expenditures and losses are deductible 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. Where prices trend higher, we may target a lower ratio and conversely, in a lower commodity price environment, the acceptable ratio may 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 accepted to be higher than the longer term target ratio. During this period, Vermilion will remain focused on maintaining a strong balance sheet and will manage the business accordingly.

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, 2014	Dec 31, 2013	Dec 31, 2014	Dec 31, 2013
Revolving credit facility	3.1%	3.3%	1,014,067	766,898
Senior unsecured notes	6.5%	6.5%	224,013	223,126
Long-term debt	3.8%	4.2%	1,238,080	990,024

Revolving Credit Facility

On January 30, 2015, Vermilion exercised its option to increase its credit facility to $1.75 billion. 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, 2014	Dec 31, 2013
Total facility amount	$1.75 billion	$1.20 billion
Amount drawn	$1.0 billion	$766.9 million
Letters of credit outstanding	$8.6 million	$8.1 million
Facility maturity date	31-May-17	31-May-16

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

		As At	
Financial covenant	Limit	Dec 31, 2014	Dec 31, 2013
Consolidated total debt to consolidated EBITDA	4.0	1.21	1.06
Consolidated total senior debt to consolidated EBITDA	3.0	0.99	0.82
Consolidated total senior debt to total capitalization	50%	31%	28%

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" 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 "Long-term debt" and "Shareholders' equity".

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

Senior Unsecured Notes

We have outstanding senior unsecured notes that are senior unsecured obligations and rank pari passu with all our other present and future 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

Subsequent to February 10, 2015, Vermilion may redeem all or part of the senior unsecured notes at 100% of their principal amount plus any accrued and unpaid interest. The notes were initially recognized at fair value net of transaction costs and are 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, 2014	Dec 31, 2013
Long-term debt	1,238,080	990,024
Current liabilities	365,729	347,444
Current assets	(338,159)	(587,783)
Net debt	1,265,650	749,685
Ratio of net debt to fund flows from operations	1.6	1.1

Long-term debt as at December 31, 2014 increased to $1.24 billion from $990.0 million as at December 31, 2013 as a result of draws on the revolving credit facility during the current year to fund our acquisitions in Germany and Saskatchewan coupled with the assumption of $47.5 million of long-term debt pursuant to the latter acquisition. This increase in long-term debt resulted in an increase to net debt from $749.7 million to $1.27 billion. As a result of this increase to long-term debt, the ratio of net debt to fund flows from operations increased from 1.1 as at December 31, 2013 to 1.6 as at December 31, 2014.

Shareholders' capital

Beginning with the January 2014 dividend paid on February 18, 2014, we increased our monthly dividend by 7.5%. This was our second consecutive annual increase.

During the year ended December 31, 2014, we maintained monthly dividends at $0.215 per share and declared dividends totalled $272.7 million.

The following table outlines our dividend payment history:

Date	Monthly dividend per unit or share
January 2003 to December 2007	$0.17
January 2008 to December 2012	$0.19
January 2013 to December 31, 2013	$0.20
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 price commodity 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. It is not currently expected that Vermilion will be required to change its dividend in 2015.

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, 2013	102,123	1,618,443
Shares issued pursuant to corporate acquisition	2,827	204,960
Issuance of shares 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

As at December 31, 2014, there were approximately 1.8 million VIP awards outstanding. As at February 27, 2015, there were approximately 107.6 million common shares issued and outstanding.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

As at December 31, 2014, 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	14,625	1,240,691	-	-	1,255,316
Operating lease obligations	14,782	19,030	16,328	18,549	68,689
Ship or pay agreement relating to the Corrib project	6,807	9,128	7,461	40,152	63,548
Purchase obligations	25,257	8,911	27	-	34,195
Drilling and service agreements	24,884	21,153	-	-	46,037
Total contractual obligations and commitments	86,355	1,298,913	23,816	58,701	1,467,785

ASSET RETIREMENT OBLIGATIONS

As at December 31, 2014, asset retirement obligations were $350.8 million compared to $326.2 million as at December 31, 2013.

The increase in asset retirement obligations is largely attributable to accretion, additions from new wells drilled during the year, and abandonment obligations associated with the assets acquired in Germany, the United States, and Canada.

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 foreign currency 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 future costs required to develop reserves. Our reserves 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, including determining the quantity of reserves, the time horizon to develop and produce such reserves 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, all of which are operating leases and accordingly no asset or liability value has been assigned to the consolidated balance sheet as at December 31, 2014.

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 logical 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, 2017.

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 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 2014, 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 2014. Examples of our accomplishments during the year included:

- Clear priorities around 5 key focus areas of HSE Culture, Communication and Knowledge Management, Technical Safety Management, Incident Prevention and Operational Stewardship & Sustainability;
- Reviewed and updated our HSE Policy to reflect our HSE maturity advances;
- Completed and published our first Corporate Sustainability Report;
- Submitted our first report to the Carbon Disclosure Project (CDP);
- Introduced a Fair Culture Policy to ensure transparency in our processes;
- Developed a robust risk mitigation program around our top fatal risk exposures;
- Advanced the completion of our Process Safety and Asset Integrity Management Systems;
- Updated various key Corporate HSE Standards such as the Event Management Practice;
- Reducing long-term environmental liabilities through decommissioning, abandoning and reclaiming well leases and facilities;
- Continuous auditing, management inspections and workforce observations to identify potential hazards and apply risk reduction measures;
- Development, communication and measurement against leading and lagging HSE key performance indicators;
- Further enhancement of our competency and training programs;
- Managing our waste products by reducing, recycling and recovering; and
- Continuing 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 10, 2015.

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, 2014, 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, 2014. The effectiveness of Vermilion's internal control over financial reporting as of December 31, 2014 has been audited by Deloitte LLP, as reflected in their report included in the 2014 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, 2014, 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, 2014			Year Ended December 31, 2014			Three Months Ended December 31, 2013	Year Ended December 31, 2013
	Oil & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Oil & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Total $/boe	Total $/boe
Canada								
Sales	71.13	3.74	51.27	88.98	4.53	64.06	61.10	61.14
Royalties	(11.00)	(0.25)	(7.12)	(11.78)	(0.32)	(7.81)	(6.93)	(6.55)
Transportation	(2.03)	(0.15)	(1.57)	(2.25)	(0.16)	(1.74)	(2.57)	(1.96)
Operating	(10.40)	(1.08)	(8.80)	(9.91)	(1.31)	(9.07)	(8.29)	(8.93)
Operating netback	47.70	2.26	33.78	65.04	2.74	45.44	43.31	43.70
General and administration			(1.29)			(2.00)	(1.60)	(2.24)
Fund flows from operations netback			32.49			43.44	41.71	41.46
France								
Sales	79.25	-	79.25	105.43	-	105.43	112.84	106.26
Royalties	(6.07)	-	(6.07)	(6.95)	-	(6.95)	(6.70)	(6.34)
Transportation	(3.94)	-	(3.94)	(4.64)	-	(4.64)	(4.71)	(2.93)
Operating	(13.01)	-	(13.01)	(15.09)	-	(15.09)	(15.82)	(15.70)
Operating netback	56.23	-	56.23	78.75	-	78.75	85.61	81.29
General and administration			(3.62)			(5.12)	(5.18)	(4.61)
Current income taxes			(5.89)			(16.36)	(28.55)	(22.16)
Fund flows from operations netback			46.72			57.27	51.88	54.52
Netherlands								
Sales	76.40	8.62	52.07	91.33	8.70	52.65	67.88	64.08
Royalties	-	(0.41)	(2.40)	-	(0.36)	(2.13)	-	-
Operating	-	(2.15)	(12.70)	-	(1.72)	(10.22)	(10.63)	(9.47)
Operating netback	76.40	6.06	36.97	91.33	6.62	40.30	57.25	54.61
General and administration			(5.10)			(1.54)	(2.67)	(1.25)
Current income taxes			4.35			(1.77)	(14.22)	(15.67)
Fund flows from operations netback			36.22			36.99	40.36	37.69
Germany								
Sales	-	8.20	49.19	-	7.67	46.03	-	-
Royalties	-	(1.52)	(9.13)	-	(1.57)	(9.45)	-	-
Transportation	-	(0.13)	(0.80)	-	(0.43)	(2.60)	-	-
Operating	-	(1.76)	(10.54)	-	(1.59)	(9.53)	-	-
Operating netback	-	4.79	28.72	-	4.08	24.45	-	-
General and administration			(8.10)			(5.14)	-	-
Current income taxes			4.21			(0.05)	-	-
Fund flows from operations netback			24.83			19.26	-	-
Australia								
Sales	90.37	-	90.37	113.80	-	113.80	124.63	119.38
Operating	(22.56)	-	(22.56)	(24.66)	-	(24.66)	(21.25)	(20.62)
PRRT (1)	(17.28)	-	(17.28)	(24.22)	-	(24.22)	(27.60)	(22.59)
Operating netback	50.53	-	50.53	64.92	-	64.92	75.78	76.17
General and administration			(2.07)			(2.36)	(2.32)	(2.30)
Corporate income taxes			(6.11)			(9.83)	(9.98)	(12.67)
Fund flows from operations netback			42.35			52.73	63.48	61.20
United States								
Sales	74.08	-	74.08	74.08	-	74.08	-	-
Royalties	(20.38)	-	(20.38)	(20.38)	-	(20.38)	-	-
Operating	(13.44)	-	(13.44)	(13.44)	-	(13.44)	-	-
Operating netback	40.26	-	40.26	40.26	-	40.26	-	-
General and administration			(53.44)			(53.44)	-	-
Fund flows from operations netback			(13.18)			(13.18)	-	-
Total Company								
Sales	78.64	5.90	63.79	100.06	6.42	77.75	86.04	83.83
Realized hedging gain (loss)	7.17	0.02	4.76	2.21	0.28	2.01	(0.34)	(0.47)
Royalties	(6.66)	(0.50)	(5.41)	(7.55)	(0.51)	(5.92)	(4.66)	(4.47)
Transportation	(2.14)	(0.28)	(1.98)	(2.60)	(0.30)	(2.32)	(2.40)	(1.90)
Operating	(14.29)	(1.50)	(12.48)	(14.87)	(1.49)	(12.72)	(12.74)	(12.84)
PRRT (1)	(4.31)	-	(2.83)	(5.19)	-	(3.30)	(4.55)	(3.72)
Operating netback	58.41	3.64	45.85	72.06	4.40	55.50	61.35	60.43
General and administration			(2.76)			(3.38)	(3.69)	(3.28)
Interest expense			(2.70)			(2.72)	(2.66)	(2.51)
Realized foreign exchange loss			(0.03)			(0.04)	(0.34)	(0.12)
Other income			0.04			0.04	0.06	0.07
Corporate income taxes (1)			(1.73)			(5.31)	(11.40)	(10.65)
Fund flows from operations netback			38.67			44.09	43.32	43.94

(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, 2014:

	Note	Volume	Strike Price(s)
Crude Oil			
WTI - Collar			
January 2015 - March 2015		500 bbl/d	76.25 - 92.15 US $
January 2015 - June 2015	1	250 bbl/d	75.00 - 82.75 US $
Dated Brent - Collar			
January 2015 - March 2015		500 bbl/d	78.75 - 89.63 US $
Dated Brent - Swap			
January 2015	2	500 bbl/d	101.55 US $
January 2015 - March 2015	3	250 bbl/d	91.95 US $
February 2015	4	500 bbl/d	103.80 US $
March 2015	5	250 bbl/d	110.40 US $
MSW - Fixed Price Differential (Physical)			
November 2014 - March 2015		1,042 bbl/d	WTI less 6.85 US $
January 2015 - March 2015		2,098 bbl/d	WTI less 7.39 US $
LSB - Fixed Price Differential (Physical)			
October 2014 - March 2015		830 bbl/d	WTI less 10.00 US $
January 2015 - March 2015		524 bbl/d	WTI less 8.60 US $

(1) The contracted volumes increase to 750 boe/d for any monthly settlement periods above the contracted ceiling price.
(2) On March 31, 2015, the counterparty has the option to extend the swap for the period of April to June 2015 for 1,000 boe/d at the contracted price.
(3) On March 31, 2015, the counterparty has the option to extend the swap for the period of April to June 2015 for 500 boe/d at the contracted price.
(4) On June 30, 2015, the counterparty has the option to extend the swap for the period of July to September 2015 for 1,000 boe/d at the contracted price.
(5) On September 30, 2015, the counterparty has the option to extend the swap for the period of October to December 2015 for 500 boe/d at the contracted price.

	Volume	Strike Price(s)
North American Natural Gas		
AECO - Collar		
April 2014 - March 2015	2,500 GJ/d	3.60 - 4.08 CAD $
November 2014 - March 2015	2,500 GJ/d	3.60 - 4.27 CAD $
April 2015 - October 2015	2,500 GJ/d	2.75 - 3.52 CAD $
April 2015 - December 2015	2,500 GJ/d	2.75 - 3.52 CAD $
AECO Basis - Fixed Price Differential		
January 2015 - December 2015	5,000 mmbtu/d	Nymex HH less 0.68 US $
Nymex HH - Collar		
November 2014 - March 2015	10,000 mmbtu/d	3.50 - 5.00 US $
January 2015 - March 2015	10,000 mmbtu/d	3.70 - 5.10 US $
April 2015 - October 2015	10,000 mmbtu/d	3.36 - 4.01 US $
April 2015 - December 2015	2,500 mmbtu/d	3.50 - 4.11 US $
Nymex HH - Swap		
January 2015	2,500 mmbtu/d	4.53 US $
January 2015 - March 2015	5,000 mmbtu/d	4.38 US $

	Volume	Strike Price(s)
European Natural Gas		
TTF - Collar		
January 2015 - December 2015	2,592 GJ/d	6.11 - 6.83 EUR €
TTF - Swap		
January 2015 - March 2015	4,392 GJ/d	6.47 EUR €
January 2015 - December 2015	11,664 GJ/d	6.45 EUR €
January 2015 - March 2016	5,184 GJ/d	6.40 EUR €
January 2015 - June 2016	2,592 GJ/d	6.07 EUR €
February 2015	2,592 GJ/d	6.46 EUR €
February 2015 - March 2016	5,184 GJ/d	6.24 EUR €
April 2015 - December 2015	2,592 GJ/d	6.30 EUR €
April 2015 - March 2016	5,832 GJ/d	6.18 EUR €

	Note	Volume	Strike Price(s)
Electricity			
AESO - Swap (Physical)			
January 2013 - December 2015		72.0 MWh/d	53.17 CAD $
US Dollar			
USD - Collar			
January 2015 - March 2015		7,000,000 US $/month	1.140 - 1.184 CAD $
January 2015 - March 2015	1	15,500,000 US $/month	1.140 - 1.157 CAD $

(1) Vermilion has upside participation on this hedge up to the limit price of 1.222 CAD; above which, settlement will occur at the conditional call level of 1.157 CAD.

Supplemental Table 3: Capital Expenditures

By classification ($M)	Three Months Ended Dec 31, 2014	Sep 30, 2014	Dec 31, 2013	Year Ended Dec 31, 2014	Dec 31, 2013
Drilling and development	151,395	180,479	147,929	618,689	537,564
Dispositions	-	-	-	-	(8,627)
Exploration and evaluation	14,848	9,554	549	69,035	13,789
Capital expenditures	166,243	190,033	148,478	687,724	542,726
Property acquisition	1,652	40,847	1,603	220,726	9,189
Corporate acquisition	-	-	27,500	381,139	27,500
Acquisitions	1,652	40,847	29,103	601,865	36,689

By category ($M)	Three Months Ended Dec 31, 2014	Sep 30, 2014	Dec 31, 2013	Year Ended Dec 31, 2014	Dec 31, 2013
Land	1,457	2,346	2,676	9,506	3,662
Seismic	7,598	6,135	1,942	19,034	16,608
Drilling and completion	69,691	93,386	68,993	311,696	279,003
Production equipment and facilities	77,272	68,964	63,420	275,538	201,846
Recompletions	7,696	10,853	3,309	36,234	27,600
Other	2,529	8,349	8,138	35,716	22,634
Dispositions	-	-	-	-	(8,627)
Capital expenditures	166,243	190,033	148,478	687,724	542,726
Acquisitions	1,652	40,847	29,103	601,865	36,689
Total capital expenditures and acquisitions	167,895	230,880	177,581	1,289,589	579,415

By country ($M)	Three Months Ended Dec 31, 2014	Sep 30, 2014	Dec 31, 2013	Year Ended Dec 31, 2014	Dec 31, 2013
Canada	87,113	125,276	78,848	750,390	250,386
France	37,189	35,082	31,899	147,852	100,378
Netherlands	10,022	10,087	43,198	61,740	56,043
Germany	563	1,358	-	175,618	-
Ireland	20,932	30,050	14,472	94,439	90,898
Australia	11,616	15,985	8,420	44,283	77,931
United States	460	11,175	-	11,635	-
Corporate	-	1,867	744	3,632	3,779
Total capital expenditures and acquisitions	167,895	230,880	177,581	1,289,589	579,415

Supplemental Table 4: Production

	Q4/14	Q3/14	Q2/14	Q1/14	Q4/13	Q3/13	Q2/13	Q1/13	Q4/12	Q3/12	Q2/12	Q1/12
Canada												
Crude oil (bbls/d)	11,384	11,469	12,676	9,437	8,719	7,969	8,885	7,966	7,983	7,322	7,757	7,574
NGLs (bbls/d)	2,741	2,291	2,796	2,071	1,699	1,897	1,725	1,335	1,106	1,204	1,321	1,302
Natural gas (mmcf/d)	58.36	57.07	57.59	49.53	41.43	43.40	43.69	41.04	31.41	35.54	41.32	41.83
Total (boe/d)	23,851	23,272	25,070	19,763	17,322	17,099	17,892	16,140	14,323	14,449	15,965	15,848
% of consolidated	49%	47%	49%	42%	43%	41%	42%	41%	40%	40%	40%	40%
France												
Crude oil (bbls/d)	11,133	11,111	11,025	10,771	11,131	11,625	10,390	10,330	9,843	9,767	9,931	10,270
Natural gas (mmcf/d)	-	-	-	-	-	5.23	4.19	4.21	3.91	3.39	3.57	3.48
Total (boe/d)	11,133	11,111	11,025	10,771	11,131	12,496	11,088	11,032	10,495	10,333	10,526	10,850
% of consolidated	22%	22%	21%	23%	27%	30%	26%	29%	29%	28%	27%	28%
Netherlands												
NGLs (bbls/d)	81	63	96	69	62	48	50	96	70	41	84	72
Natural gas (mmcf/d)	31.35	38.07	40.35	43.15	37.53	28.78	38.52	36.91	33.03	34.59	33.74	35.08
Total (boe/d)	5,306	6,407	6,822	7,260	6,318	4,845	6,470	6,248	5,574	5,806	5,707	5,919
% of consolidated	11%	13%	13%	16%	15%	12%	15%	16%	15%	16%	15%	15%
Germany												
Natural gas (mmcf/d)	17.71	15.38	16.13	10.64	-	-	-	-	-	-	-	-
Total (boe/d)	2,952	2,563	2,689	1,773	-	-	-	-	-	-	-	-
% of consolidated	6%	5%	5%	4%	-	-	-	-	-	-	-	-
Australia												
Crude oil (bbls/d)	6,134	6,567	6,483	7,110	6,189	7,070	7,363	5,287	5,873	5,958	6,970	6,648
% of consolidated	12%	13%	12%	15%	15%	17%	17%	14%	16%	16%	18%	17%
United States												
Crude oil (bbls/d)	195	-	-	-	-	-	-	-	-	-	-	-
Total (boe/d)	195	-	-	-	-	-	-	-	-	-	-	-
Consolidated												
Crude oil & NGLs (bbls/d)	31,668	31,501	33,076	29,458	27,800	28,609	28,413	25,014	24,875	24,292	26,063	25,866
% of consolidated	64%	63%	63%	63%	68%	69%	66%	65%	69%	66%	67%	66%
Natural gas (mmcf/d)	107.42	110.52	114.08	103.32	78.96	77.41	86.40	82.16	68.34	73.52	78.63	80.39
% of consolidated	36%	37%	37%	37%	32%	31%	34%	35%	31%	34%	33%	34%
Total (boe/d)	49,571	49,920	52,089	46,677	40,960	41,510	42,813	38,707	36,265	36,546	39,168	39,265

	2014	2013	2012	2011	2010	2009
Canada						
Crude oil (bbls/d)	11,248	8,387	7,659	4,701	2,778	2,137
NGLs (bbls/d)	2,476	1,666	1,232	1,297	1,427	1,518
Natural gas (mmcf/d)	55.67	42.39	37.50	43.38	43.91	47.85
Total (boe/d)	23,001	17,117	15,142	13,227	11,524	11,629
% of consolidated	47%	41%	40%	38%	36%	37%
France						
Crude oil (bbls/d)	11,011	10,873	9,952	8,110	8,347	8,246
Natural gas (mmcf/d)	-	3.40	3.59	0.95	0.92	1.05
Total (boe/d)	11,011	11,440	10,550	8,269	8,501	8,421
% of consolidated	22%	28%	28%	23%	26%	27%
Netherlands						
NGLs (bbls/d)	77	64	67	58	35	23
Natural gas (mmcf/d)	38.20	35.42	34.11	32.88	28.31	21.06
Total (boe/d)	6,443	5,967	5,751	5,538	4,753	3,533
% of consolidated	13%	15%	15%	16%	15%	11%
Germany						
Natural gas (mmcf/d)	14.99	-	-	-	-	-
Total (boe/d)	2,498	-	-	-	-	-
% of consolidated	5%	-	-	-	-	-
Australia						
Crude oil (bbls/d)	6,571	6,481	6,360	8,168	7,354	7,812
% of consolidated	13%	16%	17%	23%	23%	25%
United States						
Crude oil (bbls/d)	49	-	-	-	-	-
Total (boe/d)	49	-	-	-	-	-
Consolidated						
Crude oil & NGLs (bbls/d)	31,432	27,471	25,270	22,334	19,941	19,735
% of consolidated	63%	67%	67%	63%	62%	63%
Natural gas (mmcf/d)	108.85	81.21	75.20	77.21	73.14	69.96
% of consolidated	37%	33%	33%	37%	38%	37%
Total (boe/d)	49,573	41,005	37,803	35,202	32,132	31,395

Supplemental Table 5: Segmented Financial Results

($M)	Three Months Ended December 31, 2014								
	Canada	France	Netherlands	Germany	Ireland	Australia	United States	Corporate	Total
Drilling and development	75,186	36,455	6,183	563	20,932	11,616	460	-	151,395
Exploration and evaluation	10,256	734	3,839	-	-	-	-	19	14,848
Oil and gas sales to external customers	112,494	82,499	25,420	13,359	-	70,971	1,330	-	306,073
Royalties	(15,626)	(6,319)	(1,171)	(2,481)	-	-	(366)	-	(25,963)
Revenue from external customers	96,868	76,180	24,249	10,878	-	70,971	964	-	280,110
Transportation expense	(3,455)	(4,096)	-	(218)	(1,720)	-	-	-	(9,489)
Operating expense	(19,315)	(13,544)	(6,200)	(2,862)	-	(17,719)	(241)	-	(59,881)
General and administration	(2,840)	(3,765)	(2,489)	(2,200)	(579)	(1,628)	(959)	1,224	(13,236)
PRRT	-	-	-	-	-	(13,568)	-	-	(13,568)
Corporate income taxes	-	(6,132)	2,124	1,145	-	(4,799)	-	(642)	(8,304)
Interest expense	-	-	-	-	-	-	-	(12,943)	(12,943)
Realized gain on derivative instruments	-	-	-	-	-	-		22,816	22,816
Realized foreign exchange loss	-	-	-	-	-	-		(179)	(179)
Realized other income	-	-	-	-	-	-		202	202
Fund flows from operations	71,258	48,643	17,684	6,743	(2,299)	33,257	(236)	10,478	185,528

($M)	Year Ended December 31, 2014								
	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

ADDITIONAL AND NON-GAAP FINANCIAL MEASURES

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

Fund flows from operations: We define fund flows from operations as cash flows from operating activities before changes in non-cash operating working capital and asset retirement obligations settled. Management believes that by excluding the temporary impact of changes in non-cash operating working capital, fund flows from operations provides a measure of our ability to generate cash (that is not subject to short-term movements in non-cash operating working capital) necessary to pay dividends, repay debt, fund asset retirement obligations and make capital investments. As we have presented fund flows from operations in the "Segmented Information" note of our audited consolidated financial statements for the year ended December 31, 2014, we consider fund flows from operations to be an additional GAAP financial measure.

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 (an additional GAAP financial measure) and payout in order to assess our ability to generate cash and finance organic growth from our current producing assets.

Net debt: We define net debt as the sum of long-term debt and working capital. Management uses net debt, and the ratio of net debt to fund flows from operations, to analyze our financial position and leverage. Please refer to the preceding "Net Debt" section for a reconciliation of the net debt non-GAAP financial measure.

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.

Netbacks: Per boe and per mcf measures used in the analysis of operational activities.

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, 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, 2014	Sep 30, 2014	Dec 31, 2013	Dec 31, 2014	Dec 31, 2013
Cash flows from operating activities	229,146	235,010	177,003	791,986	705,025
Changes in non-cash operating working capital	(49,865)	(41,789)	(18,769)	(3,077)	(49,421)
Asset retirement obligations settled	6,247	4,677	5,426	15,956	11,922
Fund flows from operations	185,528	197,898	163,660	804,865	667,526
Expenses related to Corrib	2,299	1,849	839	7,841	5,607
Fund flows from operations (excluding Corrib)	187,827	199,747	164,499	812,706	673,133

	Three Months Ended			Year Ended	
($M)	Dec 31, 2014	Sep 30, 2014	Dec 31, 2013	Dec 31, 2014	Dec 31, 2013
Dividends declared	69,119	68,896	61,208	272,732	242,599
Issuance of shares pursuant to the dividend reinvestment plan	(20,980)	(20,416)	(18,775)	(79,430)	(72,291)
Net dividends	48,139	48,480	42,433	193,302	170,308
Drilling and development	151,395	180,479	147,929	618,689	537,564
Dispositions	-	-	-	-	(8,627)
Exploration and evaluation	14,848	9,554	549	69,035	13,789
Asset retirement obligations settled	6,247	4,677	5,426	15,956	11,922
Payout	220,629	243,190	196,337	896,982	724,956
Corrib drilling and development	(20,932)	(30,050)	(14,472)	(94,439)	(90,898)
Payout (excluding Corrib)	199,697	213,140	181,865	802,543	634,058

	As At		
('000s of shares)	Dec 31, 2014	Sep 30, 2014	Dec 31, 2013
Shares outstanding	107,303	106,921	102,123
Potential shares issuable pursuant to the VIP	3,031	2,828	2,746
Diluted shares outstanding	110,334	109,749	104,869

CORPORATE INFORMATION

DIRECTORS

Larry J. Macdonald [1, 2, 3, 4, 5]
Chairman & CEO, Point Energy Ltd.
Calgary, Alberta

W. Kenneth Davidson [2, 3]
Toronto, Ontario

Lorenzo Donadeo
Calgary, Alberta

Claudio A. Ghersinich [2, 5]
Executive Director, Carrera Investments Corp.
Calgary, Alberta

Joseph F. Killi [2, 3]
Chairman, Parkbridge Lifestyle Communities Inc.
Vice Chairman, Realex Properties Corp.
Calgary, Alberta

Loren M. Leiker [5]
Houston, Texas

William F. Madison [2, 4, 5]
Sugar Land, Texas

Timothy R. Marchant [3, 4, 5]
Calgary, Alberta

Sarah E. Raiss [3]
Calgary, Alberta

Kevin J. Reinhart
Calgary, Alberta

Catherine L. Williams
Calgary, Alberta

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

ANNUAL GENERAL MEETING

May 8, 2015
10:00 AM MST
The Ballroom
Metropolitan Centre
333 – 4th Avenue S.W.
Calgary, Alberta

OFFICERS AND KEY PERSONNEL

CANADA
Lorenzo Donadeo, P.Eng.
Chief Executive Officer

Anthony Marino, P.Eng.
President & Chief Operating 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., C.H.R.P.
Executive Vice President, People and Culture

Terry Hergott, CMA
Vice President Marketing

Michael Kaluza, P.Eng.
Vice President Canada Business Unit

Daniel Goulet, P.Eng.
Director Corporate HSE

Dion Hatcher, P.Eng.
Director Alberta Foothills – Canada Business Unit

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

Neil Wallace
Managing Director - Netherlands Business Unit

Albrecht Moehring
Managing Director - Germany 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")

VERMILION ENERGY

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 Inc.

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