VERMILION
ENERGY

2015

MANAGEMENT'S DISCUSSION & ANALYSIS

EXCELLENCE. TRUST. RESPECT. RESPONSIBILITY.

DEFINED PRODUCTION GROWTH | RELIABLE & GROWING DIVIDENDS

ABBREVIATIONS

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

DISCLAIMER

Certain statements included or incorporated by reference in this document may constitute forward looking statements or financial outlooks under applicable securities legislation. Such forward looking statements or information typically contain statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", or similar words suggesting future outcomes or statements regarding an outlook. Forward looking statements or information in this document may include, but are not limited to: capital expenditures; business strategies and objectives; operational and financial performance; estimated reserve quantities and the discounted net present value of future net revenue from such reserves; petroleum and natural gas sales; future production levels (including the timing thereof) and rates of average annual production growth; estimated contingent resources; exploration and development plans; acquisition and disposition plans and the timing thereof; operating and other expenses, including the payment and amount of future dividends; royalty and income tax rates; and the timing of regulatory proceedings and approvals.

Such forward looking statements or information are based on a number of assumptions all or any of which may prove to be incorrect. In addition to any other assumptions identified in this document, assumptions have been made regarding, among other things: the ability of Vermilion to obtain equipment, services and supplies in a timely manner to carry out its activities in Canada and internationally; the ability of Vermilion to market crude oil, natural gas liquids and natural gas successfully to current and new customers; the timing and costs of pipeline and storage facility construction and expansion and the ability to secure adequate product transportation; the timely receipt of required regulatory approvals; the ability of Vermilion to obtain financing on acceptable terms; foreign currency exchange rates and interest rates; future crude oil, natural gas liquids and natural gas prices; and management's expectations relating to the timing and results of exploration and development activities.

Although Vermilion believes that the expectations reflected in such forward looking statements or information are reasonable, undue reliance should not be placed on forward looking statements because Vermilion can give no assurance that such expectations will prove to be correct. Financial outlooks are provided for the purpose of understanding Vermilion's financial position and business objectives and the information may not be appropriate for other purposes. Forward looking statements or information are based on current expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by Vermilion and described in the forward looking statements or information. These risks and uncertainties include but are not limited to: the ability of management to execute its business plan; the risks of the oil and gas industry, both domestically and internationally, such as operational risks in exploring for, developing and producing crude oil, natural gas liquids and natural gas; risks and uncertainties involving geology of crude oil, natural gas liquids and natural gas deposits; risks inherent in Vermilion's marketing operations, including credit risk; the uncertainty of reserves estimates and reserves life and estimates of resources and associated expenditures; the uncertainty of estimates and projections relating to production and associated expenditures; potential delays or changes in plans with respect to exploration or development projects; Vermilion's ability to enter into or renew leases on acceptable terms; fluctuations in crude oil, natural gas liquids and natural gas prices, foreign currency exchange rates and interest rates; health, safety and environmental risks; uncertainties as to the availability and cost of financing; the ability of Vermilion to add production and reserves through exploration and development activities; the possibility that government policies or laws may change or governmental approvals may be delayed or withheld; uncertainty in amounts and timing of royalty payments; risks associated with existing and potential future law suits and regulatory actions against Vermilion; and other risks and uncertainties described elsewhere in this document or in Vermilion's other filings with Canadian securities regulatory authorities.

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

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

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

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

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is Management's Discussion and Analysis ("MD&A"), dated February 25, 2016, of Vermilion Energy Inc.'s ("Vermilion", "we", "our", "us" or the "Company") operating and financial results as at and for the three months and year ended December 31, 2015 compared with the corresponding periods in the prior year.

This discussion should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2015 and 2014, together with the accompanying notes. Additional information relating to Vermilion, including its Annual Information Form, will be available on or after March 4, 2016 on SEDAR at www.sedar.com or on Vermilion's website at www.vermilionenergy.com.

The audited consolidated financial statements for the year ended December 31, 2015 and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with International Financial Reporting Standards ("IFRS" or, alternatively, "GAAP") as issued by the International Accounting Standards Board.

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

- Fund flows from operations: This financial measure is calculated as cash flows from operating activities before changes in non-cash operating working capital and asset retirement obligations settled. We analyze fund flows from operations both on a consolidated basis and on a business unit basis in order to assess the contribution of each business unit to our ability to generate cash necessary to pay dividends, repay debt, fund asset retirement obligations and make capital investments.
- Netbacks: These financial measures are per boe and per mcf measures used in the analysis of operational activities. We assess netbacks both on a consolidated basis and on a business unit basis in order to compare and assess the operational and financial performance of each business unit versus other business units and third party crude oil and natural gas producers.

In addition, this MD&A includes references to certain financial measures which do not have standardized meanings prescribed by IFRS and are not disclosed in our audited financial statements. As such, these financial measures are considered non-GAAP financial measures and therefore are unlikely to be comparable with similar financial measures presented by other issuers. For a full description of these non-GAAP financial measures and a reconciliation of these measures to their most directly comparable GAAP measures, please refer to "NON-GAAP FINANCIAL MEASURES".

VERMILION'S BUSINESS

Vermilion is a Calgary, Alberta based international oil and gas producer focused on the acquisition, development and optimization of producing properties in North America, Europe, and Australia. We manage our business through our Calgary head office and our international business unit offices.

This MD&A separately discusses each of our business units in addition to our corporate segment.

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

2015 REVIEW AND 2016 GUIDANCE

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

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

The following table summarizes our 2015 and 2016 guidance:

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

SHAREHOLDER RETURN

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

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

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

CONSOLIDATED RESULTS OVERVIEW

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

Operational review

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

Financial review

Net earnings (loss)

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

Cash flows from operating activities

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

Fund flows from operations

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

Net debt

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

Dividends

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

COMMODITY PRICES

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

Reference prices

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

Realized prices

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

FUND FLOWS FROM OPERATIONS

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

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

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

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

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

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

CANADA BUSINESS UNIT

Overview

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

Operational review

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

Production

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

Activity review

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

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

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

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

Financial review

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

Sales

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

Royalties

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

Transportation

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

Operating expense

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

General and administration

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

Impairment

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

FRANCE BUSINESS UNIT

Overview

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

Operational review

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

Production

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

Activity review

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

Financial review

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

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

Royalties
- Royalties in France relate to two components: RCDM (levied on units of production and not subject to changes in commodity prices) and R31 (based on a percentage of sales).
- Royalties as a percentage of sales of 11.4% and 9.6% for the three months and year ended December 31, 2015 was higher than Q3 2015 (10.5%) and the 2014 periods (7.7% and 6.6%, respectively) as a result of the impact of fixed RCDM royalties coupled with lower realized pricing.

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

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

General and administration

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

Other income

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

Current income taxes

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

NETHERLANDS BUSINESS UNIT

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

Operational review

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

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

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

Financial review

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

Sales

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

Royalties

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

Transportation expense

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

Operating expense

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

General and administration

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

Current income taxes

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

GERMANY BUSINESS UNIT

Overview

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

Operational review

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

Production

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

Activity review

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

Financial review

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

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

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

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

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

General and administration

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

Current income taxes

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

IRELAND BUSINESS UNIT

Overview

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

Operational and financial review

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

Activity review

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

Transportation expense

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

AUSTRALIA BUSINESS UNIT

Overview

- Entered Australia in 2005.
- Hold a 100% operated working interest in the Wandoo field, located approximately 80 km offshore on the northwest shelf of Australia.
- Production is operated from two off-shore platforms, and originates from 21 producing well bores.
- Wells that utilize horizontal legs (ranging in length from 500 to 3,000 plus metres) are located 600 metres below the seabed in approximately 55 metres of water depth.
- Contracted crude oil production is priced with reference to Dated Brent.

Operational review

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

Production

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

Activity review

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

Financial review

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

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

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

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

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

PRRT and corporate income taxes
- In Australia, current income taxes include both PRRT and corporate income taxes. PRRT is a profit based tax applied at a rate of 40% on sales less eligible expenditures, including operating expenses and capital expenditures. Corporate income taxes are applied at a rate of 30% on taxable income after eligible deductions, which include PRRT.
- Australia is not expected to incur any corporate income tax or PRRT for 2016. This is subject to change in response to commodity price fluctuations, the timing of capital expenditures and other eligible in-country adjustments.
- Combined corporate income taxes and PRRT for the three months and full year ended December 31, 2015 were lower than the comparable periods as a result of decreased revenues and increased capital spending in the 2015 periods. Q4 2015 combined taxes were lower compared to Q3 2015 as increased sales were offset by increased capital spending.

UNITED STATES BUSINESS UNIT

Overview

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

Operational and financial review

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

Activity review

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

Sales

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

Royalties

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

Operating expense

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

General and administration

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

CORPORATE

Overview

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

Financial review

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

General and administration

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

Current income taxes

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

Interest expense

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

Hedging

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

FINANCIAL PERFORMANCE REVIEW

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

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

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

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

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

Equity based compensation

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

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

Unrealized gain or loss on derivative instruments

Unrealized gain or loss on derivative instruments arise as a result of changes in forecasted future commodity prices. As Vermilion uses derivative instruments to manage the commodity price exposure of our future crude oil and natural gas production, we will normally recognize unrealized gains on derivative instruments when forecasted future commodity prices decline and vice-versa.

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

Unrealized foreign exchange gain or loss

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

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

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

Accretion

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

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

Depletion and depreciation

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

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

Deferred tax

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

Impairment

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

TAXES

Corporate income tax rates

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

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

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

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

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

Tax pools

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

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

(1) Deduction calculated using various declining balance rates
(2) Deduction calculated using a combination of straight-line over the assets life and unit of production method
(3) Deduction calculated using a unit of production method
(4) Deduction for current development expenditures and tax losses at 100% against taxable income

FINANCIAL POSITION REVIEW

Balance sheet strategy

We believe that our balance sheet supports our defined growth initiatives and our focus is on managing and maintaining a conservative balance sheet. To ensure that our balance sheet continues to support our defined growth initiatives, we regularly review whether forecasted fund flows from operations is sufficient to finance planned capital expenditures, dividends, and abandonment and reclamation expenditures. To the extent that forecasted fund flows from operations is not expected to be sufficient to fulfill such expenditures, we will evaluate our ability to finance any excess with debt (including borrowing using the unutilized capacity of our existing revolving credit facility) or issue equity.

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

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

Long-term debt

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

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

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

Revolving Credit Facility

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

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

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

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

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

- Consolidated total debt: Includes all amounts classified as "Long-term debt", "Current portion of long-term debt", and "Finance lease obligation" on our balance sheet.
- Consolidated total senior debt: Defined as consolidated total debt excluding unsecured and subordinated debt.
- Consolidated EBITDA: Defined as consolidated net earnings before interest, income taxes, depreciation, accretion and certain other non-cash items.
- Total capitalization: Includes all amounts on our balance sheet classified as "Shareholders' equity" plus consolidated total debt as defined above.

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

Senior Unsecured Notes

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

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

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

Net debt

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

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

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

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

Shareholders' capital

During the year ended December 31, 2015, we maintained monthly dividends at $0.215 per share and declared dividends which totalled $283.6 million.

The following table outlines our dividend payment history:

Date	Monthly dividend per unit or share
January 2003 to December 2007	$0.170
January 2008 to December 2012	$0.190
January 2013 to December 31, 2013	$0.200
January 2014 to Present	$0.215

Our policy with respect to dividends is to be conservative and maintain a low ratio of dividends to fund flows from operations. During low commodity price cycles, we will initially maintain dividends and allow the ratio to rise. Should low commodity price cycles remain for an extended period of time, we will evaluate the necessity of changing the level of dividends, taking into consideration capital development requirements, debt levels and acquisition opportunities. As a further step to preserve our financial flexibility and conservatively exercise our access to capital, we amended our existing DRIP to include a Premium Dividend™ Component in February 2015. The Premium Dividend™ Component, when combined with our continuing Dividend Reinvestment Component, increases our access to the lowest cost sources of equity capital available. While the Premium Dividend™ results in a modest amount of equity issuance, we believe it represents the most prudent approach to preserving near-term balance sheet strength. We view implementation of a Premium Dividend™ as a short-term measure to maintain our financial flexibility while we continue to lower our unit costs and await further clarity on the direction of commodity prices. Both components of our program can be reduced or eliminated at the company's discretion, offering considerable flexibility. We will actively monitor our ongoing needs and manage our continued use of each component as circumstances dictate.

Although we currently expect to be able to maintain our current dividend, fund flows from operations may not be sufficient during this period to fund cash dividends, capital expenditures and asset retirement obligations. We will evaluate our ability to finance any shortfalls with debt, issuances of equity or by reducing some or all categories of expenditures to ensure that total expenditures do not exceed available funds.

The following table reconciles the change in shareholders' capital:

Shareholders' Capital	Number of Shares ('000s)	Amount ($M)
Balance as at December 31, 2014	107,303	1,959,021
Issuance of shares pursuant to the dividend reinvestment and Premium Dividend™ plans	3,338	155,033
Vesting of equity based awards	1,158	56,855
Share-settled dividends on vested equity based awards	135	7,561
Shares issued pursuant to the employee savings and bonus plans	57	2,619
Balance as at December 31, 2015	111,991	2,181,089

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

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

As at December 31, 2015, we had the following contractual obligations and commitments:

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

ASSET RETIREMENT OBLIGATIONS

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

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

RISKS AND UNCERTAINTIES

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

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

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

Production and sales volumes
The operation of crude oil and natural gas wells and facilities involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to us and possible liability to third parties. We maintain liability insurance, where available, in amounts consistent with industry standards. Business interruption insurance may also be purchased for selected operations, to the extent that such insurance is commercially viable. We may become liable for damages arising from such events against which we cannot insure or against which we may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities may materially impact our financial results.

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

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

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

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

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

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

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

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

FINANCIAL RISK MANAGEMENT

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

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

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

CRITICAL ACCOUNTING ESTIMATES

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

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

Depletion and depreciation
We classify our assets into depletion units, which are groups of assets or properties that are within a specific production area and have similar economic lives. The depletion units represent the lowest level of disaggregation for which we accumulate costs for the purposes of calculating and recording depletion and depreciation.

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

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

Assessment of impairments

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

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

Taxes

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

OFF BALANCE SHEET ARRANGEMENTS

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

ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

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

IFRS 9 "Financial Instruments"

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

IFRS 15 "Revenue from Contracts with Customers"

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

IFRS 16 "Leases"

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

HEALTH, SAFETY AND ENVIRONMENT

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

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

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

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

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

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

CORPORATE GOVERNANCE

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

We comply with the objectives and guidelines relating to corporate governance adopted by the Canadian Securities Administrators and the Toronto Stock Exchange. In addition, the Board monitors and considers the implementation of corporate governance standards proposed by various regulatory and non-regulatory authorities in Canada. A discussion of corporate governance policies will be provided in our Management Proxy Circular, which will be filed on SEDAR (www.sedar.com) and mailed to all shareholders on April 6, 2016.

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

DISCLOSURE CONTROLS AND PROCEDURES

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

As of December 31, 2015, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded and certified that our disclosure controls and procedures are effective.

INTERNAL CONTROL OVER FINANCIAL REPORTING

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

The Chief Executive Officer and the Chief Financial Officer of Vermilion have assessed the effectiveness of Vermilion's internal control over financial reporting as defined in Rule 13a-15 under the US Securities Exchange Act of 1934 and as defined in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. The assessment was based on the framework in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Chief Executive Officer and the Chief Financial Officer of Vermilion have concluded that Vermilion's internal control over financial reporting was effective as of December 31, 2015. The effectiveness of Vermilion's internal control over financial reporting as of December 31, 2015 has been audited by Deloitte LLP, as reflected in their report included in the 2015 audited annual financial statements filed with the US Securities and Exchange Commission. No changes were made to Vermilion's internal control over financial reporting during the year ended December 31, 2015, that have materially affected, or are reasonably likely to materially affect, the internal controls over financial reporting.

Supplemental Table 1: Netbacks

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

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

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

Supplemental Table 2: Hedges

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

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

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

Supplemental Table 2: Hedges (Continued)

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

Electricity			
AESO - Swap			
January 2016 - December 2016		93.6 MWh/d	38.58 CAD $

Interest Rate			
CDOR to fixed - Swap			
September 2015 - September 2019		100,000,000 CAD $/year	1.00 %
October 2015 - October 2019		100,000,000 CAD $/year	1.10 %

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

Supplemental Table 3: Capital Expenditures

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

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

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

Supplemental Table 4: Production

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

Supplemental Table 4: Production (Continued)

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

Supplemental Table 5: Segmented Financial Results

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

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

NON-GAAP FINANCIAL MEASURES

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

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

Free cash flow: Represents fund flows from operations in excess of capital expenditures. We consider free cash flow to be a key measure as it is used to determine the funding available for investing and financing activities, including payment of dividends, repayment of long-term debt, reallocation to existing business units, and deployment into new ventures.

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

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

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

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

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

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

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

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

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

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

CORPORATE INFORMATION

DIRECTORS

Lorenzo Donadeo [1]
Calgary, Alberta

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

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

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

Loren M. Leiker [6]
Houston, Texas

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

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

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

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

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

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

ANNUAL GENERAL MEETING

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

OFFICERS AND KEY PERSONNEL

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

John D. Donovan, FCA
Executive Vice President Business Development

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

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

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

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

Terry Hergott, CMA
Vice President Marketing

Daniel Goulet, P.Eng.
Director Corporate HSE

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

Dean N. Morrison, CFA
Director Investor Relations

Mike Prinz
Director Information Technology & Information Systems

Jenson Tan, P.Eng.
Director New Ventures

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

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

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

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

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

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

Albrecht Moehring
Managing Director - Germany Business Unit

Bryan Sralla
Managing Director - Central & Eastern Europe Business Unit

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

AUDITORS

Deloitte LLP
Calgary, Alberta

BANKERS

The Toronto-Dominion Bank

Bank of Montreal

Canadian Imperial Bank of Commerce

Royal Bank of Canada

The Bank of Nova Scotia

National Bank of Canada

Alberta Treasury Branches

HSBC Bank Canada

La Caisse Centrale Desjardins du Québec

Wells Fargo Bank N.A., Canadian Branch

Bank of America N.A., Canada Branch

BNP Paribas, Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

JPMorgan Chase Bank, N.A., Toronto Branch

Union Bank, Canada Branch

Canadian Western Bank

Goldman Sachs Lending Partners LLC

EVALUATION ENGINEERS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL

Norton Rose Fulbright Canada LLP
Calgary, Alberta

TRANSFER AGENT

Computershare Trust Company of Canada

STOCK EXCHANGE LISTINGS

The Toronto Stock Exchange ("VET")
The New York Stock Exchange ("VET")

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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.

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