Q1 2016

MANAGEMENT'S DISCUSSION AND ANALYSIS

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VERMILION ENERGY

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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.

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 May 5, 2016, of Vermilion Energy Inc.'s ("Vermilion", "We", "Our", "Us" or the "Company") operating and financial results as at and for the three months ended March 31, 2016 compared with the corresponding period in the prior year.

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

The unaudited condensed consolidated interim financial statements for the three months ended March 31, 2016 and comparative information have been prepared in Canadian dollars, except where another currency is indicated, and in accordance with IAS 34, "Interim Financial Reporting", as issued by the International Accounting Standard Board ("IASB").

This MD&A includes references to certain financial measures which do not have standardized meanings prescribed by International Financial Reporting Standards ("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 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, exploration, development and optimization of producing properties in North America, Europe, and Australia. We manage our business through our Calgary head office and our international business unit offices.

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

- 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 that are primarily incurred in Canada and are not directly related to the operations of a specific business unit.

CHANGE IN PRESENTATION

Prior to 2016, we reported our condensate production in Canada and the Netherlands business units within the NGLs production line. Beginning in Q1 2016, we now report condensate production within the crude oil and condensate production line. We believe that this presentation better reflects the historical and forecasted pricing for condensate, which is more closely correlated with crude oil pricing than with pricing for propane, butane and ethane (collectively "NGLs" for the purposes of this report). Comparative periods have been adjusted to reflect this change.

2015 REVIEW AND 2016 GUIDANCE

On November 9, 2015 we announced preliminary 2016 capital expenditure guidance of $350 million and 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 pipeline twinning program.

The following table summarizes our 2016 guidance:

	Date	Capital Expenditures ($MM)	Production (boe/d)
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

CONSOLIDATED RESULTS OVERVIEW

	Three Months Ended			% change	
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015	Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
Production					
Crude oil and condensate (bbls/d)	**29,199**	31,304	29,514	(7%)	(1%)
NGLs (bbls/d)	**2,672**	2,739	1,706	(2%)	57%
Natural gas (mmcf/d)	**201.11**	162.09	115.00	24%	75%
Total (boe/d)	**65,389**	61,058	50,386	7%	30%
Build (draw) in inventory (mbbls)	**142**	(93)	383		
Financial metrics					
Fund flows from operations ($M)	**93,667**	136,441	120,795	(31%)	(22%)
Per share ($/basic share)	**0.83**	1.22	1.12	(32%)	(26%)
Net (loss) earnings	**(85,848)**	(142,080)	1,275	(40%)	(6,833%)
Per share ($/basic share)	**(0.76)**	(1.28)	0.01	(41%)	(7,700%)
Cash flows from operating activities ($M)	**73,883**	164,863	22,647	(55%)	226%
Net debt ($M)	**1,367,063**	1,381,951	1,388,603	(1%)	(2%)
Cash dividends ($/share)	**0.645**	0.645	0.645	-	-
Activity					
Capital expenditures ($M)	**62,773**	128,996	174,311	(51%)	(64%)
Acquisitions ($M)	**870**	6,227	35	(86%)	2,386%
Gross wells drilled	**12.00**	8.00	29.00		
Net wells drilled	**8.26**	5.56	20.04		

Operational review

- Recorded consolidated average production of 65,389 boe/d in Q1 2016, which was a 7% increase over Q4 2015. This quarter-over-quarter increase was driven by a full quarter of production from Corrib and increased production in Canada.
- Increased consolidated average production from Q1 2015 by 30%, primarily due to the addition of Corrib production in Ireland, as well as production growth in all our business units except Germany, where production modestly declined.
- Executed capital expenditures totalling $62.8 million, primarily in Canada and France. In Canada, capital expenditures of $29.8 million were 8% higher than Q4 2015 and related to the drilling of 8.3 net wells (2.6 net wells in Q4 2015). In France, capital expenditures of $13.5 million were 44% lower than Q4 2015 and related primarily to accretive workovers and subsurface activity.

Financial review

Net (loss) earnings

- The net loss for Q1 2016 was $85.8 million ($0.76/basic share), as compared to a net loss of $142.1 million ($1.28/basic share) in Q4 2015. The decrease in the net loss was primarily attributable to a lower impairment charge recognized in the quarter, partially offset by lower petroleum and natural gas sales due to weakening commodity prices.
- The net loss in Q1 2016 represented a decrease of $87.1 million versus the comparable period in 2015. This decrease was driven primarily by lower petroleum and natural gas sales as a result of lower commodity prices, the impact of the de-recognition of certain deferred tax assets, an impairment charge recognized in Ireland, and the absence of a $31.8 million court-awarded recovery recognized in Q1 2015. The impact of weakened commodity prices was partially offset by significant production growth, global cost reductions (including a 9% reduction in per unit operating expense), and gains on derivative instruments.

Cash flows from operating activities

- Absent changes in working capital, cash flows from operating activities decreased by 30% quarter-over-quarter due to lower petroleum and natural gas sales driven by lower commodity prices.
- Absent changes in working capital, cash flows from operating activities decreased by 22% for the three months ended March 31, 2016, versus the comparable period in 2015. This decrease was primarily related to lower petroleum and natural gas sales due to lower commodity prices, partially offset by realized gains on derivative instruments and lower current taxes.

Fund flows from operations

- Generated fund flows from operations of $93.7 million during Q1 2016, a decrease of 31% from Q4 2015. This quarter-over-quarter decrease was primarily driven by unfavourable pricing variances on all commodities and lower volumes sold in Australia due to a build in inventory. The impact of lower pricing was minimized by a full quarter of production from Corrib and decreased operating costs resulting from global cost reductions.
- Fund flows from operations decreased by 22% versus Q1 2015. This decrease was the result of lower pricing on all commodities and the absence of the $31.8 million court-awarded recovery recognized in Q1 2015, partially offset by global cost reductions, realized gains on derivative instruments, and lower current taxes.

Net debt

- Net debt decreased by $14.9 million to $1.37 billion for the three months ended March 31, 2016, as we maintained a payout ratio of 96%.

Dividends

- Declared dividends of $0.215 per common share per month during the first quarter of 2016, totalling $0.645 per common share for the quarter.

COMMODITY PRICES

	Three Months Ended			% change	
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015	Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
Average reference prices					
Crude oil					
WTI (US $/bbl)	**33.45**	42.18	48.63	(21%)	(31%)
Edmonton Sweet index (US $/bbl)	**29.76**	39.72	41.83	(25%)	(29%)
Dated Brent (US $/bbl)	**33.89**	43.69	53.97	(22%)	(37%)
Natural gas					
AECO ($/mmbtu)	**1.83**	2.46	2.75	(26%)	(33%)
TTF ($/mmbtu)	**5.70**	7.28	8.70	(22%)	(34%)
TTF (€/mmbtu)	**3.76**	4.98	6.23	(24%)	(40%)
NBP ($/mmbtu)	**5.97**	7.41	9.01	(19%)	(34%)
NBP (€/mmbtu)	**3.94**	5.07	6.45	(22%)	(39%)
Henry Hub ($/mmbtu)	**2.87**	3.03	3.70	(5%)	(22%)
Henry Hub (US $/mmbtu)	**2.09**	2.27	2.98	(8%)	(30%)
Average foreign currency exchange rates					
CDN $/US $	**1.37**	1.34	1.24	2%	10%
CDN $/Euro	**1.52**	1.46	1.40	4%	9%
Average realized prices ($/boe)					
Canada	**21.16**	28.94	35.81	(27%)	(41%)
France	**43.16**	54.20	64.33	(20%)	(33%)
Netherlands	**33.26**	42.61	48.60	(22%)	(32%)
Germany	**31.78**	39.68	45.21	(20%)	(30%)
Ireland	**33.07**	-	-	100%	100%
Australia	**46.93**	58.74	83.80	(20%)	(44%)
United States	**30.10**	41.94	48.79	(28%)	(38%)
Consolidated	**30.53**	41.04	47.17	(26%)	(35%)
Production mix (% of production)					
% priced with reference to WTI	**20%**	22%	28%		
% priced with reference to AECO	**25%**	24%	20%		
% priced with reference to TTF and NBP	**26%**	20%	18%		
% priced with reference to Dated Brent	**29%**	34%	34%		

- Oil benchmarks continued to move lower throughout Q1 2016, pressured by the ongoing fundamental conditions. For Q1 2016, Dated Brent and WTI prices decreased by approximately 20% versus Q4 2015. On a year-over-year basis, WTI was down 31% and Dated Brent was down 37%.
- Crude oil prices set at Edmonton were equally as volatile during Q1 2016, averaging the quarter at US $29.76/bbl, 25% lower quarter-over-quarter, and 29% lower year-over-year.
- AECO natural gas prices declined in Q1 2016 due to the warmer-than-normal winter which lessened demand. For Q1 2016, AECO averaged $1.83/mmbtu, 26% lower quarter-over-quarter and down 33% year-over-year.
- A warmer winter in Europe combined with ample supply caused European natural gas prices to post a 22% quarter-over-quarter decline to average $5.70/mmbtu at TTF. NBP performed slightly better than TTF, with a quarter-over-quarter loss of 19%. The smaller decrease was due to stronger demand from coal-to-gas switching for power generation in the UK. On a year-over-year basis, both TTF and NBP were down 34%.
- Despite exiting the first quarter with a stronger Canadian dollar versus the US dollar, the average exchange rate for the quarter still favoured a stronger US dollar. The Canadian dollar also weakened against the Euro, with Q1 2016 averaging 1.52 versus 1.46 in Q4 2015 and 1.40 in Q1 2015.

FUND FLOWS FROM OPERATIONS

	Three Months Ended					
	Mar 31, 2016		Dec 31, 2015		Mar 31, 2015	
	$M	$/boe	$M	$/boe	$M	$/boe
Petroleum and natural gas sales	**177,385**	**30.53**	234,319	41.04	195,885	47.17
Royalties	**(13,961)**	**(2.40)**	(16,285)	(2.85)	(16,424)	(3.95)
Petroleum and natural gas revenues	**163,424**	**28.13**	218,034	38.19	179,461	43.22
Transportation	**(10,390)**	**(1.79)**	(10,147)	(1.78)	(9,540)	(2.30)
Operating	**(55,628)**	**(9.58)**	(65,645)	(11.50)	(43,851)	(10.56)
General and administration	**(13,577)**	**(2.34)**	(12,431)	(2.18)	(13,560)	(3.27)
PRRT	**(128)**	**(0.02)**	(1,054)	(0.18)	(2,354)	(0.57)
Corporate income taxes	**(3,160)**	**(0.54)**	3,113	0.55	(17,623)	(4.24)
Interest expense	**(14,750)**	**(2.54)**	(16,584)	(2.90)	(13,298)	(3.20)
Realized gain on derivative instruments	**28,423**	**4.89**	21,164	3.71	6,257	1.51
Realized foreign exchange (loss) gain	**(652)**	**(0.11)**	(252)	(0.04)	3,306	0.78
Realized other income	**105**	**0.02**	243	0.04	31,997	7.70
Fund flows from operations	**93,667**	**16.12**	136,441	23.91	120,795	29.07

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

($M)	**Q1/16 vs. Q4/15**	**Q1/16 vs. Q1/15**
Fund flows from operations – Comparative period	**136,441**	**120,795**
Sales volume variance:		
Canada	684	6,322
France	(2,470)	11,538
Netherlands	(2,473)	12,812
Germany	(245)	(464)
Ireland	16,947	17,004
Australia	(23,000)	16,313
United States	(229)	545
Pricing variance on sold volumes:		
WTI	(13,270)	(18,885)
AECO	(5,658)	(9,195)
Dated Brent	(17,833)	(38,907)
TTF and NBP	(9,387)	(15,583)
Changes in:		
Royalties	2,324	2,463
Transportation	(243)	(850)
Operating	10,017	(11,777)
General and administration	(1,146)	(17)
PRRT	926	2,226
Corporate income taxes	(6,273)	14,463
Interest	1,834	(1,452)
Realized derivatives	7,259	22,166
Realized foreign exchange	(400)	(3,958)
Realized other income	(138)	(31,892)
Fund flows from operations – Current period	**93,667**	**93,667**

Fund flows from operations of $93.7 million during Q1 2016 represented a decrease of 31% versus Q4 2015. This decrease relates primarily to lower pricing on all commodities and a 138,000 bbls build in inventory in Australia (compared to a draw of 97,000 bbls in Q4 2015). The impact of lower pricing was minimized by a full quarter of production from Corrib and global cost reductions, including a 15% decrease in operating costs.

Fund flows from operations decreased 22% for the three months ended March 31, 2016, versus the comparable period in 2015. The decrease was the result of lower pricing for all commodities and the absence of a $31.8 million court-awarded recovery recognized in Q1 2015. The decrease in pricing was partially offset by global cost reductions (including a 9% reduction in per unit operating expense), realized gains on derivative instruments, and lower current taxes.

Fluctuations in fund flows from operations (and correspondingly net (loss) earnings and cash flows from operating activities) may occur as a result of changes in commodity prices and costs to produce petroleum and natural gas. In addition, fund flows from operations may be highly affected by the timing of crude oil shipments in Australia and France. When crude oil inventory is built up, the related operating expense, royalties, and depletion expense are deferred and carried as inventory on the 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 in Alberta:
  - 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	
Canada business unit	**Mar 31, 2016**	**Dec 31, 2015**	**Mar 31, 2015**	**Q1/16 vs. Q4/15**	**Q1/16 vs. Q1/15**
Production					
Crude oil and condensate (bbls/d)	**10,317**	10,413	12,163	(1%)	(15%)
NGLs (bbls/d)	**2,633**	2,710	1,706	(3%)	54%
Natural gas (mmcf/d)	**97.16**	87.90	61.78	11%	57%
Total (boe/d)	**29,141**	27,773	24,165	5%	21%
Production mix (% of total)					
Crude oil and condensate	**35%**	38%	50%		
NGLs	**9%**	10%	7%		
Natural gas	**56%**	52%	43%		
Activity					
Capital expenditures ($M)	**29,771**	27,554	114,849	8%	(74%)
Acquisitions ($M)	**755**	6,169	35		
Gross wells drilled	**12.00**	5.00	25.00		
Net wells drilled	**8.26**	2.56	16.04		

Production

- Q1 2016 average production in Canada increased by 5% quarter-over-quarter and 21% year-over-year, primarily attributable to strong organic production growth in our Mannville condensate-rich gas resource play.
- Cardium production averaged more than 7,500 boe/d in Q1 2016, a 5% decrease quarter-over-quarter.
- Mannville production averaged approximately 13,000 boe/d in Q1 2016, an 18% increase quarter-over-quarter and more than 2.5 times Q1 2015 production of approximately 4,850 boe/d.
- Production from our southeast Saskatchewan assets averaged approximately 2,700 boe/d in Q1 2016, an increase of 6% quarter-over-quarter.

Activity review

- Vermilion drilled six (5.7 net) operated wells and participated in the drilling of six (2.6 net) non-operated wells during Q1 2016.

  Cardium
  - In Q1 2016, no new operated wells were drilled, completed or brought on production. Two (0.31 net) non-operated wells were brought on production during the quarter.
  - 2016 activity will focus on the optimization of existing assets.

  Mannville
  - During Q1 2016, we participated in a total of six (3.8 net) wells, including three (2.7 net) operated wells. Three (2.7 net) operated wells and four (1.5 net) non-operated wells were brought on production during the quarter.
  - We completed a 3D seismic program in the northern portion of our Drayton Valley lands. The program covered 34 net sections, including lands acquired in 2015.
  - Our 2016 program to drill or participate in six (3.8 net) wells was completed in the first quarter.

  Saskatchewan
  - We drilled three (3.0 net) operated Midale wells during Q1 2016 and participated in the drilling of three (1.5 net) non-operated Midale wells. Completion and tie-in of the three operated wells is currently planned for Q1 2017. Two of the three non-operated wells were placed on production in Q1 2016, with the remaining non-operated well to be placed on production in Q2 2016.
  - Q1 2016 activity included the acquisition and processing of 3D seismic of 16 net sections (100% Vermilion interest) in the West Pinto area
  - In 2016, we plan to drill or participate in seven (5.5 net) wells.

Financial review

Canada business unit ($M except as indicated)	Three Months Ended Mar 31, 2016	Dec 31, 2015	Mar 31, 2015	% change Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
Sales	**56,110**	73,952	77,884	(24%)	(28%)
Royalties	**(5,498)**	(7,146)	(8,592)	(23%)	(36%)
Transportation	**(4,151)**	(3,784)	(3,942)	10%	5%
Operating	**(21,343)**	(24,575)	(19,099)	(13%)	12%
General and administration	**(2,476)**	(3,669)	(4,015)	(33%)	(38%)
Fund flows from operations	**22,642**	34,778	42,236	(35%)	(46%)
Netbacks ($/boe)					
Sales	**21.16**	28.94	35.81	(27%)	(41%)
Royalties	**(2.07)**	(2.80)	(3.95)	(26%)	(48%)
Transportation	**(1.57)**	(1.48)	(1.81)	6%	(13%)
Operating	**(8.05)**	(9.62)	(8.78)	(16%)	(8%)
General and administration	**(0.94)**	(1.44)	(1.85)	(35%)	(49%)
Fund flows from operations netback	**8.53**	13.60	19.42	(37%)	(56%)
Realized prices					
Crude oil and condensate ($/bbl)	**39.69**	53.44	52.91	(26%)	(25%)
NGLs ($/bbl)	**7.31**	7.89	22.37	(7%)	(67%)
Natural gas ($/mmbtu)	**1.93**	2.57	2.97	(25%)	(35%)
Total ($/boe)	**21.16**	28.94	35.81	(27%)	(41%)
Reference prices					
WTI (US $/bbl)	**33.45**	42.18	48.63	(21%)	(31%)
Edmonton Sweet index (US $/bbl)	**29.76**	39.72	41.83	(25%)	(29%)
Edmonton Sweet index ($/bbl)	**40.91**	53.04	51.92	(23%)	(21%)
AECO ($/mmbtu)	**1.83**	2.46	2.75	(26%)	(33%)

Sales

- The realized price for our crude oil and condensate 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.
- Q1 2016 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 Q1 2016 of 9.8% was consistent with the rate of 9.7% for Q4 2015.
- Royalties as a percentage of sales for Q1 2016 was lower than Q1 2015 (11.0%) 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 Q1 2016 was higher than Q4 2015 and Q1 2015 as a result of increased natural gas production. On a year-over-year basis, the 13% decrease in per unit costs is due to an increased gas weighting and the lower per unit transportation costs associated with gas production.

Operating

- Operating expense reductions of 13% were achieved in Q1 2016 versus Q4 2015 while growing production by 5%. The diligent focus on cost control and cost-cutting initiatives, including service cost negotiations impacting numerous cost drivers, has resulted in a 16% per unit reduction in costs from Q4 2015 and 8% from Q1 2015.

General and administration

- General and administration expense decreased by 35% and 49% from Q4 2015 and Q1 2015 respectively. The decreases are consistent with continued cost-cutting initiatives to reduce our cost structure and preserve balance sheet strength.

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	
France business unit	**Mar 31, 2016**	**Dec 31, 2015**	**Mar 31, 2015**	**Q1/16 vs. Q4/15**	**Q1/16 vs. Q1/15**
Production					
Crude oil (bbls/d)	**12,220**	12,537	11,463	(3%)	7%
Natural gas (mmcf/d)	**0.44**	1.36	-	(68%)	100%
Total (boe/d)	**12,293**	12,763	11,463	(4%)	7%
Inventory (mbbls)					
Opening crude oil inventory	**243**	239	197		
Crude oil production	**1,112**	1,153	1,032		
Crude oil sales	**(1,108)**	(1,149)	(930)		
Closing crude oil inventory	**247**	243	299		
Production mix (% of total)					
Crude oil	**99%**	98%	100%		
Natural gas	**1%**	2%	-		
Activity					
Capital expenditures ($M)	**13,463**	24,085	34,114	(44%)	(61%)
Acquisitions ($M)	**-**	79	-		
Gross wells drilled	**-**	-	4.00		
Net wells drilled	**-**	-	4.00		

Production

- Production decreased 4% versus the prior quarter, mainly due to a reduced capital program. Gas production from Vic Bilh was negatively impacted by third party restrictions at the SOBEGI terminal.
- Year-over-year production increased 7% due to production additions from our 2015 Champotran drilling program.

Activity review

- During the quarter we completed a number of workover and optimization programs in the Aquitaine and Paris Basins.
- In 2016, our planned capital activity includes a program of approximately 15 well workovers.

Financial review

France business unit ($M except as indicated)	Three Months Ended Mar 31, 2016	Dec 31, 2015	Mar 31, 2015	% change Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
Sales	**48,125**	63,411	59,832	(24%)	(20%)
Royalties	**(6,766)**	(7,198)	(5,102)	(6%)	33%
Transportation	**(3,713)**	(4,275)	(3,011)	(13%)	23%
Operating	**(14,320)**	(15,792)	(10,826)	(9%)	32%
General and administration	**(4,676)**	(4,894)	(5,111)	(4%)	(9%)
Other income	**-**	-	31,775	-	(100%)
Current income taxes	**(34)**	4,529	(14,281)	(101%)	(100%)
Fund flows from operations	**18,616**	35,781	53,276	(48%)	(65%)
Netbacks ($/boe)					
Sales	**43.16**	54.20	64.33	(20%)	(33%)
Royalties	**(6.07)**	(6.15)	(5.49)	(1%)	11%
Transportation	**(3.33)**	(3.65)	(3.24)	(9%)	3%
Operating	**(12.84)**	(13.50)	(11.64)	(5%)	10%
General and administration	**(4.19)**	(4.18)	(5.49)	-	(24%)
Other income	**-**	-	34.16	-	(100%)
Current income taxes	**(0.03)**	3.87	(15.35)	(101%)	(100%)
Fund flows from operations netback	**16.70**	30.59	57.28	(45%)	(71%)
Realized prices					
Crude oil ($/bbl)	**43.36**	54.88	64.33	(21%)	(33%)
Natural gas ($/mmbtu)	**1.66**	2.81	-	(41%)	100%
Total ($/boe)	**43.16**	54.20	64.33	(20%)	(33%)
Reference prices					
Dated Brent (US $/bbl)	**33.89**	43.69	53.97	(22%)	(37%)
Dated Brent ($/bbl)	**46.59**	58.34	66.98	(20%)	(30%)

Sales

- Crude oil in France is priced with reference to Dated Brent.
- Sales per boe decreased relative to all comparable periods, consistent with a decrease in the Dated Brent reference price. Compared to Q1 2015, the decrease in price was partially offset by increased sales volumes, resulting in a relatively lower decrease to sales.

Royalties

- Royalties in France relate to two components: RCDM (levied on units of production and not subject to changes in commodity prices) and R31 (based on a percentage of sales).
- Royalties as a percentage of sales was 14.1% for Q1 2016, an increase over both Q4 2015 (11.4%) and Q1 2015 (8.5%) as a result of the impact of fixed RCDM royalties coupled with lower realized pricing.

Transportation

- Transportation expense for Q1 2016 was lower versus Q4 2015 due to successful vessel cost renegotiations and a lower level of project activity at the Ambès terminal.
- Transportation expense increased year-over-year primarily due to an unfavorable foreign exchange impact and increased sales. When excluding the impact of foreign exchange, per unit costs decreased by 5% as a result of ongoing cost reduction initiatives.

Operating

- Operating expense decreased in Q1 2016 versus Q4 2015 as a result of a continued emphasis on cost reduction initiatives and savings from service contract renegotiations resulting in lower costs related to electricity, maintenance and labour usage. These cost reduction initiatives more than offset the unfavorable foreign exchange impact of a weakening Canadian dollar.
- Year-over-year, operating expenses increased on a dollar and per boe basis. The 7% increase in production over this period partially contributed to the increase, and, to a larger extent, the weakening of the Canadian dollar versus the Euro resulted in increased expense. After normalizing for the unfavorable foreign exchange impact, per unit costs were essentially flat year-over-year.

General and administration

- General and administration expense for Q1 2016 was 4% lower than Q4 2015 and 9% lower than Q1 2015 as a result of cost-cutting initiatives.

Current income taxes

- Current income taxes in France are applied to taxable income, after eligible deductions, at a statutory rate of 34.4% for 2016. Our France Business Unit is expected to incur minimal 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.

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 land, 95% of which is undeveloped.

Operational review

	Three Months Ended			% change	
Netherlands business unit	**Mar 31, 2016**	**Dec 31, 2015**	**Mar 31, 2015**	**Q1/16 vs. Q4/15**	**Q1/16 vs. Q1/15**
Production					
Condensate (bbls/d)	**114**	110	63	4%	81%
Natural gas (mmcf/d)	**53.40**	56.34	36.41	(5%)	47%
Total (boe/d)	**9,015**	9,500	6,132	(5%)	47%
Activity					
Capital expenditures ($M)	**2,996**	18,810	4,333	(84%)	(31%)

Production

- Q1 2016 production decreased 5% versus the prior quarter mainly due to a decline in gas production from our Slootdorp-07 well.
- Year-over-year production increased 47%, primarily due to production additions from Diever-02 and Slootdorp-06/07 wells, and enhanced by debottlenecking at our Garijp Treatment Centre. The Diever-02 exploration well (45% working interest), which came on an extended production test in late October 2015, continues to produce approximately 13 mmcf/d (2,200 boe/d), net to Vermilion. Slootdorp-06/07, which are also on extended production tests, are currently producing approximately 23 mmcf/d (3,900 boe/d) net to Vermilion, combined.
- Production in the Netherlands is actively managed to optimize facility use and regulate declines.

Activity review

- Production and reservoir testing on our Slootdorp-06/07 wells will continue into Q2 2016, when permanent facility installation should be complete.
- Planning activities for the drilling of Langezwaag-03 (42% working interest) and Andel-6ST (45% working interest) were carried out during the quarter. We expect to drill these wells in Q3 2016, and if successful, we expect to have the wells on production prior to year end.
- In addition to the two (0.9 net) well drilling program, we are also planning permitting and optimization activities in 2016.

Financial review

Netherlands business unit ($M except as indicated)	Three Months Ended Mar 31, 2016	Dec 31, 2015	Mar 31, 2015	% change Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
Sales	**27,286**	37,243	26,818	(27%)	2%
Royalties	**(460)**	(224)	(926)	105%	(50%)
Operating	**(5,976)**	(6,263)	(5,826)	(5%)	3%
General and administration	**(773)**	(813)	(737)	(5%)	5%
Current income taxes	**(2,200)**	(2,930)	(2,388)	(25%)	(8%)
Fund flows from operations	**17,877**	27,013	16,941	(34%)	6%
Netbacks ($/boe)					
Sales	**33.26**	42.61	48.60	(22%)	(32%)
Royalties	**(0.56)**	(0.26)	(1.68)	115%	(67%)
Operating	**(7.28)**	(7.17)	(10.56)	2%	(31%)
General and administration	**(0.94)**	(0.93)	(1.34)	1%	(30%)
Current income taxes	**(2.68)**	(3.35)	(4.33)	(20%)	(38%)
Fund flows from operations netback	**21.80**	30.90	30.69	(29%)	(29%)
Realized prices					
Condensate ($/bbl)	**32.24**	48.30	52.93	(33%)	(39%)
Natural gas ($/mmbtu)	**5.55**	7.09	8.09	(22%)	(31%)
Total ($/boe)	**33.26**	42.61	48.60	(22%)	(32%)
Reference prices					
TTF ($/mmbtu)	**5.70**	7.28	8.70	(22%)	(34%)
TTF (€/mmbtu)	**3.76**	4.98	6.23	(24%)	(40%)

Sales

- The price of our natural gas in the Netherlands is based on the TTF day-ahead index. GasTerra, a state owned entity, continues to purchase all of the natural gas we produce in the Netherlands.
- Sales per boe decreased versus all comparable periods, consistent with a decrease in the TTF reference price. Compared to Q1 2015, the decrease in price was entirely offset by increased 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

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

Operating

- Operating expense decreased versus Q4 2015 on a dollar basis and increased slightly on a per unit basis. The dollar decrease was achieved as reduced maintenance activity levels more than offset a weaker Canadian dollar versus the Euro.
- Year-over-year, operating expense increases have been limited to 3% while growing production by 47%, resulting in a 31% per unit decrease in costs. When normalizing for the impact of the weaker Canadian dollar relative to the Euro for this period, absolute costs have decreased by 6% while per unit costs have decreased by 36% due to cost reduction initiatives being achieved while executing on significant production additions.

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 10% and 12% of pre-tax fund flows from operations. 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 Q1 2016 were lower compared to Q4 2015 as decreased revenues were offset by additional tax deductions taken for depletion in Q4 2015.

GERMANY BUSINESS UNIT

Overview

- Vermilion entered Germany in February 2014.
- Hold 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 18 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 18 licenses during the exploration phase.
- Awarded 110,000 net acres (100% working interest) across two exploration licenses in Lower Saxony in 2016.

Operational review

	Three Months Ended			% change	
Germany business unit	**Mar 31, 2016**	**Dec 31, 2015**	**Mar 31, 2015**	**Q1/16 vs. Q4/15**	**Q1/16 vs. Q1/15**
Production					
Natural gas (mmcf/d)	**15.96**	16.17	16.80	(1%)	(5%)
Total (boe/d)	**2,660**	2,695	2,801	(1%)	(5%)
Activity					
Capital expenditures ($M)	**539**	(441)	968	(222%)	(44%)

Production

- Q1 2016 production was relatively unchanged versus the prior quarter. Year-over-year production decreased 5%.

Activity review

- In 2016, the majority of activity will be associated with permitting and pre-drill activities for Burgmoor Z5 and two farm-in prospects, which are planned for 2017. In addition, we will continue our ongoing analysis of the proprietary geologic data associated with the farm-in assets.

Financial review

Germany business unit ($M except as indicated)	Three Months Ended Mar 31, 2016	Dec 31, 2015	Mar 31, 2015	% change Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
Sales	**7,692**	9,840	11,395	(22%)	(32%)
Royalties	**(867)**	(1,166)	(1,598)	(26%)	(46%)
Transportation	**(887)**	(508)	(894)	75%	(1%)
Operating	**(2,593)**	(4,788)	(1,999)	(46%)	30%
General and administration	**(2,428)**	(3,032)	(1,608)	(20%)	51%
Fund flows from operations	**917**	346	5,296	165%	(83%)
Netbacks ($/boe)					
Sales	**31.78**	39.68	45.21	(20%)	(30%)
Royalties	**(3.58)**	(4.70)	(6.34)	(24%)	(44%)
Transportation	**(3.67)**	(2.05)	(3.55)	79%	3%
Operating	**(10.71)**	(19.31)	(7.93)	(45%)	35%
General and administration	**(10.03)**	(12.22)	(6.38)	(18%)	57%
Fund flows from operations netback	**3.79**	1.40	21.01	171%	(82%)
Reference prices					
TTF ($/mmbtu)	**5.70**	7.28	8.70	(22%)	(34%)
TTF (€/mmbtu)	**3.76**	4.98	6.23	(24%)	(40%)

Sales

- The price of our natural gas in Germany is based on the TTF month-ahead index.
- Sales per boe decreased versus all comparable periods, consistent with a decrease in the TTF reference price.

Royalties

- Our production in Germany is subject to state and private royalties on sales after certain eligible deductions.
- Q1 2016 royalties as a percentage of sales of 11.3% was consistent with the Q4 2015 rate of 11.9% and lower than the Q1 2015 rate of 14.0%. The reduced rate year-over-year is a result of a reduction in state royalty rates.

Transportation

- Transportation expense in Germany relates to costs incurred to deliver natural gas from the processing facility to the customer.
- Q1 2016 transportation expense increased on an absolute dollar and per unit basis versus Q4 2015 due to a favourable annual adjustment recorded in Q4 2015.
- Transportation costs for the quarter relative to Q1 2015 are consistent on an absolute and per unit basis.

Operating

- Operating expenses for Germany primarily relate to tariffs charged for facility operations and gas processing.
- Q1 2016 operating expense was lower than Q4 2015 due in equal parts to charges for prior period maintenance expenditures and the inclusion of a full year gas processing tariff adjustment, both recorded in Q4 2015.
- Operating expense increased in Q1 2016 from Q1 2015 on an absolute and per unit basis due to increased maintenance activity.

General and administration

- Q1 2016 general and administration expenses were lower than Q4 2015 and higher than Q1 2015. The reduction from Q4 2015 is due to timing of expenditures, while the increase from Q1 2015 is due to higher staffing levels and office costs incurred to support 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		
Ireland business unit ($M except as indicated)	**Mar 31, 2016**	**Dec 31, 2015**	**Mar 31, 2015**
Production			
Natural gas (mmcf/d)	**33.90**	0.12	-
Total (boe/d)	**5,650**	20	-
Activity			
Capital expenditures	**3,076**	12,493	12,955
Financial Results			
Sales	**17,004**	57	-
Transportation	**(1,639)**	(1,580)	(1,693)
Operating	**(3,626)**	(15)	-
General and administration	**(1,188)**	(714)	(512)
Fund flows from operations	**10,551**	(2,252)	(2,205)
Netbacks ($/boe)			
Sales	**33.07**	-	-
Transportation	**(3.19)**	-	-
Operating	**(7.05)**	-	-
General and administration	**(2.31)**	-	-
Fund flows from operations netback	**20.52**	-	-
Reference prices			
NBP ($/mmbtu)	**5.97**	7.41	9.01
NBP (€/mmbtu)	**3.94**	5.07	6.45

Production

- Natural gas began to flow from our Corrib gas project on December 30, 2015 and to date, well performance and facility runtimes have exceeded expectations.
- Production averaged 34 mmcf/d (5,650 boe/d) net to Vermilion, during Q1 2016.
- Following the completion of previously planned recertification activities associated with the third party gas distribution pipeline network, production volumes at Corrib are expected to rise to an estimated peak rate of approximately 58 mmcf/d (9,700 boe/d), net to Vermilion.

Activity review

- The export gas sales pipeline underwent intelligent pigging in Q1 2016. As part of the recertification process, confirmatory inspection digs on the export sales pipeline are planned for Q2 2016.
- Some subsea inspections, maintenance and repairs on the subsea systems are scheduled to take place in Q2 2016.
- Five of the six wells are capable of producing, with the remaining well to be brought online in the third quarter of 2016 following the conclusion of our offshore work program to lay a pipeline to the sixth well.

Sales

- The price of our natural gas in Ireland is based on the NBP index.
- Q1 2016 represented the first full quarter of sales from Corrib.

Royalties

- Our production in Ireland is not subject to royalties.

Transportation

- Transportation expense in Ireland relates to payments under a ship or pay agreement related to the Corrib project.
- Q1 2016 transportation expense is slightly higher than Q4 2015 due to foreign exchange. The expense is lower than Q1 2015 due to lower tariffs for the current gas year, which began in October 2015, under the ship or pay agreement.

Operating

- We expect per unit costs to decrease as production ramps up.

General and administration

- General and administration expense increased quarter-over-quarter and year-over-year due to increased corporate allocations as a result of achieving our first full quarter of production.

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 18 well bores and four lateral sidetrack wells.
- 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.

Operational review

	Three Months Ended			% change	
Australia business unit	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015	Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
Production					
Crude oil (bbls/d)	**6,180**	7,824	5,672	(21%)	9%
Inventory (mbbls)					
Opening crude oil inventory	**75**	172	37		
Crude oil production	**562**	720	511		
Crude oil sales	**(424)**	(817)	(230)		
Closing crude oil inventory	**213**	75	318		
Activity					
Capital expenditures ($M)	**7,827**	40,852	6,455	(81%)	21%
Gross wells drilled	**-**	1.00	-		
Net wells drilled	**-**	1.00	-		

Production

- Q1 2016 quarterly production decreased 21% quarter-over-quarter and increased 9% year-over-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 Q1 2016, efforts were largely focused on facilities enhancement, including work relating to platform life extension, and preparation activities in advance of our upcoming drilling program.
- We plan to drill a two-well sidetrack program in Q2 2016.

Financial review

Australia business unit ($M except as indicated)	Three Months Ended Mar 31, 2016	Dec 31, 2015	Mar 31, 2015	% change Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
Sales	**19,935**	47,952	19,284	(58%)	3%
Operating	**(7,491)**	(13,941)	(5,886)	(46%)	27%
General and administration	**(1,325)**	(1,768)	(1,454)	(25%)	(9%)
PRRT	**(128)**	(1,054)	(2,354)	(88%)	(95%)
Corporate income taxes	**(777)**	1,201	(577)	(165%)	35%
Fund flows from operations	**10,214**	32,390	9,013	(68%)	13%
Netbacks ($/boe)					
Sales	**46.93**	58.74	83.80	(20%)	(44%)
Operating	**(17.63)**	(17.08)	(25.58)	3%	(31%)
General and administration	**(3.12)**	(2.17)	(6.32)	44%	(51%)
PRRT	**(0.30)**	(1.29)	(10.23)	(77%)	(97%)
Corporate income taxes	**(1.83)**	1.47	(2.51)	(224%)	(27%)
Fund flows from operations netback	**24.05**	39.67	39.16	(39%)	(39%)
Reference prices					
Dated Brent (US $/bbl)	**33.89**	43.69	53.97	(22%)	(37%)
Dated Brent ($/bbl)	**46.59**	58.34	66.98	(20%)	(30%)

Sales

- Crude oil in Australia is priced with reference to Dated Brent.
- Sales per boe decreased versus all comparable periods, consistent with a decrease in the Dated Brent reference price. Compared to Q4 2015, the decrease in price was combined with lower sales volumes, resulting in a larger decrease to sales. Compared to Q1 2015, the decrease in price was offset by higher sales volumes, resulting in relatively consistent sales.

Royalties and transportation

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

Operating

- Operating expense on a dollar basis decreased in Q1 2016 from Q4 2015 primarily due to a decrease in sold volumes. After adjusting for inventory, per unit costs were in-line with Q4 2015.
- Year-over-year, operating expense increased by 27%, however a significant increase in sales volumes resulted in per unit costs decreasing by 31%. The decrease in per unit costs is driven by a continued focus on cost reduction initiatives, including reduced helicopter and vessel costs.

General and administration

- Q1 2016 general and administration costs decreased versus Q4 2015 and Q1 2015 due to cost-cutting initiatives.

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.
- For 2016, the effective tax rate for corporate income tax is expected to be between approximately 6% to 8% of pre-tax fund flows from operations and PRRT is expected to be between approximately 0% to 2% of pre-tax fund flows from operations. This is subject to change in response to commodity price fluctuations, the timing of capital expenditures and other eligible in-country adjustments.
- Q1 2016 combined corporate income taxes and PRRT were higher compared to Q4 2015, as decreased revenues were offset by additional tax deductions taken for corporate income tax depletion in Q4 2015.
- Q1 2016 combined corporate income taxes and PRRT were lower compared to Q1 2015 due to the recognition of increased capital spending deductions for PRRT purposes in Q1 2016.

UNITED STATES BUSINESS UNIT

Overview

- Entered the United States in September 2014.
- Interests include approximately 96,200 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	
United States business unit ($M except as indicated)	**Mar 31, 2016**	**Dec 31, 2015**	**Mar 31, 2015**	**Q1/16 vs. Q4/15**	**Q1/16 vs. Q1/15**
Production					
Crude oil (bbls/d)	**368**	420	153	(12%)	141%
NGLs (bbls/d)	**39**	29	-	34%	100%
Natural gas (mmcf/d)	**0.26**	0.20	-	30%	100%
Total (boe/d)	**450**	483	153	(7%)	194%
Activity					
Capital expenditures	**5,101**	5,643	637	(10%)	701%
Acquisitions	**115**	(21)	-		
Gross wells drilled	**-**	2.00	-		
Net wells drilled	**-**	2.00	-		
Financial Results					
Sales	**1,233**	1,864	672	(34%)	83%
Royalties	**(370)**	(551)	(206)	(33%)	80%
Operating	**(279)**	(271)	(215)	3%	30%
General and administration	**(1,132)**	(897)	(1,080)	26%	5%
Fund flows from operations	**(548)**	145	(829)	(478%)	(34%)
Netbacks ($/boe)					
Sales	**30.10**	41.94	48.79	(28%)	(38%)
Royalties	**(9.03)**	(12.40)	(14.98)	(27%)	(40%)
Operating	**(6.82)**	(6.11)	(15.61)	12%	(56%)
General and administration	**(27.65)**	(20.18)	(78.41)	37%	(65%)
Fund flows from operations netback	**(13.40)**	3.25	(60.21)	(512%)	(78%)
Realized prices					
Crude oil ($/bbl)	**35.80**	47.59	48.79	(25%)	(27%)
NGLs ($/bbl)	**4.81**	5.13	-	(6%)	100%
Natural gas ($/mmbtu)	**0.67**	0.52	-	29%	100%
Total ($/boe)	**30.10**	41.94	48.79	(28%)	(38%)
Reference prices					
WTI (US $/bbl)	**33.45**	42.18	48.63	(21%)	(31%)
WTI ($/bbl)	**45.99**	56.32	60.35	(18%)	(24%)
Henry Hub (US $/mmbtu)	**2.09**	2.27	2.98	(8%)	(30%)
Henry Hub ($/mmbtu)	**2.87**	3.03	3.70	(5%)	(22%)

Production

- Q1 2016 production was relatively unchanged versus the prior quarter and nearly triple that of Q1 2015 due to production from our Seedy Draw well, which was drilled and completed in 2015.

Activity review

- In Q1 2016, we completed the two (2.0 net) wells drilled in the East Finn prospect during the prior quarter. One of the wells was placed on production at the end of Q1 2016. The other well experienced a mechanical failure during the completion operation which resulted in only 8% of the horizontal section being open to production. That well was placed on production subsequent to the quarter.

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 Q1 2016 of approximately 30.0% was consistent with the rate for Q4 2015 (29.6%) and Q1 2015 (30.7%).

Operating

- Operating expense increased on an absolute dollar and per unit basis in Q1 2016 from Q4 2015. The increase is primarily due to the weakening of the Canadian dollar relative to the US dollar. On a per unit basis, costs are flat once adjusted for the impact of foreign exchange.
- Year-over-year the increase in operating expense has been held at 30% while production has increased 194%. As a result, per unit costs have decreased by 56%.

General and administration

- General and administration expenses increased in Q1 2016 by 26% from Q4 2015 and 5% from Q1 2015 due to timing of expenditures.

CORPORATE

Overview

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

Financial review

CORPORATE ($M)	Three Months Ended Mar 31, 2016	Dec 31, 2015	Mar 31, 2015
General and administration recovery	**421**	3,356	957
Current income taxes	**(149)**	313	(377)
Interest expense	**(14,750)**	(16,584)	(13,298)
Realized gain on derivatives	**28,423**	21,164	6,257
Realized foreign exchange (loss) gain	**(652)**	(252)	3,306
Realized other income	**105**	243	222
Fund flows from operations	**13,398**	8,240	(2,933)

General and administration

- The decrease in the recovery of general and administration costs for Q1 2016 versus Q4 2015 is due to the timing of expenditures and 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 decrease in interest expense versus Q4 2015 is primarily due to the retiring of our 6.5% senior unsecured notes in February using funds from our revolving credit facility, which has a marginal rate of 3.3%.
- The increase in interest expense for Q1 2016 versus Q1 2015 is due to increased average borrowings under our revolving credit facility.

Hedging

- The nature of our operations results in exposure to fluctuations in commodity prices, interest rates and foreign currency exchange rates. We monitor and, when appropriate, use derivative financial instruments to manage our exposure to these fluctuations. All transactions of this nature entered into are related to an underlying financial position or to future crude oil and natural gas production. We do not use derivative financial instruments for speculative purposes. We have elected not to designate any of our derivative financial instruments as accounting hedges and thus account for changes in fair value in net (loss) earnings at each reporting period. We have not obtained collateral or other security to support our financial derivatives as we review the creditworthiness of our counterparties prior to entering into derivative contracts.
- Our hedging philosophy is to hedge solely for the purposes of risk mitigation. Our approach is to hedge centrally to manage our global risk (typically with an outlook of 12 to 18 months) up to 50% of net of royalty volumes through a portfolio of forward collars, swaps, and physical fixed price arrangements. We currently have European gas contracts up to 36 months forward as an exception to our typical horizon.
- 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 Q1 2016 related primarily to amounts received on our crude oil and European natural gas hedges.
- A listing of derivative positions as at March 31, 2016 is included in "Supplemental Table 2" of this MD&A.

FINANCIAL PERFORMANCE REVIEW

	Three Months Ended							
($M except per share)	Mar 31, 2016	Dec 31, 2015	Sep 30, 2015	Jun 30, 2015	Mar 31, 2015	Dec 31, 2014	Sep 30, 2014	Jun 30, 2014
Petroleum and natural gas sales	**177,385**	234,319	245,051	264,331	195,885	306,073	344,688	387,684
Net (loss) earnings	**(85,848)**	(142,080)	(83,310)	6,813	1,275	58,642	53,903	53,993
Net (loss) earnings per share								
Basic	**(0.76)**	(1.28)	(0.76)	0.06	0.01	0.55	0.50	0.51
Diluted	**(0.76)**	(1.28)	(0.76)	0.06	0.01	0.54	0.50	0.50

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

($M)	Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
Net (loss) earnings - Comparative period	(142,080)	1,275
Changes in:		
Fund flows from operations	(42,774)	(27,128)
Equity based compensation	696	(1,797)
Unrealized gain or loss on derivative instruments	(18,339)	29,024
Unrealized foreign exchange gain or loss	7,927	6,415
Unrealized other expense or income	147	174
Accretion	215	(434)
Depletion and depreciation	(17,986)	(34,841)
Deferred tax	9,485	(43,774)
Impairment	116,861	(14,762)
Net loss - Current period	**(85,848)**	**(85,848)**

The fluctuations in net (loss) earnings from period-to-period are caused by changes in both cash and non-cash based income and charges. Cash based items are reflected in fund flows from operations 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 primarily 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 in Q1 2016 was relatively consistent with Q4 2015. The increase of $1.8 million as compared to Q1 2015 is due to the settlement of the employee bonus plan with equity in Q1 2016.

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 three months ended March 31 2016, we recognized an unrealized gain on derivative instruments of $9.1 million, relating primarily to a gain on our global natural gas hedges, partially offset by a decrease in the value of crude oil and interest rate hedges. As at March 31, 2016, we have a net derivative asset position of $77.4 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, long-term debt, 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 March 31, 2016, the Canadian dollar strengthened more significantly against the US dollar than the Euro, resulting in an unrealized foreign exchange gain of $1.6 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.

Q1 2016 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 Q1 2016 of $21.65 was higher as compared to $18.88 in Q4 2015. The increase quarter-over-quarter is primarily due to a full quarter of Corrib production in Q1 2016. Depletion and depreciation on a per boe basis for Q1 2016 remained relatively consistent with the $21.90 in Q1 2015 as the impact of a full quarter of Corrib production was offset with higher production from natural gas properties in Canada.

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 deferred tax expense for Q1 2016 largely pertains to the de-recognition of certain deferred tax assets.

Impairment

For the three months ended March 31, 2016, Vermilion recorded a non-cash impairment charge of $14.8 million in Ireland as a result of a decline in the price forecast for European natural gas.

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), issue equity, or by reducing some or all categories of expenditures to ensure that total expenditures do not exceed available funds.

To ensure that we maintain a conservative balance sheet, we monitor the ratio of net debt to fund flows from operations and typically strive to maintain an internally targeted ratio of approximately 1.0 to 1.5 in a normalized commodity price environment. Where prices trend higher, we may target a lower ratio and conversely, in a lower commodity price environment, the acceptable ratio may be higher. At times, we will use our balance sheet to finance acquisitions and, in these situations, we are prepared to accept a higher ratio in the short term but will implement a strategy to reduce the ratio to acceptable levels within a reasonable period of time, usually considered to be no more than 12 to 24 months. This plan could potentially include an increase in hedging activities, a reduction in capital expenditures, an issuance of equity or the utilization of excess fund flows from operations to reduce outstanding indebtedness.

In the current low commodity price environment, Vermilion's net debt to fund flows ratio is expected to be higher than the internally targeted 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 as at March 31, 2016 consists entirely of borrowings against our revolving credit facility. We redeemed the senior unsecured notes that came due on February 10, 2016 using funds drawn against the revolving credit facility. Following the redemption, all of Vermilion's debt is now classified as senior debt pursuant to the terms of the revolving credit facility. As a result, Vermilion requested and received amendments from its lending syndicate to eliminate the consolidated total senior debt to consolidated EBITDA financial covenant and increase the ratio of consolidated total senior debt to total capitalization financial covenant from 50% to 55%. The revolving credit facility limit of $2.0 billion remains unchanged. Vermilion was in compliance with all covenants as of March 31, 2016 and expects to remain in compliance based on 2016 commodity strip pricing as of May 5, 2016.

The applicable annual interest rates and the balances recognized on our balance sheet are as follows:

	Annual Interest Rate		As at	
($M)	Mar 31, 2016	Dec 31, 2015	Mar 31, 2016	Dec 31, 2015
Revolving credit facility	**3.3%**	3.1%	**1,429,988**	1,162,998
Senior unsecured notes	**6.5%**	6.5%	**-**	224,901
Long-term debt	**3.5%**	3.7%	**1,429,988**	1,387,899

Revolving Credit Facility

The following table outlines the current terms of our revolving credit facility:

	As at	
	Mar 31, 2016	Dec 31, 2015
Total facility amount	**$2.0 billion**	$2.0 billion
Amount drawn	**$1.4 billion**	$1.2 billion
Letters of credit outstanding	**$24.7 million**	$25.2 million
Facility maturity date	**31-May-19**	31-May-19

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

		As at	
Financial covenant	Limit	Mar 31, 2016	Dec 31, 2015
Consolidated total debt to consolidated EBITDA	4.0	**2.47**	2.23
Consolidated total senior debt to consolidated EBITDA	3.0	**2.42**	1.83
Consolidated total senior debt to total capitalization	50%	**45%**	36%

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

- Consolidated total debt: Includes all amounts classified as "Long-term debt", "Current portion of long-term debt", and "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.

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

	As at	
($M)	Mar 31, 2016	Dec 31, 2015
Long-term debt	**1,429,988**	1,162,998
Current liabilities (1)	**221,225**	503,731
Current assets	**(284,150)**	(284,778)
Net debt	**1,367,063**	1,381,951
Ratio of net debt to annualized fund flows from operations	**3.6**	2.7

(1) Current liabilities at December 31, 2015 includes $224,901 relating to the current portion of long-term debt.

As at March 31, 2016, long term debt, including the current portion, increased to $1.43 billion (December 31, 2015 - $1.39 billion) as a result of draws on the revolving credit facility during the current year to fund capital expenditures. The increase in long-term debt was offset by working capital changes, such that net debt remained relatively consistent at $1.37 billion. Weaker commodity prices versus the prior periods decreased fund flows from operations, resulting in the ratio of net debt to annualized fund flows from operations increasing.

Shareholders' capital
During the three months ended March 31, 2016, we maintained monthly dividends at $0.215 per share and declared dividends which totalled $72.8 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 dividend reinvestment plan 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 expect to be able to maintain our current dividend, fund flows from operations may not be sufficient during this low commodity price environment 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, 2015	111,991	2,181,089
Shares issued for the DRIP[1]	1,354	47,990
Shares issued for equity based compensation	106	4,128
Balance as at March 31, 2016	113,451	2,233,207

(1) DRIP Refers to Vermilion's dividend reinvestment and Premium Dividend™ plans.

As at March 31, 2016, there were approximately 1.7 million VIP awards outstanding. As at May 5, 2016, there were approximately 113.9 million common shares issued and outstanding.

ASSET RETIREMENT OBLIGATIONS

As at March 31, 2016, asset retirement obligations were $319.0 million compared to $305.6 million as at December 31, 2015.

The increase in asset retirement obligations is largely attributable to an overall decrease in the discount rates applied to the abandonment obligations, as well as accretion and additions from new wells drilled year-to-date.

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 March 31, 2016.

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

RISK MANAGEMENT

Vermilion is exposed to various market and operational risks. For a detailed discussion of these risks, please see Vermilion's Annual Report for the year ended December 31, 2015.

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 Vermilion's consolidated financial statements. Estimates are reviewed by management on an ongoing basis and as a result 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 that Vermilion operates in, the critical accounting estimates may affect one or more jurisdictions. There have been no material changes to our critical accounting estimates used in applying accounting policies for the three months ended March 31, 2016. Further information, including a discussion of critical accounting estimates, can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2015, available on SEDAR at www.sedar.com or on Vermilion's website at www.vermilionenergy.com.

INTERNAL CONTROL OVER FINANCIAL REPORTING

There was no change in Vermilion's internal control over financial reporting that occurred during the period covered by this MD&A that has materially affected, or is reasonably likely to materially affect, its internal control 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 March 31, 2016			Three Months Ended March 31, 2015		
	Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe
Canada						
Sales	33.11	1.93	**21.16**	49.15	2.97	35.81
Royalties	(4.03)	(0.08)	**(2.07)**	(5.87)	(0.23)	(3.95)
Transportation	(2.30)	(0.16)	**(1.57)**	(2.42)	(0.16)	(1.81)
Operating	(7.32)	(1.44)	**(8.05)**	(9.02)	(1.41)	(8.78)
Operating netback	19.46	0.25	**9.47**	31.84	1.17	21.27
General and administration			**(0.94)**			(1.85)
Fund flows from operations netback			**8.53**			19.42
France						
Sales	43.36	1.66	**43.16**	64.33	-	64.33
Royalties	(6.09)	(0.29)	**(6.07)**	(5.48)	-	(5.49)
Transportation	(3.35)	-	**(3.33)**	(3.24)	-	(3.24)
Operating	(12.84)	(2.24)	**(12.84)**	(11.64)	-	(11.64)
Operating netback	21.08	(0.87)	**20.92**	43.97	-	43.96
General and administration			**(4.19)**			(5.49)
Other income			**-**			34.16
Current income taxes			**(0.03)**			(15.35)
Fund flows from operations netback			**16.70**			57.28
Netherlands						
Sales	32.24	5.55	**33.26**	52.93	8.09	48.60
Royalties	-	(0.09)	**(0.56)**	-	(0.28)	(1.68)
Operating	-	(1.23)	**(7.28)**	-	(1.78)	(10.56)
Operating netback	32.24	4.23	**25.42**	52.93	6.03	36.36
General and administration			**(0.94)**			(1.34)
Current income taxes			**(2.68)**			(4.33)
Fund flows from operations netback			**21.80**			30.69
Germany						
Sales	-	5.30	**31.78**	-	7.53	45.21
Royalties	-	(0.60)	**(3.58)**	-	(1.06)	(6.34)
Transportation	-	(0.61)	**(3.67)**	-	(0.59)	(3.55)
Operating	-	(1.79)	**(10.71)**	-	(1.32)	(7.93)
Operating netback	-	2.30	**13.82**	-	4.56	27.39
General and administration			**(10.03)**			(6.38)
Fund flows from operations netback			**3.79**			21.01
Ireland						
Sales	-	5.51	**33.07**	-	-	-
Transportation	-	(0.53)	**(3.19)**	-	-	-
Operating	-	(1.18)	**(7.05)**	-	-	-
Operating netback	-	3.80	**22.83**	-	-	-
General and administration			**(2.31)**			-
Fund flows from operations netback			**20.52**			-
Australia						
Sales	46.93	-	**46.93**	83.80	-	83.80
Operating	(17.63)	-	**(17.63)**	(25.58)	-	(25.58)
PRRT (1)	(0.30)	-	**(0.30)**	(10.23)	-	(10.23)
Operating netback	29.00	-	**29.00**	47.99	-	47.99
General and administration			**(3.12)**			(6.32)
Corporate income taxes			**(1.83)**			(2.51)
Fund flows from operations netback			**24.05**			39.16

Supplemental Table 1: Netbacks (Continued)

	Three Months Ended March 31, 2016			Three Months Ended March 31, 2015		
	Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe
United States						
Sales	32.84	0.67	**30.10**	48.79	-	48.79
Royalties	(9.73)	(0.40)	**(9.03)**	(14.98)	-	(14.98)
Operating	(7.54)	-	**(6.82)**	(15.61)	-	(15.61)
Operating netback	15.57	0.27	**14.25**	18.20	-	18.20
General and administration			**(27.65)**			(78.41)
Fund flows from operations netback			**(13.40)**			(60.21)
Total Company						
Sales	39.35	3.76	**30.53**	58.25	5.26	47.17
Realized hedging gain	3.18	1.07	**4.89**	0.75	0.43	1.51
Royalties	(4.30)	(0.11)	**(2.40)**	(5.21)	(0.37)	(3.95)
Transportation	(2.33)	(0.22)	**(1.79)**	(2.49)	(0.34)	(2.30)
Operating	(11.10)	(1.37)	**(9.58)**	(11.61)	(1.51)	(10.56)
PRRT (1)	(0.05)	-	**(0.02)**	(0.97)	-	(0.57)
Operating netback	24.75	3.13	**21.63**	38.72	3.47	31.30
General and administration			**(2.34)**			(3.27)
Interest expense			**(2.54)**			(3.20)
Realized foreign exchange (loss) gain			**(0.11)**			0.78
Other income			**0.02**			7.70
Corporate income taxes (1)			**(0.54)**			(4.24)
Fund flows from operations netback			**16.12**			29.07

(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 March 31, 2016:

Crude Oil	Note	Volume	Strike Price(s)
WTI - Collar			
July 2015 - June 2016	1	500 bbls/d	75.50 - 85.08 CAD $
April 2016 - September 2016	1	500 bbls/d	52.25 - 64.40 CAD $
April 2016 - September 2016	2	750 bbls/d	40.50 - 50.40 US $
Dated Brent - Collar			
July 2015 - June 2016	3	1,000 bbls/d	80.50 - 93.49 CAD $
July 2015 - June 2016	4	500 bbls/d	64.50 - 75.48 US $
October 2015 - June 2016	5	250 bbls/d	82.00 - 94.55 CAD $
January 2016 - June 2016	6	250 bbls/d	84.00 - 93.70 CAD $
April 2016 - September 2016	5	250 bbls/d	52.00 - 64.80 CAD $

North American Natural Gas			
AECO - Collar			
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 $
March 2016 - December 2016	7	5,000 GJ/d	2.05 - 2.77 CAD $
April 2016 - October 2016		5,000 GJ/d	2.30 - 2.80 CAD $
April 2016 - December 2016	8	2,500 GJ/d	2.10 - 2.92 CAD $
November 2016 - October 2017	7	7,500 GJ/d	2.07 - 2.71 CAD $
November 2016 - December 2017		10,000 GJ/d	2.21 - 2.86 CAD $
January 2017 - December 2017		5,000 GJ/d	2.25 - 3.09 CAD $
AECO - Swap			
April 2016 - October 2016	9	5,000 GJ/d	2.59 CAD $

(1) The contracted volumes increase to 1,250 bbls/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).
(2) The contracted volumes increase to 2,000 bbls/d for any monthly settlement periods above the contracted ceiling price.
(3) The contracted volumes increase to 2,500 bbls/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).
(4) The contracted volumes increase to 1,000 bbls/d for any monthly settlement periods above the contracted ceiling price.
(5) The contracted volumes increase to 750 bbls/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).
(6) The contracted volumes increase to 500 bbls/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US$/bbl multiplied by the Bank of Canada monthly average noon day rate).
(7) The contracted volumes increase to 10,000 GJ/d for any monthly settlement periods above the contracted ceiling price.
(8) The contracted volumes increase to 7,500 GJ/d for any monthly settlement periods above the contracted ceiling price.
(9) On the last business day of each month, the counterparty has the option to increase the contracted volumes to 10,000 GJ/d at the contracted price, for the following month.

Supplemental Table 2: Hedges (Continued)

European Natural Gas	Note	Volume	Strike Price(s)
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 £
July 2016 - December 2016	1	2,638 GJ/d	2.84 - 4.08 GBP £
October 2016 - March 2017	2	2,638 GJ/d	3.13 - 3.53 GBP £
October 2016 - December 2017	2	2,638 GJ/d	2.84 - 3.70 GBP £
January 2017 - December 2017	1	5,275 GJ/d	3.13 - 3.62 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			
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 €
October 2016 - December 2016		2,638 GJ/d	3.24 GBP £
January 2017 - December 2017	3	2,638 GJ/d	4.00 GBP £
January 2018 - December 2018	4	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	5	2,592 GJ/d	5.76 - 6.50 EUR €
April 2016 - December 2016	6	12,960 GJ/d	5.58 - 6.21 EUR €
April 2016 - March 2017	7	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	5	2,592 GJ/d	5.07 - 6.56 EUR €
July 2016 - March 2018	5	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	8	7,776 GJ/d	5.00 - 6.15 EUR €
April 2017 - September 2017	5	2,592 GJ/d	3.61 - 4.24 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 - June 2016		2,592 GJ/d	6.07 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	5	2,592 GJ/d	5.04 EUR €

Fuel and Electricity			
GasOil - Swap			
March 2016 - December 2016		125 bbls/d	42.55 US $
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) The contracted volumes increase to 7,913 GJ/d for any monthly settlement periods above the contracted ceiling price.
(2) The contracted volumes increase to 5,275 GJ/d for any monthly settlement periods above the contracted ceiling price.
(3) 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.
(4) 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.
(5) The contracted volumes increase to 5,184 GJ/d for any monthly settlement periods above the contracted ceiling price.
(6) The contracted volumes increase to 15,552 GJ/d for any monthly settlement periods above the contracted ceiling price.
(7) The contracted volumes increase to 10,368 GJ/d for any monthly settlement periods above the contracted ceiling price.
(8) The contracted volumes increase to 18,144 GJ/d for any monthly settlement periods above the contracted ceiling price.

Supplemental Table 3: Capital Expenditures

By classification ($M)	Three Months Ended Mar 31, 2016	Dec 31, 2015	Mar 31, 2015
Drilling and development	**62,773**	128,996	174,311
Exploration and evaluation	**-**	-	-
Capital expenditures	**62,773**	128,996	174,311
Property acquisition	**870**	6,227	35
Acquisitions	**870**	6,227	35

By category ($M)	Three Months Ended Mar 31, 2016	Dec 31, 2015	Mar 31, 2015
Land	**1,039**	819	742
Seismic	**6,268**	4,217	1,493
Drilling and completion	**27,853**	58,327	82,343
Production equipment and facilities	**6,238**	55,662	74,755
Recompletions	**3,598**	6,338	7,115
Other	**17,777**	3,633	7,863
Capital expenditures	**62,773**	128,996	174,311
Acquisitions	**870**	6,227	35
Total capital expenditures and acquisitions	**63,643**	135,223	174,346

By country ($M)	Three Months Ended Mar 31, 2016	Dec 31, 2015	Mar 31, 2015
Canada	**30,526**	33,723	114,884
France	**13,463**	24,164	34,114
Netherlands	**2,996**	18,810	4,333
Germany	**539**	(441)	968
Ireland	**3,076**	12,493	12,955
Australia	**7,827**	40,852	6,455
United States	**5,216**	5,622	637
Total capital expenditures and acquisitions	**63,643**	135,223	174,346

Supplemental Table 4: Production

	Q1/16	Q4/15	Q3/15	Q2/15	Q1/15	Q4/14	Q3/14	Q2/14	Q1/14	Q4/13	Q3/13	Q2/13
Canada												
Crude oil & condensate (bbls/d)	**10,317**	10,413	11,030	11,843	12,163	12,681	12,755	14,108	10,390	8,719	7,969	8,885
NGLs (bbls/d)	**2,633**	2,710	2,678	2,094	1,706	1,444	1,005	1,364	1,118	1,699	1,897	1,725
Natural gas (mmcf/d)	**97.16**	87.90	71.94	64.66	61.78	58.36	57.07	57.59	49.53	41.43	43.40	43.69
Total (boe/d)	**29,141**	27,773	25,698	24,713	24,165	23,851	23,272	25,070	19,763	17,322	17,099	17,892
% of consolidated	**44%**	45%	47%	48%	48%	49%	47%	49%	42%	43%	41%	42%
France												
Crude oil (bbls/d)	**12,220**	12,537	12,310	12,746	11,463	11,133	11,111	11,025	10,771	11,131	11,625	10,390
Natural gas (mmcf/d)	**0.44**	1.36	1.47	1.03	-	-	-	-	-	-	5.23	4.19
Total (boe/d)	**12,293**	12,763	12,555	12,917	11,463	11,133	11,111	11,025	10,771	11,131	12,496	11,088
% of consolidated	**19%**	21%	22%	25%	23%	22%	22%	21%	23%	27%	30%	26%
Netherlands												
Condensate (bbls/d)	**114**	110	109	112	63	81	63	96	69	62	48	50
Natural gas (mmcf/d)	**53.40**	56.34	53.56	32.43	36.41	31.35	38.07	40.35	43.15	37.53	28.78	38.52
Total (boe/d)	**9,015**	9,500	9,035	5,517	6,132	5,306	6,407	6,822	7,260	6,318	4,845	6,470
% of consolidated	**14%**	16%	16%	11%	12%	11%	13%	13%	16%	15%	12%	15%
Germany												
Natural gas (mmcf/d)	**15.96**	16.17	14.00	16.18	16.80	17.71	15.38	16.13	10.64	-	-	-
Total (boe/d)	**2,660**	2,695	2,333	2,696	2,801	2,952	2,563	2,689	1,773	-	-	-
% of consolidated	**4%**	4%	4%	5%	6%	6%	5%	5%	4%	-	-	-
Ireland												
Natural gas (mmcf/d)	**33.90**	0.12	-	-	-	-	-	-	-	-	-	-
Total (boe/d)	**5,650**	20	-	-	-	-	-	-	-	-	-	-
% of consolidated	**9%**	-	-	-	-	-	-	-	-	-	-	-
Australia												
Crude oil (bbls/d)	**6,180**	7,824	6,433	5,865	5,672	6,134	6,567	6,483	7,110	6,189	7,070	7,363
% of consolidated	**9%**	13%	11%	11%	11%	12%	13%	12%	15%	15%	17%	17%
United States												
Crude oil (bbls/d)	**368**	420	226	123	153	195	-	-	-	-	-	-
NGLs (bbls/d)	**39**	29	-	-	-	-	-	-	-	-	-	-
Natural gas (mmcf/d)	**0.26**	0.20	-	-	-	-	-	-	-	-	-	-
Total (boe/d)	**450**	483	226	123	153	195	-	-	-	-	-	-
% of consolidated	**1%**	1%	-	-	-	-	-	-	-	-	-	-
Consolidated												
Crude oil, condensate & NGLs (bbls/d)	**31,871**	34,043	32,786	32,783	31,220	31,668	31,501	33,076	29,458	27,800	28,609	28,413
% of consolidated	**49%**	56%	58%	63%	62%	64%	63%	63%	63%	68%	69%	66%
Natural gas (mmcf/d)	**201.11**	162.09	140.97	114.29	115.00	107.42	110.52	114.08	103.32	78.96	77.41	86.40
% of consolidated	**51%**	44%	42%	37%	38%	36%	37%	37%	37%	32%	31%	34%
Total (boe/d)	**65,389**	61,058	56,280	51,831	50,386	49,571	49,920	52,089	46,677	40,960	41,510	42,813

Supplemental Table 4: Production (Continued)

	2016	2015	2014	2013	2012	2011
Canada						
Crude oil and condensate (bbls/d)	**10,317**	11,357	12,491	8,387	7,659	4,701
NGLs (bbls/d)	**2,633**	2,301	1,233	1,666	1,232	1,297
Natural gas (mmcf/d)	**97.16**	71.65	55.67	42.39	37.50	43.38
Total (boe/d)	**29,141**	25,598	23,001	17,117	15,142	13,227
% of consolidated	**44%**	46%	47%	41%	40%	38%
France						
Crude oil (bbls/d)	**12,220**	12,267	11,011	10,873	9,952	8,110
Natural gas (mmcf/d)	**0.44**	0.97	-	3.40	3.59	0.95
Total (boe/d)	**12,293**	12,429	11,011	11,440	10,550	8,269
% of consolidated	**19%**	23%	22%	28%	28%	23%
Netherlands						
Condensate (bbls/d)	**114**	99	77	64	67	58
Natural gas (mmcf/d)	**53.40**	44.76	38.20	35.42	34.11	32.88
Total (boe/d)	**9,015**	7,559	6,443	5,967	5,751	5,538
% of consolidated	**14%**	14%	13%	15%	15%	16%
Germany						
Natural gas (mmcf/d)	**15.96**	15.78	14.99	-	-	-
Total (boe/d)	**2,660**	2,630	2,498	-	-	-
% of consolidated	**4%**	5%	5%	-	-	-
Ireland						
Natural gas (mmcf/d)	**33.90**	0.03	-	-	-	-
Total (boe/d)	**5,650**	5	-	-	-	-
% of consolidated	**9%**	-	-	-	-	-
Australia						
Crude oil (bbls/d)	**6,180**	6,454	6,571	6,481	6,360	8,168
% of consolidated	**9%**	12%	13%	16%	17%	23%
United States						
Crude oil (bbls/d)	**368**	231	49	-	-	-
NGLs (bbls/d)	**39**	7	-	-	-	-
Natural gas (mmcf/d)	**0.26**	0.05	-	-	-	-
Total (boe/d)	**450**	247	49	-	-	-
% of consolidated	**1%**	-	-	-	-	-
Consolidated						
Crude oil, condensate & NGLs (bbls/d)	**31,871**	32,716	31,432	27,471	25,270	22,334
% of consolidated	**49%**	60%	63%	67%	67%	63%
Natural gas (mmcf/d)	**201.11**	133.24	108.85	81.21	75.20	77.21
% of consolidated	**51%**	40%	37%	33%	33%	37%
Total (boe/d)	**65,389**	54,922	49,573	41,005	37,803	35,202

Supplemental Table 5: Segmented Financial Results

	Three Months Ended March 31, 2016								
($M)	**Canada**	**France**	**Netherlands**	**Germany**	**Ireland**	**Australia**	**United States**	**Corporate**	**Total**
Total assets	1,584,947	833,145	195,413	159,522	838,240	240,352	44,585	176,136	4,072,340
Drilling and development	29,771	13,463	2,996	539	3,076	7,827	5,101	-	62,773
Oil and gas sales to external customers	56,110	48,125	27,286	7,692	17,004	19,935	1,233	-	177,385
Royalties	(5,498)	(6,766)	(460)	(867)	-	-	(370)	-	(13,961)
Revenue from external customers	50,612	41,359	26,826	6,825	17,004	19,935	863	-	163,424
Transportation	(4,151)	(3,713)	-	(887)	(1,639)	-	-	-	(10,390)
Operating	(21,343)	(14,320)	(5,976)	(2,593)	(3,626)	(7,491)	(279)	-	(55,628)
General and administration	(2,476)	(4,676)	(773)	(2,428)	(1,188)	(1,325)	(1,132)	421	(13,577)
PRRT	-	-	-	-	-	(128)	-	-	(128)
Corporate income taxes	-	(34)	(2,200)	-	-	(777)	-	(149)	(3,160)
Interest expense	-	-	-	-	-	-	-	(14,750)	(14,750)
Realized gain on derivative instruments	-	-	-	-	-	-	-	28,423	28,423
Realized foreign exchange loss	-	-	-	-	-	-	-	(652)	(652)
Realized other income	-	-	-	-	-	-	-	105	105
Fund flows from operations	22,642	18,616	17,877	917	10,551	10,214	(548)	13,398	93,667

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 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 drilling and development and exploration and evaluation costs (collectively referred to as 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 and Premium Dividend™ plans. 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 costs, exploration and evaluation costs, 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. Beginning in Q1 2016, the Corrib project is considered a producing asset, so these financial measures are not applicable for the current period.

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.

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

	Three Months Ended		
($M)	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015
Cash flows from operating activities	**73,883**	164,863	22,647
Changes in non-cash operating working capital	**17,760**	(33,343)	95,041
Asset retirement obligations settled	**2,024**	4,921	3,107
Fund flows from operations	**93,667**	136,441	120,795
Expenses related to Corrib	**N/A**	2,252	2,205
Fund flows from operations (excluding Corrib)	**N/A**	138,693	123,000

	Three Months Ended		
($M)	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015
Dividends declared	**72,847**	71,965	69,390
Shares issued for the DRIP[1]	**(47,990)**	(46,764)	(21,378)
Net dividends	**24,857**	25,201	48,012
Drilling and development	**62,773**	128,996	174,311
Asset retirement obligations settled	**2,024**	4,921	3,107
Payout	**89,654**	159,118	225,430
Corrib drilling and development	**N/A**	(12,493)	(12,955)
Payout (excluding Corrib)	**N/A**	146,625	212,475

(1) DRIP Refers to Vermilion's dividend reinvestment and Premium Dividend™ plans.

	As at		
('000s of shares)	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015
Shares outstanding	**113,451**	111,991	107,718
Potential shares issuable pursuant to the VIP	**3,040**	3,033	3,043
Diluted shares outstanding	**116,491**	115,024	110,761

CORPORATE INFORMATION

DIRECTORS

Lorenzo Donadeo [1]
Calgary, Alberta

Larry J. Macdonald [2, 3, 4, 5, 6]
Chairman & CEO, Point Energy Ltd.
Calgary, Alberta

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

Loren M. Leiker [6]
Houston, Texas

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

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

Anthony Marino
Calgary, Alberta

Sarah E. Raiss [4, 5]
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

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, condensate, natural gas liquids, and natural gas (converted on the basis of one boe for six mcf of natural gas)
boe/d	barrel of oil equivalent per day
btu	British thermal units
CGU	Cash generating unit, the basis upon which Vermilion's assets are evaluated for potential impairments
DRIP	Dividend Reinvestment Plan
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, which includes butane, propane, and ethane
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

OFFICERS AND KEY PERSONNEL

CANADA
Anthony Marino
President & Chief Executive Officer

John D. Donovan
Executive Vice President Business Development

Curtis W. Hicks
Executive Vice President & Chief Financial Officer

Mona Jasinski
Executive Vice President, People and Culture

Michael Kaluza
Executive Vice President & Chief Operating Officer

Dion Hatcher
Vice President Canada Business Unit

Terry Hergott
Vice President Marketing

Daniel Goulet
Director Corporate HSE

Bryce Kremnica
Director Field Operations – Canada Business Unit

Dean N. Morrison
Director Investor Relations

Mike Prinz
Director Information Technology & Information Systems

Jenson Tan
Director New Ventures

Robert (Bob) J. Engbloom
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
Vice President European Operations

Darcy Kerwin
Managing Director - France Business Unit

Scott Seatter
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
Managing Director - Australia Business Unit

AUDITORS

Deloitte LLP
Calgary, Alberta

BANKERS

The Toronto-Dominion Bank

Bank of Montreal

Canadian Imperial Bank of Commerce

National Bank of Canada

Royal Bank of Canada

The Bank of Nova Scotia

HSBC Bank Canada

La Caisse Centrale Desjardins du Québec

Wells Fargo Bank N.A., Canadian Branch

Alberta Treasury Branches

Bank of America N.A., Canada Branch

BNP Paribas, Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

Union Bank, Canada Branch

JPMorgan Chase Bank, N.A., Toronto Branch

Canadian Western Bank

Goldman Sachs Lending Partners LLC

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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.

VERMILION ENERGY

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