Q3 2016

MANAGEMENT'S DISCUSSION AND ANALYSIS

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VERMILION ENERGY

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is Management's Discussion and Analysis ("MD&A"), dated October 28, 2016, of Vermilion Energy Inc.'s ("Vermilion", "We", "Our", "Us" or the "Company") operating and financial results as at and for the three and nine months ended September 30, 2016 compared with the corresponding periods in the prior year.

This discussion should be read in conjunction with the unaudited condensed consolidated interim financial statements for the three and nine months ended September 30, 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 and nine months ended September 30, 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 and performance measures which do not have standardized meanings prescribed by International Financial Reporting Standards ("IFRS"). These measures include:

(1) Fund flows from operations: Fund flows from operations is a measure of profit or loss in accordance with IFRS 8 "Operating Segments". Please see SEGMENTED INFORMATION in the NOTES TO THE CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS for a reconciliation of fund flows from operations to net earnings. We analyze fund flows from operations both on a consolidated basis and on a business unit basis in order to assess the contribution of each business unit to our ability to generate income necessary to pay dividends, repay debt, fund asset retirement obligations and make capital investments.

(2) Netbacks: Netbacks are per boe and per mcf performance measures used in the analysis of operational activities. We assess netbacks both on a consolidated basis and on a business unit basis in order to compare and assess the operational and financial performance of each business unit versus other business units and also versus third party crude oil and natural gas producers.

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

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.

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.

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 reduced 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 reflected lower expected non-operated drilling activity in Canada, fewer workovers in France, and a deferral of our Netherlands pipeline twinning program. On August 8, 2016, we modestly increased our 2016 capital expenditure guidance to $240 million with the reinstatement of a four-well drilling program in the Champotran field in France and added drilling activity in Canada, partially offset by capital cost savings achieved to date.

We released our 2017 capital budget and related guidance concurrent with the release of our Q3 2016 results.

The following table summarizes our 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
2016 Guidance	August 8, 2016	240	62,500 to 63,500
2017 Guidance			
2017 Guidance	October 31, 2016	295	69,000 to 70,000

CONSOLIDATED RESULTS OVERVIEW

	Three Months Ended			% change		Nine Months Ended		% change
	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Q3/16 vs. Q2/16	Q3/16 vs. Q3/15	Sep 30, 2016	Sep 30, 2015	2016 vs. 2015
Production								
Crude oil and condensate (bbls/d)	27,842	28,416	30,108	(2%)	(8%)	28,483	30,106	(5%)
NGLs (bbls/d)	2,478	2,713	2,678	(9%)	(7%)	2,621	2,163	21%
Natural gas (mmcf/d)	199.66	198.93	140.97	-	42%	199.90	123.51	62%
Total (boe/d)	63,596	64,285	56,280	(1%)	13%	64,421	52,854	22%
Build (draw) in inventory (mbbls)	(209)	70	(85)			3	177	
Financial metrics								
Fund flows from operations ($M)	140,974	126,568	129,435	11%	9%	361,209	379,726	(5%)
Per share ($/basic share)	1.21	1.10	1.17	10%	3%	3.14	3.48	(10%)
Net loss	(14,475)	(55,696)	(83,310)	(74%)	(83%)	(156,019)	(75,222)	107%
Per share ($/basic share)	(0.12)	(0.48)	(0.76)	(75%)	(84%)	(1.36)	(0.69)	97%
Net debt ($M)	1,343,923	1,398,950	1,363,043	(4%)	(1%)	1,343,923	1,363,043	(1%)
Cash dividends ($/share)	0.645	0.645	0.645	-	-	1.935	1.935	-
Activity								
Capital expenditures ($M)	41,039	71,714	93,381	(43%)	(56%)	175,526	357,865	(51%)
Acquisitions ($M)	10,391	8,550	22,155	22%	(53%)	19,811	22,670	(13%)
Gross wells drilled	6.00	4.00	11.00			22.00	45.00	
Net wells drilled	2.08	3.14	6.91			13.48	30.56	

Operational review

- Achieved consolidated average production of 63,596 boe/d in Q3 2016, a 1% decrease from Q2 2016 due to lower production in Canada, France, and the Netherlands, which was largely offset by increased production in Ireland and Australia.
- Increased consolidated average production for the three and nine months ended September 30, 2016, by 13% and 22%, versus the comparable periods in 2015. These increases were primarily due to the addition of Corrib production in Ireland. The increase for the nine months ended September 30, 2016, was also due to production increases in Canada and the Netherlands.
- Executed capital expenditures totaling $41.0 million, primarily in France, Australia, Canada, and the Netherlands. In France, capital expenditures of $11.1 million were incurred related to a number of workover and optimization programs in the Aquitaine and Paris basins. In Australia, capital expenditures of $6.9 million were incurred as we continued to advance our Wandoo Platforms Life Extension project during the quarter. Capital expenditures of $10.4 million and $6.4 million were incurred in Canada and the Netherlands, respectively, related largely to drilling activity.

Financial review

Net loss

- The net loss for Q3 2016 was $14.5 million ($0.12/basic share), compared to a net loss of $55.7 million ($0.48/basic share) in Q2 2016. The decrease in the net loss was primarily attributable to higher revenues as a result of higher sales volumes.
- The net loss for Q3 2016 was $14.5 million, compared to a net loss of $83.3 million in Q3 2015. The change was a result of the absence of a non-cash impairment charge recognized in Q3 2015, partially offset by lower unrealized gains on derivative instruments.
- The net loss for the nine months ended September 30, 2016 of $156.0 million is compared to a net loss of $75.2 million for the 2015 period. The change was a result of lower commodity prices and the absence of a $31.8 million court-awarded recovery recognized in Q1 2015.

Fund flows from operations

- Generated fund flows from operations of $141.0 million during Q3 2016, an increase of 11% from Q2 2016. This quarter-over-quarter increase was primarily attributable to higher sales volumes in Australia, France, and Ireland, as well as stronger AECO natural gas prices in Canada.
- Fund flows from operations increased by 9% in Q3 2016 as compared to Q3 2015 as revenue from Ireland, coupled with lower operating expenses, taxes and royalties, more than offset lower commodity prices. For the nine months ended September 30, 2016, fund flows from operations decreased by 5% as compared to the corresponding period in 2015, largely due to lower commodity prices, partially offset by higher production volumes in Australia and Ireland and an 18% reduction in per unit operating expenses.

Net debt

- Net debt decreased to $1.34 billion from $1.40 billion at June 30, 2016 as fund flows from operations generated in excess of capital expenditures, abandonment expenditures, net dividends, and minor acquisitions was used to reduce net debt.

Dividends

- Declared dividends of $0.215 per common share per month during the third quarter of 2016, totalling $1.935 per common share for the nine months ended September 30, 2016.

COMMODITY PRICES

	Three Months Ended			% change		Nine Months Ended		% change
	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Q3/16 vs. Q2/16	Q3/16 vs. Q3/15	Sep 30, 2016	Sep 30, 2015	2016 vs. 2015
Average reference prices								
Crude oil								
WTI (US $/bbl)	44.94	45.59	46.43	(1%)	(3%)	41.33	51.00	(19%)
Edmonton Sweet index (US $/bbl)	42.06	42.51	43.01	(1%)	(2%)	38.11	46.64	(18%)
Dated Brent (US $/bbl)	45.85	45.57	50.26	1%	(9%)	41.77	55.39	(25%)
Natural gas								
AECO ($/mmbtu)	2.32	1.40	2.90	66%	(20%)	1.85	2.77	(33%)
TTF ($/mmbtu)	5.43	5.61	8.48	(3%)	(36%)	5.58	8.52	(35%)
TTF (€/mmbtu)	3.73	3.86	5.82	(3%)	(36%)	3.78	6.07	(38%)
NBP ($/mmbtu)	5.29	5.78	8.40	(8%)	(37%)	5.69	8.62	(34%)
NBP (€/mmbtu)	3.63	3.97	5.77	(9%)	(37%)	3.85	6.14	(37%)
Henry Hub ($/mmbtu)	3.67	2.52	3.62	46%	1%	3.03	3.52	(14%)
Henry Hub (US $/mmbtu)	2.81	1.95	2.77	44%	1%	2.29	2.80	(18%)
Average foreign currency exchange rates								
CDN $/US $	1.31	1.29	1.31	2%	-	1.32	1.26	5%
CDN $/Euro	1.46	1.46	1.46	-	-	1.48	1.40	6%
Average realized prices ($/boe)								
Canada	28.75	25.39	32.78	13%	(12%)	24.89	36.34	(32%)
France	55.88	57.82	60.96	(3%)	(8%)	52.26	65.66	(20%)
Netherlands	31.80	31.77	49.42	-	(36%)	32.31	48.70	(34%)
Germany	30.47	28.94	44.36	5%	(31%)	30.45	44.30	(31%)
Ireland	28.68	32.59	-	(12%)	100%	31.04	-	100%
Australia	60.61	61.53	68.20	(1%)	(11%)	57.51	76.46	(25%)
United States	44.53	46.80	51.60	(5%)	(14%)	40.78	52.95	(23%)
Consolidated	38.40	36.83	46.56	4%	(18%)	35.29	49.48	(29%)
Production mix (% of production)								
% priced with reference to WTI	19%	20%	24%			20%	26%	
% priced with reference to AECO	20%	22%	22%			22%	21%	
% priced with reference to TTF and NBP	32%	29%	20%			29%	18%	
% priced with reference to Dated Brent	29%	29%	34%			29%	35%	

- Q3 2016 was a volatile quarter for oil benchmarks that ended with prices largely unchanged quarter-over-quarter. The impact of continued reductions in non-OPEC supply and above-trend demand growth was offset by record high output from OPEC, including the partial return of Libyan and Nigerian volumes.
- Natural gas prices at AECO increased by 66% as compared to Q2 2016, as the warmer-than-normal summer in the United States boosted demand for Canadian natural gas. Despite the rise in AECO prices over Q2 2016, AECO decreased by 20% as compared to Q3 2015 as a result of high storage levels and strong Canadian production.
- Ample supply and coal-to-gas switching economics resulted in European natural gas price declines quarter-over-quarter, with TTF down 3% and NBP down 8% in Q3 2016 versus Q2 2016.
- In Q3 2016, the Canadian dollar was relatively consistent versus both the US dollar and Euro compared to Q2 2016 and Q3 2015, respectively.

FUND FLOWS FROM OPERATIONS

	Three Months Ended						Nine Months Ended			
	Sep 30, 2016		Jun 30, 2016		Sep 30, 2015		Sep 30, 2016		Sep 30, 2015	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Petroleum and natural gas sales	232,660	38.40	212,855	36.83	245,051	46.56	622,900	35.29	705,267	49.48
Royalties	(12,969)	(2.14)	(12,355)	(2.14)	(17,100)	(3.25)	(39,285)	(2.23)	(49,635)	(3.48)
Petroleum and natural gas revenues	219,691	36.26	200,500	34.69	227,951	43.31	583,615	33.06	655,632	46.00
Transportation	(9,696)	(1.60)	(9,860)	(1.71)	(11,090)	(2.11)	(29,946)	(1.70)	(31,513)	(2.21)
Operating	(54,825)	(9.05)	(52,116)	(9.02)	(57,826)	(10.99)	(162,569)	(9.21)	(160,293)	(11.25)
General and administration	(12,295)	(2.03)	(15,493)	(2.68)	(13,088)	(2.49)	(41,365)	(2.34)	(41,153)	(2.89)
PRRT	272	0.04	(144)	(0.02)	(99)	(0.02)	-	-	(5,824)	(0.41)
Corporate income taxes	(3,546)	(0.59)	(5,564)	(0.96)	(12,383)	(2.35)	(12,270)	(0.70)	(47,350)	(3.32)
Interest expense	(14,150)	(2.34)	(13,647)	(2.36)	(15,420)	(2.93)	(42,547)	(2.41)	(43,268)	(3.04)
Realized gain on derivative instruments	13,532	2.23	21,501	3.72	10,854	2.06	63,456	3.60	20,192	1.42
Realized foreign exchange gain	2,073	0.34	1,329	0.23	309	0.06	2,750	0.16	875	0.06
Realized other (expense) income	(82)	(0.01)	62	0.01	227	0.04	85	-	32,428	2.28
Fund flows from operations	140,974	23.25	126,568	21.90	129,435	24.58	361,209	20.46	379,726	26.64

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

($M)	Q3/16 vs. Q2/16	Q3/16 vs. Q3/15	2016 vs. 2015
Fund flows from operations – Comparative period	126,568	129,435	379,726
Sales volume variance:			
Canada	(3,556)	(8,195)	(5,807)
France	6,010	(4,819)	2,596
Netherlands	(503)	(4,602)	20,498
Germany	156	345	(1,341)
Ireland	2,705	26,065	66,429
Australia	11,803	11,125	16,121
United States	(304)	746	2,815
Pricing variance on sales volumes:			
WTI	(1,290)	(1,334)	(34,348)
AECO	7,498	(3,499)	(24,178)
Dated Brent	(3,061)	(12,127)	(78,121)
TTF and NBP	347	(16,096)	(47,031)
Changes in:			
Royalties	(614)	4,131	10,350
Transportation	164	1,394	1,567
Operating	(2,709)	3,001	(2,276)
General and administration	3,198	793	(212)
PRRT	416	371	5,824
Corporate income taxes	2,018	8,837	35,080
Interest	(503)	1,270	721
Realized derivatives	(7,969)	2,678	43,264
Realized foreign exchange	744	1,764	1,875
Realized other income	(144)	(309)	(32,343)
Fund flows from operations – Current period	140,974	140,974	361,209

Generated fund flows from operations of $141.0 million during Q3 2016, an increase of 11% from Q2 2016. This quarter-over-quarter increase was primarily attributable to higher sales volumes in Australia, France, and Ireland, as well as stronger AECO natural gas prices in Canada.

Fund flows from operations increased by 9% in Q3 2016 as compared to Q3 2015 as revenue from Ireland, coupled with lower operating expenses, taxes and royalties, more than offset lower commodity prices. For the nine months ended September 30, 2016, fund flows from operations decreased by 5% as compared to the corresponding period in 2015, largely due to lower commodity prices, partially offset by higher production volumes in Australia and Ireland and an 18% reduction in per unit operating expenses.

Fluctuations in fund flows from operations and net income 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 significantly 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.

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 with no investment at present
- Canadian cash flows are fully tax-sheltered for the foreseeable future.

Operational and financial review

	Three Months Ended			% change		Nine Months Ended		% change
Canada business unit ($M except as indicated)	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Q3/16 vs. Q2/16	Q3/16 vs. Q3/15	Sep 30, 2016	Sep 30, 2015	2016 vs. 2015
Production								
Crude oil and condensate (bbls/d)	8,984	9,453	11,030	(5%)	(19%)	9,582	11,674	(18%)
NGLs (bbls/d)	2,448	2,687	2,678	(9%)	(9%)	2,589	2,163	20%
Natural gas (mmcf/d)	77.62	87.44	71.94	(11%)	8%	87.37	66.16	32%
Total (boe/d)	24,368	26,713	25,698	(9%)	(5%)	26,732	24,864	8%
Production mix (% of total)								
Crude oil and condensate	37%	35%	43%			36%	47%	
NGLs	10%	10%	10%			10%	9%	
Natural gas	53%	55%	47%			54%	44%	
Activity								
Capital expenditures	10,421	5,619	37,224	85%	(72%)	45,811	173,954	(74%)
Acquisitions	10,380	796	8,062			11,931	8,481	
Gross wells drilled	4.00	2.00	11.00			18.00	37.00	
Net wells drilled	1.20	1.14	6.91			10.60	23.45	
Financial results								
Sales	64,453	61,731	77,493	4%	(17%)	182,294	246,661	(26%)
Royalties	(4,817)	(3,770)	(6,638)	28%	(27%)	(14,085)	(20,998)	(33%)
Transportation	(3,978)	(3,759)	(4,131)	6%	(4%)	(11,888)	(12,542)	(5%)
Operating	(15,579)	(16,460)	(23,877)	(5%)	(35%)	(53,382)	(64,510)	(17%)
General and administration	(3,010)	(4,305)	(3,694)	(30%)	(19%)	(9,791)	(13,219)	(26%)
Fund flows from operations	37,069	33,437	39,153	11%	(5%)	93,148	135,392	(31%)
Netbacks ($/boe)								
Sales	28.75	25.39	32.78	13%	(12%)	24.89	36.34	(32%)
Royalties	(2.15)	(1.55)	(2.81)	39%	(23%)	(1.92)	(3.09)	(38%)
Transportation	(1.77)	(1.55)	(1.75)	14%	1%	(1.62)	(1.85)	(12%)
Operating	(6.95)	(6.77)	(10.10)	3%	(31%)	(7.29)	(9.50)	(23%)
General and administration	(1.34)	(1.77)	(1.56)	(24%)	(14%)	(1.34)	(1.95)	(31%)
Fund flows from operations netback	16.54	13.75	16.56	20%	-	12.72	19.95	(36%)
Realized prices								
Crude oil and condensate ($/bbl)	53.96	56.67	56.95	(5%)	(5%)	49.75	58.99	(16%)
NGLs ($/bbl)	12.49	9.56	2.73	31%	358%	9.73	11.35	(14%)
Natural gas ($/mmbtu)	2.39	1.34	2.88	78%	(17%)	1.87	2.88	(35%)
Total ($/boe)	28.75	25.39	32.78	13%	(12%)	24.89	36.34	(32%)
Reference prices								
WTI (US $/bbl)	44.94	45.59	46.43	(1%)	(3%)	41.33	51.00	(19%)
Edmonton Sweet index (US $/bbl)	42.06	42.51	43.01	(1%)	(2%)	38.11	46.64	(18%)
Edmonton Sweet index ($/bbl)	54.89	54.78	56.32	-	(3%)	50.41	58.77	(14%)
AECO ($/mmbtu)	2.32	1.40	2.90	66%	(20%)	1.85	2.77	(33%)

Production

- Q3 2016 average production in Canada decreased by 9% quarter-over-quarter and 5% year-over-year due to production declines, the impact of a voluntary curtailment of natural gas-weighted production in response to low AECO prices and weather related power outages impacting Saskatchewan production. The year-over-year decrease was partially offset by organic production growth in our Mannville condensate-rich gas resource play.
- Cardium production averaged approximately 6,600 boe/d in Q3 2016, a 2% decrease quarter-over-quarter.
- Mannville production averaged approximately 10,200 boe/d in Q3 2016 representing an 11% decrease quarter-over-quarter and an increase of 48% from Q3 2015 production of approximately 6,900 boe/d.
- Production from our southeast Saskatchewan assets averaged approximately 2,400 boe/d in Q3 2016, a decrease of 15% quarter-over-quarter due to major power outages largely related to weather.

Activity review

- Vermilion participated in the drilling of four (1.2 net) non-operated wells during Q3 2016.

  Cardium

  - Prior to Q3 2016, one (0.1 net) non-operated well was drilled and three (0.5 net) non-operated wells were brought on production, completing our planned activity for the year.

  Mannville

  - During Q3 2016, we participated in the drilling of four (1.2 net) non-operated wells and two (0.7 net) non-operated wells were brought on production.
  - In 2016, we plan to drill or participate in 17 (10.6 net) wells; ten (5.0 net) wells have been drilled to date.

  Saskatchewan

  - Prior to Q3 2016, we drilled four (4.0 net) operated wells and participated in three (1.5 net) non-operated wells. We plan to complete and bring the four operated wells on production in Q1 2017. The non-op wells were brought on production during the first half of 2016.
  - We have drilled and participated in seven (5.5 net) wells, completing our 2016 planned capital activity.

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.
- Q3 2016 sales per boe increased versus Q2 2016 due to stronger AECO pricing.
- Sales per boe for the three and nine months ended September 30, 2016 decreased versus the comparable periods in 2015, largely as a result of lower crude oil and natural gas pricing.

Royalties

- Royalties as a percentage of sales for Q3 2016 increased to 7.5% as compared to 6.1% in Q2 2016 as a result of an annual favourable gas cost allowance adjustment in Alberta recorded in the second quarter of 2016.
- Royalties as a percentage of sales for the three and nine months ended September 30, 2016 decreased to 7.5% and 7.7% versus 8.6% and 8.5% for the comparable 2015 periods 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 Q3 2016 was lower than Q3 2015 due to lower production.
- Transportation expense for the nine months ended September 30, 2016 was lower than the same period in the prior year despite an 8% increase in production due to an increased gas weighting and lower per unit rates.

Operating

- Operating expenses were lower on a dollar basis for Q3 2016 versus Q2 2016 and Q3 2015. On a per unit basis, costs were relatively consistent with Q2 2016 and down 31% from Q3 2015 due to our ability to execute on cost-cutting initiatives, including service cost negotiations impacting numerous cost drivers.
- Year-over-year operating expense decreased 17% while we achieved an 8% increase in production, resulting in a 23% reduction in per unit expenses as a result of initiatives to reduce our cost structure.

General and administration

- General and administration expense fluctuation in Q3 2016 as compared to Q2 2016 was the result of expenditure timing.
- Year-over-year, general and administration expense for the nine months ended September 30, 2016 was 26% lower than the comparable period in 2015 due to 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.
- Low base decline producing assets comprised of large conventional oil fields with high working interests located in the Aquitaine and Paris Basins.
- Identified inventory of workover, infill drilling, and secondary recovery opportunities.

Operational and financial review

	Three Months Ended			% change		Nine Months Ended		% change
France business unit ($M except as indicated)	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Q3/16 vs. Q2/16	Q3/16 vs. Q3/15	Sep 30, 2016	Sep 30, 2015	2016 vs. 2015
Production								
Crude oil (bbls/d)	11,827	12,326	12,310	(4%)	(4%)	12,123	12,176	-
Natural gas (mmcf/d)	0.42	0.54	1.47	(22%)	(71%)	0.47	0.84	(44%)
Total (boe/d)	11,897	12,416	12,555	(4%)	(5%)	12,201	12,316	(1%)
Inventory (mbbls)								
Opening crude oil inventory	312	247	340			243	197	
Crude oil production	1,088	1,122	1,133			3,322	3,324	
Crude oil sales	(1,161)	(1,057)	(1,234)			(3,326)	(3,282)	
Closing crude oil inventory	239	312	239			239	239	
Activity								
Capital expenditures	11,110	12,772	17,369	(13%)	(36%)	37,345	68,180	(45%)
Acquisitions	-	-	142			-	238	
Gross wells drilled	-	-	-			-	4.00	
Net wells drilled	-	-	-			-	4.00	
Financial results								
Sales	65,221	61,591	76,552	6%	(15%)	174,937	218,011	(20%)
Royalties	(7,069)	(6,564)	(8,038)	8%	(12%)	(20,399)	(19,760)	3%
Transportation	(3,586)	(3,476)	(4,566)	3%	(21%)	(10,775)	(11,103)	(3%)
Operating	(12,933)	(11,265)	(11,998)	15%	8%	(38,518)	(34,926)	10%
General and administration	(4,590)	(4,734)	(5,338)	(3%)	(14%)	(14,000)	(15,323)	(9%)
Other income	-	-	-	-	-	-	31,775	(100%)
Current income taxes	955	(921)	(4,696)	(204%)	(120%)	-	(28,293)	(100%)
Fund flows from operations	37,998	34,631	41,916	10%	(9%)	91,245	140,381	(35%)
Netbacks ($/boe)								
Sales	55.88	57.82	60.96	(3%)	(8%)	52.26	65.66	(20%)
Royalties	(6.06)	(6.16)	(6.40)	(2%)	(5%)	(6.09)	(5.95)	2%
Transportation	(3.07)	(3.26)	(3.64)	(6%)	(16%)	(3.22)	(3.34)	(4%)
Operating	(11.08)	(10.57)	(9.55)	5%	16%	(11.51)	(10.52)	9%
General and administration	(3.93)	(4.44)	(4.25)	(11%)	(8%)	(4.18)	(4.61)	(9%)
Other income	-	-	-	-	-	-	9.57	(100%)
Current income taxes	0.82	(0.86)	(3.74)	(195%)	(122%)	-	(8.52)	(100%)
Fund flows from operations	32.56	32.53	33.38	-	(2%)	27.26	42.29	(36%)
Realized prices								
Crude oil ($/bbl)	56.14	58.19	61.75	(4%)	(9%)	52.53	66.26	(21%)
Natural gas ($/mmbtu)	1.58	1.58	2.93	-	(46%)	1.61	2.36	(32%)
Total ($/boe)	55.88	57.82	60.96	(3%)	(8%)	52.26	65.66	(20%)
Reference prices								
Dated Brent (US $/bbl)	45.85	45.57	50.26	1%	(9%)	41.77	55.39	(25%)
Dated Brent ($/bbl)	59.84	58.72	65.81	2%	(9%)	55.25	69.79	(21%)

Production

- Q3 2016 production decreased 4% versus the prior quarter and 5% versus Q3 2015 due to production declines, well downtime and third party restrictions impacting Vic Bilh gas production.

Activity review

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

Sales

- Crude oil in France is priced with reference to Dated Brent.
- Q3 2016 sales per boe was relatively consistent with Q2 2016.
- Sales per boe for the three and nine months ended September 30, 2016, decreased versus the comparable periods in 2015 as a result of lower crude oil pricing.

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 10.8% and 11.7% for the three and nine months ended September 30, 2016, consistent with the 10.7% realized in Q2 2016 and an increase over the comparable periods in 2015. These fluctuations in royalties as a percentage of sales were the result of fixed per unit RCDM royalties.

Transportation

- Transportation expense per boe for the three months ended September 30, 2016 decreased 6% and 16% respectively from Q2 2016 and Q3 2015 as a result of successful vessel cost renegotiations and a lower level of project activity at the Ambès terminal.
- Transportation expense per boe for the nine months ended September 30, 2016 decreased by 4% versus the comparable period in 2015 as a result of initiatives to reduce our cost structure.

Operating

- Operating expense on a dollar and per boe basis increased for the three and nine months ended September 30, 2016 versus the same periods in 2015. These increases were primarily due to increased project costs and timing of credits received on electricity charges. On a year-over-year basis, operating expenses were further impacted by unfavourable foreign exchange rates as the Canadian dollar weakened versus the Euro. After normalizing for the unfavourable foreign exchange, per unit costs have increased 4% for the nine months ended September 30, 2016.

General and administration

- General and administration expense for the three and nine months ended September 30, 2016 decreased by 14% and 9% respectively compared to the prior year due to cost reduction initiatives.

Current income taxes

- In France, current income taxes are applied to taxable income, after eligible deductions, at a statutory rate of 34.4% for 2016. For 2016, the effective rate on current taxes 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.
- Current income taxes in Q3 2016 were lower compared to Q2 2016 due to decreased forecasted revenues for the full year 2016. Q3 2016 current income taxes were lower compared to Q3 2015 due to decreased sales.
- Current income taxes for the nine months ended September 30, 2016 were lower versus the comparative period in 2015 as a result of decreased sales.

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 and financial review

	Three Months Ended			% change		Nine Months Ended		% change
Netherlands business unit ($M except as indicated)	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Q3/16 vs. Q2/16	Q3/16 vs. Q3/15	Sep 30, 2016	Sep 30, 2015	2016 vs. 2015
Production								
Condensate (bbls/d)	86	96	109	(10%)	(21%)	99	95	4%
Natural gas (mmcf/d)	47.62	49.18	53.56	(3%)	(11%)	50.06	40.86	23%
Total (boe/d)	8,023	8,293	9,035	(3%)	(11%)	8,442	6,905	22%
Activity								
Capital expenditures	6,441	8,566	5,297	(25%)	22%	18,003	28,515	(37%)
Gross wells drilled	2.00	-	-			2.00	2.00	
Net wells drilled	0.88	-	-			0.88	1.86	
Financial results								
Sales	23,470	23,973	41,083	(2%)	(43%)	74,729	91,814	(19%)
Royalties	(312)	(396)	(638)	(21%)	(51%)	(1,168)	(2,858)	(59%)
Operating	(4,854)	(4,306)	(5,243)	13%	(7%)	(15,136)	(16,483)	(8%)
General and administration	633	(1,223)	(2,154)	(152%)	(129%)	(1,363)	(3,345)	(59%)
Current income taxes	(1,264)	(3,260)	(4,487)	(61%)	(72%)	(6,724)	(9,222)	(27%)
Fund flows from operations	17,673	14,788	28,561	20%	(38%)	50,338	59,906	(16%)
Netbacks ($/boe)								
Sales	31.80	31.77	49.42	-	(36%)	32.31	48.70	(34%)
Royalties	(0.42)	(0.52)	(0.77)	(19%)	(45%)	(0.50)	(1.52)	(67%)
Operating	(6.58)	(5.71)	(6.31)	15%	4%	(6.54)	(8.74)	(25%)
General and administration	0.86	(1.62)	(2.59)	(153%)	(133%)	(0.59)	(1.77)	(67%)
Current income taxes	(1.71)	(4.32)	(5.40)	(60%)	(68%)	(2.91)	(4.89)	(40%)
Fund flows from operations netback	23.95	19.60	34.35	22%	(30%)	21.77	31.78	(31%)
Realized prices								
Condensate ($/bbl)	49.43	45.05	46.65	10%	6%	41.43	50.63	(18%)
Natural gas ($/mmbtu)	5.27	5.27	8.24	-	(36%)	5.37	8.11	(34%)
Total ($/boe)	31.80	31.77	49.42	-	(36%)	32.31	48.70	(34%)
Reference prices								
TTF ($/mmbtu)	5.43	5.61	8.48	(3%)	(36%)	5.58	8.52	(35%)
TTF (€/mmbtu)	3.73	3.86	5.82	(3%)	(36%)	3.78	6.07	(38%)

Production

- Q3 2016 production decreased 3% versus the prior quarter due to expected production curtailments pending approval to increase production rates at the conclusion of extended well testing being conducted at Slootdorp 06/07 and Diever-02. We expect the extended well tests to be completed, and the related approvals to be received, during the first half of 2017.
- Year-over-year production decreased 11%, as the Slootdorp-06/07 wells came on production in Q3 2015 at higher rates pursuant to the extended well test plan.
- Production in the Netherlands is actively managed to optimize facility use and regulate declines.

Activity review

- We completed our two-well drilling campaign in the Netherlands during the quarter. Langezwaag-3 encountered 17 meters of net pay in the Zechstein-2 carbonate formation. This well is being completed and is expected to be placed on production in November, at which time an in-line production test will be conducted. Andel-6ST encountered a large gas column of inadequate reservoir quality to justify completion. Potential remains to sidetrack this well to an updip location where higher quality gas zones may be encountered. The well has been suspended to allow us to reprocess seismic data to determine the viability of the potential updip target.

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.
- Q3 2016 sales per boe was consistent with Q2 2016, despite a slight decline in the TTF reference price, due to the timing of sales.
- Sales per boe for the three and nine months ended September 30, 2016 decreased versus the comparable periods in the prior year, consistent with a decrease in the TTF reference price.

Royalties

- In the Netherlands, we pay overriding royalties on certain wells. 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

- For the three months ended September 30, 2016 operating expense was higher on a dollar basis versus Q2 2016 and lower than Q3 2015. The increase from Q2 2016 was due to timing of project work and the decrease from Q3 2015 was due to initiatives to reduce our cost structure and lower volumes.
- For the nine months ended September 30, 2016 operating costs have decreased 8% as compared to the same period in the prior year. This decrease is primarily due to our ongoing focus on cost control, while increasing produced volumes by 22%, resulting in a per unit cost decrease of 25%.

General and administration

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

Current income taxes

- In the Netherlands, current income taxes are applied 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 Q3 2016 were lower compared to Q2 2016 due to increased tax deductions for current year capital expenditures. Q3 2016 current income taxes were lower compared to Q3 2015 mainly due to decreased sales.
- Current income taxes for the nine months ended September 30, 2016 were lower versus the comparative period in 2015 as a result of decreased sales in 2016 which offset tax deductions for capital expenditures in 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 operate 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 2015.
- During Q2 2016, Vermilion entered into a definitive purchase and sale agreement for operated and non-operated interests in five oil and three gas producing fields from Engie E&P Deutschland GmbH, for total consideration of €33 million ($47.9 million). Vermilion will assume operatorship of six of the eight producing fields. For 2016, the assets are expected to produce approximately 2,000 boe/d (50% oil). The acquisition has an effective date of January 1, 2016 and is anticipated to close in late Q4 2016.

Operational and financial review

	Three Months Ended			% change		Nine Months Ended		% change
Germany business unit ($M except as indicated)	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Q3/16 vs. Q2/16	Q3/16 vs. Q3/15	Sep 30, 2016	Sep 30, 2015	2016 vs. 2015
Production								
Natural gas (mmcf/d)	14.52	14.31	14.00	1%	4%	14.93	15.65	(5%)
Total (boe/d)	2,420	2,385	2,333	1%	4%	2,488	2,608	(5%)
Activity								
Capital expenditures	978	592	1,605	65%	(39%)	2,109	5,804	(64%)
Gross wells drilled	-	-	-			-	1.00	
Net wells drilled	-	-	-			-	0.25	
Financial results								
Sales	6,783	6,280	9,523	8%	(29%)	20,755	31,544	(34%)
Royalties	(246)	(964)	(1,477)	(74%)	(83%)	(2,077)	(5,313)	(61%)
Transportation	(556)	(1,051)	(627)	(47%)	(11%)	(2,494)	(2,761)	(10%)
Operating	(3,321)	(2,506)	(2,796)	33%	19%	(8,420)	(6,168)	37%
General and administration	(1,657)	(2,474)	(1,311)	(33%)	26%	(6,559)	(4,354)	51%
Fund flows from operations	1,003	(715)	3,312	(240%)	(70%)	1,205	12,948	(91%)
Netbacks ($/boe)								
Sales	30.47	28.94	44.36	5%	(31%)	30.45	44.30	(31%)
Royalties	(1.10)	(4.44)	(6.88)	(75%)	(84%)	(3.05)	(7.46)	(59%)
Transportation	(2.50)	(4.84)	(2.92)	(48%)	(14%)	(3.66)	(3.88)	(6%)
Operating	(14.92)	(11.55)	(13.03)	29%	15%	(12.35)	(8.66)	43%
General and administration	(7.44)	(11.40)	(6.11)	(35%)	22%	(9.62)	(6.12)	57%
Fund flows from operations netback	4.51	(3.29)	15.42	(237%)	(71%)	1.77	18.18	(90%)
Reference prices								
TTF ($/mmbtu)	5.43	5.61	8.48	(3%)	(36%)	5.58	8.52	(35%)
TTF (€/mmbtu)	3.73	3.86	5.82	(3%)	(36%)	3.78	6.07	(38%)

Production

- Q3 2016 production remained consistent with the prior quarter and Q3 2015.

Activity review

- In 2016, the majority of activity will be associated with permitting and pre-drill activities for the Burgmoor Z5 well. During Q3 2016, we continued our ongoing analysis of the proprietary geologic data associated with the farm-in assets and commenced integration activities associated with the Engie acquisition.

Sales

- The price of our natural gas in Germany is based on the TTF month-ahead index.
- Q3 2016 sales per boe increased versus Q2 2016, despite a slight decline in the TTF reference price, due to the timing of sales.
- Sales per boe for the three and nine months ended September 30, 2016 decreased versus the comparable periods in the prior year, 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.
- Royalties as a percentage of sales was 3.6% and 10.0% for the three and nine months ended September 30, 2016, a decrease from the 15.5% and 16.8% for the comparable periods in 2015. The decrease is due to favourable prior year adjustments impacting 2016.

Transportation

- Transportation expense in Germany relates to costs incurred to deliver natural gas from the processing facility to the customer.
- Q3 2016 transportation expense decreased from Q2 2016 on a total dollar and per unit basis due to an unfavourable prior year adjustment recorded in the second quarter of 2016.
- Transportation expense decreased by 11% and 10% for the three and nine months ended September 30, 2016 compared to the same periods in 2015 due to lower unfavourable prior year adjustments in 2016.

Operating

- Operating expenses for Germany primarily relate to tariffs charged for facility operations and gas processing.
- Operating expense for Q3 2016 increased versus Q2 2016 and Q3 2015 due to a full year 2015 adjustment recorded in the current quarter.
- Year-to-date Q3 2016 operating expense increased versus 2015 on a total dollar and per unit basis due to higher levels of project activity and the aforementioned 2015 adjustment recorded in the current quarter.

General and administration

- Q3 2016 general and administration expenses were lower than Q2 2016 due to lower head office allocations.
- General and administration costs for the three and nine months ended September 30, 2016 were higher compared to 2015 due to higher staffing levels and office costs incurred to support our farm-in agreement, as well as costs incurred to support asset acquisition activity.
- We expect per unit general and administration costs to improve as our production base in Germany grows.

Current income taxes

- Current income taxes in Germany are applied to taxable income, after eligible deductions, at a statutory tax rate of approximately 24.2%. As a function of Vermilion's tax basis in Germany, Vermilion does not presently pay income 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.
- Production volumes reached full plant capacity of approximately 65 mmcf/d (10,900 boe/d), net to Vermilion, at the end of Q2 2016.

Operational and financial review

Ireland business unit ($M except as indicated)	Three Months Ended Sep 30, 2016	Three Months Ended Jun 30, 2016	Three Months Ended Sep 30, 2015	% change Q3/16 vs. Q2/16	% change Q3/16 vs. Q3/15	Nine Months Ended Sep 30, 2016	Nine Months Ended Sep 30, 2015	% change 2016 vs. 2015
Production								
Natural gas (mmcf/d)	59.28	47.26	-	25%	100%	46.86	-	100%
Total (boe/d)	9,879	7,877	-	25%	100%	7,810	-	100%
Activity								
Capital expenditures	2,416	2,172	20,694	11%	(88%)	7,664	53,916	(86%)
Financial results								
Sales	26,065	23,360	-	12%	100%	66,429	-	100%
Transportation	(1,576)	(1,574)	(1,766)	-	(11%)	(4,789)	(5,107)	(6%)
Operating	(4,695)	(5,177)	-	(9%)	100%	(13,498)	-	100%
General and administration	(955)	(1,106)	(663)	(14%)	44%	(3,249)	(1,803)	80%
Fund flows from operations	18,839	15,503	(2,429)	22%	(876%)	44,893	(6,910)	(750%)
Netbacks ($/boe)								
Sales	28.68	32.59	-	(12%)	100%	31.04	-	100%
Transportation	(1.73)	(2.20)	-	(21%)	100%	(2.24)	-	100%
Operating	(5.17)	(7.22)	-	(28%)	100%	(6.31)	-	100%
General and administration	(1.05)	(1.54)	-	(32%)	100%	(1.52)	-	100%
Fund flows from operations netback	20.73	21.63	-	(4%)	100%	20.97	-	
Reference prices								
NBP ($/mmbtu)	5.29	5.78	8.40	(8%)	(37%)	5.69	8.62	(34%)
NBP (€/mmbtu)	3.63	3.97	5.77	(9%)	(37%)	3.85	6.14	(37%)

Production

- Natural gas began to flow from our Corrib gas project on December 30, 2015 and production volumes reached full plant capacity of approximately 65 mmcf/d (10,900 boe/d), net to Vermilion at the end of Q2 2016
- Production averaged 59 mmcf/d (9,879 boe/d) net to Vermilion during Q3 2016, an increase of 25% versus the prior quarter.
- Production results continued to benefit from better than expected well deliverability and minimal downtime.

Activity review

- Following the conclusion of a successful offshore work campaign in Q3 2016 that included laying a flowline to the P2 well, all six wells are now available for production.

Sales

- The price of our natural gas in Ireland is based on the NBP index.
- Q3 2016 sales per boe decreased relative to Q2 2016, consistent with a decrease in the NBP reference price.

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.
- Transportation expense for the three and nine months ended September 30, 2016 is lower versus the comparable periods in 2015, due to a decrease in the ship or pay obligation.

Operating

- Q3 2016 operating expense decreased on a dollar basis from Q2 2016 by 9% due to less project activity. Production increased 25% over this period resulting in a 28% decrease in per unit costs.

General and administration

- General and administrative expense for the three and nine months ended September 30, 2016 is higher versus the comparable periods in 2015 due to increased corporate support provided for production operations now underway.

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 five 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 and financial review

	Three Months Ended			% change		Nine Months Ended		% change
Australia business unit ($M except as indicated)	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Q3/16 vs. Q2/16	Q3/16 vs. Q3/15	Sep 30, 2016	Sep 30, 2015	2016 vs. 2015
Production								
Crude oil (bbls/d)	6,562	6,083	6,433	8%	2%	6,276	5,993	5%
Inventory (mbbls)								
Opening crude oil inventory	218	213	156			75	37	
Crude oil production	604	554	592			1,720	1,636	
Crude oil sales	(740)	(549)	(576)			(1,713)	(1,501)	
Closing crude oil inventory	82	218	172			82	172	
Activity								
Capital expenditures	6,908	39,939	7,966	(83%)	(13%)	54,674	20,889	162%
Gross wells drilled	-	2.00	-			2.00	-	
Net wells drilled	-	2.00	-			2.00	-	
Financial results								
Sales	44,835	33,713	39,325	33%	14%	98,483	114,813	(14%)
Operating	(13,011)	(12,100)	(13,766)	8%	(5%)	(32,602)	(37,735)	(14%)
General and administration	(1,289)	(1,788)	(1,391)	(28%)	(7%)	(4,402)	(3,986)	10%
PRRT	272	(144)	(99)	(289%)	(375%)	-	(5,824)	(100%)
Current income taxes	(2,916)	(1,126)	(2,720)	159%	7%	(4,819)	(8,431)	(43%)
Fund flows from operations	27,891	18,555	21,349	50%	31%	56,660	58,837	(4%)
Netbacks ($/boe)								
Sales	60.61	61.53	68.20	(1%)	(11%)	57.51	76.46	(25%)
Operating	(17.59)	(22.08)	(23.87)	(20%)	(26%)	(19.04)	(25.13)	(24%)
General and administration	(1.74)	(3.26)	(2.41)	(47%)	(28%)	(2.57)	(2.65)	(3%)
PRRT	0.37	(0.26)	(0.17)	(242%)	(318%)	-	(3.88)	(100%)
Current income taxes	(3.94)	(2.05)	(4.72)	92%	(17%)	(2.81)	(5.61)	(50%)
Fund flows from operations netback	37.71	33.88	37.03	11%	2%	33.09	39.19	(16%)
Reference prices								
Dated Brent (US $/bbl)	45.85	45.57	50.26	1%	(9%)	41.77	55.39	(25%)
Dated Brent ($/bbl)	59.84	58.72	65.81	2%	(9%)	55.25	69.79	(21%)

Production

- Q3 2016 production increased 8% quarter-over-quarter and 2% 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

- The two sidetrack wells we drilled during the prior quarter continued to demonstrate strong productive capability during Q3 with combined production rates exceeding 4,500 bbls/d when utilized. Vermilion intends to produce these wells intermittently to meet corporate production targets while seeking to optimize ultimate recoveries and oil pricing. Following our successful 2015 and 2016 drilling campaigns, we do not expect to drill any additional wells in Australia until 2019.
- Late in the third quarter, we commenced a planned 10-day maintenance shutdown. The scope of activities was completed as scheduled and production resumed on October 3, 2016.
- We continued to advance our Wandoo Platforms Life Extension project during the quarter.

Sales

- Crude oil in Australia is priced with reference to Dated Brent.
- Q3 2016 sales per boe were relatively consistent with Q2 2016.
- Sales per boe for the three and nine months ended September 30, 2016, decreased versus the comparable periods in 2015 due to weaker crude oil pricing. In both periods, this decline in price was partially offset by higher sales volumes, minimizing the impact on 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 increased from Q2 2016 primarily due to a 35% increase in volumes sold. On a per unit basis costs decreased by 20% primarily due to lower diesel costs.
- Year-over-year operating expense is down 5% and 14% for the three and nine months ended September 30, 2016 versus the comparable periods in 2015. These decreases have been achieved while growing production and sales through a continued focus on cost reduction initiatives, including reduced helicopter and vessel costs. As a result, per unit costs have decreased by 26% and 24% respectively for the three and nine months ended September 30, 2016 versus 2015.

General and administration

- Fluctuation in general and administration expense for the three and nine months ended September 30, 2016 versus the comparable periods in 2015 was largely a result of the timing of expenditures.

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 8% to 10% 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.
- Current income taxes in Q3 2016 were higher compared to Q2 2016 due to an increase in sales. Q3 2016 current income taxes were higher compared to Q3 2015 due to increased sales partially offset with higher tax deductions for capital expenditures.
- PRRT in Q3 2016 was relatively flat compared to Q2 2016 and Q3 2015 as sales were offset with capital expenditures.
- Current income taxes and PRRT for the nine months ended September 30, 2016 were lower versus the comparable period in 2015 as a result of decreased sales and higher tax deductions for capital expenditures.

UNITED STATES BUSINESS UNIT

Overview

- Entered the United States in September 2014.
- Interests include approximately 97,100 net acres of land (97% 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		Nine Months Ended		% change
United States business unit ($M except as indicated)	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Q3/16 vs. Q2/16	Q3/16 vs. Q3/15	Sep 30, 2016	Sep 30, 2015	2016 vs. 2015
Production								
Crude oil (bbls/d)	383	458	226	(16%)	69%	403	168	140%
NGLs (bbls/d)	30	26	-	15%	100%	32	-	100%
Natural gas (mmcf/d)	0.20	0.20	-	-	100%	0.21	-	100%
Total (boe/d)	447	518	226	(14%)	98%	472	168	181%
Activity								
Capital expenditures	2,765	1,636	3,226	69%	(14%)	9,502	6,607	44%
Acquisitions	11	5,432	12,785			5,558	12,785	
Gross wells drilled	-	-	-			-	1.00	
Net wells drilled	-	-	-			-	1.00	
Financial results								
Sales	1,833	2,207	1,075	(17%)	71%	5,273	2,424	118%
Royalties	(525)	(661)	(309)	(21%)	70%	(1,556)	(706)	120%
Operating	(432)	(302)	(146)	43%	196%	(1,013)	(471)	115%
General and administration	(918)	(697)	(896)	32%	2%	(2,747)	(2,939)	(7%)
Fund flows from operations	(42)	547	(276)	(108%)	(85%)	(43)	(1,692)	(97%)
Netbacks ($/boe)								
Sales	44.53	46.80	51.60	(5%)	(14%)	40.78	52.95	(23%)
Royalties	(12.74)	(14.02)	(14.83)	(9%)	(14%)	(12.03)	(15.42)	(22%)
Operating	(10.50)	(6.39)	(6.98)	64%	50%	(7.84)	(10.28)	(24%)
General and administration	(22.30)	(14.77)	(43.03)	51%	(48%)	(21.25)	(64.20)	(67%)
Fund flows from operations netback	(1.01)	11.62	(13.24)	(109%)	(92%)	(0.34)	(36.95)	(99%)
Realized prices								
Crude oil ($/bbl)	51.29	52.56	51.60	(2%)	(1%)	47.07	52.95	(11%)
NGLs ($/bbl)	5.14	3.25	-	58%	100%	4.49	-	100%
Natural gas ($/mmbtu)	0.64	0.37	-	73%	100%	0.57	-	100%
Total ($/boe)	44.53	46.80	51.60	(5%)	(14%)	40.78	52.95	(23%)
Reference prices								
WTI (US $/bbl)	44.94	45.59	46.43	(1%)	(3%)	41.33	51.00	(19%)
WTI ($/bbl)	58.65	58.75	60.80	-	(4%)	54.67	64.26	(15%)
Henry Hub (US $/mmbtu)	2.81	1.95	2.77	44%	1%	2.29	2.80	(18%)
Henry Hub ($/mmbtu)	3.67	2.52	3.62	46%	1%	3.03	3.52	(14%)

Production

- Q3 2016 production decreased 14% versus the prior quarter due to natural declines and downtime associated with the attempted repair of the Reed 17-1H well following a mechanical failure during the well's completion. The repair was unsuccessful in establishing communication with the remainder of the hydraulically-fractured horizontal lateral, and the well was returned to production during 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 (including severance and ad valorem taxes) as a percentage of sales are approximately 30% and has remained consistent across all periods.

Operating

- The increase in operating expense for Q3 2016 compared to Q2 2016 and Q3 2015 was primarily due to increased project activity and well repairs in the current quarter.
- On a year-over-year basis, per unit costs have decreased 24% due to production growth and initiatives to reduce our cost structure.

General and administration

- On a year-over-year basis cost-cutting initiatives have resulted in a 7% reduction in expenses.

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. Expenditures relating to our activities in Central and Eastern Europe are also included in the Corporate segment.

Financial review

CORPORATE ($M)	Three Months Ended Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Nine Months Ended Sep 30, 2016	Sep 30, 2015
General and administration (expense) recovery	(509)	834	2,359	746	3,816
Current income taxes	(321)	(257)	(480)	(727)	(1,404)
Interest expense	(14,150)	(13,647)	(15,420)	(42,547)	(43,268)
Realized gain on derivatives	13,532	21,501	10,854	63,456	20,192
Realized foreign exchange gain	2,073	1,329	309	2,750	875
Realized other (expense) income	(82)	62	227	85	653
Fund flows from operations	543	9,822	(2,151)	23,763	(19,136)

General and administration

- The fluctuations in general and administration costs for Q3 2016 versus all comparable periods is due to the timing of expenditures and allocations to the various business unit segments.

Current income taxes

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

Interest expense

- Interest expense in Q3 2016 was relatively consistent with Q2 2016.
- The decrease in interest expense for the three and nine months ended September 30, 2016, was 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 3.4%. This was partially offset by higher 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 for 2018 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 on derivatives in Q3 2016 related primarily to amounts received on our European natural gas hedges.
- A listing of derivative positions as at September 30, 2016 is included in "Supplemental Table 2" of this MD&A.

FINANCIAL PERFORMANCE REVIEW

	Three Months Ended							
($M except per share)	Sep 30, 2016	Jun 30, 2016	Mar 31, 2016	Dec 31, 2015	Sep 30, 2015	Jun 30, 2015	Mar 31, 2015	Dec 31, 2014
Petroleum and natural gas sales	232,660	212,855	177,385	234,319	245,051	264,331	195,885	306,073
Net (loss) earnings	(14,475)	(55,696)	(85,848)	(142,080)	(83,310)	6,813	1,275	58,642
Net (loss) earnings per share								
Basic	(0.12)	(0.48)	(0.76)	(1.28)	(0.76)	0.06	0.01	0.55
Diluted	(0.12)	(0.48)	(0.76)	(1.28)	(0.76)	0.06	0.01	0.54

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

	Three Months Ended			Nine Months Ended	
	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Sep 30, 2016	Sep 30, 2015
Fund flows from operations	140,974	126,568	129,435	361,209	379,726
Equity based compensation	(15,642)	(13,267)	(16,773)	(49,746)	(53,699)
Unrealized gain (loss) on derivative instruments	332	(72,436)	32,020	(63,050)	16,155
Unrealized foreign exchange gain (loss)	2,899	(2,804)	14,958	1,665	15,144
Unrealized other expense	(24)	(20)	(309)	(131)	(774)
Accretion	(6,341)	(6,025)	(6,199)	(18,475)	(17,587)
Depletion and depreciation	(143,556)	(131,793)	(148,843)	(401,147)	(350,946)
Deferred tax	6,883	44,081	55,401	28,418	79,759
Impairment	-	-	(143,000)	(14,762)	(143,000)
Net loss	(14,475)	(55,696)	(83,310)	(156,019)	(75,222)

The fluctuations in net income from period-to-period are caused by changes in both cash and non-cash based income and charges. Cash based items are reflected in fund flows from operations 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 Q3 2016 increased as compared to Q2 2016 due to a revision of performance estimates. For the three and nine months ended September 30, 2016, the decrease in equity based compensation is primarily due to the lower average grant value of outstanding awards.

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 well as the impact of contracts settled during the period. 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 nine months ended September 30, 2016, we recognized an unrealized loss on derivative instruments of $63.1 million. This unrealized loss resulted from realizing gains on derivatives for contracts settled during the period, coupled with higher forward prices for European natural gas as at September 30, 2016. As at September 30, 2016, we have a net derivative asset position of $5.3 million.

Unrealized foreign exchange gain or loss

As a result of Vermilion's international operations, Vermilion has monetary assets and liabilities denominated in currencies other than the Canadian dollar. These monetary assets and liabilities include cash, receivables, payables, long-term debt, derivative instruments and intercompany loans, primarily denominated in the US dollar and Euro.

Unrealized foreign exchange gains and losses result from translating these monetary assets and liabilities from their underlying currency to the functional currency 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 September 30, 2016, the Canadian dollar weakened more significantly against the Euro than the US dollar, resulting in an unrealized foreign exchange gain of $2.9 million. For the nine months ended September 30, 2016, the Canadian dollar strengthened more significantly against the US dollar than the Euro, resulting in an unrealized foreign exchange gain of $1.7 million.

Accretion

Accretion expense is recognized to update the present value of the asset retirement obligation balance. Fluctuations in accretion expense are primarily the result of changes in discount rates applicable to the balance of asset retirement obligations and changes in the balance of asset retirement obligations, including the impact of additions resulting from drilling and acquisitions.

Accretion expense was relatively consistent with all comparative periods.

Depletion and depreciation

Depletion and depreciation expense is recognized to allocate the capitalized cost of extracting natural resources and the cost of material assets over the useful life of the respective assets. 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 Q3 2016 of $23.69 was relatively consistent as compared to $22.80 in Q2 2016.

For the three and nine months ended September 30, 2016, depletion and depreciation on a per boe basis of $23.69 and $22.73 was lower than $28.28 and $24.62 in the same periods of 2015 due to increased production from our Mannville condensate-rich gas properties, which have lower per boe depletion.

Deferred tax

Deferred tax 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.

Impairment

In Q1 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 shortfall with debt (including borrowing using the unutilized capacity of our existing revolving credit facility), issue equity, or by reducing some or all categories of expenditures to ensure that total expenditures do not exceed available funds.

To ensure that we maintain a conservative balance sheet, we monitor the ratio of net debt to fund flows from operations 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 from operations 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 September 30, 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.

The balances recognized on our balance sheet are as follows:

	As at	
($M)	Sep 30, 2016	Dec 31, 2015
Revolving credit facility	1,312,652	1,162,998
Senior unsecured notes	-	224,901
Long-term debt	1,312,652	1,387,899

Revolving Credit Facility

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

	As at	
	Sep 30, 2016	Dec 31, 2015
Total facility amount	$2.0 billion	$2.0 billion
Amount drawn	$1.3 billion	$1.2 billion
Letters of credit outstanding	$21.0 million	$25.2 million
Facility maturity date	31-May-19	31-May-19

In addition, as at September 30, 2016, the revolving credit facility was subject to the following covenants:

		As at	
Financial covenant	Limit	Sep 30, 2016	Dec 31, 2015
Consolidated total debt to consolidated EBITDA	4.0	2.36	2.23
Consolidated total senior debt to total capitalization	55%	44%	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)	Sep 30, 2016	Dec 31, 2015
Long-term debt	1,312,652	1,162,998
Current liabilities [(1)]	246,498	503,731
Current assets	(215,227)	(284,778)
Net debt	1,343,923	1,381,951
Ratio of net debt to annualized fund flows from operations	2.8	2.7

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

As at September 30, 2016, long term debt decreased to $1.31 billion (December 31, 2015 - $1.39 billion, including the current portion of long-term debt) as fund flows from operations generated in excess of capital expenditures, abandonment expenditures, acquisitions, and cash dividends was used to reduce debt. The decrease in long-term debt was coupled with working capital changes, such that net debt decreased from $1.38 billion at December 31, 2015 to $1.34 billion at September 30, 2016. Weaker commodity prices versus the prior period decreased fund flows from operations, resulting in the ratio of net debt to annualized fund flows from operations increasing slightly from 2.7 to 2.8.

Shareholders' capital

During the nine months ended September 30, 2016, we maintained monthly dividends at $0.215 per share and declared dividends which totalled $223.0 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.

In February of 2015, we amended our existing dividend reinvestment plan to include a Premium Dividend™ Component. 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. Both components of our program can be reduced or eliminated at the company's discretion, offering considerable flexibility.

As previously announced, we commenced proration of the Premium Dividend™ of our Dividend Reinvestment Plan by 25% beginning with our October dividend payment. Eligible shareholders who have elected to participate in the Premium Dividend™ component are now receiving the 1.5% premium on 75% of their participating shares and the regular cash dividend on the remaining 25% of their shares. We expect to increase the proration factor by a further 25% beginning with the January 2017 dividend payment. Subject to unexpected changes in the commodity price outlook, we will continue to increase the proration during 2017, at the end of which there would be no further equity issuance under the Premium Dividend™ component of our Dividend Reinvestment Plan. We also intend to reduce the discount associated with our traditional Dividend Reinvestment Plan from 3% to 2%, beginning with the January 2017 dividend payment (subject to TSX approval).

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 shortfall with debt, issuances of equity, or by reducing some or all categories of expenditures to ensure that total expenditures do not exceed available funds.

The following table reconciles the change in shareholders' capital:

Shareholders' Capital	Number of Shares ('000s)	Amount ($M)
Balance as at December 31, 2015	111,991	2,181,089
Shares issued for the DRIP[(1)]	3,823	149,418
Vesting of equity based awards	1,320	67,146
Share-settled dividends on vested equity based awards	87	3,242
Shares issued for equity based compensation	165	6,700
Balance as at September 30, 2016	117,386	2,407,595

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

As at September 30, 2016, there were approximately 1.7 million VIP awards outstanding. As at October 28, 2016, there were approximately 117.7 million common shares issued and outstanding.

ASSET RETIREMENT OBLIGATIONS

As at September 30, 2016, asset retirement obligations were $344.0 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 obligation and accretion expense.

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 September 30, 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 nine months ended September 30, 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 September 30, 2016			Nine Months Ended September 30, 2016			Three Months Ended Sep 30, 2015	Nine Months Ended Sep 30, 2015
	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Total $/boe	Total $/boe
Canada								
Sales	45.08	2.39	28.75	41.23	1.87	24.89	32.78	36.34
Royalties	(3.64)	(0.14)	(2.15)	(3.85)	(0.05)	(1.92)	(2.81)	(3.09)
Transportation	(2.56)	(0.18)	(1.77)	(2.36)	(0.17)	(1.62)	(1.75)	(1.85)
Operating	(8.36)	(0.95)	(6.95)	(7.64)	(1.17)	(7.29)	(10.10)	(9.50)
Operating netback	30.52	1.12	17.88	27.38	0.48	14.06	18.12	21.90
General and administration			(1.34)			(1.34)	(1.56)	(1.95)
Fund flows from operations netback			16.54			12.72	16.56	19.95
France								
Sales	56.14	1.58	55.88	52.53	1.61	52.26	60.96	65.66
Royalties	(6.08)	(0.32)	(6.06)	(6.12)	(0.34)	(6.09)	(6.40)	(5.95)
Transportation	(3.09)	-	(3.07)	(3.24)	-	(3.22)	(3.64)	(3.34)
Operating	(11.06)	(2.55)	(11.08)	(11.49)	(2.35)	(11.51)	(9.55)	(10.52)
Operating netback	35.91	(1.29)	35.67	31.68	(1.08)	31.44	41.37	45.85
General and administration			(3.93)			(4.18)	(4.25)	(4.61)
Other income			-			-	-	9.57
Current income taxes			0.82			-	(3.74)	(8.52)
Fund flows from operations netback			32.56			27.26	33.38	42.29
Netherlands								
Sales	49.43	5.27	31.80	41.43	5.37	32.31	49.42	48.70
Royalties	-	(0.07)	(0.42)	-	(0.09)	(0.50)	(0.77)	(1.52)
Operating	-	(1.11)	(6.58)	-	(1.10)	(6.54)	(6.31)	(8.74)
Operating netback	49.43	4.09	24.80	41.43	4.18	25.27	42.34	38.44
General and administration			0.86			(0.59)	(2.59)	(1.77)
Current income taxes			(1.71)			(2.91)	(5.40)	(4.89)
Fund flows from operations netback			23.95			21.77	34.35	31.78
Germany								
Sales	-	5.08	30.47	-	5.07	30.45	44.36	44.30
Royalties	-	(0.18)	(1.10)	-	(0.51)	(3.05)	(6.88)	(7.46)
Transportation	-	(0.42)	(2.50)	-	(0.61)	(3.66)	(2.92)	(3.88)
Operating	-	(2.49)	(14.92)	-	(2.06)	(12.35)	(13.03)	(8.66)
Operating netback	-	1.99	11.95	-	1.89	11.39	21.53	24.30
General and administration			(7.44)			(9.62)	(6.11)	(6.12)
Fund flows from operations netback			4.51			1.77	15.42	18.18
Ireland								
Sales	-	4.78	28.68	-	5.17	31.04	-	-
Transportation	-	(0.29)	(1.73)	-	(0.37)	(2.24)	-	-
Operating	-	(0.86)	(5.17)	-	(1.05)	(6.31)	-	-
Operating netback	-	3.63	21.78	-	3.75	22.49	-	-
General and administration			(1.05)			(1.52)	-	-
Fund flows from operations netback			20.73			20.97	-	-
Australia								
Sales	60.61	-	60.61	57.51	-	57.51	68.20	76.46
Operating	(17.59)	-	(17.59)	(19.04)	-	(19.04)	(23.87)	(25.13)
PRRT (1)	0.37	-	0.37	-	-	-	(0.17)	(3.88)
Operating netback	43.39	-	43.39	38.47	-	38.47	44.16	47.45
General and administration			(1.74)			(2.57)	(2.41)	(2.65)
Corporate income taxes			(3.94)			(2.81)	(4.72)	(5.61)
Fund flows from operations netback			37.71			33.09	37.03	39.19

	Three Months Ended September 30, 2016			Nine Months Ended September 30, 2016			Three Months Ended Sep 30, 2015	Nine Months Ended Sep 30, 2015
	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Total $/bbl	Total $/boe
United States								
Sales	47.91	0.64	44.53	43.96	0.57	40.78	51.60	52.95
Royalties	(13.61)	(0.39)	(12.74)	(12.89)	(0.33)	(12.03)	(14.83)	(15.42)
Operating	(11.38)	-	(10.50)	(8.50)	-	(7.84)	(6.98)	(10.28)
Operating netback	22.92	0.25	21.29	22.57	0.24	20.91	29.79	27.25
General and administration			(22.30)			(21.25)	(43.03)	(64.20)
Fund flows from operations netback			(1.01)			(0.34)	(13.24)	(36.95)
Total Company								
Sales	53.24	3.98	38.40	48.95	3.76	35.29	46.56	49.48
Realized hedging gain	0.40	0.67	2.23	1.77	0.88	3.60	2.06	1.42
Royalties	(3.80)	(0.09)	(2.14)	(4.08)	(0.08)	(2.23)	(3.25)	(3.48)
Transportation	(2.09)	(0.19)	(1.60)	(2.19)	(0.21)	(1.70)	(2.11)	(2.21)
Operating	(11.70)	(1.08)	(9.05)	(11.42)	(1.19)	(9.21)	(10.99)	(11.25)
PRRT [(1)]	0.09	-	0.04	-	-	-	(0.02)	(0.41)
Operating netback	36.14	3.29	27.88	33.03	3.16	25.75	32.25	33.55
General and administration			(2.03)			(2.34)	(2.49)	(2.89)
Interest expense			(2.34)			(2.41)	(2.93)	(3.04)
Realized foreign exchange gain			0.34			0.16	0.06	0.06
Other (expense) income			(0.01)			-	0.04	2.28
Corporate income taxes [(1)]			(0.59)			(0.70)	(2.35)	(3.32)
Fund flows from operations netback			23.25			20.46	24.58	26.64

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

Supplemental Table 2: Hedges

The prices in these tables may represent the weighted averages for several contracts. The weighted average price for the portfolio of options listed below may not have the same payoff profile as the individual contracts. As such, the presentation of the weighted average prices is purely for indicative purposes.

The following tables outline Vermilion's outstanding risk management positions as at September 30, 2016:

Crude Oil	Period	Currency	Bought Put Volume (bbl/d)	Weighted Average Bought Put Price / bbl	Sold Call Volume (bbl/d)	Weighted Average Sold Call Price / bbl	Sold Put Volume (bbl/d)	Weighted Average Sold Put Price / bbl
Dated Brent								
3-Way Collar	Jul 2016 - Dec 2016	USD	3,000	48.68	3,000	60.00	3,000	39.33
3-Way Collar [1]	Jan 2017 - Dec 2017	USD	2,000	50.00	2,000	60.00	2,000	40.00

North American Gas	Period	Currency	Bought Put Volume (mmbtu/d)	Weighted Average Bought Put Price / mmbtu	Sold Call Volume (mmbtu/d)	Weighted Average Sold Call Price / mmbtu	Swap Volume (mmbtu/d)	Weighted Average Swap Price / mmbtu	Additional Swap Volume (mmbtu/d) [2]
AECO									
Collar	Nov 2015 - Oct 2016	CAD	9,478	2.70	9,478	3.41	-	-	-
Collar	Jan 2016 - Dec 2016	CAD	9,478	2.66	9,478	3.47	-	-	-
Collar	Mar 2016 - Dec 2016	CAD	4,739	2.16	9,478	2.92	-	-	-
Collar	Apr 2016 - Oct 2016	CAD	4,739	2.43	4,739	2.96	-	-	-
Collar	Apr 2016 - Dec 2016	CAD	2,370	2.22	7,109	3.08	-	-	-
Collar	Nov 2016 - Oct 2017	CAD	7,109	2.18	9,478	2.86	-	-	-
Collar	Nov 2016 - Dec 2017	CAD	9,478	2.33	9,478	3.02	-	-	-
Collar	Jan 2017 - Dec 2017	CAD	4,739	2.37	4,739	3.25	-	-	-
Swap	Apr 2016 - Oct 2016	CAD	-	-	-	-	4,739	2.73	4,739
Swap	Aug 2016 - Oct 2016	CAD	-	-	-	-	2,370	2.56	-
Swap	Nov 2016 - Dec 2017	CAD	-	-	-	-	2,370	2.99	-
Swap	Jan 2017 - Dec 2017	CAD	-	-	-	-	7,109	2.94	-
AECO Basis									
Swap	Jan 2017 - Dec 2017	USD	-	-	-	-	5,000	(0.75)	-
Swap	Jan 2018 - Dec 2018	USD	-	-	-	-	7,500	(0.83)	-
NYMEX									
Swap	Jan 2017 - Dec 2017	USD	-	-	-	-	5,000	3.00	-

European Gas	Period	Currency	Bought Put Volume (mmbtu/d)	Weighted Average Bought Put Price / mmbtu	Sold Call Volume (mmbtu/d)	Weighted Average Sold Call Price / mmbtu	Swap Volume (mmbtu/d)	Weighted Average Swap price / mmbtu	Additional Swap Volume (mmbtu/d) [2]
NBP									
Collar	Apr 2016 - Mar 2017	GBP	2,500	4.00	2,500	4.77	-	-	-
Collar	Jul 2016 - Dec 2016	GBP	2,500	3.00	7,500	4.30	-	-	-
Collar	Oct 2016 - Mar 2017	GBP	2,500	3.30	5,000	3.72	-	-	-
Collar	Oct 2016 - Sep 2017	GBP	5,000	3.25	10,000	4.03	-	-	-
Collar	Oct 2016 - Dec 2017	GBP	5,000	3.25	10,000	4.07	-	-	-
Collar	Jan 2017 - Dec 2017	GBP	5,000	3.30	7,500	3.77	-	-	-
Collar	Jan 2018 - Dec 2018	GBP	2,500	3.15	2,500	3.82	-	-	-
Put [3]	Dec 2016 - Feb 2017	GBP	20,000	4.00	-	-	-	-	-
Call	Oct 2016 - Mar 2017	GBP	-	-	2,500	4.90	-	-	-
Swap	Jul 2016 - Dec 2016	GBP	-	-	-	-	2,500	3.81	-
Swap	Oct 2016 - Dec 2016	GBP	-	-	-	-	2,500	3.41	-
Swap	Jan 2017 - Dec 2017	GBP	-	-	-	-	2,500	4.22	2,500
Swap	Jul 2017 - Dec 2017	GBP	-	-	-	-	2,500	3.95	-
Swap	Jan 2018 - Dec 2018	GBP	-	-	-	-	2,500	4.04	5,000
Swap	Jul 2016 - Mar 2017	EUR	-	-	-	-	2,457	5.73	-

(1) To fund the execution of the 3-way collar, Vermilion sold a swaption instrument. This instrument allows the counterparty, on December 30, 2016, to enter into a Dated Brent swap price of US$55.00 for 1,000 bbls/d for 2017.
(2) On the last business day of each month, the counterparty has the option to increase the contracted volumes for the following month.
(3) To fund the execution of the put, Vermilion sold a swaption instrument. This instrument allows the counterparty, on December 29, 2016, to enter into a NBP swap with Vermilion at a swap price of £4.20 per mmbtu for 5,300 mmbtu/d for the period of April 2017 to March 2018.

European Gas	Period	Currency	Bought Put Volume (mmbtu/d)	Weighted Average Bought Put Price / mmbtu	Sold Call Volume (mmbtu/d)	Weighted Average Sold Call Price / mmbtu	Sold Put / Swap Volume (mmbtu/d)	Weighted Average Sold Put / Swap Price / mmbtu	Additional Swap Volume (mmbtu/d) [1]
TTF									
3-Way Collar [2]	Apr 2017 - Sep 2017	EUR	9,827	4.18	9,827	5.06	9,827	3.08	-
3-Way Collar [2]	Jan 2018 - Dec 2018	EUR	4,913	4.40	4,913	5.28	4,913	3.22	-
Collar	Jan 2016 - Dec 2016	EUR	2,457	6.08	4,913	6.86	-	-	-
Collar	Apr 2016 - Dec 2016	EUR	12,284	5.89	14,740	6.55	-	-	-
Collar	Apr 2016 - Mar 2017	EUR	4,913	5.57	9,827	6.70	-	-	-
Collar	Jul 2016 - Dec 2016	EUR	2,457	5.28	2,457	5.93	-	-	-
Collar	Jul 2016 - Mar 2017	EUR	2,457	5.35	4,913	6.92	-	-	-
Collar	Jul 2016 - Mar 2018	EUR	2,457	5.61	4,913	6.90	-	-	-
Collar	Oct 2016 - Dec 2017	EUR	2,457	5.28	2,457	6.21	-	-	-
Collar	Jan 2017 - Dec 2017	EUR	9,827	5.06	22,111	6.37	-	-	-
Collar	Apr 2017 - Sep 2017	EUR	2,457	3.81	4,913	4.47	-	-	-
Collar	Jan 2018 - Dec 2018	EUR	4,913	4.40	4,913	5.31	-	-	-
Call	Oct 2016 - Mar 2017	EUR	-	-	2,457	6.36	-	-	-
Swap	Apr 2016 - Dec 2016	EUR	-	-	-	-	2,457	6.23	-
Swap	Jul 2016 - Jun 2018	EUR	-	-	-	-	2,559	5.89	-
Swap	Oct 2016 - Dec 2016	EUR	-	-	-	-	2,457	5.75	-
Swap	Jan 2017 - Dec 2017	EUR	-	-	-	-	2,457	5.32	2,457
Swap	Oct 2017 - Dec 2018	EUR	-	-	-	-	2,457	4.69	-

Fuel and Electricity	Period	Currency	Swap Volume (unit/d)	Weighted Average Swap price / unit
GasOil (bbl)				
Swap	Mar 2016 - Dec 2016	USD	125	42.55
AESO (mwh)				
Swap	Jan 2016 - Dec 2016	CAD	94	38.58
Swap	Jan 2017 - Dec 2017	CAD	65	33.47

Interest Rate			Notional amount	Rate (%)
CDOR Swap	Sep 2015 - Sep 2019	CAD	100,000,000	1.00
CDOR Swap	Oct 2015 - Oct 2019	CAD	100,000,000	1.10

Cross Currency		Receive Notional amount (USD)	Rate (US%)	Pay Notional amount (CAD)	Rate (CAD%)
Swap [3]	Oct 2016	872,238,352	3.27	1,145,799,999	3.15

(1) On the last business day of each month, the counterparty has the option to increase the contracted volumes for the following month.

(2) To fund the execution of the 3-way collar, Vermilion sold a swaption instrument. This instrument allows the counterparty, on March 31, 2017, to enter into a TTF swap price of €4.55 per mmbtu for 4,913 mmbtu/d for the period of April 2017 to June 2018.

(3) Subsequent to September 30, 2016, Vermilion repaid $1.1 billion of borrowings on the revolving credit facility bearing interest at CDOR plus applicable margins and simultaneously borrowed US $0.9 billion on the revolving credit facility bearing interest at LIBOR plus applicable margins.

Supplemental Table 3: Capital Expenditures and Acquisitions

By classification ($M)	Three Months Ended Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Nine Months Ended Sep 30, 2016	Sep 30, 2015
Drilling and development	41,039	71,296	93,381	175,108	357,865
Exploration and evaluation	-	418	-	418	-
Capital expenditures	41,039	71,714	93,381	175,526	357,865
Property acquisition	10,391	8,550	22,155	19,811	22,670
Acquisitions	10,391	8,550	22,155	19,811	22,670

By category ($M)	Three Months Ended Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Nine Months Ended Sep 30, 2016	Sep 30, 2015
Land	(36)	493	763	1,496	2,974
Seismic	1,110	1,323	810	8,701	4,026
Drilling and completion	18,694	36,542	39,712	83,089	154,031
Production equipment and facilities	18,046	35,612	44,589	59,896	163,301
Recompletions	603	768	3,948	4,969	20,351
Other	2,622	(3,024)	3,559	17,375	13,182
Capital expenditures	41,039	71,714	93,381	175,526	357,865
Acquisitions	10,391	8,550	22,155	19,811	22,670
Total capital expenditures and acquisitions	51,430	80,264	115,536	195,337	380,535

By country ($M)	Three Months Ended Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Nine Months Ended Sep 30, 2016	Sep 30, 2015
Canada	20,801	6,415	45,286	57,742	182,435
France	11,110	12,772	17,511	37,345	68,418
Netherlands	6,441	8,566	5,297	18,003	28,515
Germany	978	592	1,605	2,109	5,804
Ireland	2,416	2,172	20,694	7,664	53,916
Australia	6,908	39,939	7,966	54,674	20,889
United States	2,776	7,068	16,011	15,060	19,392
Corporate	-	2,740	1,166	2,740	1,166
Total capital expenditures and acquisitions	51,430	80,264	115,536	195,337	380,535

Supplemental Table 4: Production

	Q3/16	Q2/16	Q1/16	Q4/15	Q3/15	Q2/15	Q1/15	Q4/14	Q3/14	Q2/14	Q1/14	Q4/13
Canada												
Crude oil & condensate (bbls/d)	8,984	9,453	10,317	10,413	11,030	11,843	12,163	12,681	12,755	14,108	10,390	8,719
NGLs (bbls/d)	2,448	2,687	2,633	2,710	2,678	2,094	1,706	1,444	1,005	1,364	1,118	1,699
Natural gas (mmcf/d)	77.62	87.44	97.16	87.90	71.94	64.66	61.78	58.36	57.07	57.59	49.53	41.43
Total (boe/d)	24,368	26,713	29,141	27,773	25,698	24,713	24,165	23,851	23,272	25,070	19,763	17,322
% of consolidated	37%	42%	44%	45%	47%	48%	48%	49%	47%	49%	42%	43%
France												
Crude oil (bbls/d)	11,827	12,326	12,220	12,537	12,310	12,746	11,463	11,133	11,111	11,025	10,771	11,131
Natural gas (mmcf/d)	0.42	0.54	0.44	1.36	1.47	1.03	-	-	-	-	-	-
Total (boe/d)	11,897	12,416	12,293	12,763	12,555	12,917	11,463	11,133	11,111	11,025	10,771	11,131
% of consolidated	19%	19%	19%	21%	22%	25%	23%	22%	22%	21%	23%	27%
Netherlands												
Condensate (bbls/d)	86	96	114	110	109	112	63	81	63	96	69	62
Natural gas (mmcf/d)	47.62	49.18	53.40	56.34	53.56	32.43	36.41	31.35	38.07	40.35	43.15	37.53
Total (boe/d)	8,023	8,293	9,015	9,500	9,035	5,517	6,132	5,306	6,407	6,822	7,260	6,318
% of consolidated	13%	13%	14%	16%	16%	11%	12%	11%	13%	13%	16%	15%
Germany												
Natural gas (mmcf/d)	14.52	14.31	15.96	16.17	14.00	16.18	16.80	17.71	15.38	16.13	10.64	-
Total (boe/d)	2,420	2,385	2,660	2,695	2,333	2,696	2,801	2,952	2,563	2,689	1,773	-
% of consolidated	4%	4%	4%	4%	4%	5%	6%	6%	5%	5%	4%	-
Ireland												
Natural gas (mmcf/d)	59.28	47.26	33.90	0.12	-	-	-	-	-	-	-	-
Total (boe/d)	9,879	7,877	5,650	20	-	-	-	-	-	-	-	-
% of consolidated	16%	12%	9%	-	-	-	-	-	-	-	-	-
Australia												
Crude oil (bbls/d)	6,562	6,083	6,180	7,824	6,433	5,865	5,672	6,134	6,567	6,483	7,110	6,189
% of consolidated	10%	9%	9%	13%	11%	11%	11%	12%	13%	12%	15%	15%
United States												
Crude oil (bbls/d)	383	458	368	420	226	123	153	195	-	-	-	-
NGLs (bbls/d)	30	26	39	29	-	-	-	-	-	-	-	-
Natural gas (mmcf/d)	0.20	0.20	0.26	0.20	-	-	-	-	-	-	-	-
Total (boe/d)	447	518	450	483	226	123	153	195	-	-	-	-
% of consolidated	1%	1%	1%	1%	-	-	-	-	-	-	-	-
Consolidated												
Crude oil, condensate & NGLs (bbls/d)	30,320	31,129	31,871	34,043	32,786	32,783	31,220	31,668	31,501	33,076	29,458	27,800
% of consolidated	48%	48%	49%	56%	58%	63%	62%	64%	63%	63%	63%	68%
Natural gas (mmcf/d)	199.65	198.93	201.11	162.09	140.97	114.29	115.00	107.42	110.52	114.08	103.32	78.96
% of consolidated	52%	52%	51%	44%	42%	37%	38%	36%	37%	37%	37%	32%
Total (boe/d)	63,596	64,285	65,389	61,058	56,280	51,831	50,386	49,571	49,920	52,089	46,677	40,960

	YTD 2016	2015	2014	2013	2012	2011
Canada						
Crude oil & condensate (bbls/d)	9,582	11,357	12,491	8,387	7,659	4,701
NGLs (bbls/d)	2,589	2,301	1,233	1,666	1,232	1,297
Natural gas (mmcf/d)	87.37	71.65	55.67	42.39	37.50	43.38
Total (boe/d)	26,732	25,598	23,001	17,117	15,142	13,227
% of consolidated	41%	46%	47%	41%	40%	38%
France						
Crude oil (bbls/d)	12,123	12,267	11,011	10,873	9,952	8,110
Natural gas (mmcf/d)	0.47	0.97	-	3.40	3.59	0.95
Total (boe/d)	12,201	12,429	11,011	11,440	10,550	8,269
% of consolidated	19%	23%	22%	28%	28%	23%
Netherlands						
Condensate (bbls/d)	99	99	77	64	67	58
Natural gas (mmcf/d)	50.06	44.76	38.20	35.42	34.11	32.88
Total (boe/d)	8,442	7,559	6,443	5,967	5,751	5,538
% of consolidated	13%	14%	13%	15%	15%	16%
Germany						
Natural gas (mmcf/d)	14.93	15.78	14.99	-	-	-
Total (boe/d)	2,488	2,630	2,498	-	-	-
% of consolidated	4%	5%	5%	-	-	-
Ireland						
Natural gas (mmcf/d)	46.86	0.03	-	-	-	-
Total (boe/d)	7,810	5	-	-	-	-
% of consolidated	12%	-	-	-	-	-
Australia						
Crude oil (bbls/d)	6,276	6,454	6,571	6,481	6,360	8,168
% of consolidated	10%	12%	13%	16%	17%	23%
United States						
Crude oil (bbls/d)	403	231	49	-	-	-
NGLs (bbls/d)	32	7	-	-	-	-
Natural gas (mmcf/d)	0.21	0.05	-	-	-	-
Total (boe/d)	472	247	49	-	-	-
% of consolidated	1%	-	-	-	-	-
Consolidated						
Crude oil, condensate & NGLs (bbls/d)	31,104	32,716	31,432	27,471	25,270	22,334
% of consolidated	48%	60%	63%	67%	67%	63%
Natural gas (mmcf/d)	199.89	133.24	108.85	81.21	75.20	77.21
% of consolidated	52%	40%	37%	33%	33%	37%
Total (boe/d)	64,421	54,922	49,573	41,005	37,803	35,202

Supplemental Table 5: Segmented Financial Results

	Three Months Ended September 30, 2016								
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	United States	Corporate	Total
Drilling and development	10,421	11,110	6,441	978	2,416	6,908	2,765	-	41,039
Oil and gas sales to external customers	64,453	65,221	23,470	6,783	26,065	44,835	1,833	-	232,660
Royalties	(4,817)	(7,069)	(312)	(246)	-	-	(525)	-	(12,969)
Revenue from external customers	59,636	58,152	23,158	6,537	26,065	44,835	1,308	-	219,691
Transportation	(3,978)	(3,586)	-	(556)	(1,576)	-	-	-	(9,696)
Operating	(15,579)	(12,933)	(4,854)	(3,321)	(4,695)	(13,011)	(432)	-	(54,825)
General and administration	(3,010)	(4,590)	633	(1,657)	(955)	(1,289)	(918)	(509)	(12,295)
PRRT	-	-	-	-	-	272	-	-	272
Corporate income taxes	-	955	(1,264)	-	-	(2,916)	-	(321)	(3,546)
Interest expense	-	-	-	-	-	-	-	(14,150)	(14,150)
Realized gain on derivative instruments	-	-	-	-	-	-	-	13,532	13,532
Realized foreign exchange gain	-	-	-	-	-	-	-	2,073	2,073
Realized other expense	-	-	-	-	-	-	-	(82)	(82)
Fund flows from operations	37,069	37,998	17,673	1,003	18,839	27,891	(42)	543	140,974

	Nine Months Ended September 30, 2016								
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	United States	Corporate	Total
Total assets	1,507,693	816,731	186,524	154,699	807,534	258,257	54,953	129,026	3,915,417
Drilling and development	45,811	37,345	18,003	2,109	7,664	54,674	9,502	-	175,108
Exploration and evaluation	-	-	-	-	-	-	-	418	418
Oil and gas sales to external customers	182,294	174,937	74,729	20,755	66,429	98,483	5,273	-	622,900
Royalties	(14,085)	(20,399)	(1,168)	(2,077)	-	-	(1,556)	-	(39,285)
Revenue from external customers	168,209	154,538	73,561	18,678	66,429	98,483	3,717	-	583,615
Transportation	(11,888)	(10,775)	-	(2,494)	(4,789)	-	-	-	(29,946)
Operating	(53,382)	(38,518)	(15,136)	(8,420)	(13,498)	(32,602)	(1,013)	-	(162,569)
General and administration	(9,791)	(14,000)	(1,363)	(6,559)	(3,249)	(4,402)	(2,747)	746	(41,365)
PRRT	-	-	-	-	-	-	-	-	-
Corporate income taxes	-	-	(6,724)	-	-	(4,819)	-	(727)	(12,270)
Interest expense	-	-	-	-	-	-	-	(42,547)	(42,547)
Realized gain on derivative instruments	-	-	-	-	-	-	-	63,456	63,456
Realized foreign exchange gain	-	-	-	-	-	-	-	2,750	2,750
Realized other income	-	-	-	-	-	-	-	85	85
Fund flows from operations	93,148	91,245	50,338	1,205	44,893	56,660	(43)	23,763	361,209

NON-GAAP FINANCIAL MEASURES

This MD&A includes references to certain financial measures which do not have standardized meanings. These financial measures include fund flows from operations, a measure of profit or loss in accordance with IFRS 8 "Operating Segments" (please see SEGMENTED INFORMATION in the NOTES TO THE CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS) and net debt, a measure of capital in accordance with IAS 1 "Presentation of Financial Statements" (please see CAPITAL DISCLOSURES in the NOTES TO THE CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS).

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

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

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

	Three Months Ended			Nine Months Ended	
($M)	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015	Sep 30, 2016	Sep 30, 2015
Dividends declared	75,465	74,662	71,244	222,974	211,610
Shares issued for the DRIP[1]	(50,912)	(50,516)	(44,590)	(149,418)	(108,269)
Net dividends	24,553	24,146	26,654	73,556	103,341
Drilling and development	41,039	71,296	93,381	175,108	357,865
Exploration and evaluation	-	418	-	418	-
Asset retirement obligations settled	2,066	2,200	2,123	6,290	6,448
Payout	67,658	98,060	122,158	255,372	467,654

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

	As at		
('000s of shares)	Sep 30, 2016	Jun 30, 2016	Sep 30, 2015
Shares outstanding	117,386	116,173	110,818
Potential shares issuable pursuant to the VIP	2,797	2,775	2,825

CORPORATE INFORMATION

DIRECTORS

Lorenzo Donadeo [1]
Calgary, Alberta

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

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

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

Robert Michaleski
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

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

Kyle Preston
Director Investor Relations

Mike Prinz
Director Information Technology & Information Systems

Jenson Tan
Director Business Development

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

JPMorgan Chase Bank, N.A., Toronto Branch

Union Bank, Canada Branch

Barclays Bank PLC

Canadian Western Bank

Goldman Sachs Lending Partners LLC

EVALUATION ENGINEERS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL

Norton Rose Fulbright Canada LLP
Calgary, Alberta

TRANSFER AGENT

Computershare Trust Company of Canada

STOCK EXCHANGE LISTINGS

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

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EXCELLENCE

We aim for exceptional results in everything we do.

TRUST

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

RESPECT

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

RESPONSIBILITY

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

VERMILION ENERGY

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