Q1 2017

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 April 27, 2017, of Vermilion Energy Inc.'s ("Vermilion", "We", "Our", "Us" or the "Company") operating and financial results as at and for the three months ended March 31, 2017 compared with the corresponding period in the prior year.

This discussion should be read in conjunction with the unaudited condensed consolidated interim financial statements for the three months ended March 31, 2017 and the audited consolidated financial statements for the year ended December 31, 2016 and 2015, together with accompanying notes. Additional information relating to Vermilion, including its Annual Information Form, is available on SEDAR at www.sedar.com or on Vermilion's website at www.vermilionenergy.com.

The unaudited condensed consolidated interim financial statements for the three months ended March 31, 2017 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:

- 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.
- 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.

CONDENSATE PRESENTATION

We report our condensate production in Canada and the Netherlands business units 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).

2017 GUIDANCE

On October 31, 2016, we released our 2017 capital expenditure guidance of $295 million and associated production guidance of between 69,000-70,000 boe/d.

The following table summarizes our guidance:

	Date	Capital Expenditures ($MM)	Production (boe/d)
2017 Guidance			
2017 Guidance	October 31, 2016	295	69,000 to 70,000

CONSOLIDATED RESULTS OVERVIEW

	Three Months Ended			% change	
	Mar 31, 2017	Dec 31, 2016	Mar 31, 2016	Q1/17 vs. Q4/16	Q1/17 vs. Q1/16
Production					
Crude oil and condensate (bbls/d)	26,832	25,972	29,199	3%	(8%)
NGLs (bbls/d)	2,694	2,467	2,672	9%	1%
Natural gas (mmcf/d)	210.07	194.54	201.11	8%	4%
Total (boe/d)	64,537	60,863	65,389	6%	(1%)
Sales					
Crude oil and condensate (bbls/d)	24,218	26,610	27,648	(9%)	(12%)
NGLs (bbls/d)	2,694	2,467	2,672	9%	1%
Natural gas (mmcf/d)	210.07	194.54	201.11	8%	4%
Total (boe/d)	61,923	61,501	63,838	1%	(3%)
Build (draw) in inventory (mbbls)	235	(58)	142		
Financial metrics					
Fund flows from operations ($M)	143,434	149,582	93,667	(4%)	53%
Per share ($/basic share)	1.21	1.27	0.83	(5%)	46%
Net earnings (loss)	44,540	(4,032)	(85,848)	(1,205%)	(152%)
Per share ($/basic share)	0.38	(0.03)	(0.76)	(1,367%)	(150%)
Net debt ($M)	1,377,636	1,427,148	1,367,063	(3%)	1%
Cash dividends ($/share)	0.645	0.645	0.645	-	-
Activity					
Capital expenditures ($M)	95,889	66,882	62,773	43%	53%
Acquisitions ($M)	2,620	78,713	870	(97%)	201%
Gross wells drilled	29.00	16.00	12.00		
Net wells drilled	25.41	12.02	8.26		

Operational review

- Consolidated average production increased by 6% in Q1 2017 versus Q4 2016. This increase is primarily due to higher volumes in Canada from the resumption of voluntarily curtailed natural gas production and organic growth from development activities, as well as incremental volumes from our German acquisition that closed in late 2016.
- Production during the first quarter of 2017 was consistent with the same period in the prior year as increased production in Ireland and Germany offset production declines and well downtime in Canada and France.
- We expect production volumes to continue increasing throughout the year and are targeting full year average production of between 69,000 to 70,000 boe/d in 2017.

For the three months ended March 31, 2017, capital expenditures of $95.9 million primarily related to Canada, France, and the United States. In Canada, capital expenditures of $57.5 million related primarily to drilling activity and facility maintenance. In France, capital expenditures of $20.9 million related to drilling activity and workover programs. In the United States, capital expenditures of $11.5 million related to drilling

Financial review

Net earnings

- Net earnings for Q1 2017 was $44.5 million ($0.38/basic share), compared to a net loss of $4.0 million ($0.03/basic share) in Q4 2016. The change in net earnings was primarily attributable to an unrealized gain on derivative instruments, compared to an unrealized loss in the prior quarter, partially offset by the impact of a deferred tax expense, compared to a recovery in the prior quarter.
- Net earnings in Q1 2017 of $44.5 million ($0.38/basic share) compared to a net loss of $85.8 million ($0.76/basic share) in Q1 2016. The change in net earnings was primarily attributable to higher revenue resulting from higher commodity prices, as well as a higher unrealized gain on derivative instruments in the current period.

Fund flows from operations

- Generated fund flows from operations of $143.4 million during Q1 2017, a decrease of 4% from Q4 2016. This quarter-over-quarter decrease was primarily attributable a build in inventory in France and Australia, partially offset by stronger crude oil and European natural gas prices.
- Fund flows from operations increased by 53% in Q1 2017 as compared to Q1 2016 primarily due to higher commodity prices

Net debt

- Net debt decreased to $1.38 billion as at March 31, 2017 from $1.43 billion at December 31, 2016, due to an increase in net current derivative assets resulting from changes in forward commodity price assumptions quarter-over-quarter.

Dividends

- Declared dividends of $0.215 per common share per month during the first quarter of 2017, totalling $0.645 per common share for the quarter.

COMMODITY PRICES

	Three Months Ended			% change	
	Mar 31, 2017	Dec 31, 2016	Mar 31, 2016	Q1/17 vs. Q4/16	Q1/17 vs. Q1/16
Average reference prices					
Crude oil					
WTI (US $/bbl)	51.92	49.29	33.45	5%	55%
Edmonton Sweet index (US $/bbl)	48.37	46.18	29.76	5%	63%
Dated Brent (US $/bbl)	53.78	49.46	33.89	9%	59%
Natural gas					
AECO ($/mmbtu)	2.69	3.09	1.83	(13%)	47%
NBP ($/mmbtu)	7.96	7.51	5.97	6%	33%
NBP (€/mmbtu)	5.64	5.22	3.94	8%	43%
TTF ($/mmbtu)	7.65	7.21	5.70	6%	34%
TTF (€/mmbtu)	5.43	5.01	3.76	8%	44%
Henry Hub ($/mmbtu)	4.38	3.98	2.87	10%	53%
Henry Hub (US $/mmbtu)	3.31	2.98	2.09	11%	58%
Average foreign currency exchange rates					
CDN $/US $	1.32	1.33	1.37	(1%)	(4%)
CDN $/Euro	1.41	1.44	1.52	(2%)	(7%)

- For the three months ended March 31, 2017, crude oil pricing increased versus both the previous quarter and the comparable period in 2016. Supported by improving fundamentals, including adherence to the OPEC-led coordinated cut, Dated Brent increased 9% quarter-over-quarter and 59% versus the same period last year. WTI also increased 5% quarter-over-quarter and 55% year-over-year. Edmonton Sweet prices followed WTI closely and increased 5% quarter-over-quarter and 63% versus the same period last year.
- Warmer weather through extended periods of Q1 2017 resulted in decreased AECO natural gas prices compared to Q4 2016. However, AECO increased 47% over the same period in 2016.
- With a return to normal winter weather conditions, European natural gas prices increased on both a quarter-over-quarter basis and year-over-year basis. Draws from gas-in-storage and increased power demand resulted in both NBP and TTF prices 8% higher in Q1 2017 than Q4 2016. Similarly, NBP and TTF increased 43% and 44%, respectively, versus Q1 2016.
- The Canadian dollar was relatively consistent against the US dollar and Euro quarter-over-quarter. However, the Canadian dollar strengthened versus both the US dollar and Euro year-over-year.

FUND FLOWS FROM OPERATIONS

	Three Months Ended					
	Mar 31, 2017		Dec 31, 2016		Mar 31, 2016	
	$M	$/boe	$M	$/boe	$M	$/boe
Petroleum and natural gas sales	261,601	46.94	259,891	45.93	177,385	30.53
Royalties	(16,205)	(2.91)	(14,999)	(2.65)	(13,961)	(2.40)
Petroleum and natural gas revenues	245,396	44.03	244,892	43.28	163,424	28.13
Transportation	(9,819)	(1.76)	(9,565)	(1.69)	(10,390)	(1.79)
Operating	(52,121)	(9.35)	(59,616)	(10.54)	(55,628)	(9.58)
General and administration	(13,151)	(2.36)	(11,464)	(2.03)	(13,577)	(2.34)
PRRT	(5,434)	(0.97)	(1,568)	(0.28)	(128)	(0.02)
Corporate income taxes	(7,479)	(1.34)	(5,840)	(1.03)	(3,160)	(0.54)
Interest expense	(14,695)	(2.64)	(14,410)	(2.55)	(14,750)	(2.54)
Realized (loss) gain on derivative instruments	(1,851)	(0.33)	1,920	0.34	28,423	4.89
Realized foreign exchange gain (loss)	2,546	0.46	1,291	0.23	(652)	(0.11)
Realized other income	42	0.01	3,942	0.70	105	0.02
Fund flows from operations	143,434	25.75	149,582	26.43	93,667	16.12

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

($M)	Q1/17 vs. Q4/16	Q1/17 vs. Q1/16
Fund flows from operations – Comparative period	149,582	93,667
Sales volume variance:		
Canada	2,609	(9,468)
France	(15,715)	(10,035)
Netherlands	(1,195)	(7,133)
Germany	8,173	7,397
Ireland	346	15,160
Australia	(7,022)	1,358
United States	(19)	(71)
Pricing variance on sales volumes:		
WTI	2,875	21,610
AECO	(453)	8,212
Dated Brent	7,056	35,214
TTF and NBP	5,055	21,972
Changes in:		
Royalties	(1,206)	(2,244)
Transportation	(254)	571
Operating	7,495	3,507
General and administration	(1,687)	426
PRRT	(3,866)	(5,306)
Corporate income taxes	(1,639)	(4,319)
Interest	(285)	55
Realized derivatives	(3,771)	(30,274)
Realized foreign exchange	1,255	3,198
Realized other income	(3,900)	(63)
Fund flows from operations – Current period	143,434	143,434

Please see CONSOLIDATED RESULTS OVERVIEW for a discussion of the key variances for the periods presented.

Fluctuations in fund flows from operations 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
- Southeast Saskatchewan light oil development:
  - Primary target is the Mississippian Midale formation (1,400 – 1,700m depth)
  - Secondary targets of Mississippian Frobisher (1,400 – 1,700m depth) and Devonian Bakken/Three Forks (2,000 – 2,100m depth)
- Canadian cash flows are fully tax-sheltered for the foreseeable future.

Operational and financial review

	Three Months Ended			% change	
Canada business unit ($M except as indicated)	Mar 31, 2017	Dec 31, 2016	Mar 31, 2016	Q1/17 vs. Q4/16	Q1/17 vs. Q1/16
Production and sales					
Crude oil and condensate (bbls/d)	7,987	7,945	10,317	1%	(23%)
NGLs (bbls/d)	2,670	2,444	2,633	9%	1%
Natural gas (mmcf/d)	85.74	75.12	97.16	14%	(12%)
Total (boe/d)	24,947	22,910	29,141	9%	(14%)
Production mix (% of total)					
Crude oil and condensate	32%	35%	35%		
NGLs	11%	11%	9%		
Natural gas	57%	54%	56%		
Activity					
Capital expenditures	57,457	16,895	29,771	240%	93%
Acquisitions	576	1,378	755		
Gross wells drilled	22.00	11.00	12.00		
Net wells drilled	18.41	7.02	8.26		
Financial results					
Sales	75,500	70,573	56,110	7%	35%
Royalties	(8,499)	(7,390)	(5,498)	15%	55%
Transportation	(4,103)	(3,504)	(4,151)	17%	(1%)
Operating	(16,670)	(18,161)	(21,343)	(8%)	(22%)
General and administration	(1,698)	(2,035)	(2,476)	(17%)	(31%)
Fund flows from operations	44,530	39,483	22,642	13%	97%
Netbacks ($/boe)					
Sales	33.63	33.48	21.16	-	59%
Royalties	(3.79)	(3.51)	(2.07)	8%	83%
Transportation	(1.83)	(1.66)	(1.57)	10%	17%
Operating	(7.42)	(8.62)	(8.05)	(14%)	(8%)
General and administration	(0.76)	(0.97)	(0.94)	(22%)	(19%)
Fund flows from operations netback	19.83	18.72	8.53	6%	132%
Realized prices					
Crude oil and condensate ($/bbl)	64.76	62.13	39.69	4%	63%
NGLs ($/bbl)	24.12	18.12	7.31	33%	230%
Natural gas ($/mmbtu)	2.99	3.05	1.93	(2%)	55%
Total ($/boe)	33.63	33.48	21.16	-	59%
Reference prices					
WTI (US $/bbl)	51.92	49.29	33.45	5%	55%
Edmonton Sweet index (US $/bbl)	48.37	46.18	29.76	5%	63%
Edmonton Sweet index ($/bbl)	63.99	61.60	40.91	4%	56%
AECO ($/mmbtu)	2.69	3.09	1.83	(13%)	47%

Production

- Q1 2017 average production increased by 9% from Q4 2016 primarily due to organic production growth in our Mannville condensate-rich gas resource play and the reinstatement of voluntarily curtailed production in Alberta. On a year-over-year basis, production decreased as a result of capital investment timing associated with business unit and corporate production targets.
- Mannville production averaged approximately 12,000 boe/d in Q1 2017 representing a 25% increase quarter-over-quarter.
- Cardium production averaged approximately 5,800 boe/d in Q1 2017, a 5% decrease quarter-over-quarter.
- Production from southeast Saskatchewan averaged approximately 2,000 boe/d in Q1 2017, a decrease of 5% quarter-over-quarter.

Activity review

- Vermilion drilled 18 (16.8 net) operated wells and participated in the drilling of four (1.6 net) non-operated wells during Q1 2017.

  Mannville
  - During Q1 2017, we drilled six (4.8 net) operated wells and brought seven (5.6 net) operated wells on production. We also participated in the drilling of one (0.3 net) non-operated well and four (1.5 net) non-operated wells were placed on production.
  - In 2017, we plan to drill or participate in 23 (15.0 net) wells and complete and tie-in six (5.0 net) wells drilled in Q4 2016.

  Cardium
  - In Q1 2017, we drilled five (5.0 net) operated wells and brought two (2.0 net) operated wells on production.
  - Our 2017 program to drill five (5.0 net) wells was completed in the first quarter.

  Saskatchewan
  - In Q1 2017 we drilled seven (7.0 net) operated wells and brought six (6.0 net) operated wells on production. We participated in the drilling of three (1.3 net) non-operated wells and two (1.0 net) non-operated wells were placed on production.
  - In 2017, we plan to drill or participate in 13 (11.3 net) wells.

Sales

- The realized price for our crude oil and condensate production in Canada is linked to WTI, and 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 index in Canada.
- Q1 2017 sales per boe was consistent with Q4 2016 as stronger crude oil pricing was offset by weaker natural gas pricing.
- Sales per boe for the three months ended March 31, 2017 increased versus the comparable period in 2016 as a result of higher average crude oil and natural gas pricing.

Royalties

- Royalties as a percentage of sales for Q1 2017 increased modestly to 11.2% from 10.5% in Q4 2016.
- Royalties as a percentage of sales for Q1 2017 increased to 11.2% from 9.8% for Q1 2016 as a result of the impact of higher commodity prices on the sliding scale used to determine royalty rates.

Transportation

- Transportation expense relates to the delivery of crude oil and natural gas production to major pipelines where legal title transfers.
- Transportation expense for Q1 2017 increased as compared to Q4 2016 due to a prior period amendment recorded in the current period, coupled with higher production.
- Transportation expense for Q1 2017 remained consistent with the expense for Q1 2016 despite lower production volumes due to a prior period amendment recorded in the current period.

Operating

- Operating expense was lower on an absolute dollar and per boe basis in Q1 2017 versus Q4 2016 and Q1 2016. This was primarily due to the timing of project and maintenance activity.

General and administration

- The decrease in general and administration expense for Q1 2017 as compared to Q4 2016 was primarily the result of expenditure timing.
- Year-over-year, Q1 2017 general and administration expense was 31% lower than the same quarter in the prior year due to ongoing initiatives to reduce our cost structure.

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	
France business unit ($M except as indicated)	Mar 31, 2017	Dec 31, 2016	Mar 31, 2016	Q1/17 vs. Q4/16	Q1/17 vs. Q1/16
Production					
Crude oil (bbls/d)	10,834	11,220	12,220	(3%)	(11%)
Natural gas (mmcf/d)	0.01	0.38	0.44	(97%)	(98%)
Total (boe/d)	10,836	11,283	12,293	(4%)	(12%)
Sales					
Crude oil (bbls/d)	9,760	12,209	12,181	(20%)	(20%)
Natural gas (mmcf/d)	0.01	0.38	0.44	(98%)	(98%)
Total (boe/d)	9,761	12,272	12,254	(20%)	(20%)
Inventory (mbbls)					
Opening crude oil inventory	148	239	243		
Crude oil production	975	1,032	1,112		
Crude oil sales	(878)	(1,123)	(1,108)		
Closing crude oil inventory	245	148	247		
Activity					
Capital expenditures	20,916	31,127	13,463	(33%)	55%
Gross wells drilled	4.00	4.00	-		
Net wells drilled	4.00	4.00	-		
Financial results					
Sales	59,610	71,926	48,125	(17%)	24%
Royalties	(5,320)	(6,692)	(6,766)	(21%)	(21%)
Transportation	(3,032)	(3,983)	(3,713)	(24%)	(18%)
Operating	(11,369)	(11,482)	(14,320)	(1%)	(21%)
General and administration	(3,070)	(5,101)	(4,676)	(40%)	(34%)
Other income	-	3,822	-	(100%)	-
Current income taxes	(4,982)	(2,867)	(34)	74%	14,553%
Fund flows from operations	31,837	45,623	18,616	(30%)	71%
Netbacks ($/boe)					
Sales	67.85	63.71	43.16	6%	57%
Royalties	(6.06)	(5.93)	(6.07)	2%	-
Transportation	(3.45)	(3.53)	(3.33)	(2%)	4%
Operating	(12.94)	(10.17)	(12.84)	27%	1%
General and administration	(3.49)	(4.52)	(4.19)	(23%)	(17%)
Other income	-	3.39	-	(100%)	-
Current income taxes	(5.67)	(2.54)	(0.03)	123%	18,800%
Fund flows from operations	36.24	40.41	16.70	(10%)	117%
Realized prices					
Crude oil ($/bbl)	67.86	63.99	43.36	6%	57%
Natural gas ($/mmbtu)	1.52	1.55	1.66	(2%)	(8%)
Total ($/boe)	67.85	63.71	43.16	6%	57%
Reference prices					
Dated Brent (US $/bbl)	53.78	49.46	33.89	9%	59%
Dated Brent ($/bbl)	71.15	65.97	46.59	8%	53%

Production

- Q1 2017 production decreased 4% versus the prior quarter and 12% versus Q1 2016 due to production declines, well downtime and third party restrictions impacting Vic Bilh gas production. These decreases more than off-set new well production and optimization activities.

Activity review

- During Q1 2017 we commenced our first drilling campaign in the Neocomian fields in the Paris Basin and drilled three (3.0 net) of the four (4.0 net) planned wells. Drilling of the fourth well was completed in April.
- We drilled a horizontal sidetrack well in the Vulaines field during the quarter. Initial completion (excluding acidization) and tie-in activity was completed for this well and the four (4.0 net) Champotran wells drilled in Q4 2016.
- In addition to the drilling and completion activity, we will continue to focus on workover and optimization activities throughout the remainder of 2017.

Sales

- Crude oil in France is priced with reference to Dated Brent.
- Q1 2017 sales per boe increased versus Q4 2016 and Q1 2016 as a result of stronger Dated Brent pricing. Quarter-over-quarter, the increase in sales per boe was offset by a decrease in sales volumes due to a 97,000 bbl inventory build related to shipment timing. Based on anticipated shipment schedules, we expect that this inventory build will reverse over the course of the year. Year-over-year, the increase in price more than offset the lower sales volumes, resulting in an increase in sales.

Royalties

- Royalties in France relate to two components: RCDM (levied on units of production and not subject to changes in commodity prices) and R31 (based on a percentage of sales).
- Royalties as a percentage of sales of 8.9% for the three months ended March 31, 2017 was lower than the prior quarter (9.3%) and Q1 2016 (14.1%) as a result of the impact of fixed RCDM royalties coupled with higher realized pricing in the current quarter.

Transportation

- Transportation expense per boe for Q1 2017 was lower than Q4 2016 and Q1 2016 due to fewer vessel-based shipments of crude oil in the current quarter versus the comparative periods.

Operating

- Operating expense on a per boe basis for Q1 2017 increased as compared to Q4 2016 as a result of expenditure timing. Operating expense on a per boe basis for Q1 2017 was consistent with Q1 2016.

General and administration

- General and administration expense for Q1 2017 was lower than Q4 2016 and Q1 2016 due to the timing of expenditures and recoveries as well as allocations from our corporate segment.

Current income taxes

- In France, current income taxes are applied to taxable income, after eligible deductions, at a statutory rate of 34.4%. For 2017, the effective rate on current taxes is expected to be between approximately 12% to 14% of pre-tax fund flows from operations. This is subject to change in response to production variations, commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.
- Current income taxes in Q1 2017 were higher compared to Q4 2016 as decreased sales and the absence of other income in Q1 2017 were offset by a higher forecasted full year effective tax rate. Current income taxes in Q1 2017 were higher compared to Q1 2016 mainly due to increased sales in Q1 2017.

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

Netherlands business unit ($M except as indicated)	Three Months Ended Mar 31, 2017	Dec 31, 2016	Mar 31, 2016	% change Q1/17 vs. Q4/16	Q1/17 vs. Q1/16
Production and sales					
Condensate (bbls/d)	76	57	114	33%	(33%)
Natural gas (mmcf/d)	39.92	41.15	53.40	(3%)	(25%)
Total (boe/d)	6,729	6,915	9,015	(3%)	(25%)
Activity					
Capital expenditures	1,712	5,737	2,996	(70%)	(43%)
Acquisitions	16	28,259	-		
Financial results					
Sales	26,762	25,978	27,286	3%	(2%)
Royalties	(419)	(294)	(460)	43%	(9%)
Operating	(4,841)	(5,660)	(5,976)	(14%)	(19%)
General and administration	(596)	(162)	(773)	268%	(23%)
Current income taxes	(907)	100	(2,200)	(1,007%)	(59%)
Fund flows from operations	19,999	19,962	17,877	-	12%
Netbacks ($/boe)					
Sales	44.19	40.84	33.26	8%	33%
Royalties	(0.69)	(0.46)	(0.56)	50%	23%
Operating	(7.99)	(8.90)	(7.28)	(10%)	10%
General and administration	(0.98)	(0.26)	(0.94)	277%	4%
Current income taxes	(1.50)	0.16	(2.68)	(1,038%)	(44%)
Fund flows from operations netback	33.03	31.38	21.80	5%	52%
Realized prices					
Condensate ($/bbl)	58.33	63.18	32.24	(8%)	81%
Natural gas ($/mmbtu)	7.34	6.78	5.55	8%	32%
Total ($/boe)	44.19	40.84	33.26	8%	33%
Reference prices					
TTF ($/mmbtu)	7.65	7.21	5.70	6%	34%
TTF (€/mmbtu)	5.43	5.01	3.76	8%	44%

Production
- Q1 2017 production decreased 3% quarter-over-quarter and 25% year-over-year due to the restriction of production related to permitting delays.
- Production in the Netherlands is actively managed to optimize facility use and regulate declines.

Activity review
- Q1 2017 was focused on addressing production permitting delays and new well permitting work related to 2017 drilling activity.
- In 2017, we plan to drill two (1.0 net) exploration wells, acquire 220 square kilometers of 3D seismic, and execute a major turnaround at the Garjip Treatment Centre.

Sales

- The price of our natural gas in the Netherlands is based on the TTF index.
- Q1 2017 sales per boe increased versus Q4 2016 and Q1 2016, consistent with increases 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

- Q1 2017 operating expense on a per boe basis decreased versus Q4 2016 due to higher project activity in the prior quarter, including compressor maintenance.
- On a per boe basis, Q1 2017 operating expense increased as compared to Q1 2016 due to the impact of fixed costs on lower volumes.

General and administration

- Variances in general and administration expense from quarter to quarter relate to timing of expenditures as well as allocations from Vermilion's Corporate segment.

Current income taxes

- In the Netherlands, current income taxes are applied to taxable income, after eligible deductions and a 10% uplift deduction applied to operating expenses, eligible G&A and tax deductions for depletion and abandonment retirement obligations, at a tax rate of 50%. For 2017, the effective rate on current taxes is expected to be between approximately 3% and 5% of pre-tax fund flows from operations. This rate is subject to change in response to production variations, commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.
- Current income taxes in Q1 2017 were higher compared to Q4 2016 due to increased sales in Q1 2017. Current income taxes in Q1 2017 were lower compared to Q1 2016 mainly due to a lower forecasted full year effective tax rate.

GERMANY BUSINESS UNIT

Overview

- Vermilion entered Germany in February 2014.
- Vermilion successfully integrated the December 2016 acquisition of operated and non-operated interests in five oil and three gas producing fields from Engie E&P Deutschland GmbH ("Engie Acquisition"). Vermilion has assumed operatorship of six of the eight producing fields, representing our first operated producing properties in Germany.
- 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 an exploration license in Lower Saxony in March 2017 comprising 150,000 gross acres (50,000 acres net to Vermilion) surrounding the operated oil fields acquired in December 2016.

Operational and financial review

	Three Months Ended			% change	
Germany business unit ($M except as indicated)	Mar 31, 2017	Dec 31, 2016	Mar 31, 2016	Q1/17 vs. Q4/16	Q1/17 vs. Q1/16
Production and sales					
Crude oil (bbls/d)	989	-	-	100%	100%
Natural gas (mmcf/d)	19.39	14.80	15.96	31%	21%
Total (boe/d)	4,220	2,467	2,660	71%	59%
Activity					
Capital expenditures	906	1,694	539	(47%)	68%
Acquisitions	-	48,377	-		
Financial results					
Sales	17,968	8,294	7,692	117%	134%
Royalties	(1,368)	(12)	(867)	11,300%	58%
Transportation	(1,485)	(375)	(887)	296%	67%
Operating	(4,921)	(3,959)	(2,593)	24%	90%
General and administration	(1,880)	(1,755)	(2,428)	7%	(23%)
Fund flows from operations	8,314	2,193	917	279%	807%
Netbacks ($/boe)					
Sales	47.30	36.54	31.78	29%	49%
Royalties	(3.60)	(0.06)	(3.58)	5,900%	1%
Transportation	(3.91)	(1.65)	(3.67)	137%	7%
Operating	(12.96)	(17.44)	(10.71)	(26%)	21%
General and administration	(4.95)	(7.73)	(10.03)	(36%)	(51%)
Fund flows from operations netback	21.88	9.66	3.79	127%	477%
Realized prices					
Crude oil ($/bbl)	65.62	-	-	100%	100%
Natural gas ($/mmbtu)	6.95	6.09	5.30	14%	31%
Total ($/boe)	47.30	36.54	31.78	29%	49%
Reference prices					
Dated Brent (US $/bbl)	53.78	49.46	33.89	9%	59%
Dated Brent ($/bbl)	71.15	65.97	46.59	8%	53%
TTF ($/mmbtu)	7.65	7.21	5.70	6%	34%
TTF (€/mmbtu)	5.43	5.01	3.76	8%	44%

Production

- Q1 2017 production increased 71% from the prior quarter and 59% year-over-year due to production additions from the Engie Acquisition that closed December 2016.

Activity review

- Q1 2017 activity focused on the successful integration of the acquired assets and field staff.
- In 2017, we plan to continue our ongoing analysis of the geologic data associated with the farm-in assets and to continue integration activities associated with the asset acquisition. We will also continue permitting and pre-drill activities associated with our first operated well in Germany, Burgmoor Z5 well (25% working interest) in the Dümmersee-Uchte area, which we plan to drill in 2018.

Sales

- The price of our natural gas in Germany is based on the TTF index.
- Q1 2017 sales per boe increased versus Q4 2016 and Q1 2016 as a result of the addition of crude oil production from the Engie Acquisition, as well as stronger TTF prices.

Royalties

- Our production in Germany is subject to state and private royalties on sales after certain eligible deductions.
- Q1 2017 royalties as a percentage of sales was 7.6% as compared to a negligible amount in Q4 2016 as a result of favorable prior period adjustments recorded in the prior quarter.

Transportation

- Transportation expense in Germany relates to costs incurred to deliver natural gas from the processing facility to the customer.
- Q1 2017 transportation expense increased as compared to Q4 2016 and Q1 2016 due to additional volumes associated with the Engie Acquisition.

Operating

- Operating expense for Q1 2017 increased versus Q4 2016 and Q1 2016 due to the Engie Acquisition.

General and administration

- Q1 2017 general and administration expense was consistent with Q4 2016 and lower than Q1 2016 due to head office allocations.
- Our per unit general and administration costs have improved as a result of our growing production base 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

	Three Months Ended			% change	
Ireland business unit ($M except as indicated)	Mar 31, 2017	Dec 31, 2016	Mar 31, 2016	Q1/17 vs. Q4/16	Q1/17 vs. Q1/16
Production and sales					
Natural gas (mmcf/d)	64.82	62.92	33.90	3%	91%
Total (boe/d)	10,803	10,486	5,650	3%	91%
Activity					
Capital expenditures	(804)	1,711	3,076	(147%)	(126%)
Financial results					
Sales	44,648	42,727	17,004	4%	163%
Transportation	(1,199)	(1,703)	(1,639)	(30%)	(27%)
Operating	(3,999)	(5,148)	(3,626)	(22%)	10%
General and administration	(438)	(1,523)	(1,188)	(71%)	(63%)
Fund flows from operations	39,012	34,353	10,551	14%	270%
Netbacks ($/boe)					
Sales	45.92	44.29	33.07	4%	39%
Transportation	(1.23)	(1.77)	(3.19)	(31%)	(61%)
Operating	(4.11)	(5.34)	(7.05)	(23%)	(42%)
General and administration	(0.45)	(1.58)	(2.31)	(72%)	(81%)
Fund flows from operations netback	40.13	35.60	20.52	13%	96%
Reference prices					
NBP ($/mmbtu)	7.96	7.51	5.97	6%	33%
NBP (€/mmbtu)	5.64	5.22	3.94	8%	43%

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.
- Q1 2017 production increased 3% quarter-over-quarter due to reduced downtime and increased 91% year-over-year as Q1 2016 production volumes were restricted during the commissioning period that occurred in the first half of 2016.
- Production results continued to benefit from better than expected well deliverability and minimal downtime.

Activity review

- There is limited capital activity planned for 2017.

Sales

- The price of our natural gas in Ireland is based on the NBP index.
- Q1 2017 sales per boe increased relative to Q4 2016 and Q1 2016, consistent with increases 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.
- Q1 2017 transportation expense decreased versus Q4 2016 due to a prior period adjustment recorded in the previous quarter.
- Q1 2017 transportation expense decreased as compared to Q1 2016 due to an expected decrease in the current year ship or pay obligation.

Operating

- Q1 2017 operating expense on a per unit basis decreased as compared to Q4 2016 as a result of less costs allocated by the project operator as well as higher production. As compared to Q1 2016, operating expense per boe decreased by 42% predominately as a result of increased production.

General and administration

- General and administrative expense for the three months ended March 31, 2017 was lower versus the comparative periods due to timing of expenditures and allocations from our corporate segment.

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

Australia business unit ($M except as indicated)	Three Months Ended Mar 31, 2017	Dec 31, 2016	Mar 31, 2016	% change Q1/17 vs. Q4/16	Q1/17 vs. Q1/16
Production					
Crude oil (bbls/d)	6,581	6,388	6,180	3%	6%
Total (boe/d)	6,581	6,388	6,180	3%	6%
Sales					
Crude oil (bbls/d)	5,041	6,038	4,668	(17%)	8%
Inventory (mbbls)					
Opening crude oil inventory	115	82	75	40%	53%
Crude oil production	592	588	562	1%	5%
Crude oil sales	(454)	(555)	(424)	(18%)	7%
Closing crude oil inventory	253	115	213		
Activity					
Capital expenditures	3,438	5,236	7,827	(34%)	(56%)
Financial results					
Sales	34,987	38,352	19,935	(9%)	76%
Operating	(10,036)	(14,905)	(7,491)	(33%)	34%
General and administration	(2,430)	(1,998)	(1,325)	22%	83%
PRRT	(5,434)	(1,568)	(128)	247%	4,145%
Corporate income taxes	(1,396)	(2,703)	(777)	(48%)	80%
Fund flows from operations	15,691	17,178	10,214	(9%)	54%
Netbacks ($/boe)					
Sales	77.11	69.05	46.93	12%	64%
Operating	(22.12)	(26.83)	(17.63)	(18%)	25%
General and administration	(5.35)	(3.60)	(3.12)	49%	71%
PRRT	(11.98)	(2.82)	(0.30)	325%	3,893%
Corporate income taxes	(3.08)	(4.87)	(1.83)	(37%)	68%
Fund flows from operations netback	34.58	30.93	24.05	12%	44%
Reference prices					
Dated Brent (US $/bbl)	53.78	49.46	33.89	9%	59%
Dated Brent ($/bbl)	71.15	65.97	46.59	8%	53%

Production

- Q1 2017 production increased 3% quarter-over-quarter and 6% 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

- Q1 2017 efforts were largely focused on facilities enhancement, including work relating to platform life extension.
- Following our successful 2015 and 2016 drilling campaigns, we do not expect to drill any additional wells in Australia until 2019.
- 2017 activity will be focused on adding value through asset optimization and targeted proactive maintenance.

Sales

- Crude oil in Australia is priced with reference to Dated Brent.
- Q1 2017 sales per boe increased versus Q4 2016 and Q1 2016, consistent with higher Dated Brent prices. Quarter-over-quarter, the increase in sales per boe was offset by a decrease in sales volumes due to a 138,000 bbl inventory build related to shipment timing. Based on anticipated shipment schedules, we expect that this inventory build will reverse over the course of the year. Year-over-year, the increase in price was combined with higher sales volumes, resulting in an increase in 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 per boe basis for Q1 2017 decreased as compared to Q4 2016 and increased as compared to Q1 2016 as a result of the timing of major project and maintenance work.

General and administration

- Variances in general and administration expense for Q1 2017 versus the comparable quarters was largely the result of expenditure timing and allocations from our corporate segment.

Current 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 paid.
- For 2017, the effective tax rate for current income taxes is expected to be between approximately 29% and 31% of pre-tax fund flows from operations. This is subject to change in response to production variations, commodity price fluctuations, the timing of capital expenditures and other eligible in-country adjustments.
- Current income taxes in Q1 2017 were higher compared to Q4 2016 as decreased sales in Q1 2017 were offset by a higher forecasted full year effective tax rate. Current income taxes in Q1 2017 were higher compared to Q1 2016 due to increased sales in the current quarter.

UNITED STATES BUSINESS UNIT

Overview

- Entered the United States in September 2014.
- Interests include approximately 94,600 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	
United States business unit ($M except as indicated)	Mar 31, 2017	Dec 31, 2016	Mar 31, 2016	Q1/17 vs. Q4/16	Q1/17 vs. Q1/16
Production and sales					
Crude oil (bbls/d)	365	362	368	1%	(1%)
NGLs (bbls/d)	24	23	39	4%	(38%)
Natural gas (mmcf/d)	0.20	0.18	0.26	11%	(23%)
Total (boe/d)	422	414	450	2%	(6%)
Activity					
Capital expenditures	11,539	4,037	5,101	186%	126%
Acquisitions	2,013	377	115		
Gross wells drilled	3.00	1.00	-		
Net wells drilled	3.00	1.00	-		
Financial results					
Sales	2,126	2,041	1,233	4%	72%
Royalties	(599)	(611)	(370)	(2%)	62%
Operating	(285)	(301)	(279)	(5%)	2%
General and administration	(1,005)	(877)	(1,132)	15%	(11%)
Fund flows from operations	237	252	(548)	(6%)	143%
Netbacks ($/boe)					
Sales	55.99	53.58	30.10	4%	86%
Royalties	(15.79)	(16.05)	(9.03)	(2%)	75%
Operating	(7.51)	(7.91)	(6.82)	(5%)	10%
General and administration	(26.46)	(23.02)	(27.65)	15%	(4%)
Fund flows from operations netback	6.23	6.60	(13.40)	(6%)	146%
Realized prices					
Crude oil ($/bbl)	61.68	59.09	35.80	4%	72%
NGLs ($/bbl)	25.67	19.48	4.81	32%	434%
Natural gas ($/mmbtu)	2.48	1.93	0.67	28%	270%
Total ($/boe)	55.99	53.58	30.10	4%	86%
Reference prices					
WTI (US $/bbl)	51.92	49.29	33.45	5%	55%
WTI ($/bbl)	68.69	65.75	45.99	4%	49%
Henry Hub (US $/mmbtu)	3.31	2.98	2.09	11%	58%
Henry Hub ($/mmbtu)	4.38	3.98	2.87	10%	53%

Production

- Q1 2017 production was consistent with the prior quarter and the year-over-year production decrease of 6% is due to natural declines.

Activity

- In Q1 2017, we drilled three (3.0 net) wells targeting the light oil prone Turner Sand in the Powder River Basin with horizontal laterals ranging from 1,400 to 1,800 metres. The wells were completed late in the first quarter and into the second quarter with frac stages ranging from 31 to 40 stages per well.
- In Q4 2016, we completed the Seedy Draw East Federal well. The nearly 1,400 metre horizontal lateral was stimulated with 32 frac stages, but due to a screen-out during treatment, only 23 stages were completed. We initiated the clean out of sand from this well during the first quarter resulting in an additional 18 stages being completed. The well is planned to be returned to production in Q2 2017.
- Vermilion closed the acquisition of an overriding royalty interest in the quarter.

Sales

- The price of crude oil in the United States is directly linked to WTI, but is also subject to market conditions in the United States.
- Q1 2017 sales per boe increased versus Q4 2016 and Q1 2016, consistent with increases in the WTI reference price.

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 for Q1 2017 decreased to 28% from 30% in the prior quarter. This decrease is a result of our purchase of overriding royalty interests (ranging from 0.83% to 5%) for US$1.5 million, effective January 1, 2017. On a go-forward basis, we expect royalties as a percentage of sales to remain at approximately 28%.

Operating

- Operating expense remained consistent across the periods presented.

General and administration

- Variances in general and administration expense for Q1 2017 versus the comparable quarters was largely the result of expenditure timing and allocations from our corporate segment.

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 Mar 31, 2017	Dec 31, 2016	Mar 31, 2016
Activity			
Capital expenditures	725	445	-
Financial Results			
General and administration (expense) recovery	(2,034)	1,987	421
Current income taxes	(194)	(370)	(149)
Interest expense	(14,695)	(14,410)	(14,750)
Realized (loss) gain on derivatives	(1,851)	1,920	28,423
Realized foreign exchange gain (loss)	2,546	1,291	(652)
Realized other income	42	120	105
Fund flows from operations	(16,186)	(9,462)	13,398

General and administration

- Fluctuations in general and administration costs for Q1 2017 versus both comparable periods were due to 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 Q1 2017 was relatively consistent with Q4 2016 and Q1 2016.

Realized gain or loss on derivatives

- The realized loss on derivatives in Q1 2017 related primarily to amounts paid on our European natural gas hedges.
- A listing of derivative positions as at March 31, 2017 is included in “Supplemental Table 2” of this MD&A.

FINANCIAL PERFORMANCE REVIEW

($M except per share)	Three Months Ended Mar 31, 2017	Dec 31, 2016	Sep 30, 2016	Jun 30, 2016	Mar 31, 2016	Dec 31, 2015	Sep 30, 2015	Jun 30, 2015
Petroleum and natural gas sales	261,601	259,891	232,660	212,855	177,385	234,319	245,051	264,331
Net earnings (loss)	44,540	(4,032)	(14,475)	(55,696)	(85,848)	(142,080)	(83,310)	6,813
Net earnings (loss) per share								
Basic	0.38	(0.03)	(0.12)	(0.48)	(0.76)	(1.28)	(0.76)	0.06
Diluted	0.37	(0.03)	(0.12)	(0.48)	(0.76)	(1.28)	(0.76)	0.06

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

	Three Months Ended Mar 31, 2017	Dec 31, 2016	Mar 31, 2016
Fund flows from operations	143,434	149,582	93,667
Equity based compensation	(18,738)	(19,489)	(20,837)
Unrealized gain (loss) on derivative instruments	79,865	(74,943)	9,054
Unrealized foreign exchange (loss) gain	(4,518)	(2,457)	1,570
Unrealized (expense) income	(30)	-	(87)
Accretion	(6,382)	(6,308)	(6,109)
Depletion and depreciation	(115,409)	(126,855)	(125,798)
Deferred taxes	(33,682)	54,437	(22,546)
Gain on business combination	-	22,001	-
Impairment	-	-	(14,762)
Net earnings (loss)	44,540	(4,032)	(85,848)

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. 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 business combinations or charges resulting from impairment or impairment reversals.

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").

Equity based compensation in Q1 2017 decreased as compared to Q4 2016 due to the absence of performance estimate revisions that occurred in Q4 2016. For the three months ended March 31, 2017, the decrease in equity based compensation is primarily due to a lower average grant value.

Unrealized gain or loss on derivative instruments

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

For the three months ended March 31, 2017, we recognized an unrealized gain on derivative instruments of $79.9 million. This unrealized gain resulted from lower forward prices for crude oil and European natural gas as at March 31, 2017. As at March 31, 2017, we have a net derivative asset position of $10.2 million as compared to a net derivative liability position of $69.7 million as at December 31, 2016.

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).

The unrealized foreign exchange loss for Q1 2017 resulted was primarily due to the impact of fluctuations in the US dollar and resulting impact on the translation of US dollar denominated long-term debt.

Accretion

Accretion expense is recognized to update the present value of the asset retirement obligation balance. 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 Q1 2017 of $20.71 was lower than $22.42 in Q4 2016 due to higher natural gas production in Canada. For the three months ended March 31, 2017, depletion and depreciation on a per boe basis of $20.71 was relatively consistent with $21.65 in the same period of 2016.

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.

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, an 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 and net dividends within forecasted fund flows from operations, which is continually monitored for revised forward price estimates, as well as by hedging additional European natural gas volumes to maintain a diversified commodity portfolio.

The balances recognized on our balance sheet are as follows:

	As at	
($M)	Mar 31, 2017	Dec 31, 2016
Revolving credit facility	874,292	1,362,192
Senior unsecured notes	393,042	-
Long-term debt	1,267,334	1,362,192

Revolving Credit Facility

As at March 31, 2017, Vermilion had in place a bank revolving credit facility maturing May 31, 2019 with the following terms:

	As at	
($M)	Mar 31, 2017	Dec 31, 2016
Total facility amount	2,000,000	2,000,000
Amount drawn	(874,292)	(1,362,192)
Letters of credit outstanding	(4,400)	(20,100)
Unutilized capacity	1,121,308	617,708

Subsequent to March 31, 2017, we negotiated an extension of our revolving credit facility with our syndicate of lenders to May 31, 2021. Further, as a result of projected liquidity requirements and the proceeds from our Senior Unsecured Notes issuance, we elected to reduce the total facility amount from $2.0 billion to $1.4 billion. The revolving credit facility remains subject to the covenants applicable as at March 31, 2017.

As at March 31, 2017, the revolving credit facility was subject to the following covenants:

		As at	
Financial covenant	Limit	Mar 31, 2017	Dec 31, 2016
Consolidated total debt to consolidated EBITDA	4.0	2.00	2.36
Consolidated total senior debt to consolidated EBITDA	3.5	1.35	2.32
Consolidated total senior debt to total capitalization	55%	30%	46%

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” 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.

Senior Unsecured Notes

On March 13, 2017, Vermilion issued US $300.0 million of senior unsecured notes at par. The notes bear interest at a rate of 5.625% per annum, to be paid semi-annually on March 15 and September 15, and mature on March 15, 2025. As direct senior unsecured obligations of Vermilion, the notes rank equally in right of payment with existing and future senior indebtedness of the Company.

The senior unsecured notes were recognized at amortized cost and include the transaction costs directly related to the issuance.

Vermilion may, at its option, redeem the notes prior to maturity as follows:

- Prior to March 15, 2020, Vermilion may redeem up to 35% of the original principal amount of the senior unsecured notes with the proceeds of certain equity offerings by the Company at a redemption price of 105.625% of the principal amount, plus any accrued and unpaid interest to but excluding the applicable redemption date.
- Prior to March 15, 2020, Vermilion may redeem some or all of the senior unsecured notes at a price equal to 100% of the principal amount of the senior unsecured notes, plus a “make-whole” premium and any accrued and unpaid interest.
- On or after March 15, 2020, Vermilion may redeem some or all of the senior unsecured notes at the redemption prices set forth in the following table, plus any accrued and unpaid interest.

Year	Redemption price
2020	104.219%
2021	102.819%
2022	101.406%
2023 and thereafter	100.000%

Net debt

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

($M)	As at Mar 31, 2017	Dec 31, 2016
Long-term debt	1,267,334	1,362,192
Current liabilities	268,282	290,862
Current assets	(157,980)	(225,906)
Net debt	1,377,636	1,427,148
Ratio of net debt to annualized fund flows from operations	2.4	2.8

As at March 31, 2017, long term debt decreased to $1.27 billion (December 31, 2016 - $1.36 billion) as fund flows from operations generated in excess of expenditures was used to reduce debt. This decrease in long-term debt, in addition to an increase in net current derivative assets, decreased net debt from $1.43 billion at December 31, 2016 to $1.38 billion at March 31, 2017. The decrease in net debt coupled with relatively consistent fund flows from operations resulted in a decrease in the ratio of net debt to annualized fund flows from operations from 2.8 to 2.4.

Shareholders' capital

During the three months ended March 31, 2017, we maintained monthly dividends at $0.215 per share and declared $76.6 million of dividends.

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.

We commenced proration of the Premium Dividend™ of our Dividend Reinvestment Plan by 25% beginning with our October 2016 dividend payment. We continued to further increase the level of proration applied to the Premium Dividend™ Component of our Premium Dividend™ and Dividend Reinvestment Plan during the first quarter. Beginning with the January 2017 dividend payment, the number of participating shares was prorated to 50% and we further increased the proration factor by an additional 25% beginning with the April 2017 dividend payment. As such, eligible shareholders who have elected to participate in the Premium Dividend™ Component now receive a 1.5% premium on 25% of their participating shares, and the regular cash dividend on the remaining 75% of their shares. We plan to discontinue the Premium Dividend™ Component of our Premium Dividend™ and Dividend Reinvestment Plan beginning with the July 2017 dividend payment, such that there would be no further equity issuance under this program. We also reduced the discount associated with the traditional component of our Premium Dividend™ and Dividend Reinvestment Plan from 3% to 2% beginning with the January 2017 dividend.

Although we expect to be able to maintain our current dividend, fund flows from operations may not be sufficient 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, 2016	118,263	2,452,722
Shares issued for the Dividend Reinvestment Plan	686	35,506
Shares issued for equity based compensation	97	4,894
Balance as at March 31, 2017	119,046	2,493,122

As at March 31, 2017, there were approximately 1.7 million VIP awards outstanding. As at April 27, 2017, there were approximately 120.5 million common shares issued and outstanding.

ASSET RETIREMENT OBLIGATIONS

As at March 31, 2017, asset retirement obligations were $529.4 million compared to $525.0 million as at December 31, 2016.

The increase in asset retirement obligations is largely attributable to accretion.

OFF BALANCE SHEET ARRANGEMENTS

We have certain lease agreements that are entered into in the normal course of operations, including operating leases for which no asset or liability value has been assigned to the consolidated balance sheet as at March 31, 2017.

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, 2016.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with IFRS requires management to make estimates, judgments and assumptions that affect reported assets, liabilities, revenues and expenses, gains and losses, and disclosures of any possible contingencies. These estimates and assumptions are developed based on the best available information which management believed to be reasonable at the time such estimates and assumptions were made. As such, these assumptions are uncertain at the time estimates are made and could change, resulting in a material impact on Vermilion's consolidated financial statements. Estimates are reviewed by management on an ongoing basis and as a result may change from period to period due to the availability of new information or changes in circumstances. Additionally, as a result of the unique circumstances of each jurisdiction that Vermilion operates in, the critical accounting estimates may affect one or more jurisdictions. There have been no material changes to our critical accounting estimates used in applying accounting policies for the three months ended March 31, 2017. 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, 2016, 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.

ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

The following IFRS have been issued by the IASB but are not yet effective:

- IFRS 9 "Financial Instruments" will be adopted January 1, 2018. IFRS 9 includes changes to the classification and measurement of financial instruments and general hedge accounting.
- IFRS 15 "Revenue from Contracts with Customers" will be adopted January 1, 2018. IFRS 15 specifies recognition and measurement requirements for contracts with customers.
- IFRS 16 "Leases" will be adopted January 1, 2019. IFRS 16 requires lessees to recognize a lease obligation and right-of-use asset for the majority of leases.

On the adoption of IFRS 9, Vermilion does not currently anticipate changes to the measured amount of financial instruments and correspondingly does not currently anticipate material changes to net earnings.

In the adoption of IFRS 15, Vermilion has in place a transition team that has been performing a detailed review of the Company's standard contracts with customers in accordance with the issued IFRS to determine the impact, if any, the adoption of IFRS 15 will have on its financial statements. Vermilion continues to assess this new standard and review its impacts.

The impact of the adoption of IFRS 16 is currently being evaluated.

Supplemental Table 1: Netbacks

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

	Three Months Ended March 31, 2017			Three Months Ended March 31, 2016		
	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe
Canada						
Sales	54.67	2.99	33.63	33.11	1.93	21.16
Royalties	(7.16)	(0.21)	(3.79)	(4.03)	(0.08)	(2.07)
Transportation	(2.52)	(0.22)	(1.83)	(2.30)	(0.16)	(1.57)
Operating	(8.07)	(1.16)	(7.42)	(7.32)	(1.44)	(8.05)
Operating netback	36.92	1.40	20.59	19.46	0.25	9.47
General and administration			(0.76)			(0.94)
Fund flows from operations netback			19.83			8.53
France						
Sales	67.86	1.52	67.85	43.36	1.66	43.16
Royalties	(6.06)	(0.44)	(6.06)	(6.09)	(0.29)	(6.07)
Transportation	(3.45)	-	(3.45)	(3.35)	-	(3.33)
Operating	(12.94)	(1.18)	(12.94)	(12.84)	(2.24)	(12.84)
Operating netback	45.41	(0.10)	45.40	21.08	(0.87)	20.92
General and administration			(3.49)			(4.19)
Current income taxes			(5.67)			(0.03)
Fund flows from operations netback			36.24			16.70
Netherlands						
Sales	58.33	7.34	44.19	32.24	5.55	33.26
Royalties	-	(0.12)	(0.69)	-	(0.09)	(0.56)
Operating	-	(1.35)	(7.99)	-	(1.23)	(7.28)
Operating netback	58.33	5.87	35.51	32.24	4.23	25.42
General and administration			(0.98)			(0.94)
Current income taxes			(1.50)			(2.68)
Fund flows from operations netback			33.03			21.80
Germany						
Sales	65.62	6.95	47.30	-	5.30	31.78
Royalties	(3.67)	(0.60)	(3.60)	-	(0.60)	(3.58)
Transportation	(8.11)	(0.44)	(3.91)	-	(0.61)	(3.67)
Operating	(16.53)	(1.98)	(12.96)	-	(1.79)	(10.71)
Operating netback	37.31	3.93	26.83	-	2.30	13.82
General and administration			(4.95)			(10.03)
Fund flows from operations netback			21.88			3.79
Ireland						
Sales	-	7.65	45.92	-	5.51	33.07
Transportation	-	(0.21)	(1.23)	-	(0.53)	(3.19)
Operating	-	(0.69)	(4.11)	-	(1.18)	(7.05)
Operating netback	-	6.75	40.58	-	3.80	22.83
General and administration			(0.45)			(2.31)
Fund flows from operations netback			40.13			20.52
Australia						
Sales	77.11	-	77.11	46.93	-	46.93
Operating	(22.12)	-	(22.12)	(17.63)	-	(17.63)
PRRT [1]	(11.98)	-	(11.98)	(0.30)	-	(0.30)
Operating netback	43.01	-	43.01	29.00	-	29.00
General and administration			(5.35)			(3.12)
Corporate income taxes			(3.08)			(1.83)
Fund flows from operations netback			34.58			24.05

	Three Months Ended March 31, 2017			Three Months Ended March 31, 2016		
	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe
United States						
Sales	59.45	2.48	55.99	32.84	0.67	30.10
Royalties	(16.60)	(1.03)	(15.79)	(9.73)	(0.40)	(9.03)
Operating	(8.15)	-	(7.51)	(7.54)	-	(6.82)
Operating netback	34.70	1.45	32.69	15.57	0.27	14.25
General and administration			(26.46)			(27.65)
Fund flows from operations netback			6.23			(13.40)
Total Company						
Sales	64.14	5.62	46.94	39.35	3.76	30.53
Realized hedging gain (loss)	0.39	(0.15)	(0.33)	3.18	1.07	4.89
Royalties	(5.41)	(0.16)	(2.91)	(4.30)	(0.11)	(2.40)
Transportation	(2.55)	(0.19)	(1.76)	(2.33)	(0.22)	(1.79)
Operating	(12.76)	(1.12)	(9.35)	(11.10)	(1.37)	(9.58)
PRRT (1)	(2.24)	-	(0.97)	(0.05)	-	(0.02)
Operating netback	41.57	4.00	31.62	24.75	3.13	21.63
General and administration			(2.36)			(2.34)
Interest expense			(2.64)			(2.54)
Realized foreign exchange gain (loss)			0.46			(0.11)
Other income			0.01			0.02
Corporate income taxes (1)			(1.34)			(0.54)
Fund flows from operations netback			25.75			16.12

(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 March 31, 2017:

Crude Oil	Period	Exercise date[1]	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	Swap Volume (bbl/d)	Weighted Average Swap Price / bbl	Additional Swap Volume (mmbtu/d) [2]
Dated Brent												
3-Way Collar	Jan 2017 - Dec 2017		USD	2,500	51.00	2,500	60.50	2,500	41.50	-	-	-
3-Way Collar	Jul 2017 - Jun 2018		USD	2,000	55.00	2,000	64.06	2,000	45.00	-	-	-
Put Spread	Apr 2017 - Dec 2017		USD	600	56.00	-	-	600	46.25	-	-	-
Put Spread	Jul 2017 - Dec 2017		USD	500	55.00	-	-	500	47.50	-	-	-
Swap	Jan 2017 - Dec 2017		USD	-	-	-	-	-	-	650	55.00	-
Swaption	Jul 2017 - Jun 2018	May 31, 2017	USD	-	-	-	-	-	-	975	60.00	-
Swaption	Jul 2017 - Jun 2018	Jun 30, 2017	USD	-	-	-	-	-	-	1,000	60.00	-
WTI												
3-Way Collar	Jan 2017 - Dec 2017		CAD	1,500	70.00	1,500	75.00	1,500	55.00	-	-	-
Swap	Apr 2017		CAD	-	-	-	-	-	-	500	72.70	-
3-Way Collar	Jul 2017 - Dec 2017		USD	3,000	54.33	3,000	65.58	3,000	45.00	-	-	-
Swap	Apr 2017		USD	-	-	-	-	-	-	1,000	54.85	-

North American Gas	Period	Exercise date[1]	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 Volume (mmbtu/d)	Weighted Average Sold Put Price / mmbtu	Swap Volume (mmbtu/d)	Weighted Average Swap Price / mmbtu	Additional Swap Volume (mmbtu/d) [2]
AECO												
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	Nov 2016 - Dec 2017		CAD	-	-	-	-	-	-	2,370	2.99	-
Swap	Jan 2017 - Dec 2017		CAD	-	-	-	-	-	-	7,109	2.94	-
Swap	Apr 2017 - Oct 2017		CAD	-	-	-	-	-	-	7,109	3.01	-
Swap	Nov 2017 - Dec 2017		CAD	-	-	-	-	-	-	7,109	3.35	-
AECO Basis (AECO less NYMEX HH)												
Swap	Jan 2017 - Dec 2017		USD	-	-	-	-	-	-	5,000	(0.75)	-
Swap	Jan 2018 - Dec 2018		USD	-	-	-	-	-	-	10,000	(0.83)	-
NYMEX HH												
Swap	Jan 2017 - Dec 2017		USD	-	-	-	-	-	-	5,000	3.00	-
Swap	Jan 2018 - Dec 2018		USD	-	-	-	-	-	-	2,500	3.10	-

(1) The sold swaption instrument allows the counterparty, at the specified date, to enter into a swap with Vermilion at the above detailed terms.

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

European Gas	Period	Exercise date[1]	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 Volume (mmbtu/d)	Weighted Average Sold Put Price / mmbtu	Swap Volume (mmbtu/d)	Weighted Average Swap price / mmbtu	Additional Swap Volume (mmbtu/d) [2]
NBP												
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	-	-	-	-	-
Swap	Jan 2017 - Dec 2017		GBP	-	-	-	-	-	-	2,500	4.22	2,500
Swap	Apr 2017 - Mar 2018		GBP	-	-	-	-	-	-	5,300	4.20	-
Swap	Jul 2017 - Dec 2017		GBP	-	-	-	-	-	-	2,500	3.95	-
Swap	Jan 2018 - Dec 2018		GBP	-	-	-	-	-	-	2,500	4.04	5,000
NBP Basis (NBP less NYMEX HH)												
Collar	Jan 2017 - Dec 2017		USD	2,500	1.85	2,500	4.00	-	-	-	-	-
TTF												
3-Way Collar	Apr 2017 - Sep 2017		EUR	9,827	4.18	9,827	5.06	9,827	3.08	-	-	-
3-Way Collar	Oct 2017 - Dec 2019		EUR	7,370	4.59	7,370	5.42	7,370	2.93	-	-	-
3-Way Collar	Jan 2018 - Dec 2018		EUR	12,284	4.75	12,284	5.48	12,284	3.25	-	-	-
3-Way Collar	Jan 2018 - Dec 2019		EUR	3,685	4.74	3,685	5.52	3,685	3.13	-	-	-
3-Way Collar	Jan 2019 - Dec 2019		EUR	7,370	5.00	7,370	5.54	7,370	3.57	-	-	-
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	-	-	-	-	-
Swap	Jul 2016 - Jun 2018		EUR	-	-	-	-	-	-	2,559	5.89	-
Swap	Jan 2017 - Dec 2017		EUR	-	-	-	-	-	-	2,457	5.32	2,457
Swap	Apr 2017 - Jun 2018		EUR	-	-	-	-	-	-	4,299	4.50	-
Swap	Oct 2017 - Dec 2018		EUR	-	-	-	-	-	-	17,197	4.80	-
Swap	Oct 2017 - Dec 2019		EUR	-	-	-	-	-	-	7,370	4.87	-
Swap	Jan 2018 - Dec 2019		EUR	-	-	-	-	-	-	1,228	5.00	-
Swap	Jan 2019 - Dec 2019		EUR	-	-	-	-	-	-	2,457	4.92	-
Put Spread	Apr 2017 - Sep 2017		EUR	14,740	4.40	-	-	14,740	3.15	-	-	-

Fuel and Electricity	Period	Currency	Swap Volume (unit/d)	Weighted Average Swap price / unit
AESO (mwh)				
Swap	Jan 2017 - Dec 2017	CAD	65	33.47

Interest Rate	Period	Currency	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 Interest Rate	Period	Receive Notional amount(USD)	Rate (USD%)	Pay Notional amount(CAD)	Rate (CAD%)
Swap [3]	Apr 2017	633,907,993	3.54	845,800,000	3.33

(1) The sold swaption instrument allows the counterparty, at the specified date, to enter into a swap with Vermilion at the above detailed terms.

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

(3) In April 2017, Vermilion repaid $0.9 billion of borrowings on the revolving credit facility bearing interest at CDOR plus applicable margins and simultaneously borrowed US $0.6 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 Mar 31, 2017	Dec 31, 2016	Mar 31, 2016
Drilling and development	95,164	66,437	62,773
Exploration and evaluation	725	445	-
Capital expenditures	95,889	66,882	62,773
Property acquisition	2,620	78,713	870
Acquisitions	2,620	78,713	870

By category ($M)	Three Months Ended Mar 31, 2017	Dec 31, 2016	Mar 31, 2016
Land	1,445	59	1,039
Seismic	2,011	1,757	6,268
Drilling and completion	55,386	38,233	27,853
Production equipment and facilities	30,176	26,768	6,238
Recompletions	5,501	3,293	3,598
Other	1,370	(3,228)	17,777
Capital expenditures	95,889	66,882	62,773
Acquisitions	2,620	78,713	870
Total capital expenditures and acquisitions	98,509	145,595	63,643

Capital expenditures by country ($M)	Three Months Ended Mar 31, 2017	Dec 31, 2016	Mar 31, 2016
Canada	57,457	16,895	29,771
France	20,916	31,127	13,463
Netherlands	1,712	5,737	2,996
Germany	906	1,694	539
Ireland	(804)	1,711	3,076
Australia	3,438	5,236	7,827
United States	11,539	4,037	5,101
Corporate	725	445	-
Total capital expenditures	95,889	66,882	62,773

Acquisitions by country ($M)	Three Months Ended Mar 31, 2017	Dec 31, 2016	Mar 31, 2016
Canada	576	1,378	755
France	-	-	-
Netherlands	16	28,259	-
Germany	-	48,377	-
Ireland	-	-	-
Australia	-	-	-
United States	2,013	377	115
Corporate	15	322	-
Total acquisitions	2,620	78,713	870

Supplemental Table 4: Production

	Q1/17	Q4/16	Q3/16	Q2/16	Q1/16	Q4/15	Q3/15	Q2/15	Q1/15	Q4/14	Q3/14	Q2/14
Canada												
Crude oil & condensate (bbls/d)	7,987	7,945	8,984	9,453	10,317	10,413	11,030	11,843	12,163	12,681	12,755	14,108
NGLs (bbls/d)	2,670	2,444	2,448	2,687	2,633	2,710	2,678	2,094	1,706	1,444	1,005	1,364
Natural gas (mmcf/d)	85.74	75.12	77.62	87.44	97.16	87.90	71.94	64.66	61.78	58.36	57.07	57.59
Total (boe/d)	24,947	22,910	24,368	26,713	29,141	27,773	25,698	24,713	24,165	23,851	23,272	25,070
% of consolidated	38%	38%	37%	42%	44%	45%	47%	48%	48%	49%	47%	49%
France												
Crude oil (bbls/d)	10,834	11,220	11,827	12,326	12,220	12,537	12,310	12,746	11,463	11,133	11,111	11,025
Natural gas (mmcf/d)	0.01	0.38	0.42	0.54	0.44	1.36	1.47	1.03	-	-	-	-
Total (boe/d)	10,836	11,283	11,897	12,416	12,293	12,763	12,555	12,917	11,463	11,133	11,111	11,025
% of consolidated	17%	19%	19%	19%	19%	21%	22%	25%	23%	22%	22%	21%
Netherlands												
Condensate (bbls/d)	76	57	86	96	114	110	109	112	63	81	63	96
Natural gas (mmcf/d)	39.92	41.15	47.62	49.18	53.40	56.34	53.56	32.43	36.41	31.35	38.07	40.35
Total (boe/d)	6,729	6,915	8,023	8,293	9,015	9,500	9,035	5,517	6,132	5,306	6,407	6,822
% of consolidated	10%	11%	13%	13%	14%	16%	16%	11%	12%	11%	13%	13%
Germany												
Crude Oil (bbls/d)	989	-	-	-	-	-	-	-	-	-	-	-
Natural gas (mmcf/d)	19.39	14.80	14.52	14.31	15.96	16.17	14.00	16.18	16.80	17.71	15.38	16.13
Total (boe/d)	4,220	2,467	2,420	2,385	2,660	2,695	2,333	2,696	2,801	2,952	2,563	2,689
% of consolidated	7%	4%	4%	4%	4%	4%	4%	5%	6%	6%	5%	5%
Ireland												
Natural gas (mmcf/d)	64.82	62.92	59.28	47.26	33.90	0.12	-	-	-	-	-	-
Total (boe/d)	10,803	10,486	9,879	7,877	5,650	20	-	-	-	-	-	-
% of consolidated	17%	17%	16%	12%	9%	-	-	-	-	-	-	-
Australia												
Crude oil (bbls/d)	6,581	6,388	6,562	6,083	6,180	7,824	6,433	5,865	5,672	6,134	6,567	6,483
% of consolidated	10%	10%	10%	9%	9%	13%	11%	11%	11%	12%	13%	12%
United States												
Crude oil (bbls/d)	365	362	383	458	368	420	226	123	153	195	-	-
NGLs (bbls/d)	24	23	30	26	39	29	-	-	-	-	-	-
Natural gas (mmcf/d)	0.20	0.18	0.20	0.20	0.26	0.20	-	-	-	-	-	-
Total (boe/d)	422	414	447	518	450	483	226	123	153	195	-	-
% of consolidated	1%	1%	1%	1%	1%	1%	-	-	-	-	-	-
Consolidated												
Crude oil, condensate & NGLs (bbls/d)	29,526	28,439	30,320	31,129	31,871	34,043	32,786	32,783	31,220	31,668	31,501	33,076
% of consolidated	46%	47%	48%	48%	49%	56%	58%	63%	62%	64%	63%	63%
Natural gas (mmcf/d)	210.07	194.54	199.65	198.93	201.11	162.09	140.97	114.29	115.00	107.42	110.52	114.08
% of consolidated	54%	53%	52%	52%	51%	44%	42%	37%	38%	36%	37%	37%
Total (boe/d)	64,537	60,863	63,596	64,285	65,389	61,058	56,280	51,831	50,386	49,571	49,920	52,089

	YTD 2017	2016	2015	2014	2013	2012
Canada						
Crude oil & condensate (bbls/d)	7,987	9,171	11,357	12,491	8,387	7,659
NGLs (bbls/d)	2,670	2,552	2,301	1,233	1,666	1,232
Natural gas (mmcf/d)	85.74	84.29	71.65	55.67	42.39	37.50
Total (boe/d)	24,947	25,771	25,598	23,001	17,117	15,142
% of consolidated	38%	40%	46%	47%	41%	40%
France						
Crude oil (bbls/d)	10,834	11,896	12,267	11,011	10,873	9,952
Natural gas (mmcf/d)	0.01	0.44	0.97	-	3.40	3.59
Total (boe/d)	10,836	11,970	12,429	11,011	11,440	10,550
% of consolidated	17%	19%	23%	22%	28%	28%
Netherlands						
Condensate (bbls/d)	76	88	99	77	64	67
Natural gas (mmcf/d)	39.92	47.82	44.76	38.20	35.42	34.11
Total (boe/d)	6,729	8,058	7,559	6,443	5,967	5,751
% of consolidated	10%	13%	14%	13%	15%	15%
Germany						
Crude oil (bbls/d)	989	-	-	-	-	-
Natural gas (mmcf/d)	19.39	14.90	15.78	14.99	-	-
Total (boe/d)	4,220	2,483	2,630	2,498	-	-
% of consolidated	7%	4%	5%	5%	-	-
Ireland						
Natural gas (mmcf/d)	64.82	50.89	0.03	-	-	-
Total (boe/d)	10,803	8,482	5	-	-	-
% of consolidated	17%	13%	-	-	-	-
Australia						
Crude oil (bbls/d)	6,581	6,304	6,454	6,571	6,481	6,360
% of consolidated	10%	10%	12%	13%	16%	17%
United States						
Crude oil (bbls/d)	365	393	231	49	-	-
NGLs (bbls/d)	24	29	7	-	-	-
Natural gas (mmcf/d)	0.20	0.21	0.05	-	-	-
Total (boe/d)	422	457	247	49	-	-
% of consolidated	1%	1%	-	-	-	-
Consolidated						
Crude oil, condensate & NGLs (bbls/d)	29,526	30,433	32,716	31,432	27,471	25,270
% of consolidated	46%	48%	60%	63%	67%	67%
Natural gas (mmcf/d)	210.07	198.55	133.24	108.85	81.21	75.20
% of consolidated	54%	52%	40%	37%	33%	33%
Total (boe/d)	64,537	63,526	54,922	49,573	41,005	37,803

NON-GAAP FINANCIAL MEASURES

This MD&A includes references to certain financial measures which do not have standardized meanings and may not be comparable to similar measures presented by other issuers. 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:

Capital expenditures: The sum of drilling and development and exploration and evaluation from the Consolidated Statement of Cash Flows. We consider capital expenditures to be a useful measure of our investment in our existing asset base. Capital expenditures are also referred to as E&D capital.

Cash dividends per share: Represents cash dividends declared per share and is a useful measure of the dividends a common shareholder was entitled to during the period.

Covenants: The financial covenants on our revolving credit facility contain non-GAAP measures. The definitions for these financial covenants are included in FINANCIAL POSITION REVIEW.

Diluted shares outstanding: 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.

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

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.

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.

Operating netback: Sales less royalties, operating expense, transportation costs, PRRT, and realized hedging gains and losses presented on a per unit basis. Management assesses operating netback as a measure of the profitability and efficiency of our field operations. In contrast, fund flows from operations netback also includes general and administration expense, corporate income taxes and interest. Fund flows from operations netback is used by management to assess the profitability of our business units and Vermilion as a whole.

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.

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		
($M)	Mar 31, 2017	Dec 31, 2016	Mar 31, 2016
Dividends declared	76,593	76,096	72,847
Shares issued for the Dividend Reinvestment Plan	(35,506)	(43,580)	(47,990)
Net dividends	41,087	32,516	24,857
Drilling and development	95,164	66,437	62,773
Exploration and evaluation	725	445	-
Asset retirement obligations settled	2,249	3,327	2,024
Payout	139,225	102,725	89,654

	As at		
('000s of shares)	Mar 31, 2017	Dec 31, 2016	Mar 31, 2016
Shares outstanding	119,046	118,263	113,451
Potential shares issuable pursuant to the VIP	3,089	3,090	3,040
Diluted shares outstanding	122,135	121,353	116,491

CORPORATE INFORMATION

DIRECTORS

Lorenzo Donadeo [1]
Calgary, Alberta

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

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

William Roby [5, 6]
Katy, Texas

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

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

Alberta Treasury Branches

Bank of America N.A., Canada Branch

BNP Paribas, Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

HSBC Bank Canada

JPMorgan Chase Bank, N.A., Toronto Branch

La Caisse Centrale Desjardins du Québec

Wells Fargo Bank N.A., Canadian 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")

INVESTOR RELATIONS

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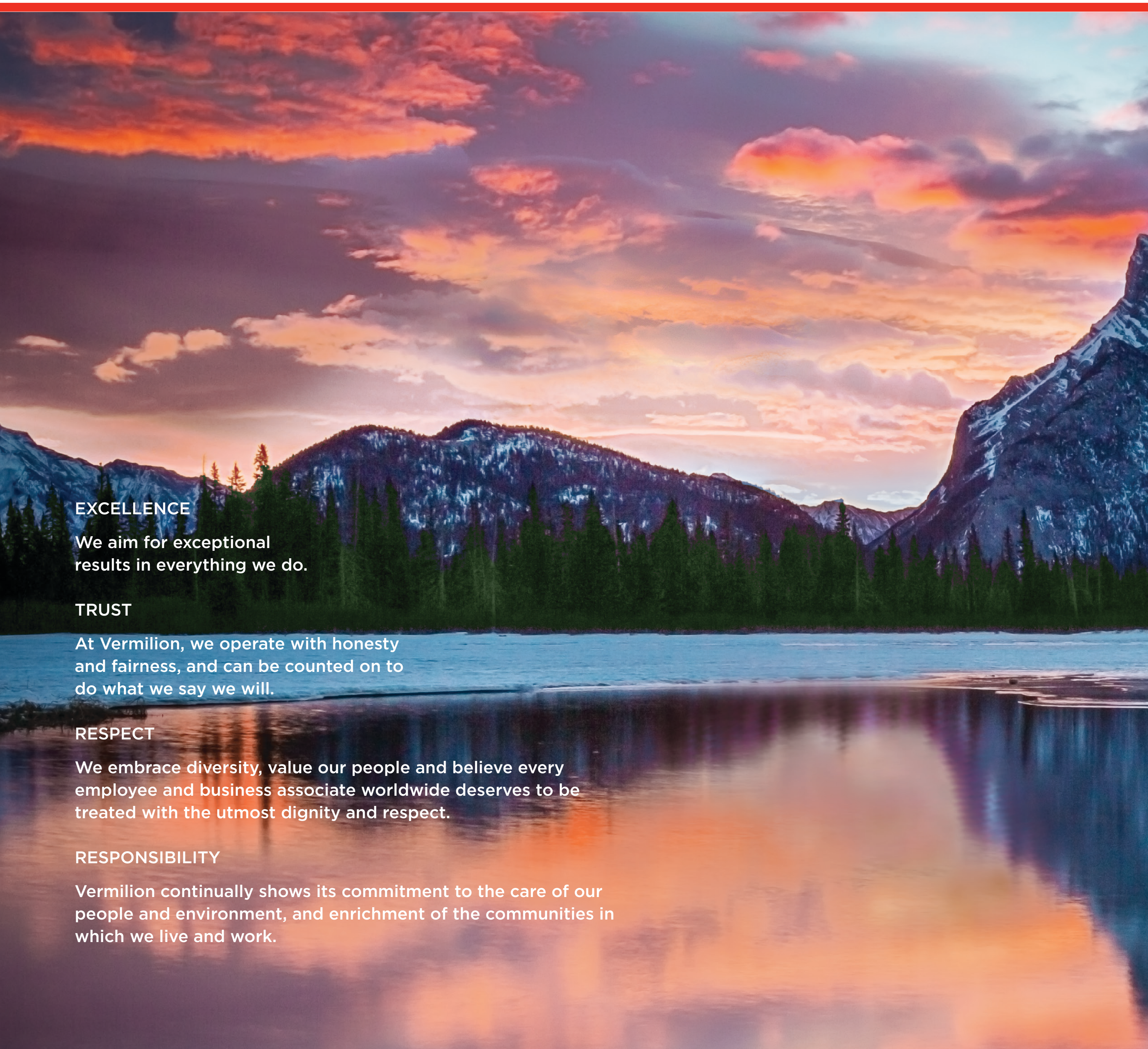

EXCELLENCE

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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