Q3 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 October 26, 2017, 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, 2017 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, 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 and nine months ended September 30, 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).

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. On July 26, 2017 we announced an increase in our capital expenditure guidance from $295 million to $315 million following the acceleration of 2018 activities in our Canadian business unit. We also adjusted our 2017 annual production guidance on October 30, 2017 to 68,000-69,000 boe/d to reflect an extended downtime period following a plant turnaround at our Corrib asset in Ireland.

We released our 2018 capital budget and related guidance concurrent with the release of our Q3 2017 results.

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
2017 Guidance	July 26, 2017	315	69,000 to 70,000
2017 Guidance	October 30, 2017	315	68,000 to 69,000
2018 Guidance			
2018 Guidance	October 30, 2017	315	74,500 to 76,500

CONSOLIDATED RESULTS OVERVIEW

	Three Months Ended			% change		Nine Months Ended		% change
	Sep 30, 2017	Jun 30, 2017	Sep 30, 2016	Q3/17 vs. Q2/17	Q3/17 vs. Q3/16	Sep 30, 2017	Sep 30, 2016	2017 vs. 2016
Production								
Crude oil and condensate (bbls/d)	27,687	28,525	27,842	(3%)	(1%)	27,684	28,483	(3%)
NGLs (bbls/d)	4,947	3,821	2,478	29%	100%	3,828	2,621	46%
Natural gas (mmcf/d)	208.63	209.36	199.66	-	4%	209.35	199.90	5%
Total (boe/d)	67,403	67,240	63,596	-	6%	66,404	64,421	3%
Sales								
Crude oil and condensate (bbls/d)	28,391	29,639	30,111	(4%)	(6%)	27,431	28,474	(4%)
NGLs (bbls/d)	4,947	3,821	2,478	29%	100%	3,828	2,621	46%
Natural gas (mmcf/d)	208.63	209.36	199.66	-	4%	209.35	199.90	5%
Total (boe/d)	68,107	68,355	65,865	-	3%	66,151	64,411	3%
Build (draw) in inventory (mbbls)	(64)	(102)	(209)			69	3	
Financial metrics								
Fund flows from operations ($M)	130,755	147,123	140,974	(11%)	(7%)	421,312	361,209	17%
Per share ($/basic share)	1.08	1.22	1.21	(11%)	(11%)	3.51	3.14	12%
Net earnings (loss)	(39,191)	48,264	(14,475)	N/A	171%	53,613	(156,019)	N/A
Per share ($/basic share)	(0.32)	0.40	(0.12)	N/A	167%	0.45	(1.36)	N/A
Net debt ($M)	1,370,995	1,314,766	1,343,923	4%	2%	1,370,995	1,343,923	2%
Cash dividends ($/share)	0.645	0.645	0.645	-	-	1.935	1.935	-
Activity								
Capital expenditures ($M)	91,382	58,875	41,039	55%	123%	246,146	175,526	40%
Acquisitions ($M)	20,976	993	10,391	2,012%	102%	24,589	19,811	24%
Gross wells drilled	17.00	2.00	6.00			48.00	22.00	
Net wells drilled	13.77	1.40	2.08			40.58	13.48	

Operational review

- Consolidated average production during Q3 2017 was up slightly from Q2 2017 as production increases in Canada, driven by continued organic production growth from our Mannville condensate-rich resource play, the Netherlands, and the US were offset by production decreases due to unplanned downtime at the Corrib project in Ireland.
- Consolidated average production increased by 6% for the three months ended September 30, 2017, versus the comparable period in 2016 as increased production in Canada and Germany offset production decreases in the Netherlands and Ireland. Production increases were primarily driven by continued organic production growth from our Mannville condensate-rich resource play in Canada and incremental volumes from our acquisition in Germany in late 2016. Production decreases were primarily due to permitting restrictions in the Netherlands and unplanned downtime at the Corrib project in Ireland.
- For the nine months ended September 30, 2017, production increased 3% versus 2016. The production increases in Canada and Germany were coupled with increased production in Ireland as volumes in the prior year were restricted during the commissioning period that occurred in the first half of 2016. These increases were partially offset by decreased production in the Netherlands due to permitting restrictions and lower production in France due to natural declines.
- For the three months ended September 30, 2017, capital expenditures of $91.4 million related primarily to Canada, France, and the Netherlands. In Canada, capital expenditures of $43.7 million related primarily to the drilling of 15 (12.8 net) wells and associated completion and tie-in activities. In France, capital expenditures of $15.8 million largely related to subsurface and workover programs. In the Netherlands, capital expenditures of $11.6 million related primarily to the drilling of two (1.0 net) wells.

Financial review

Net earnings

- The net loss for Q3 2017 was $39.2 million ($0.32/basic share), compared to net earnings of $48.3 million ($0.40/basic share) in Q2 2017 and a net loss of $14.5 million ($0.12/basic share) in Q3 2016. The net loss in Q3 2017 largely resulted from a $24.2 million unrealized loss on derivative instruments in Q3 2017, compared to unrealized gains of $22.3 million and $0.3 million in the comparative periods.
- Unrealized losses and gains on derivative instruments result from mark-to-market accounting based on prevailing commodity prices at each period end. As a result, unrealized gains and losses for all derivative instruments are recognized in current period earnings based on current forward price curves, while the instruments themselves reduce Vermilion's exposure to commodity prices in future periods.

- The unrealized loss on derivative instruments recognized in Q3 2017 primarily related to crude oil and European natural gas derivative instruments for 2018 and 2019, partially offset by unrealized gains on our North American natural gas derivative instruments for 2018. As at September 30, 2017, our crude oil swaps and collars provide an average Dated Brent floor of $63.38/bbl for 7,250 bbls/d of production in 2018. Our European natural gas swaps and collars provide an average floor of $6.91/mmbtu for 64,380 mmbtu/d of production in 2018 and of $7.06/mmbtu for 41,738 mmbtu/d of production in 2019. Our North American natural gas derivative instruments provide an average floor of $2.61/mmbtu for 39,478 mmbtu/d of production in 2018.
- Net earnings for the nine months ended September 30, 2017 of $53.6 million ($0.45/basic share) versus a net loss of $156.0 million ($1.36/basic share) for the comparative period in 2016. The change in net earnings primarily resulted from higher revenue and reduced depletion and depreciation expense, in addition to an unrealized gain on derivative instruments and foreign exchange.

Fund flows from operations

- Generated fund flows from operations of $130.8 million during Q3 2017, a decrease of 11% from Q2 2017. This quarter-over-quarter decrease was driven by lower realized commodity prices for both crude oil and natural gas and lower sales volumes in Australia and Ireland. These decreases were partially offset by higher production in Canada and the Netherlands.
- Fund flows from operations decreased by 7% for the three months ended September 30, 2017 versus the comparable period in 2016. This decrease was driven by lower sales volumes in Australia, France, and the Netherlands, offset by higher commodity prices and increased production in Canada and Germany. For the nine months ended September 30, 2017, fund flows from operations increased by 17% versus the comparable period in the prior year, driven by higher commodity prices and increased production in Germany, Ireland, and Canada, partially offset by lower production in the Netherlands and lower sales volumes in France.

Net debt

- Net debt decreased to $1.37 billion as at September 30, 2017 from $1.43 billion at December 31, 2016 as fund flows from operations generated in excess of capital expenditures and net dividends was used to reduce long-term debt.

Dividends

- Declared dividends of $0.215 per common share per month during the nine months ended September 30, 2017, totalling $1.935 per common share.

COMMODITY PRICES

	Three Months Ended			% change		Nine Months Ended		% change
	Sep 30, 2017	Jun 30, 2017	Sep 30, 2016	Q3/17 vs. Q2/17	Q3/17 vs. Q3/16	Sep 30, 2017	Sep 30, 2016	2017 vs. 2016
Average reference prices								
Crude oil								
WTI ($/bbl)	60.37	64.92	58.65	(7%)	3%	64.64	54.67	18%
WTI (US $/bbl)	48.20	48.28	44.94	-	7%	49.47	41.33	20%
Edmonton Sweet index ($/bbl)	56.76	61.90	54.89	(8%)	3%	60.85	50.41	21%
Edmonton Sweet index (US $/bbl)	45.32	46.03	42.06	(2%)	8%	46.57	38.11	22%
Dated Brent ($/bbl)	65.22	67.01	59.84	(3%)	9%	67.82	55.25	23%
Dated Brent (US $/bbl)	52.08	49.83	45.85	5%	14%	51.90	41.77	24%
Natural gas								
AECO ($/mmbtu)	1.45	2.78	2.32	(48%)	(38%)	2.31	1.85	25%
NBP ($/mmbtu)	6.78	6.52	5.29	4%	28%	7.10	5.69	25%
NBP (€/mmbtu)	4.61	4.41	3.63	5%	27%	4.88	3.85	27%
TTF ($/mmbtu)	6.93	6.74	5.43	3%	28%	7.12	5.58	28%
TTF (€/mmbtu)	4.71	4.56	3.73	3%	26%	4.90	3.78	30%
Henry Hub ($/mmbtu)	3.76	4.28	3.67	(12%)	2%	4.14	3.03	37%
Henry Hub (US $/mmbtu)	3.00	3.18	2.81	(6%)	7%	3.17	2.29	38%
Average foreign currency exchange rates								
CDN $/US $	1.25	1.34	1.31	(7%)	(5%)	1.31	1.32	(1%)
CDN $/Euro	1.47	1.48	1.46	(1%)	1%	1.45	1.48	(2%)
Realized prices								
Crude oil and condensate ($/bbl)	61.47	64.35	56.60	(4%)	9%	64.58	52.57	23%
NGLs ($/bbl)	23.96	20.98	12.40	14%	93%	23.01	9.67	138%
Natural gas ($/mmbtu)	4.01	4.75	3.98	(16%)	1%	4.79	3.76	27%
Total ($/boe)	39.66	43.63	38.40	(9%)	3%	43.27	35.29	23%

Crude oil

- Crude oil prices were volatile throughout Q3 2017. Early in the third quarter, WTI was near 2017 year-to-date lows and then increased 15% throughout the quarter. This resulted in an average price of US$48.20/bbl, relatively consistent with the US$48.28/bbl average price for WTI in Q2 2017. Likewise, Dated Brent increased over 17% during Q3 2017 to average the quarter at US$52.08/bbl, 5% higher than Q2 2017. The increase in crude oil prices through Q3 2017 was a result of tightening fundamentals, with changes in both supply and demand contributing to the rebalancing.
- During Q3 2017, Dated Brent crude oil averaged a premium to WTI of US$3.88/bbl and a premium to the Edmonton Sweet index of US$6.76/bbl. Approximately 63% of our crude oil and condensate production during Q3 2017 benefited from this premium pricing. As a result, our third quarter consolidated crude oil and condensate realized price of $61.47/bbl was $1.10/bbl higher than the Canadian dollar WTI average price and $4.71/bbl higher than the Canadian dollar Edmonton Sweet index price, representing premiums of approximately 2% and 8%, respectively.

Natural gas

- Despite the hot summer weather in Western Canada, AECO gas prices fell by 48% quarter-over-quarter as demand was offset by rising supply, lower net exports, and pipeline restrictions caused by both planned and unplanned maintenance.
- Following a similar pattern to crude oil, European natural gas prices started lower and rallied higher throughout the quarter, resulting in consistent quarter-over-quarter average pricing. This increase was largely due to lower continental Europe gas production, planned and unplanned maintenance impacting Norwegian supply, and a year-over-year deficit in gas-in-storage. However, these gains were limited by overall weaker power demand and an increase in Russian exports to Europe.
- During Q3 2017, average European gas prices were $6.86/mmbtu, which was a $5.41/mmbtu premium to AECO and a $3.10/mmbtu premium to Henry Hub pricing. We receive this premium pricing on our natural gas production in Europe, which made up nearly 50% of our natural gas production during Q3 2017. As a result, our third quarter consolidated realized natural gas price of $4.01/mmbtu represented a $2.56/mmbtu premium to AECO and a $0.25/mmbtu premium to Henry Hub Pricing.

Foreign exchange

- As a result of two separate overnight rate hikes by the Bank of Canada in Q3 2017, the Canadian dollar strengthened relative to the US dollar but was relatively flat against the Euro.
- The strengthening of the Canadian dollar against the US dollar resulted in lower crude oil prices in Canadian dollar terms.

FUND FLOWS FROM OPERATIONS

	Three Months Ended						Nine Months Ended			
	Sep 30, 2017		Jun 30, 2017		Sep 30, 2016		Sep 30, 2017		Sep 30, 2016	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Petroleum and natural gas sales	248,505	39.66	271,391	43.63	232,660	38.40	781,497	43.27	622,900	35.29
Royalties	(16,994)	(2.71)	(17,736)	(2.85)	(12,969)	(2.14)	(50,935)	(2.82)	(39,285)	(2.23)
Petroleum and natural gas revenues	231,511	36.95	253,655	40.78	219,691	36.26	730,562	40.45	583,615	33.06
Transportation	(10,800)	(1.72)	(10,843)	(1.74)	(9,696)	(1.60)	(31,462)	(1.74)	(29,946)	(1.70)
Operating	(61,832)	(9.87)	(63,074)	(10.14)	(54,825)	(9.05)	(177,027)	(9.80)	(162,569)	(9.21)
General and administration	(12,114)	(1.93)	(13,167)	(2.12)	(12,295)	(2.03)	(38,432)	(2.13)	(41,365)	(2.34)
PRRT	(4,345)	(0.69)	(6,468)	(1.04)	272	0.04	(16,247)	(0.90)	-	-
Corporate income taxes	(3,092)	(0.49)	(4,047)	(0.65)	(3,546)	(0.59)	(14,618)	(0.81)	(12,270)	(0.70)
Interest expense	(13,400)	(2.14)	(15,508)	(2.49)	(14,150)	(2.34)	(43,603)	(2.41)	(42,547)	(2.41)
Realized gain on derivatives	8,723	1.39	5,342	0.86	13,532	2.23	12,214	0.68	63,456	3.60
Realized foreign exchange (loss) gain	(4,110)	(0.66)	981	0.16	2,073	0.34	(583)	(0.03)	2,750	0.16
Realized other income (expense)	214	0.03	252	0.04	(82)	(0.01)	508	0.03	85	-
Fund flows from operations	130,755	20.87	147,123	23.66	140,974	23.25	421,312	23.34	361,209	20.46

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

($M)	Q3/17 vs. Q2/17	Q3/17 vs. Q3/16	2017 vs. 2016
Fund flows from operations – Comparative period	147,123	140,974	361,209
Sales volume variance:			
Canada	9,334	17,247	7,938
France	1,283	(6,542)	(20,076)
Netherlands	2,051	(6,211)	(21,783)
Germany	1,117	8,103	23,099
Ireland	(8,137)	(4,479)	17,104
Australia	(10,488)	(12,926)	(3,394)
United States	636	2,329	3,409
Pricing variance on sales volumes:			
WTI	(6,278)	1,320	31,796
AECO	(9,434)	(5,173)	16,676
Dated Brent	(1,643)	10,769	57,680
TTF and NBP	(1,327)	11,408	46,148
Changes in:			
Royalties	742	(4,025)	(11,650)
Transportation	43	(1,104)	(1,516)
Operating	1,242	(7,007)	(14,458)
General and administration	1,053	181	2,933
PRRT	2,123	(4,617)	(16,247)
Corporate income taxes	955	454	(2,348)
Interest	2,108	750	(1,056)
Realized derivatives	3,381	(4,809)	(51,242)
Realized foreign exchange	(5,091)	(6,183)	(3,333)
Realized other income	(38)	296	423
Fund flows from operations – Current period	130,755	130,755	421,312

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)

Operational and financial review

	Three Months Ended			% change		Nine Months Ended		% change
Canada business unit ($M except as indicated)	Sep 30, 2017	Jun 30, 2017	Sep 30, 2016	Q3/17 vs. Q2/17	Q3/17 vs. Q3/16	Sep 30, 2017	Sep 30, 2016	2017 vs. 2016
Production and sales								
Crude oil and condensate (bbls/d)	9,288	9,205	8,984	1%	3%	8,831	9,582	(8%)
NGLs (bbls/d)	4,891	3,745	2,448	31%	100%	3,776	2,589	46%
Natural gas (mmcf/d)	103.92	93.68	77.62	11%	34%	94.52	87.37	8%
Total (boe/d)	31,499	28,563	24,368	10%	29%	28,360	26,732	6%
Production mix (% of total)								
Crude oil and condensate	29%	32%	37%			31%	36%	
NGLs	16%	13%	10%			13%	10%	
Natural gas	55%	55%	53%			56%	54%	
Activity								
Capital expenditures	43,746	20,599	10,421	112%	320%	121,802	45,811	166%
Acquisitions	19,712	935	10,380			21,223	11,931	
Gross wells drilled	15.00	1.00	4.00			38.00	18.00	
Net wells drilled	12.75	0.40	1.20			31.56	10.60	
Financial results								
Sales	77,238	83,643	64,453	(8%)	20%	236,381	182,294	30%
Royalties	(6,653)	(8,805)	(4,817)	(24%)	38%	(23,957)	(14,085)	70%
Transportation	(4,485)	(3,944)	(3,978)	14%	13%	(12,532)	(11,888)	5%
Operating	(22,071)	(19,347)	(15,579)	14%	42%	(58,088)	(53,382)	9%
General and administration	(2,239)	(3,127)	(3,010)	(28%)	(26%)	(7,064)	(9,791)	(28%)
Fund flows from operations	41,790	48,420	37,069	(14%)	13%	134,740	93,148	45%
Netbacks ($/boe)								
Sales	26.65	32.18	28.75	(17%)	(7%)	30.53	24.89	23%
Royalties	(2.30)	(3.39)	(2.15)	(32%)	7%	(3.09)	(1.92)	61%
Transportation	(1.55)	(1.52)	(1.77)	2%	(12%)	(1.62)	(1.62)	-
Operating	(7.62)	(7.44)	(6.95)	2%	10%	(7.50)	(7.29)	3%
General and administration	(0.77)	(1.20)	(1.34)	(36%)	(43%)	(0.91)	(1.34)	(32%)
Fund flows from operations netback	14.41	18.63	16.54	(23%)	(13%)	17.41	12.72	37%
Realized prices								
Crude oil and condensate ($/bbl)	57.15	62.46	53.96	(9%)	6%	61.26	49.75	23%
NGLs ($/bbl)	23.93	21.11	12.49	13%	92%	23.04	9.73	137%
Natural gas ($/mmbtu)	1.84	2.83	2.39	(35%)	(23%)	2.51	1.87	34%
Total ($/boe)	26.65	32.18	28.75	(17%)	(7%)	30.53	24.89	23%
Reference prices								
WTI (US $/bbl)	48.20	48.28	44.94	-	7%	49.47	41.33	20%
Edmonton Sweet index (US $/bbl)	45.32	46.03	42.06	(2%)	8%	46.57	38.11	22%
Edmonton Sweet index ($/bbl)	56.76	61.90	54.89	(8%)	3%	60.85	50.41	21%
AECO ($/mmbtu)	1.45	2.78	2.32	(48%)	(38%)	2.31	1.85	25%

Production

- Q3 2017 average production increased by 10% from Q2 2017, and 29% year-over-year primarily due to organic production growth in our Mannville condensate-rich gas resource play.
- Mannville production averaged approximately 17,300 boe/d in Q3 2017 representing an 18% increase quarter-over-quarter.
- Cardium production averaged approximately 5,800 boe/d in Q3 2017, an increase of 2% over the prior quarter.
- Production from southeast Saskatchewan averaged approximately 2,600 boe/d in Q3 2017, a decrease of 10% quarter-over-quarter.

Activity review

- Vermilion drilled or participated in the drilling of 15 (12.8 net) wells during Q3 2017.

  Mannville
  - During Q3 2017, we drilled or participated in the drilling of 10 (8.0 net) wells and brought seven (5.6 net) wells on production.
  - We have drilled or participated in the drilling of 18 (13.5 net) wells year-to-date 2017. We plan to drill or participate in 22 (16.6 net) wells in 2017.

  Cardium
  - In Q3 2017, we drilled two (2.0 net) operated wells and brought two (2.0 net) wells on production.
  - We have drilled seven (7.0 net) wells, completing our 2017 planned drilling activity.

  Saskatchewan
  - In Q3 2017, we drilled and brought on production three (2.8 net) operated wells.
  - We have drilled 13 (11.1 net) wells, completing our 2017 planned drilling activity.

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.
- Q3 2017 sales per boe decreased compared to Q2 2017 and Q3 2016, driven by lower natural gas pricing.
- For the nine months ended September 30, 2017, sales per boe increased versus the comparable period in 2016 as a result of higher average crude oil, NGL, and natural gas pricing.

Royalties

- In Q3 2017, royalties as a percentage of sales decreased from 10.5% in Q2 2017 to 8.6% in Q3 2017 due to the impact of lower commodity prices on the sliding scale used to determine royalty rates.
- For the nine months ended September 30, 2017, royalties as a percentage of sales increased to 10.1%, compared to 7.7% in the comparable period in the prior year, due to 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.
- In Q3 2017, transportation expense on a per unit basis was relatively consistent with Q2 2017. In dollars, the increased transportation expense was consistent with higher volumes.
- For the nine months ended September 30, 2017, transportation expense on a per unit basis was consistent with the comparable period in the prior year. In dollars, the increase in transportation expense versus both comparable periods in the prior year was consistent with higher volumes.

Operating

- In Q3 2017, operating expense on a per unit basis was relatively consistent with Q2 2017. In dollars, operating expense increased compared to Q2 2017 as a result of higher volumes.
- For the three months ended September 30, 2017, operating expense on a per unit basis increased versus the comparable period in the prior year due to the timing of maintenance activity. For the nine months ended September 30, 2017, operating expense on a per unit basis was consistent with the comparable period in the prior year. In dollars, the increase in operating expense versus both comparable periods in 2016 was consistent with higher volumes.

General and administration

- Fluctuations in general and administration expense for all comparable periods were due to the timing of expenditures and allocations from our corporate segment.

Current income taxes

- As a result of our tax pools in Canada, we do not expect to incur current income taxes in the Canada Business Unit for the foreseeable future.

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 ($M except as indicated)	Sep 30, 2017	Jun 30, 2017	Sep 30, 2016	Q3/17 vs. Q2/17	Q3/17 vs. Q3/16	Sep 30, 2017	Sep 30, 2016	2017 vs. 2016
Production								
Crude oil (bbls/d)	10,918	11,368	11,827	(4%)	(8%)	11,040	12,123	(9%)
Natural gas (mmcf/d)	-	-	0.42	-	(100%)	-	0.47	(100%)
Total (boe/d)	10,918	11,368	11,897	(4%)	(8%)	11,041	12,201	(10%)
Sales								
Crude oil (bbls/d)	11,360	11,259	12,617	1%	(10%)	10,799	12,140	(11%)
Natural gas (mmcf/d)	-	-	0.42	-	(100%)	-	0.47	(100%)
Total (boe/d)	11,360	11,259	12,687	1%	(10%)	10,799	12,218	(12%)
Inventory (mbbls)								
Opening crude oil inventory	254	245	312			148	243	
Crude oil production	1,004	1,034	1,088			3,014	3,322	
Crude oil sales	(1,044)	(1,025)	(1,161)			(2,948)	(3,326)	
Closing crude oil inventory	214	254	239			214	239	
Activity								
Capital expenditures	15,756	16,682	11,110	(6%)	42%	53,354	37,345	43%
Gross wells drilled	-	1.00	-			5.00	-	
Net wells drilled	-	1.00	-			5.00	-	
Financial results								
Sales	66,100	63,615	65,221	4%	1%	189,325	174,937	8%
Royalties	(6,399)	(6,247)	(7,069)	2%	(9%)	(17,966)	(20,399)	(12%)
Transportation	(3,434)	(3,686)	(3,586)	(7%)	(4%)	(10,152)	(10,775)	(6%)
Operating	(13,148)	(12,153)	(12,933)	8%	2%	(36,670)	(38,518)	(5%)
General and administration	(2,543)	(3,713)	(4,590)	(32%)	(45%)	(9,326)	(14,000)	(33%)
Current income taxes	(1,396)	(1,830)	955	(24%)	N/A	(8,208)	-	100%
Fund flows from operations	39,180	35,986	37,998	9%	3%	107,003	91,245	17%
Netbacks ($/boe)								
Sales	63.24	62.09	55.88	2%	13%	64.22	52.26	23%
Royalties	(6.12)	(6.10)	(6.06)	-	1%	(6.09)	(6.09)	-
Transportation	(3.29)	(3.60)	(3.07)	(9%)	7%	(3.44)	(3.22)	7%
Operating	(12.58)	(11.86)	(11.08)	6%	14%	(12.44)	(11.51)	8%
General and administration	(2.43)	(3.62)	(3.93)	(33%)	(38%)	(3.16)	(4.18)	(24%)
Current income taxes	(1.34)	(1.79)	0.82	(25%)	N/A	(2.78)	-	100%
Fund flows from operations	37.48	35.12	32.56	7%	15%	36.31	27.26	33%
Realized prices								
Crude oil ($/bbl)	63.24	62.09	56.14	2%	13%	64.22	52.53	22%
Natural gas ($/mmbtu)	-	-	1.58	-	(100%)	1.52	1.61	(6%)
Total ($/boe)	63.24	62.09	55.88	2%	13%	64.22	52.26	23%
Reference prices								
Dated Brent (US $/bbl)	52.08	49.83	45.85	5%	14%	51.90	41.77	24%
Dated Brent ($/bbl)	65.22	67.01	59.84	(3%)	9%	67.82	55.25	23%

Production

- Q3 2017 production decreased 4% versus the prior quarter due to production declines and well downtime. Production decreased by 8% versus Q3 2016 due to production declines, well downtime and third party restrictions impacting Vic Bilh gas production. These decreases more than offset new well production and optimization activities.

Activity review

- During the quarter we continued our workover and optimization programs in the Aquitaine and Paris Basins.
- Our 2017 capital activity to-date has included the drilling and completion of four (4.0 net) Neocomian wells and one (1.0 net) horizontal sidetrack well in the Vulaines field as well as the completion of four (4.0 net) Champotran wells that were drilled in Q4 2016.

Sales

- Crude oil in France is priced with reference to Dated Brent.
- Q3 2017 sales per boe were relatively consistent with Q2 2017.
- Sales per boe for the three and nine months ended September 30, 2017 increased versus the comparable periods in 2016, consistent with stronger Dated Brent pricing. In dollar terms for both periods, the increase in price was partially offset by lower sales volumes.

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 9.7% in Q3 2017 was consistent with 9.8% in Q2 2017.
- For the three and nine months ended September 30, 2017, royalties as a percentage of sales of 9.7% and 9.5%, respectively, were lower than the comparable periods in the prior year (10.8% and 11.7%, respectively) as a result of the impact of fixed RCDM royalties coupled with higher realized pricing in the current year.

Transportation

- Transportation expense decreased in Q3 2017 compared to Q2 2017 due to reduced pricing for a shipping vessel in August of 2017, which impacted one of three shipments during the quarter.
- For the three and nine months ended September 30, 2017, transportation expense was relatively consistent with the comparable periods in 2016.

Operating

- Operating expense on a per unit and dollar basis increased in Q3 2017 as compared to Q2 2017 due to the timing of maintenance activity.
- For the three and nine months ended September 30, 2017, operating expense on a per unit basis increased versus the comparable periods in the prior year due to the impact of spreading fixed costs over lower sales volumes. In dollars, operating expense was relatively consistent.

General and administration

- Fluctuations in general and administration expense for all comparable periods were due to the timing of expenditures and 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 5% to 7% 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 Q3 2017 was relatively consistent with Q2 2017.
- Current income taxes for the nine months ended September 30, 2017 versus nil in the prior year was the result of higher Dated Brent prices resulting in increased 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

Netherlands business unit ($M except as indicated)	Three Months Ended Sep 30, 2017	Jun 30, 2017	Sep 30, 2016	% change Q3/17 vs. Q2/17	Q3/17 vs. Q3/16	Nine Months Ended Sep 30, 2017	Sep 30, 2016	% change 2017 vs. 2016
Production and sales								
Condensate (bbls/d)	74	104	86	(29%)	(14%)	85	99	(14%)
Natural gas (mmcf/d)	34.90	31.58	47.62	11%	(27%)	35.45	50.06	(29%)
Total (boe/d)	5,890	5,368	8,023	10%	(27%)	5,992	8,442	(29%)
Activity								
Capital expenditures	11,590	5,973	6,441	94%	80%	19,275	18,003	7%
Acquisitions	14	(16)	-			14	-	
Gross wells drilled	2.00	-	2.00			2.00	2.00	
Net wells drilled	1.02	-	0.88			1.02	0.88	
Financial results								
Sales	21,258	19,126	23,470	11%	(9%)	67,146	74,729	(10%)
Royalties	(360)	(296)	(312)	22%	15%	(1,075)	(1,168)	(8%)
Operating	(4,498)	(4,892)	(4,854)	(8%)	(7%)	(14,231)	(15,136)	(6%)
General and administration	(510)	(560)	633	(9%)	N/A	(1,666)	(1,363)	22%
Current income taxes	(1,983)	(754)	(1,264)	163%	57%	(3,644)	(6,724)	(46%)
Fund flows from operations	13,907	12,624	17,673	10%	(21%)	46,530	50,338	(8%)
Netbacks ($/boe)								
Sales	39.23	39.16	31.80	-	23%	41.04	32.31	27%
Royalties	(0.66)	(0.61)	(0.42)	8%	57%	(0.66)	(0.50)	32%
Operating	(8.30)	(10.01)	(6.58)	(17%)	26%	(8.70)	(6.54)	33%
General and administration	(0.94)	(1.14)	0.86	(18%)	N/A	(1.02)	(0.59)	73%
Current income taxes	(3.66)	(1.54)	(1.71)	138%	114%	(2.23)	(2.91)	(23%)
Fund flows from operations netback	25.67	25.86	23.95	(1%)	7%	28.43	21.77	31%
Realized prices								
Condensate ($/bbl)	52.10	49.59	49.43	5%	5%	52.92	41.43	28%
Natural gas ($/mmbtu)	6.51	6.49	5.27	-	24%	6.81	5.37	27%
Total ($/boe)	39.23	39.16	31.80	-	23%	41.04	32.31	27%
Reference prices								
TTF ($/mmbtu)	6.93	6.74	5.43	3%	28%	7.12	5.58	28%
TTF (€/mmbtu)	4.71	4.56	3.73	3%	26%	4.90	3.78	30%

Production

- Q3 2017 production increased 10% quarter-over-quarter following the receipt of a permit to increase production on a key well, and also due to the impact of a major turnaround at the Garjip processing facility that occurred during Q2 2017. Year-over-year production decreased 27% due to the restriction of production related to permitting delays.

Activity review

- We completed our two (1.0 net) well drilling campaign in the Netherlands during the quarter with the drilling of Eesveen-02 (60% working interest) and Nieuwehorne-02 (42% working interest). The Eesveen-02 well encountered 24 metres of net pay in two separate intervals targeting the Zechstein-2 carbonate formation and the Rotliegend sandstone and is expected to be placed on production mid-2018. The Nieuwehorne-02 well also targeted two separate intervals, the Zechstein-2 carbonate formation and the Vlieland sandstone, encountering 10 metres of net pay combined and is currently being prepared for a flow test.
- During the remainder of 2017, we plan to complete a 315 square kilometre 3D seismic survey.

Sales

- The price of our natural gas in the Netherlands is based on the TTF index.
- Q3 2017 sales per boe was relatively unchanged from Q2 2017.
- Sales per boe for the three and nine months ended September 30, 2017 increased versus the comparable periods in the prior year, 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 primarily relates 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

- Fluctuations in operating expense on a per unit basis across all periods presented were due to relatively fixed expenditures and changes in production volumes.

General and administration

- Fluctuations in general and administration expense for all comparable periods were due to the timing of expenditures and allocations from our 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 7% and 9% 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 Q3 2017 were higher compared to Q2 2017 due to increased sales in Q3 2017.
- Current income taxes for the nine months ended September 30, 2017 were lower than the comparable period in the prior year due to decreased sales in 2017.

GERMANY BUSINESS UNIT

Overview

- Entered Germany in February 2014.
- 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 at Dummersee-Uchte. 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 a 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 Ossenbeck and Weesen licenses (110,000 net acres) in 2015 and Aller license (50,000 net acres) in March 2017 surrounding the operated oil fields acquired in December 2016.

Operational and financial review

	Three Months Ended			% change		Nine Months Ended		% change
Germany business unit ($M except as indicated)	Sep 30, 2017	Jun 30, 2017	Sep 30, 2016	Q3/17 vs. Q2/17	Q3/17 vs. Q3/16	Sep 30, 2017	Sep 30, 2016	2017 vs. 2016
Production								
Crude oil (bbls/d)	1,054	1,047	-	1%	100%	1,030	-	100%
Natural gas (mmcf/d)	20.12	19.86	14.52	1%	39%	19.79	14.93	33%
Total (boe/d)	4,407	4,357	2,420	1%	82%	4,329	2,488	74%
Production mix (% of total)								
Crude oil	24%	24%	-			24%	-	
Natural gas	76%	76%	100%			76%	100%	
Activity								
Capital expenditures	3,020	326	978	826%	209%	4,252	2,109	102%
Financial results								
Sales	15,663	16,167	6,783	(3%)	131%	49,798	20,755	140%
Royalties	(2,261)	(1,228)	(246)	84%	819%	(4,857)	(2,077)	134%
Transportation	(1,603)	(1,955)	(556)	(18%)	188%	(5,043)	(2,494)	102%
Operating	(3,477)	(5,753)	(3,321)	(40%)	5%	(14,151)	(8,420)	68%
General and administration	(1,708)	(2,099)	(1,657)	(19%)	3%	(5,687)	(6,559)	(13%)
Fund flows from operations	6,614	5,132	1,003	29%	559%	20,060	1,205	1,565%
Netbacks ($/boe)								
Sales	38.52	41.96	30.47	(8%)	26%	42.50	30.45	40%
Royalties	(5.56)	(3.19)	(1.10)	74%	405%	(4.15)	(3.05)	36%
Transportation	(3.94)	(5.07)	(2.50)	(22%)	58%	(4.30)	(3.66)	17%
Operating	(8.55)	(14.93)	(14.92)	(43%)	(43%)	(12.08)	(12.35)	(2%)
General and administration	(4.20)	(5.45)	(7.44)	(23%)	(44%)	(4.85)	(9.62)	(50%)
Fund flows from operations netback	16.27	13.32	4.51	22%	261%	17.12	1.77	867%
Realized prices								
Crude oil ($/bbl)	55.95	61.34	-	(9%)	100%	60.79	-	100%
Natural gas ($/mmbtu)	5.50	6.09	5.08	(10%)	8%	6.17	5.07	22%
Total ($/boe)	38.52	41.96	30.47	(8%)	26%	42.50	30.45	40%
Reference prices								
Dated Brent (US $/bbl)	52.08	49.83	45.85	5%	14%	51.90	41.77	24%
Dated Brent ($/bbl)	65.22	67.01	59.84	(3%)	9%	67.82	55.25	23%
TTF ($/mmbtu)	6.93	6.74	5.43	3%	28%	7.12	5.58	28%
TTF (€/mmbtu)	4.71	4.56	3.73	3%	26%	4.90	3.78	30%

Production

- Q3 2017 production was relatively consistent with the prior quarter as well optimization activities offset production declines. Production increased 82% year-over-year due to production additions from the Engie Acquisition that closed December 2016.

Activity review

- Q3 2017 activity focused on workover and optimization opportunities on the acquired assets.
- In 2017, we plan to continue permitting and pre-drill activities associated with our first operated well in Germany, Burgmoor Z5 (25% working interest) in the Dümmersee-Uchte area, which we expect to drill in 2019.

Sales

- The price of our natural gas in Germany is based on the TTF index. Crude oil in Germany is priced with reference to Dated Brent.
- Q3 2017 sales per boe decreased versus Q2 2017, despite stronger crude oil and natural gas benchmark prices, due to the timing of sales and the impact of a stronger Canadian dollar versus the US dollar.
- Sales per boe for the three and nine months ended September 30, 2017 increased versus the comparative periods in 2016 as a result of stronger TTF prices and the addition of crude oil production in 2017.

Royalties

- Our production in Germany is subject to state and private royalties on sales after certain eligible deductions.
- Royalties as a percentage of sales of 14.4% in Q3 2017 was higher than 7.6% in Q2 2017 and 3.6% in Q3 2016 due to the impact of prior period adjustments.
- Royalties as a percentage of sales of 9.8% for the nine months ended September 30, 2017 was consistent with 10.0% for the comparable period in the prior year.

Transportation

- Transportation expense in Germany relates to costs incurred to deliver natural gas from the processing facility to the customer and deliver crude oil to the refinery.
- Q3 2017 transportation expense decreased versus Q2 2017 on both a per unit and dollar basis due to a prior period amendment relating to 2016 recorded in the prior quarter.
- For the three and nine months ended September 30, 2017, transportation expense increased on a per unit basis relative to the comparable periods in the prior year due to the impact of prior period amendments.

Operating

- Operating expense decreased in Q3 2017 versus both Q2 2017 and Q3 2016 on a per unit basis due to the impact of a prior period amendment recorded in the current quarter.
- For the nine months ended September 30, 2017, operating expense on a per unit basis was relatively consistent with the comparable period in 2016.

General and administration

- Fluctuations in general and administration expense for all comparable periods were due to the timing of expenditures and allocations from our corporate segment.
- On a per unit basis, general and administration costs have improved compared to 2016 as a result of our growing production base in Germany.

Current income taxes

- As a result of our tax pools in Germany, we do not expect to incur current income taxes in the Germany Business Unit for the foreseeable future.

IRELAND BUSINESS UNIT

Overview

- Entered Ireland in 2009.
- Initial investment was an 18.5% non-operating interest in the offshore Corrib gas field located approximately 83 km off the northwest coast of Ireland.
- On July 12, 2017, Vermilion and Canada Pension Plan Investment Board ("CPPIB") announced a strategic partnership that is expected to result in Vermilion increasing ownership in Corrib to 20% and taking over operatorship upon close of the acquisition.
- The Corrib gas development comprises six offshore wells, offshore and onshore sales and transportation pipeline segments as well as a natural gas processing facility.
- 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.

Operational and financial review

	Three Months Ended			% change		Nine Months Ended		% change
Ireland business unit ($M except as indicated)	Sep 30, 2017	Jun 30, 2017	Sep 30, 2016	Q3/17 vs. Q2/17	Q3/17 vs. Q3/16	Sep 30, 2017	Sep 30, 2016	2017 vs. 2016
Production and sales								
Natural gas (mmcf/d)	49.04	63.81	59.28	(23%)	(17%)	59.16	46.86	26%
Total (boe/d)	8,173	10,634	9,879	(23%)	(17%)	9,861	7,810	26%
Activity								
Capital expenditures	1,101	(73)	2,416	N/A	(54%)	224	7,664	(97%)
Financial results								
Sales	28,218	36,671	26,065	(23%)	8%	109,537	66,429	65%
Transportation	(1,252)	(1,258)	(1,576)	-	(21%)	(3,709)	(4,789)	(23%)
Operating	(5,717)	(4,903)	(4,695)	17%	22%	(14,619)	(13,498)	8%
General and administration	(670)	(695)	(955)	(4%)	(30%)	(1,803)	(3,249)	(45%)
Fund flows from operations	20,579	29,815	18,839	(31%)	9%	89,406	44,893	99%
Netbacks ($/boe)								
Sales	37.53	37.90	28.68	(1%)	31%	40.69	31.04	31%
Transportation	(1.66)	(1.30)	(1.73)	28%	(4%)	(1.38)	(2.24)	(38%)
Operating	(7.60)	(5.07)	(5.17)	50%	47%	(5.43)	(6.31)	(14%)
General and administration	(0.89)	(0.72)	(1.05)	24%	(15%)	(0.67)	(1.52)	(56%)
Fund flows from operations netback	27.38	30.81	20.73	(11%)	32%	33.21	20.97	58%
Reference prices								
NBP ($/mmbtu)	6.78	6.52	5.29	4%	28%	7.10	5.69	25%
NBP (€/mmbtu)	4.61	4.41	3.63	5%	27%	4.88	3.85	27%

Production

- Q3 2017 production decreased by 23% quarter-over-quarter and by 17% year-over-year due to an extended downtime period during Q3 2017 following a plant turnaround.

Activity review

- On July 12, 2017 Vermilion and CPPIB announced a strategic partnership in Corrib, whereby CPPIB will acquire Shell E&P Ireland Limited's 45% interest in Corrib for total cash consideration of €830 million, subject to customary closing adjustments and future contingent value payments based on performance and realized pricing. At closing, Vermilion expects to assume operatorship of Corrib. In addition to operatorship, CPPIB plans to transfer a 1.5% working interest to Vermilion for €19.4 million ($28.4 million), before closing adjustments. Vermilion's incremental 1.5% ownership of Corrib would represent approximately 850 boe/d (100% gas) based on 2017 production expectations for Corrib. The acquisition has an effective date of January 1, 2017 and is anticipated to close in the first half of 2018.
- There is limited capital activity planned for 2017.

Sales

- The price of our natural gas in Ireland is based on the NBP index.
- Q3 2017 sales per boe were relatively consistent with Q2 2017, despite a modest increase in reference pricing, due to the timing of sales.
- Sales per boe for the three and nine months ended September 30, 2017 increased relative to the comparable periods in the prior year, 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.
- Q3 2017 transportation expense was consistent with Q2 2017.
- Transportation expense for the three and nine months ended September 30, 2017 decreased relative to the comparable periods in the prior year due to a decrease in the current year ship-or-pay obligation.

Operating

- Q3 2017 operating expense on a per unit and dollar basis increased as compared to Q2 2017 and Q3 2016 due to the timing of maintenance work and lower volumes.
- For the nine months ended September 30, 2017, operating expense on a per unit basis decreased versus the comparable period in the prior year due to the impact of higher volumes. In dollars, the increase in operating expense was due to additional maintenance work in the current year.

General and administration

- Fluctuations in general and administration expense for all comparable periods were due to the timing of expenditures and allocations from our corporate segment.

Current income taxes

- Given the significant level of investment in Corrib and the resulting tax pools, we do not expect to pay any cash taxes for the foreseeable future.

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 ($M except as indicated)	Sep 30, 2017	Jun 30, 2017	Sep 30, 2016	Q3/17 vs. Q2/17	Q3/17 vs. Q3/16	Sep 30, 2017	Sep 30, 2016	2017 vs. 2016
Production								
Crude oil (bbls/d)	5,473	6,054	6,562	(10%)	(17%)	6,032	6,276	(4%)
Sales								
Crude oil (bbls/d)	5,722	7,400	8,041	(23%)	(29%)	6,057	6,250	(3%)
Inventory (mbbls)								
Opening crude oil inventory	131	253	218	(48%)	(40%)	115	75	53%
Crude oil production	503	550	604	(9%)	(17%)	1,647	1,720	(4%)
Crude oil sales	(526)	(672)	(740)	(22%)	(29%)	(1,654)	(1,713)	(3%)
Closing crude oil inventory	108	131	82			108	82	
Activity								
Capital expenditures	10,154	9,158	6,908	11%	47%	22,750	54,674	(58%)
Gross wells drilled	-	-	-			-	2.00	
Net wells drilled	-	-	-			-	2.00	
Financial results								
Sales	35,257	48,061	44,835	(27%)	(21%)	118,305	98,483	20%
Operating	(12,292)	(15,639)	(13,011)	(21%)	(6%)	(37,967)	(32,602)	16%
General and administration	(1,675)	(896)	(1,289)	87%	30%	(5,001)	(4,402)	14%
Current income taxes	(4,538)	(7,660)	(2,644)	(41%)	72%	(19,028)	(4,819)	295%
Fund flows from operations	16,752	23,866	27,891	(30%)	(40%)	56,309	56,660	(1%)
Netbacks ($/boe)								
Sales	66.97	71.37	60.61	(6%)	10%	71.55	57.51	24%
Operating	(23.35)	(23.22)	(17.59)	1%	33%	(22.96)	(19.04)	21%
General and administration	(3.18)	(1.33)	(1.74)	139%	83%	(3.02)	(2.57)	18%
PRRT	(8.25)	(9.61)	0.37	(14%)	N/A	(9.83)	-	100%
Corporate income taxes	(0.37)	(1.77)	(3.94)	(79%)	(91%)	(1.68)	(2.81)	(40%)
Fund flows from operations netback	31.82	35.44	37.71	(10%)	(16%)	34.06	33.09	3%
Reference prices								
Dated Brent (US $/bbl)	52.08	49.83	45.85	5%	14%	51.90	41.77	24%
Dated Brent ($/bbl)	65.22	67.01	59.84	(3%)	9%	67.82	55.25	23%

Production

- Q3 2017 production decreased 10% quarter-over-quarter and 17% 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 annual production levels of approximately 6,000 bbls/d.

Activity review

- Q3 2017 efforts were largely focused on facility enhancements, 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.
- Q3 2017 sales per boe decreased by 6% as compared to Q2 2017, consistent with the decrease in Canadian dollar Dated Brent. In dollars, sales decreased quarter-over-quarter due to lower sales associated with shipment timing.
- Sales per boe for the three and nine months ended September 30, 2017 increased versus the comparable periods in 2016, consistent with higher Dated Brent prices. For the three months ended September 30, 2017, the increase in price was more than offset by lower sales volumes, resulting in a decrease in sales. For the nine months ended September 30, 2017, the increase in price was coupled with relatively consistent 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 unit basis in Q3 2017 was relatively consistent with Q2 2017. On a dollar basis, operating expense decreased due to lower sales volumes.
- For the three and nine months ended September 30, 2017, operating expense on a per unit basis increased versus the comparable periods in the prior year due to the timing of maintenance work and lower production volumes.

General and administration

- Fluctuations in general and administration expense for all comparable periods were due to the timing of expenditures 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 23% and 25% 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 Q3 2017 were lower compared to Q2 2017 due to decreased sales in Q3 2017.
- Current income taxes for the nine months ended September 30, 2017 were higher than 2016 due to increased sales, partially offset by higher capital expenditure deductions in 2016.

UNITED STATES BUSINESS UNIT

Overview

- Entered the United States in September 2014.
- Interests include approximately 97,000 net acres of land (95% 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

United States business unit ($M except as indicated)	Three Months Ended Sep 30, 2017	Jun 30, 2017	Sep 30, 2016	% change Q3/17 vs. Q2/17	Q3/17 vs. Q3/16	Nine Months Ended Sep 30, 2017	Sep 30, 2016	% change 2017 vs. 2016
Production and sales								
Crude oil (bbls/d)	880	747	383	18%	130%	666	403	65%
NGLs (bbls/d)	56	76	30	(26%)	87%	52	32	63%
Natural gas (mmcf/d)	0.64	0.44	0.20	45%	222%	0.43	0.21	104%
Total (boe/d)	1,043	896	447	16%	133%	789	472	67%
Activity								
Capital expenditures	1,362	5,155	2,765	(74%)	(51%)	18,056	9,502	90%
Acquisitions	1,250	49	11			3,312	5,558	
Gross wells drilled	-	-	-			3.00	-	
Net wells drilled	-	-	-			3.00	-	
Financial results								
Sales	4,771	4,108	1,833	16%	160%	11,005	5,273	109%
Royalties	(1,321)	(1,160)	(525)	14%	152%	(3,080)	(1,556)	98%
Transportation	(26)	-	-	100%	100%	(26)	-	100%
Operating	(629)	(387)	(432)	63%	46%	(1,301)	(1,013)	28%
General and administration	(935)	(1,127)	(918)	(17%)	2%	(3,067)	(2,747)	12%
Fund flows from operations	1,860	1,434	(42)	30%	N/A	3,531	(43)	N/A
Netbacks ($/boe)								
Sales	49.72	50.37	44.53	(1%)	12%	51.07	40.78	25%
Royalties	(13.77)	(14.21)	(12.74)	(3%)	8%	(14.29)	(12.03)	19%
Transportation	(0.27)	-	-	100%	100%	(0.12)	-	100%
Operating	(6.56)	(4.74)	(10.50)	38%	(38%)	(6.04)	(7.84)	(23%)
General and administration	(9.74)	(13.82)	(22.30)	(30%)	(56%)	(14.23)	(21.25)	(33%)
Fund flows from operations netback	19.38	17.60	(1.01)	10%	N/A	16.39	(0.34)	N/A
Realized prices								
Crude oil ($/bbl)	55.74	58.05	51.29	(4%)	9%	57.68	47.07	23%
NGLs ($/bbl)	26.35	14.70	5.14	79%	413%	20.58	4.49	358%
Natural gas ($/mmbtu)	2.07	1.55	0.64	34%	223%	1.95	0.57	242%
Total ($/boe)	49.72	50.37	44.53	(1%)	12%	51.07	40.78	25%
Reference prices								
WTI (US $/bbl)	48.20	48.28	44.94	-	7%	49.47	41.33	20%
WTI ($/bbl)	60.37	64.92	58.65	(7%)	3%	64.64	54.67	18%
Henry Hub (US $/mmbtu)	3.00	3.18	2.81	(6%)	7%	3.17	2.29	38%
Henry Hub ($/mmbtu)	3.76	4.28	3.67	(12%)	2%	4.14	3.03	37%

Production

- Q3 2017 production increased 16% from the prior quarter as a result of a full quarter of production from the three (3.0 net) wells placed on production during Q2 2017. Quarterly production increased 133% year-over-year as a result of the 2017 drilling program.

Activity

- 2017 activity was focused on drilling three (3.0 net) horizontal wells targeting the light oil bearing Turner Sand in the Powder River Basin. The wells were completed late in the first quarter and into the second quarter with fracs ranging from 31 to 40 stages per well.

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.
- Q3 2017 sales per boe was relatively consistent with Q2 2017.
- For the three and nine months ended September 30, 2017, sales per boe increased relative to the comparable periods in the prior year, consistent with stronger crude oil pricing.

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 28% and remained relatively consistent across all periods.

Operating

- Operating expense on a per unit and dollar basis increased in Q3 2017 as compared to Q2 2017 due to the timing of maintenance work.
- For the three and nine months ended September 30, 2017, operating expense on a per unit basis decreased versus the comparable periods in the prior year due to the impact of higher volumes. In dollars, the increase in operating expense in both periods was attributable to higher production.

General and administration

- Fluctuations in general and administration expense for all comparable periods were due to the timing of expenditures and allocations from our corporate segment.

Current income taxes

- As a result of our tax pools in the United States, we do not expect to incur current income taxes in the United States Business Unit for the foreseeable future.

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

	Three Months Ended			Nine Months Ended	
CORPORATE ($M)	Sep 30, 2017	Jun 30, 2017	Sep 30, 2016	Sep 30, 2017	Sep 30, 2016
Activity					
Capital expenditures	4,653	1,055	-	6,433	418
Acquisitions	-	25	-	40	2,322
Financial Results					
General and administration (expense) recovery	(1,834)	(950)	(509)	(4,818)	746
Current income taxes	480	(271)	(321)	15	(727)
Interest expense	(13,400)	(15,508)	(14,150)	(43,603)	(42,547)
Realized gain on derivatives	8,723	5,342	13,532	12,214	63,456
Realized foreign exchange (loss) gain	(4,110)	981	2,073	(583)	2,750
Realized other income (expense)	214	252	(82)	508	85
Fund flows from operations	(9,927)	(10,154)	543	(36,267)	23,763

General and administration

- Fluctuations in general and administration costs for the three and nine months ended September 30, 2017 versus all 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

- The decrease in interest expense in Q3 2017 versus Q2 2017 and Q3 2016 was primarily due to lower drawings and reduced stamping fees on the revolving credit facility following the issuance of the senior unsecured notes in Q1 2017.
- The increase in interest expense for the nine months ended September 30, 2017 versus the comparable period in the prior year was due to the issuance of the senior unsecured notes in Q1 2017, which bear interest at a higher fixed rate compared to the variable rates under the revolving credit facility. The impact of the higher fixed rates was partially offset by lower drawings on the revolving credit facility.

Realized gain or loss on derivatives

- The realized gain on derivatives for the three and nine months ended September 30, 2017 related primarily to amounts received on crude oil and North American natural gas hedges.
- A listing of derivative positions as at September 30, 2017 is included in "Supplemental Table 2" of this MD&A.

FINANCIAL PERFORMANCE REVIEW

	Three Months Ended							
($M except per share)	Sep 30, 2017	Jun 30, 2017	Mar 31, 2017	Dec 31, 2016	Sep 30, 2016	Jun 30, 2016	Mar 31, 2016	Dec 31, 2015
Petroleum and natural gas sales	248,505	271,391	261,601	259,891	232,660	212,855	177,385	234,319
Net (loss) earnings	(39,191)	48,264	44,540	(4,032)	(14,475)	(55,696)	(85,848)	(142,080)
Net (loss) earnings per share								
Basic	(0.32)	0.40	0.38	(0.03)	(0.12)	(0.48)	(0.76)	(1.28)
Diluted	(0.32)	0.39	0.37	(0.03)	(0.12)	(0.48)	(0.76)	(1.28)

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

	Three Months Ended			Nine Months Ended	
	Sep 30, 2017	Jun 30, 2017	Sep 30, 2016	Sep 30, 2017	Sep 30, 2016
Fund flows from operations	130,755	147,123	140,974	421,312	361,209
Equity based compensation	(12,858)	(13,896)	(15,642)	(45,492)	(49,746)
Unrealized (loss) gain on derivative instruments	(24,198)	23,283	332	78,950	(63,050)
Unrealized foreign exchange (loss) gain	(3,016)	38,616	2,899	31,082	1,665
Unrealized other expense	(200)	(210)	(24)	(440)	(131)
Accretion	(6,850)	(6,748)	(6,341)	(19,980)	(18,475)
Depletion and depreciation	(120,826)	(126,269)	(143,556)	(362,504)	(401,147)
Deferred taxes	(1,998)	(13,635)	6,883	(49,315)	28,418
Impairment	-	-	-	-	(14,762)
Net (loss) earnings	(39,191)	48,264	(14,475)	53,613	(156,019)

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").

For the three and nine months ended September 30, 2017, equity based compensation decreased versus all comparable periods due to a reduction in the value of VIP outstanding.

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 September 30, 2017, we recognized an unrealized loss on derivative instruments of $24.2 million. This loss primarily related to crude oil and European natural gas derivative instruments for 2018 and 2019, partially offset by unrealized gains on our North American natural gas derivative instruments for 2018. As at September 30, 2017, our crude oil swaps and collars provide an average Dated Brent floor of $63.38/bbl for 7,250 bbls/d of production in 2018. Our European natural gas swaps and collars provide an average floor of $6.91/mmbtu for 64,380 mmbtu/d of production in 2018 and of $7.06/mmbtu for 41,738 mmbtu/d of production in 2019. Our North American natural gas derivative instruments provide an average floor of $2.61/mmbtu for 39,478 mmbtu/d of production in 2018.

For the nine months ended September 30, 2017, we recognized an unrealized gain on derivative instruments of $79.0 million. This unrealized gain largely relates to the reversal of the net derivative liability position of $69.7 million on our balance sheet 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).

For the three months ended September 30, 2017, the unfavourable impact of the Canadian dollar strengthening against the Euro was more significant than the favourable impact of the Canadian dollar strengthening against the US dollar, resulting in an unrealized foreign exchange loss. For the nine months ended September 30, 2017, the Canadian dollar weakened against the Euro and strengthened against the US dollar, resulting in an unrealized foreign exchange gain.

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 and changes in depletion and depreciation rates. Fluctuations in depletion and depreciation rates are the result of changes in reserves, future development costs, and relative production mix.

Depletion and depreciation on a per boe basis for Q3 2017 of $19.28 decreased compared to $20.30 in Q2 2017, driven by lower production from Ireland. For the three and nine months ended September 30, 2017, depletion and depreciation on a per boe basis of $19.28 and $20.07 were lower than $23.69 and $22.73 in the respective comparable periods in 2016 due to reduced depletion and depreciation rates as a result of increased reserves coupled with lower estimated future development costs.

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 volumes to maintain a diversified commodity portfolio.

The balances recognized on our balance sheet are as follows:

	As at	
($M)	Sep 30, 2017	Dec 31, 2016
Revolving credit facility	933,137	1,362,192
Senior unsecured notes	368,620	-
Long-term debt	1,301,757	1,362,192

Revolving Credit Facility

As at September 30, 2017, Vermilion had in place a bank revolving credit facility maturing May 31, 2021 with the following outstanding positions:

	As at	
($M)	Sep 30, 2017	Dec 31, 2016
Total facility amount	1,400,000	2,000,000
Amount drawn	(933,137)	(1,362,192)
Letters of credit outstanding	(3,900)	(20,100)
Unutilized capacity	462,963	617,708

In April of 2017, we negotiated an extension of our revolving credit facility with our syndicate of lenders from May 31, 2019 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.

As at September 30, 2017, the revolving credit facility was subject to the following covenants:

		As at	
Financial covenant	Limit	Sep 30, 2017	Dec 31, 2016
Consolidated total debt to consolidated EBITDA	4.0	1.99	2.36
Consolidated total senior debt to consolidated EBITDA	3.5	1.40	2.32
Consolidated total senior debt to total capitalization	55%	32%	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 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	102.813%
2022	101.406%
2023 and thereafter	100.000%

Net debt

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

	As at	
($M)	Sep 30, 2017	Dec 31, 2016
Long-term debt	1,301,757	1,362,192
Current liabilities	298,236	290,862
Current assets	(228,998)	(225,906)
Net debt	1,370,995	1,427,148
Ratio of net debt to annualized fund flows from operations	2.4	2.8

As at September 30, 2017, long term debt decreased to $1.30 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 decreased net debt from $1.43 billion at December 31, 2016 to $1.37 billion at September 30, 2017. The decrease in net debt coupled with an increase in annualized 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 nine months ended September 30, 2017, we maintained monthly dividends at $0.215 per share and declared $232.7 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 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.

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	1,929	88,676
Vesting of equity based awards	1,060	69,743
Equity based compensation	163	7,749
Share-settled dividends on vested equity based awards	170	8,478
Balance as at September 30, 2017	121,585	2,627,368

As at September 30, 2017, there were approximately 1.7 million VIP awards outstanding. As at October 26, 2017, there were approximately 121.8 million common shares issued and outstanding.

ASSET RETIREMENT OBLIGATIONS

As at September 30, 2017, asset retirement obligations were $550.4 million compared to $525.0 million as at December 31, 2016.

The increase in asset retirement obligations is largely attributable to accretion and the impact of the strengthening of the Euro resulting in a higher Canadian dollar liability.

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, 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 nine months ended September 30, 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.

On the adoption of IFRS 15, Vermilion has assessed the Company's current outstanding contracts with customers. Based on this assessment, Vermilion does not presently anticipate any changes in the timing, measurement, or presentation of revenue upon adoption of IFRS 15. However, Vermilion anticipates the inclusion of additional disclosures within the Consolidated Financial Statements in accordance with IFRS 15. This additional disclosure is anticipated to include the additional disaggregation of revenue by commodity, information which is currently available within Management's Discussion and Analysis.

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 Sep 30, 2017			Nine Months Ended Sep 30, 2017			Three Months Ended Sep 30, 2016	Nine Months Ended Sep 30, 2016
	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	45.69	1.84	26.65	49.84	2.51	30.53	28.75	24.89
Royalties	(4.90)	(0.03)	(2.30)	(6.19)	(0.10)	(3.09)	(2.15)	(1.92)
Transportation	(2.16)	(0.17)	(1.55)	(2.19)	(0.19)	(1.62)	(1.77)	(1.62)
Operating	(7.95)	(1.22)	(7.62)	(7.76)	(1.22)	(7.50)	(6.95)	(7.29)
Operating netback	30.68	0.42	15.18	33.70	1.00	18.32	17.88	14.06
General and administration			(0.77)			(0.91)	(1.34)	(1.34)
Fund flows from operations netback			14.41			17.41	16.54	12.72
France								
Sales	63.24	-	63.24	64.22	1.52	64.22	55.88	52.26
Royalties	(6.12)	-	(6.12)	(6.09)	(0.03)	(6.09)	(6.06)	(6.09)
Transportation	(3.29)	-	(3.29)	(3.44)	-	(3.44)	(3.07)	(3.22)
Operating	(12.58)	-	(12.58)	(12.44)	-	(12.44)	(11.08)	(11.51)
Operating netback	41.25	-	41.25	42.25	1.49	42.25	35.67	31.44
General and administration			(2.43)			(3.16)	(3.93)	(4.18)
Current income taxes			(1.34)			(2.78)	0.82	-
Fund flows from operations netback			37.48			36.31	32.56	27.26
Netherlands								
Sales	52.10	6.51	39.23	52.92	6.81	41.04	31.80	32.31
Royalties	-	(0.11)	(0.66)	-	(0.11)	(0.66)	(0.42)	(0.50)
Operating	-	(1.40)	(8.30)	-	(1.47)	(8.70)	(6.58)	(6.54)
Operating netback	52.10	5.00	30.27	52.92	5.23	31.68	24.80	25.27
General and administration			(0.94)			(1.02)	0.86	(0.59)
Current income taxes			(3.66)			(2.23)	(1.71)	(2.91)
Fund flows from operations netback			25.67			28.43	23.95	21.77
Germany								
Sales	55.95	5.50	38.52	60.79	6.17	42.50	30.47	30.45
Royalties	(2.43)	(1.09)	(5.56)	(1.70)	(0.81)	(4.15)	(1.10)	(3.05)
Transportation	(8.97)	(0.39)	(3.94)	(8.77)	(0.49)	(4.30)	(2.50)	(3.66)
Operating	(12.75)	(1.20)	(8.55)	(18.27)	(1.70)	(12.08)	(14.92)	(12.35)
Operating netback	31.80	2.82	20.47	32.05	3.17	21.97	11.95	11.39
General and administration			(4.20)			(4.85)	(7.44)	(9.62)
Fund flows from operations netback			16.27			17.12	4.51	1.77
Ireland								
Sales	-	6.25	37.53	-	6.78	40.69	28.68	31.04
Transportation	-	(0.28)	(1.66)	-	(0.23)	(1.38)	(1.73)	(2.24)
Operating	-	(1.27)	(7.60)	-	(0.91)	(5.43)	(5.17)	(6.31)
Operating netback	-	4.70	28.27	-	5.64	33.88	21.78	22.49
General and administration			(0.89)			(0.67)	(1.05)	(1.52)
Fund flows from operations netback			27.38			33.21	20.73	20.97
Australia								
Sales	66.97	-	66.97	71.55	-	71.55	60.61	57.51
Operating	(23.35)	-	(23.35)	(22.96)	-	(22.96)	(17.59)	(19.04)
PRRT (1)	(8.25)	-	(8.25)	(9.83)	-	(9.83)	0.37	-
Operating netback	35.37	-	35.37	38.76	-	38.76	43.39	38.47
General and administration			(3.18)			(3.02)	(1.74)	(2.57)
Corporate income taxes			(0.37)			(1.68)	(3.94)	(2.81)
Fund flows from operations netback			31.82			34.06	37.71	33.09

	Three Months Ended Sep 30, 2017			Nine Months Ended Sep 30, 2017			Three Months Ended Sep 30, 2016	Nine Months Ended Sep 30, 2016
	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Total $/boe	Total $/boe
United States								
Sales	54.00	2.07	49.72	54.99	1.95	51.07	44.53	40.78
Royalties	(14.80)	(0.78)	(13.77)	(15.25)	(0.78)	(14.29)	(12.74)	(12.03)
Transportation	(0.30)	-	(0.27)	(0.13)	-	(0.12)	-	-
Operating	(7.31)	-	(6.56)	(6.64)	-	(6.04)	(10.50)	(7.84)
Operating netback	31.59	1.29	29.12	32.97	1.17	30.62	21.29	20.91
General and administration			(9.74)			(14.23)	(22.30)	(21.25)
Fund flows from operations netback			19.38			16.39	(1.01)	(0.34)
Total Company								
Sales	55.90	4.01	39.66	59.49	4.79	43.27	38.40	35.29
Realized hedging gain	1.69	0.18	1.39	0.99	0.07	0.68	2.23	3.60
Royalties	(4.66)	(0.14)	(2.71)	(5.01)	(0.14)	(2.82)	(2.14)	(2.23)
Transportation	(2.33)	(0.19)	(1.72)	(2.35)	(0.20)	(1.74)	(1.60)	(1.70)
Operating	(12.29)	(1.26)	(9.87)	(12.61)	(1.21)	(9.80)	(9.05)	(9.21)
PRRT [1]	(1.42)	-	(0.69)	(1.90)	-	(0.90)	0.04	-
Operating netback	36.89	2.60	26.06	38.61	3.31	28.69	27.88	25.75
General and administration			(1.93)			(2.13)	(2.03)	(2.34)
Interest expense			(2.14)			(2.41)	(2.34)	(2.41)
Realized derivatives			(0.66)			(0.03)	0.34	0.16
Other income (expense)			0.03			0.03	(0.01)	-
Corporate income taxes [1]			(0.49)			(0.81)	(0.59)	(0.70)
Fund flows from operations netback			20.87			23.34	23.25	20.46

[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, 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	-	-	-
3-Way Collar	Jul 2017 - Dec 2018		USD	2,000	48.89	2,000	55.00	2,000	42.50	-	-	-
3-Way Collar	Oct 2017 - Dec 2018		USD	2,000	50.50	2,000	55.75	2,000	43.00	-	-	-
3-Way Collar	Jan 2018 - Dec 2018		USD	500	52.15	500	59.00	500	45.00	-	-	-
Collar	Jan 2018 - Dec 2018		USD	1,000	50.00	1,000	57.50	-	-	-	-	-
Put Spread	Apr 2017 - Dec 2017		USD	600	56.00	-	-	600	46.25	-	-	-
Put Spread	May 2017 - Dec 2017		USD	680	55.00	-	-	680	46.00	-	-	-
Put Spread	Jul 2017 - Dec 2017		USD	500	55.00	-	-	500	47.50	-	-	-
Swap	Jan 2018 - Dec 2018		USD	-	-	-	-	-	-	1,000	55.00	-
Swaption	Jan 2018 - Dec 2018	Dec 29, 2017	USD	-	-	-	-	-	-	1,000	48.75	-
WTI												
3-Way Collar	Jan 2017 - Dec 2017		CAD	1,500	70.00	1,500	75.00	1,500	55.00	-	-	-
3-Way Collar	Jul 2017 - Dec 2017		USD	3,000	54.33	3,000	65.58	3,000	45.00	-	-	-
3-Way Collar	Jan 2018 - Jun 2018		USD	500	48.50	500	56.00	500	42.50	-	-	-
Swaption	Jan 2018 - Dec 2018	Dec 29, 2017	USD	-	-	-	-	-	-	1,000	54.00	-

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	-	-	-	-	-
Collar	Nov 2017 - Dec 2017		CAD	4,739	2.95	4,739	3.38	-	-	-	-	-
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	Jun 2017 - Oct 2017		CAD	-	-	-	-	-	-	4,739	2.91	-
Swap	Nov 2017 - Dec 2017		CAD	-	-	-	-	-	-	7,109	3.35	-
Swap	Jan 2018 - Dec 2018		CAD	-	-	-	-	-	-	9,478	2.80	-
AECO Basis (AECO less NYMEX HH)												
Swap	Jan 2017 - Dec 2017		USD	-	-	-	-	-	-	5,000	(0.75)	-
Swap	Oct 2017 - Dec 2018		USD	-	-	-	-	-	-	10,000	(1.03)	-
Swap	Jan 2018 - Dec 2018		USD	-	-	-	-	-	-	20,000	(0.95)	-
Swap	Jan 2019 - Jun 2020		USD	-	-	-	-	-	-	2,500	(0.93)	-
NYMEX HH												
3-Way Collar	Oct 2017 - Dec 2018		USD	10,000	3.11	10,000	3.40	10,000	2.40	-	-	-
3-Way Collar	Jan 2018 - Dec 2018		USD	10,000	3.06	10,000	3.40	10,000	2.40	-	-	-
Swap	Jan 2017 - Dec 2017		USD	-	-	-	-	-	-	5,000	3.00	-
Swap	Jan 2018 - Dec 2018		USD	-	-	-	-	-	-	10,000	3.10	-
Swaption	Jan 2018 - Dec 2018	Oct 31, 2017	USD	-	-	-	-	-	-	5,000	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												
3-Way Collar	Jan 2019 - Dec 2019		EUR	9,827	4.79	9,827	5.42	9,827	3.66	-	-	-
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	-	-	-	-	-
Collar	Jan 2019 - Sep 2020		USD	7,500	2.07	7,500	4.00	-	-	-	-	-
TTF												
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	9,827	4.92	9,827	5.48	9,827	3.66	-	-	-
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	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	-
Swaption	Jul 2018 - Dec 2019	Oct 31, 2017	EUR	-	-	-	-	-	-	4,913	4.98	-

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			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		Receive Notional amount (USD)	Rate (US%)	Pay Notional amount (CAD)	Rate (CAD%)
Swap	Oct 2017	629,493,264	2.94	775,800,000	2.58

(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.

Supplemental Table 3: Capital Expenditures and Acquisitions

By classification ($M)	Three Months Ended Sep 30, 2017	Jun 30, 2017	Sep 30, 2016	Nine Months Ended Sep 30, 2017	Sep 30, 2016
Drilling and development	75,837	57,681	41,039	228,682	175,108
Exploration and evaluation	15,545	1,194	-	17,464	418
Capital expenditures	91,382	58,875	41,039	246,146	175,526
Property acquisitions	20,976	993	10,391	24,589	19,811
Acquisitions	20,976	993	10,391	24,589	19,811

By category ($M)	Three Months Ended Sep 30, 2017	Jun 30, 2017	Sep 30, 2016	Nine Months Ended Sep 30, 2017	Sep 30, 2016
Land	483	1,103	(36)	3,031	1,496
Seismic	8,859	2,028	1,110	12,898	8,701
Drilling and completion	40,923	19,942	18,694	116,251	83,089
Production equipment and facilities	33,099	27,146	18,046	90,421	59,896
Recompletions	5,411	4,071	603	14,983	4,969
Other	2,607	4,585	2,622	8,562	17,375
Capital expenditures	91,382	58,875	41,039	246,146	175,526
Acquisitions	20,976	993	10,391	24,589	19,811
Total capital expenditures and acquisitions	112,358	59,868	51,430	270,735	195,337

Capital expenditures by country ($M)	Three Months Ended Sep 30, 2017	Jun 30, 2017	Sep 30, 2016	Nine Months Ended Sep 30, 2017	Sep 30, 2016
Canada	43,746	20,599	10,421	121,802	45,811
France	15,756	16,682	11,110	53,354	37,345
Netherlands	11,590	5,973	6,441	19,275	18,003
Germany	3,020	326	978	4,252	2,109
Ireland	1,101	(73)	2,416	224	7,664
Australia	10,154	9,158	6,908	22,750	54,674
United States	1,362	5,155	2,765	18,056	9,502
Corporate	4,653	1,055	-	6,433	418
Total capital expenditures	91,382	58,875	41,039	246,146	175,526

Acquisitions by country ($M)	Three Months Ended Sep 30, 2017	Jun 30, 2017	Sep 30, 2016	Nine Months Ended Sep 30, 2017	Sep 30, 2016
Canada	19,712	935	10,380	21,223	11,931
Netherlands	14	(16)	-	14	-
United States	1,250	49	11	3,312	5,558
Corporate	-	25	-	40	2,322
Total acquisitions	20,976	993	10,391	24,589	19,811

Supplemental Table 4: Production

	Q3/17	Q2/17	Q1/17	Q4/16	Q3/16	Q2/16	Q1/16	Q4/15	Q3/15	Q2/15	Q1/15	Q4/14
Canada												
Crude oil & condensate (bbls/d)	9,288	9,205	7,987	7,945	8,984	9,453	10,317	10,413	11,030	11,843	12,163	12,681
NGLs (bbls/d)	4,891	3,745	2,670	2,444	2,448	2,687	2,633	2,710	2,678	2,094	1,706	1,444
Natural gas (mmcf/d)	103.92	93.68	85.74	75.12	77.62	87.44	97.16	87.90	71.94	64.66	61.78	58.36
Total (boe/d)	31,499	28,563	24,947	22,910	24,368	26,713	29,141	27,773	25,698	24,713	24,165	23,851
% of consolidated	46%	43%	38%	38%	37%	42%	44%	45%	47%	48%	48%	49%
France												
Crude oil (bbls/d)	10,918	11,368	10,834	11,220	11,827	12,326	12,220	12,537	12,310	12,746	11,463	11,133
Natural gas (mmcf/d)	-	-	0.01	0.38	0.42	0.54	0.44	1.36	1.47	1.03	-	-
Total (boe/d)	10,918	11,368	10,836	11,283	11,897	12,416	12,293	12,763	12,555	12,917	11,463	11,133
% of consolidated	16%	17%	17%	19%	19%	19%	19%	21%	22%	25%	23%	22%
Netherlands												
Condensate (bbls/d)	74	104	76	57	86	96	114	110	109	112	63	81
Natural gas (mmcf/d)	34.90	31.58	39.92	41.15	47.62	49.18	53.40	56.34	53.56	32.43	36.41	31.35
Total (boe/d)	5,890	5,368	6,729	6,915	8,023	8,293	9,015	9,500	9,035	5,517	6,132	5,306
% of consolidated	9%	8%	10%	11%	13%	13%	14%	16%	16%	11%	12%	11%
Germany												
Crude oil (bbls/d)	1,054	1,047	989	-	-	-	-	-	-	-	-	-
Natural gas (mmcf/d)	20.12	19.86	19.39	14.80	14.52	14.31	15.96	16.17	14.00	16.18	16.80	17.71
Total (boe/d)	4,407	4,357	4,220	2,467	2,420	2,385	2,660	2,695	2,333	2,696	2,801	2,952
% of consolidated	7%	6%	7%	4%	4%	4%	4%	4%	4%	5%	6%	6%
Ireland												
Natural gas (mmcf/d)	49.04	63.81	64.82	62.92	59.28	47.26	33.90	0.12	-	-	-	-
Total (boe/d)	8,173	10,634	10,803	10,486	9,879	7,877	5,650	20	-	-	-	-
% of consolidated	12%	16%	17%	17%	16%	12%	9%	-	-	-	-	-
Australia												
Crude oil (bbls/d)	5,473	6,054	6,581	6,388	6,562	6,083	6,180	7,824	6,433	5,865	5,672	6,134
% of consolidated	8%	9%	10%	10%	10%	9%	9%	13%	11%	11%	11%	12%
United States												
Crude oil (bbls/d)	880	747	365	362	383	458	368	420	226	123	153	195
NGLs (bbls/d)	56	76	24	23	30	26	39	29	-	-	-	-
Natural gas (mmcf/d)	0.64	0.44	0.20	0.18	0.20	0.20	0.26	0.20	-	-	-	-
Total (boe/d)	1,043	896	422	414	447	518	450	483	226	123	153	195
% of consolidated	2%	1%	1%	1%	1%	1%	1%	1%	-	-	-	-
Consolidated												
Crude oil, condensate & NGLs (bbls/d)	32,634	32,346	29,526	28,439	30,320	31,129	31,871	34,043	32,786	32,783	31,220	31,668
% of consolidated	48%	48%	46%	47%	48%	48%	49%	56%	58%	63%	62%	64%
Natural gas (mmcf/d)	208.62	209.36	210.07	194.54	199.65	198.93	201.11	162.09	140.97	114.29	115.00	107.42
% of consolidated	52%	52%	54%	53%	52%	52%	51%	44%	42%	37%	38%	36%
Total (boe/d)	67,403	67,240	64,537	60,863	63,596	64,285	65,389	61,058	56,280	51,831	50,386	49,571

	YTD 2017	2016	2015	2014	2013	2012
Canada						
Crude oil & condensate (bbls/d)	8,831	9,171	11,357	12,491	8,387	7,659
NGLs (bbls/d)	3,776	2,552	2,301	1,233	1,666	1,232
Natural gas (mmcf/d)	94.52	84.29	71.65	55.67	42.39	37.50
Total (boe/d)	28,360	25,771	25,598	23,001	17,117	15,142
% of consolidated	42%	40%	46%	47%	41%	40%
France						
Crude oil (bbls/d)	11,040	11,896	12,267	11,011	10,873	9,952
Natural gas (mmcf/d)	-	0.44	0.97	-	3.40	3.59
Total (boe/d)	11,041	11,970	12,429	11,011	11,440	10,550
% of consolidated	17%	19%	23%	22%	28%	28%
Netherlands						
Condensate (bbls/d)	85	88	99	77	64	67
Natural gas (mmcf/d)	35.45	47.82	44.76	38.20	35.42	34.11
Total (boe/d)	5,992	8,058	7,559	6,443	5,967	5,751
% of consolidated	9%	13%	14%	13%	15%	15%
Germany						
Crude oil (bbls/d)	1,030	-	-	-	-	-
Natural gas (mmcf/d)	19.79	14.90	15.78	14.99	-	-
Total (boe/d)	4,329	2,483	2,630	2,498	-	-
% of consolidated	7%	4%	5%	5%	-	-
Ireland						
Natural gas (mmcf/d)	59.16	50.89	0.03	-	-	-
Total (boe/d)	9,861	8,482	5	-	-	-
% of consolidated	15%	13%	-	-	-	-
Australia						
Crude oil (bbls/d)	6,032	6,304	6,454	6,571	6,481	6,360
% of consolidated	9%	10%	12%	13%	16%	17%
United States						
Crude oil (bbls/d)	666	393	231	49	-	-
NGLs (bbls/d)	52	29	7	-	-	-
Natural gas (mmcf/d)	0.43	0.21	0.05	-	-	-
Total (boe/d)	789	457	247	49	-	-
% of consolidated	1%	1%	-	-	-	-
Consolidated						
Crude oil, condensate & NGLs (bbls/d)	31,512	30,433	32,716	31,432	27,471	25,270
% of consolidated	47%	48%	60%	63%	67%	67%
Natural gas (mmcf/d)	209.35	198.55	133.24	108.85	81.21	75.20
% of consolidated	53%	52%	40%	37%	33%	33%
Total (boe/d)	66,404	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 use free cash flow 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. We also assess free cash flow as a percentage of fund flows from operations, which is a measure of the percentage of fund flows from operations that is retained for incremental investing and financing activities.

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 Plan. Management monitors net dividends and net dividends as a percentage of fund flows from operations to assess our ability to pay dividends.

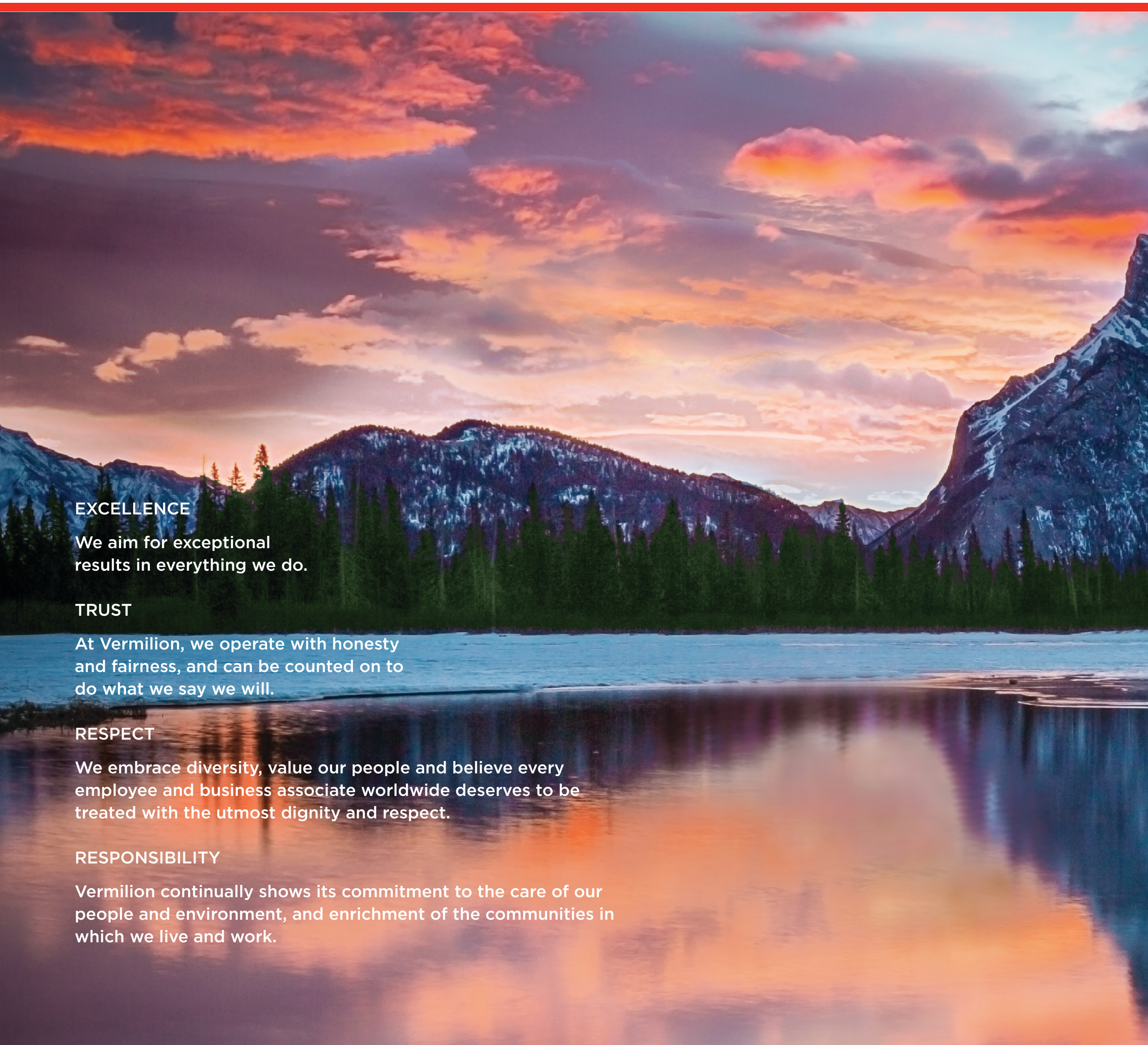
Operating netback: Sales less royalties, operating expense, transportation costs, PRRT, and realized hedging gains and losses presented on a per unit basis. Management assesses operating netback as a measure of the profitability and efficiency of our field operations. In contrast, fund flows from operations 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 and payout as a percentage of fund flows from operations (also referred to as the sustainability ratio) 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			Nine Months Ended	
($M)	Sep 30, 2017	Jun 30, 2017	Sep 30, 2016	Sep 30, 2017	Sep 30, 2016
Dividends declared	78,293	77,858	75,465	232,744	222,974
Shares issued for the Dividend Reinvestment Plan	(23,929)	(29,241)	(50,912)	(88,676)	(149,418)
Net dividends	54,364	48,617	24,553	144,068	73,556
Drilling and development	75,837	57,681	41,039	228,682	175,108
Exploration and evaluation	15,545	1,194	-	17,464	418
Asset retirement obligations settled	1,749	2,120	2,066	6,118	6,290
Payout	147,495	109,612	67,658	396,332	255,372

	As at		
('000s of shares)	Sep 30, 2017	Jun 30, 2017	Sep 30, 2016
Shares outstanding	121,585	120,947	117,386
Potential shares issuable pursuant to the VIP	2,868	2,847	2,797
Diluted shares outstanding	124,453	123,794	120,183



EXCELLENCE

We aim for exceptional results in everything we do.

TRUST

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

RESPECT

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

RESPONSIBILITY

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

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