Q2 2018

MANAGEMENT'S DISCUSSION AND ANALYSIS

EXCELLENCE. TRUST. RESPECT. RESPONSIBILITY.

INTERNATIONALLY DIVERSIFIED | SUSTAINABLE GROWTH AND INCOME

VERMILION ENERGY

Front Cover Theme

Sustainability is integrated into every facet of Vermilion's business. This 15-hectare greenhouse is an example of how Vermilion reduces greenhouse emissions with geothermal energy. At Vermilion's production facility in Parentis-en-Born, France, heat from our produced water is transferred to the heating system of the adjacent greenhouse. The result is an economically and ecologically viable greenhouse operation growing tomatoes with heat generated without carbon emissions.

Across the company, Vermilion has decreased our emissions intensity on a per unit of production basis. This is due to our energy efficiency programs, emission reduction initiatives and an operational structure that maximizes production while reducing our footprint and energy consumption intensity.

Read more about Vermilion's renewable energy projects in our Sustainability Report online at www.vermilionenergy.com.

Management's Discussion and Analysis

The following is Management's Discussion and Analysis ("MD&A"), dated July 27, 2018, of Vermilion Energy Inc.'s ("Vermilion", "we", "our", "us" or the "Company") operating and financial results as at and for the three and six months ended June 30, 2018 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 six months ended June 30, 2018 and the audited consolidated financial statements for the year ended December 31, 2017 and 2016, together with the 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 six months ended June 30, 2018 and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with IAS 31, "Interim Financial Reporting", as issued by the International Accounting Standards 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".

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).

2018 Guidance

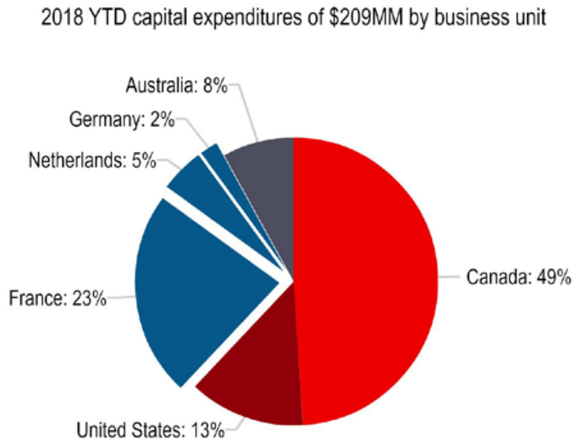
On October 30, 2017, we released our 2018 capital expenditure guidance of $315 million and associated production guidance of between 74,500 to 76,500 boe/d. On January 15, 2018, we increased our capital expenditure guidance to $325 million and production guidance to between 75,000 to 77,500 boe/d to reflect the post-closing impact of the acquisition of a private southeast Saskatchewan and southwest Manitoba light oil producer. On April 16, 2018, we increased our capital expenditure guidance to $430 million and production guidance to between 86,000 to 90,000 boe/d to reflect the post-closing impact of the acquisition of Spartan Energy Corp. On July 30, 2018, we increased our capital expenditure guidance to $500 million to reflect the acceleration of our Australia drilling campaign into Q4 2018, and to a lesser extent to account for the impact of foreign exchange fluctuations on our Canadian dollar capital levels.

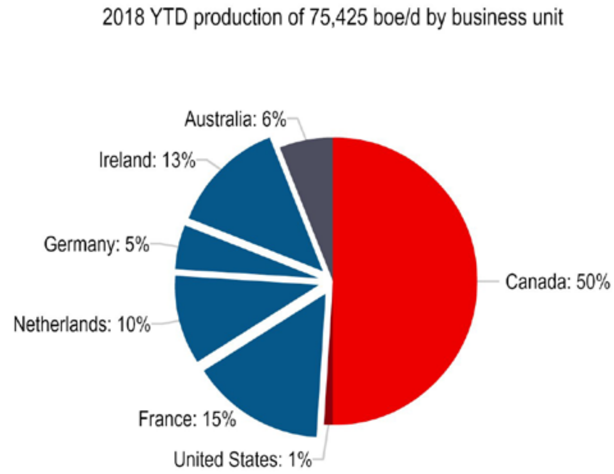
The following table summarizes our guidance:

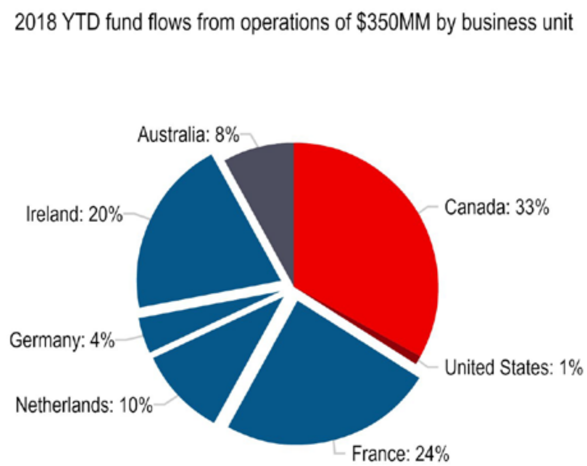
	Date	Capital Expenditures ($MM)	Production (boe/d)
2018 Guidance			
2018 Guidance	October 30, 2017	315	74,500 to 76,500
2018 Guidance	January 15, 2018	325	75,000 to 77,500
2018 Guidance	April 16, 2018	430	86,000 to 90,000
2018 Guidance	July 30, 2018	500	86,000 to 90,000

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.





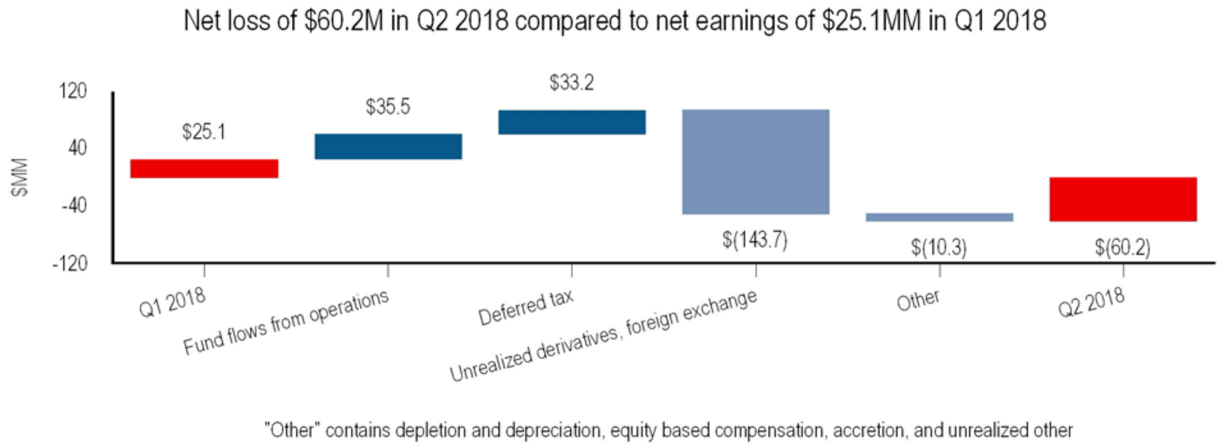


Consolidated Results Overview

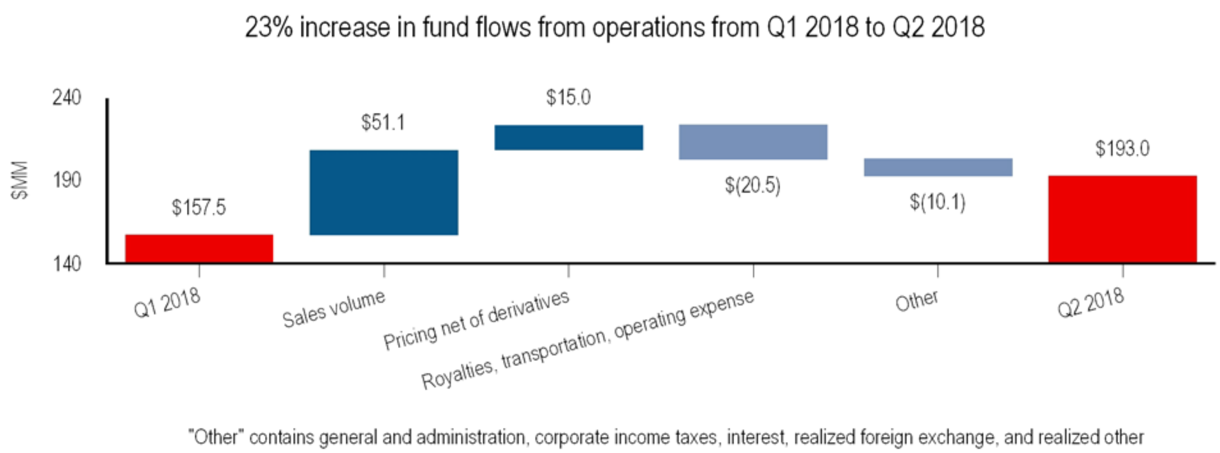
	Q2 2018	Q1 2018	Q2 2017	Q2/18 vs. Q1/18	Q2/18 vs. Q2/17	YTD 2018	YTD 2017	2018 vs. 2017
Production								
Crude oil and condensate (bbls/d)	34,574	27,008	28,525	28%	21%	30,812	27,683	11%
NGLs (bbls/d)	5,651	5,126	3,821	10%	48%	5,390	3,260	65%
Natural gas (mmcf/d)	242.40	228.20	209.36	6%	16%	235.34	209.71	12%
Total (boe/d)	80,625	70,167	67,240	15%	20%	75,425	65,896	14%
Sales								
Crude oil and condensate (bbls/d)	34,655	26,001	29,639	33%	17%	30,352	26,943	13%
NGLs (bbls/d)	5,651	5,126	3,821	10%	48%	5,390	3,260	65%
Natural gas (mmcf/d)	242.40	228.20	209.36	6%	16%	235.34	209.71	12%
Total (boe/d)	80,706	69,159	68,355	17%	18%	74,965	65,157	15%
Build (draw) in inventory (mbbls)	(7)	90	(102)			84	133	
Financial metrics								
Fund flows from operations ($M)	192,990	157,480	147,123	23%	31%	350,470	290,557	21%
Per share ($/basic share)	1.43	1.29	1.22	11%	17%	2.73	2.43	12%
Net (loss) earnings	(60,224)	25,139	48,264	N/A	N/A	(35,085)	92,804	N/A
Per share ($/basic share)	(0.45)	0.21	0.40	N/A	N/A	(0.27)	0.78	N/A
Net debt ($M)	1,787,603	1,514,645	1,314,766	18%	36%	1,787,603	1,314,766	36%
Cash dividends ($/share)	0.690	0.645	0.645	7%	7%	1.335	1.290	3%
Activity								
Capital expenditures ($M)	80,129	128,618	58,875	(38)%	36%	208,747	154,764	35%
Acquisitions ($M)	1,468,645	93,078	993			1,561,723	3,613	
Gross wells drilled	18.00	29.00	2.00			47.00	31.00	
Net wells drilled	16.19	27.69	1.40			43.88	26.81	

Financial performance review

Q2 2018 vs. Q1 2018

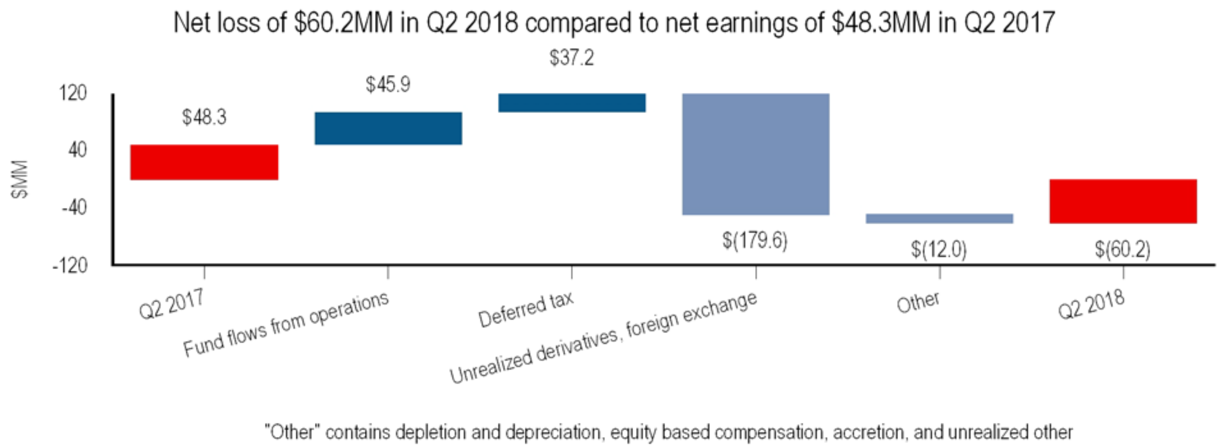


- We recorded a net loss for Q2 2018 of $60.2 million ($0.45/basic share) compared to net earnings of $25.1 million ($0.21/basic share) in Q1 2018. The net loss in Q2 2018 resulted from a $105.3 million unrealized loss on derivative instruments and a $12.5 million unrealized loss on foreign exchange. Quarter-over-quarter, the increases in unrealized losses were partially offset by a $35.5 million increase in fund flows from operations.
- 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 forecast price curves, while the instruments themselves reduce Vermilion's exposure to commodity prices in future periods.
- The unrealized loss on derivative instruments recognized in Q2 2018 primarily related to European natural gas and crude oil derivative instruments for 2018 and 2019. As of June 30, 2018, our European natural gas swaps and collars for provide an average floor of $7.26/mmbtu for 74,802 mmcf/d for the remainder of 2018, $7.53/mmbtu for 63,835 mmcf/d for 2019, and $7.64/mmbtu for 29,544 mmcf/d for 2020. Our crude oil swaps and collars provide an average floor of $72.46/bbl for 8,792 bbls/d for the remainder of 2018 and $90.40/bbl for 2,388 bbls/d for 2019. Subsequent to June 30, 2018, we have entered into additional swap contracts at higher prices.

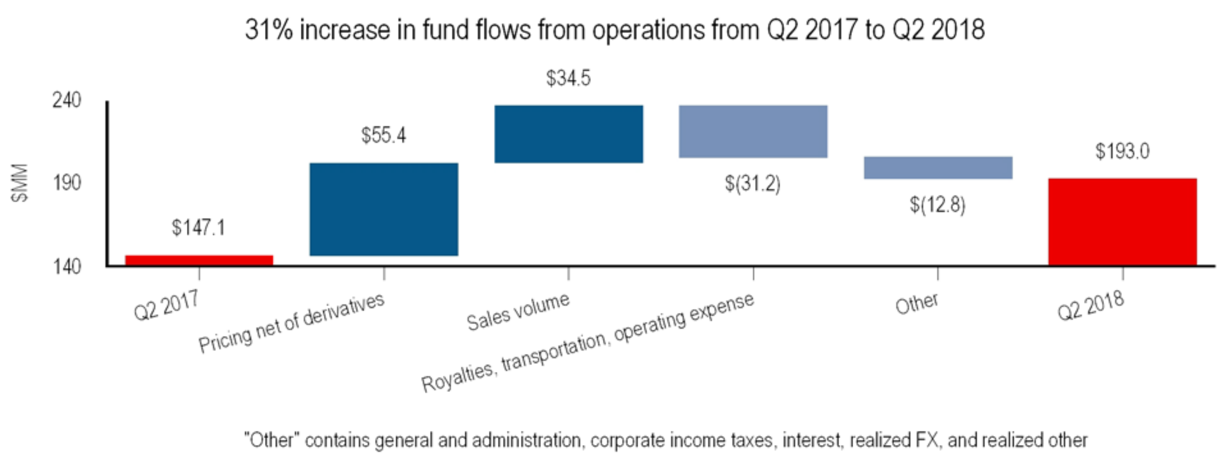


- Generated fund flows from operations of $193.0 million during Q2 2018, an increase of 23% from Q1 2018. This quarter-over-quarter increase was due to the contribution of $27.6 million in fund flows from operations from Spartan Energy Corp. ("Spartan") from May 28, 2018 to the end of Q2 2018 along with stronger crude oil pricing.

Q2 2018 vs. Q2 2017

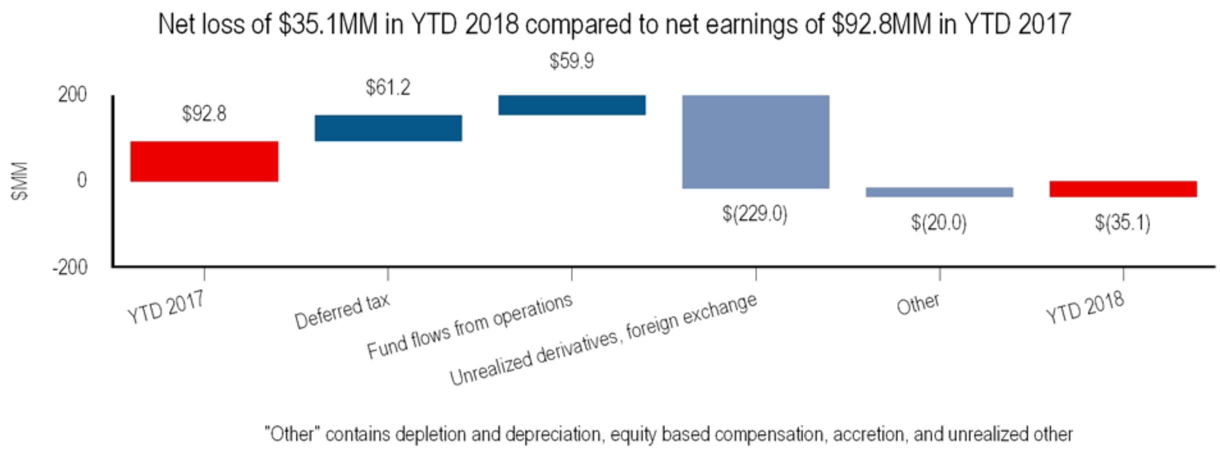


- We recorded a net loss for Q2 2018 of $60.2 million ($0.45/basic share) compared to net earnings of $48.3 million ($0.40/basic share) in Q2 2017 . The net loss in Q2 2018 resulted from a $105.3 million unrealized loss on derivative instruments and a $12.5 million unrealized loss on foreign exchange. The quarter-over-quarter increases in unrealized losses were partially offset by a $45.9 million increase in fund flows from operations.

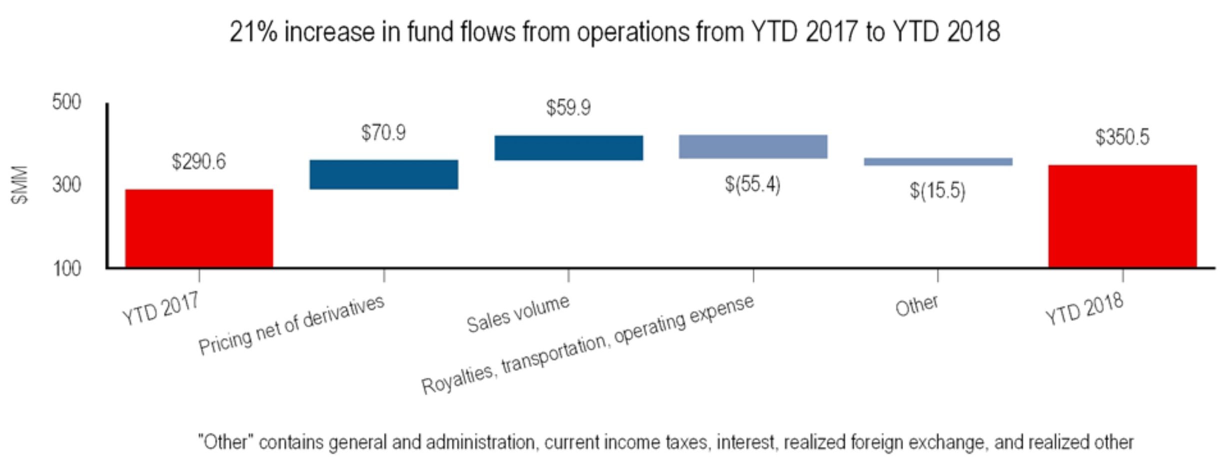


- Fund flows from operations increased by 31% in Q2 2018 versus Q2 2017 due to the acquisition of Spartan and higher crude oil and European prices.

YTD 2018 vs. YTD 2017



- For the six months ended June 30, 2018, the net loss of $35.1 million compared to net earnings of $92.8 million for the comparative year-to-date ("YTD") period in the prior year. The net loss primarily related to an unrealized loss on derivative instruments of $87.9 million (compared to an unrealized gain of $103.1 million in the prior year) and an unrealized loss on foreign exchange of $3.8 million in the current period (compared to an unrealized gain of $34.1 million in the prior year). These unrealized losses were partially offset by $59.9 million higher fund flows from operations in the current year-to-date period.



- Fund flows from operations increased 21% for the six months ended June 30, 2018 versus the comparable period in the prior year. The increase in fund flows from operations was due to the acquisition of Spartan and higher crude oil and European gas prices.

Production review

Q2 2018 vs. Q1 2018

- Consolidated average production of 80,625 boe/d during Q2 2018 increased 15% versus Q1 2018. The increase in production was primarily attributable to growth in Canada from acquisitions and continued development of our Mannville condensate-rich resource play in addition to incremental production from new wells drilled in Q1 2018 in France and the United States.

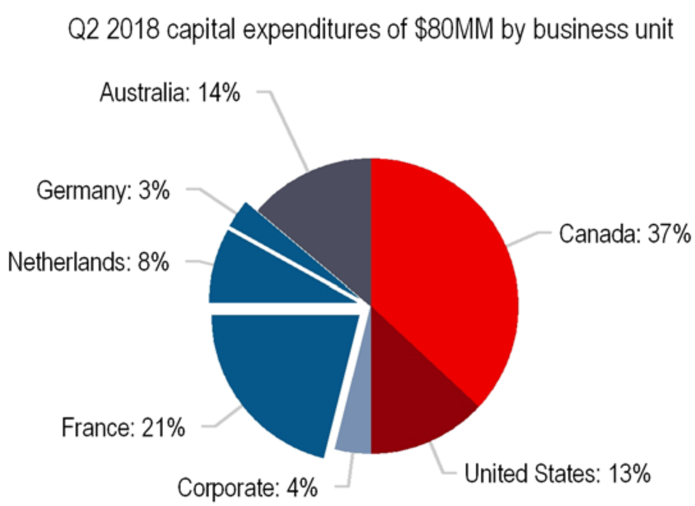
Q2 2018 vs. Q2 2017

- Consolidated average production of 80,625 boe/d in Q2 2018 represented an increase of 20% from Q2 2017. Year-over-year production growth resulted from growth in Canada and the Netherlands. In Canada, year-over-year growth was the result of both acquisitions and continued development of our Mannville condensate-rich resource play. In the Netherlands, year-over-year growth occurred following the receipt of production permits which restricted production from certain wells during the first half of 2017.

YTD 2018 vs. YTD 2017

- For the six months ended June 30, 2018, consolidated average production of 75,425 boe/d in Q2 2018 represented an increase of 14% from the comparable period in 2017 due to production growth in Canada and the Netherlands. In Canada, production increased by 11,215 boe/d, due largely to production from the continued development of our Mannville condensate-rich resource play in addition to contribution from acquisitions. In the Netherlands, year-over-year growth occurred following the receipt of production permits which restricted production from certain wells during the first half of 2017.

Activity review



- For the three months ended June 30, 2018, capital expenditures of $80.1 million primarily related to activity in Canada and France. In Canada, capital expenditures of $28.7 million included the drilling of 18.0 (16.2 net) wells in southeast Saskatchewan. In France, capital expenditures of $17.1 million primarily related to subsurface and workover programs.

Sustainability review

Dividends

- Declared dividends of $0.23 per common share per month for Q2 2018 - a 7% increase from dividends declared of in Q1 2018, resulting in total dividends declared of $1.335 per common share for the six months ended June 30, 2018.
- The dividend increase in Q2 2018 was our fourth dividend increase (previously Vermilion's distribution in the income trust era) since we began paying a distribution in 2003.

Net debt

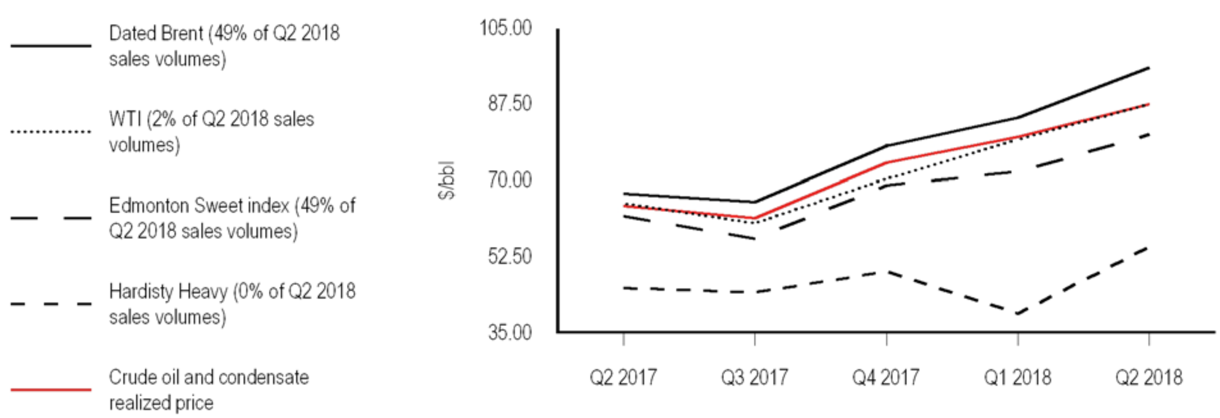
- Net debt increased to $1.79 billion as at June 30, 2018 from $1.37 billion at December 31, 2017, and was primarily due to acquisition activity in 2018 and an increase in net current derivative liability to $124.6 million as at June 30, 2018 (compared to $60.9 million as at December 31, 2017).

Commodity Prices

	Q2 2018	Q1 2018	Q2 2017	Q2/18 vs. Q1/18	Q2/18 vs. Q2/17	YTD 2018	YTD 2017	2018 vs. 2017
Crude oil								
WTI ($/bbl)	87.63	79.52	64.92	10%	35%	83.54	66.82	25%
WTI (US $/bbl)	67.88	62.87	48.28	8%	41%	65.37	50.10	30%
Edmonton Sweet index ($/bbl)	80.60	72.07	61.90	12%	30%	76.29	62.96	21%
Edmonton Sweet index (US $/bbl)	62.43	56.98	46.03	10%	36%	59.70	47.20	26%
Dated Brent ($/bbl)	95.99	84.44	67.01	14%	43%	90.16	69.10	30%
Dated Brent (US $/bbl)	74.35	66.76	49.83	11%	49%	70.55	51.81	36%
Hardisty Heavy ($/bbl)	54.92	39.54	45.42	39%	21%	47.15	44.43	6%
Hardisty Heavy (US $/bbl)	42.54	31.26	33.78	36%	26%	36.90	33.31	11%
Natural gas								
AECO ($/mmbtu)	1.18	2.08	2.78	(43)%	(58)%	1.63	2.74	(41)%
NBP ($/mmbtu)	9.42	9.96	6.52	(5)%	44%	9.69	7.26	33%
NBP (€/mmbtu)	6.12	6.41	4.41	(5)%	39%	6.27	5.02	25%
TTF ($/mmbtu)	9.50	9.59	6.74	(1)%	41%	9.54	7.21	32%
TTF (€/mmbtu)	6.17	6.17	4.56	—%	35%	6.17	4.99	24%
Henry Hub ($/mmbtu)	3.61	3.80	4.28	(5)%	(16)%	3.70	4.33	(15)%
Henry Hub (US $/mmbtu)	2.80	3.00	3.18	(7)%	(12)%	2.90	3.25	(11)%
Average exchange rates								
CDN $/US $	1.29	1.26	1.34	2%	(4)%	1.28	1.33	(4)%
CDN $/Euro	1.54	1.55	1.48	(1)%	4%	1.55	1.44	8%
Realized Prices								
Crude oil and condensate ($/bbl)	87.50	80.03	64.35	9%	36%	84.32	66.25	27%
NGLs ($/bbl)	26.06	25.37	20.98	3%	24%	25.73	22.28	15%
Natural gas ($/mmbtu)	4.77	5.81	4.75	(18)%	—%	5.27	5.18	2%
Total ($/boe)	53.72	51.13	43.63	5%	23%	52.53	45.19	16%

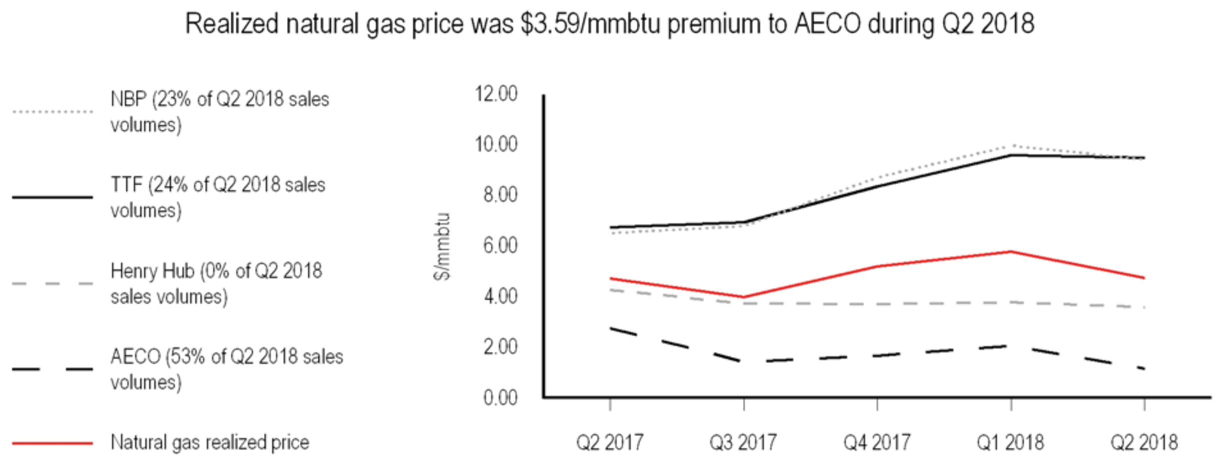
Crude oil

Realized crude oil and condensate price was a 9% premium to the Edmonton Sweet index during Q2 2018



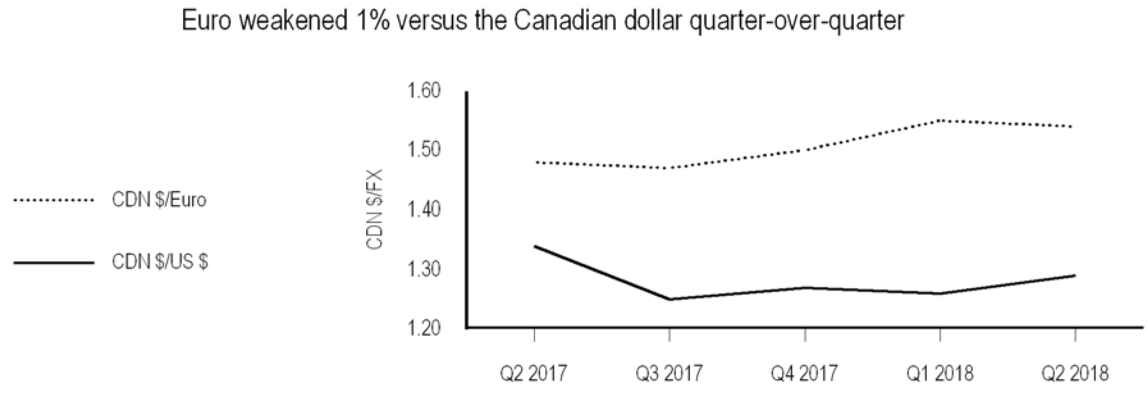
- Crude oil markets moved higher during the three months ended June 30, 2018, particularly in Canadian dollar terms where Dated Brent increased 14% quarter-over-quarter and 43% versus the same quarter in the previous year.
- Support for stronger crude oil prices was primarily driven by continued efforts to rebalance the global crude oil market. Inventories of crude oil have continued to decline and have recently moved below the target five-year average. Strong compliance to the OPEC+ coordinated cut along with robust demand growth have combined to lead inventories lower and tighten the oil market.
- Despite takeaway capacity constraints impacting certain Canadian crude oil streams, prices for Edmonton Sweet kept pace with WTI by posting a 12% quarter-over-quarter gain versus the 10% quarter-over-quarter increase in WTI.
- For the three months ended June 30, 2018, Vermilion's crude oil and condensate realized price was $87.50/bbl, an increase of 9% from Q1 2018 and a 36% increase over the same quarter in 2017.
- Vermilion's crude oil production benefits from light oil pricing and we have no exposure to significantly discounted heavy crude oil. Approximately 49% of our Q2 2018 crude oil and condensate production was priced at Dated Brent (which averaged a premium to WTI of US$6.47) while the remainder of our crude oil and condensate production was priced at the Edmonton Sweet index (which averaged a $19.89 premium to Hardisty Heavy). As a result, our Q2 2018 crude oil and condensate realized price of $87.50 was a 9% premium to the Edmonton Sweet index and a 59% premium to Hardisty Heavy.

Natural gas



- European natural gas markets managed to retain most of the winter weather-driven gains as depleted gas-in-storage, warm weather, and strong Asian demand for LNG combined to boost European gas markets
- For the three months ended June 30, 2018, NBP averaged $9.42/mmbtu, down 5% versus Q1 2018, but up 44% versus the same quarter in 2017. Similarly, TTF average Q2 2018 at $9.50/mmbtu, which was down 1% versus the previous quarter but up 41% from the same quarter in 2017.
- Henry Hub prices followed a similar path as European hubs by posting only small declines quarter-over-quarter. For the three month period ended June 30, 2018, natural gas prices at Henry Hub averaged $3.61/mmbtu, or 5% lower than in Q1 2018.
- Egress challenges and maintenance impacting flows on the TCPL Alberta system caused the AECO natural gas market to decrease in Q2 2018. Averaging $1.18/mmbtu for the three months ended June 30, 2018, AECO natural gas prices are down 43% quarter-over-quarter and 58% versus the same quarter last year.
- During Q2 2018, average European gas prices were a $8.28 premium to AECO and a $5.85 premium to Henry Hub pricing. Approximately 47% of our natural gas production in Q2 2018 benefited from this pricing.

Foreign exchange



- Early Q2 2018 US dollar gains led CAD/USD to average 1.29, a gain of 2% versus Q1 2018, but down 4% versus the same period last year.
- While the US dollar posted gains, the CAD/EUR cross remained stable over the quarter, averaging 1.54 versus 1.55 in Q1 2018.

Canada Business Unit

Overview

Production and assets focused in West Pembina near Drayton Valley, Alberta and in southeast Saskatchewan and Manitoba.

- Potential for three significant resource plays sharing the same surface infrastructure in the West Pembina region in Alberta:
  - Mannville condensate-rich gas (2,400 - 2,700m depth) - in development phase
  - Cardium light oil (1,800m 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:
  - Targeting the Mississippian Midale (1,400 - 1,700m depth), Frobisher/Alida (1,200 - 1,400m depth) and Ratcliffe (1,800 - 1,900m) formations

Operational and financial review

Canada business unit ($M except as indicated)	Q2 2018	Q1 2018	Q2 2017	Q2/18 vs. Q1/18	Q2/18 vs. Q2/17	YTD 2018	YTD 2017	2018 vs. 2017
Production and sales								
Crude oil and condensate (bbls/d)	17,009	9,272	9,205	83%	85%	13,161	8,599	53%
NGLs (bbls/d)	5,589	5,106	3,745	9%	49%	5,349	3,210	67%
Natural gas (mmcf/d)	127.32	106.21	93.68	20%	36%	116.82	89.73	30%
Total (boe/d)	43,817	32,078	28,563	37%	53%	37,980	26,765	42%
Production mix (% of total)								
Crude oil and condensate	39%	29%	32%			35%	32%	
NGLs	13%	16%	13%			14%	12%	
Natural gas	48%	55%	54%			51%	55%	
Activity								
Capital expenditures	28,694	69,117	20,599	(58)%	39%	97,811	78,056	25%
Acquisitions	1,468,495	90,250	935			1,558,745	1,511	
Gross wells drilled	18.00	18.00	1.00			36.00	23.00	
Net wells drilled	16.19	16.69	0.40			32.88	18.81	
Financial results								
Sales	148,915	92,933	83,643	60%	78%	241,848	159,143	52%
Royalties	(15,463)	(9,848)	(8,805)	57%	76%	(25,311)	(17,304)	46%
Transportation	(5,186)	(4,540)	(3,944)	14%	31%	(9,726)	(8,047)	21%
Operating	(36,031)	(24,348)	(19,347)	48%	86%	(60,379)	(36,017)	68%
General and administration	(2,719)	(1,867)	(3,127)	46%	(13)%	(4,586)	(4,825)	(5)%
Fund flows from operations	89,516	52,330	48,420	71%	85%	141,846	92,950	53%
Netbacks ($/boe)								
Sales	37.35	32.19	32.18	16%	16%	35.18	32.85	7%
Royalties	(3.88)	(3.41)	(3.39)	14%	14%	(3.68)	(3.57)	3%
Transportation	(1.30)	(1.57)	(1.52)	(17)%	(14)%	(1.41)	(1.66)	(15)%
Operating	(9.04)	(8.43)	(7.44)	7%	22%	(8.78)	(7.43)	18%
General and administration	(0.68)	(0.65)	(1.20)	5%	(43)%	(0.67)	(1.00)	(33)%
Fund flows from operations netback	22.45	18.13	18.63	24%	21%	20.64	19.19	8%
Realized prices								
Crude oil and condensate ($/bbl)	79.43	75.05	62.46	6%	27%	77.89	63.52	23%
NGLs ($/bbl)	26.00	25.33	21.11	3%	23%	25.68	22.35	15%
Natural gas ($/mmbtu)	1.09	1.95	2.83	(44)%	(61)%	1.48	2.91	(49)%
Total ($/boe)	37.35	32.19	32.18	16%	16%	35.18	32.85	7%
Reference prices								
WTI (US $/bbl)	67.88	62.87	48.28	8%	41%	65.37	50.10	30%
Edmonton Sweet index (US $/bbl)	62.43	56.98	46.03	10%	36%	59.70	47.20	26%
Edmonton Sweet index ($/bbl)	80.60	72.07	61.90	12%	30%	76.29	62.96	21%
AECO ($/mmbtu)	1.18	2.08	2.78	(43)%	(58)%	1.63	2.74	(41)%

Production

- Q2 2018 average production increased 37% from the prior quarter and 53% year-over-year primarily due to the production contribution from the Spartan acquisition. Production also benefited from our successful Q1 drilling program and less weather-related downtime and planned maintenance on third party infrastructure as compared to Q1 2018.
- Mannville production averaged approximately 21,700 boe/d in Q2 2018, an increase of 15% quarter-over-quarter.
- Cardium production averaged approximately 4,900 boe/d in Q2 2018, a decrease of 4% quarter-over-quarter.
- Our southeast Saskatchewan assets produced an average of approximately 11,000 boe/d in Q2 2018 as compared to 2,800 boe/d in Q1 2018 due to the Spartan acquisition. Base production increased by 18% from the prior quarter as a result of the Q1 capital program.

Activity review

- Vermilion drilled 18 (16.2 net) operated wells during Q2 2018.

  Alberta
  - In Q2 2018, we completed and brought on production one (1.0 net) operated Mannville well. We also participated in the completion and bringing on production of one (0.4 net) non-operated Mannville well.
  - In 2018, we plan to drill or participate in 16 (12.6 net) Mannville wells and four (2.5 net) Cardium wells.

  Saskatchewan
  - In Q2 2018, we drilled 18 (16.2 net) operated wells, 17 (15.2 net) of which were drilled from inventory acquired with Spartan. We also completed 12 (10.2 net) wells and brought seven (6.5 net) wells on production.
  - In 2018, we plan to drill or participate in 20 (19.5 net) wells from our legacy Vermilion inventory and we plan to drill 107 (89.0 net) wells from the newly acquired Spartan inventory.

- On May 28, 2018, Vermilion acquired 100% of the issued and outstanding common shares of Spartan, a publicly traded southeast Saskatchewan oil and gas producer. Consideration consisted of the issuance of 27.9 million Vermilion common shares valued at approximately $1.2 billion (based on the closing price per Vermilion common share of $44.30 on the Toronto Stock Exchange on May 28, 2018). Vermilion also assumed approximately $175 million of Spartan's outstanding debt at the time the transaction closed.

Sales

- The realized price for our crude oil and condensate production in Canada is linked to WTI subject to market conditions in western Canada (as reflected by the Edmonton Sweet index price). The realized price of our natural gas in Canada is based on the AECO index in Canada.
- Q2 2018 sales per boe increased 16% versus Q1 2018 and Q2 2017 while year-to-date 2018 sales per boe increased 7% versus the same period in 2017 due to increased Edmonton Sweet index pricing coupled with an increased weighting towards higher priced crude oil and condensate production.

Royalties

- Royalties as a percentage of sales for the three and six months ended June 30, 2018 of 10.4% and 10.5%, respectively, were relatively consistent with Q1 2018 (10.6%), Q2 2017 (10.5%), and the six months ended June 30, 2017 (10.9%).

Transportation

- Q2 2018 transportation expense on a dollar basis increased versus both Q1 2018 and Q2 2017 due to higher production volumes. On a per unit basis, transportation expense decreased as compared to both Q1 2018 and Q2 2017 due to an increase in production that incurs relatively lower transportation expense.
- Transportation expense for the six months ended June 30, 2018 decreased on a per unit basis versus the comparable period in 2017 due to the impact a prior period adjustment recorded in Q1 2017.

Operating

- Operating expense increased in Q2 2018 relative to Q1 2018 due to incremental operating expense following the acquisition of Spartan and an increase in production volumes. On a per unit basis, the increase in operating expense was primarily attributable to the impact of approximately one month of production from the Spartan assets, which have a higher associated per unit operating expense, and higher gas processing costs, water trucking costs, and the timing of maintenance activities.
- Q2 2018 operating expense increased on a per unit and dollar basis as compared to Q2 2017. On a dollar basis, the increase was consistent with higher production volumes. On a per unit basis, higher operating expense was primarily due to higher gas processing, gathering, and compression fees and higher electricity prices, partially offset by the impact of higher volumes on fixed costs.

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

France business unit ($M except as indicated)	Q2 2018	Q1 2018	Q2 2017	Q2/18 vs. Q1/18	Q2/18 vs. Q2/17	YTD 2018	YTD 2017	2018 vs. 2017
Production								
Crude oil (bbls/d)	11,683	11,037	11,368	6%	3%	11,362	11,103	2%
Sales								
Crude oil (bbls/d)	11,682	9,893	11,259	18%	4%	10,792	10,514	3%
Inventory (mbbls)								
Opening crude oil inventory	300	197	245			197	148	
Crude oil production	1,063	993	1,034			2,057	2,010	
Crude oil sales	(1,063)	(890)	(1,025)			(1,953)	(1,904)	
Closing crude oil inventory	300	300	254			300	254	
Activity								
Capital expenditures	17,088	29,972	16,682	(43)%	2%	47,060	37,598	25%
Gross wells drilled	—	5.00	1.00			5.00	5.00	
Net wells drilled	—	5.00	1.00			5.00	5.00	
Financial results								
Sales	101,128	72,745	63,615	39%	59%	173,873	123,225	41%
Royalties	(12,602)	(9,438)	(6,247)	34%	102%	(22,040)	(11,567)	91%
Transportation	(3,618)	(3,195)	(3,686)	13%	(2)%	(6,813)	(6,718)	1%
Operating	(14,000)	(13,159)	(12,153)	6%	15%	(27,159)	(23,522)	15%
General and administration	(3,500)	(3,513)	(3,713)	—%	(6)%	(7,013)	(6,783)	3%
Current income taxes	(5,234)	(2,053)	(1,830)	155%	186%	(7,287)	(6,812)	7%
Fund flows from operations	62,174	41,387	35,986	50%	73%	103,561	67,823	53%
Netbacks ($/boe)								
Sales	95.13	81.70	62.09	16%	53%	89.01	64.75	37%
Royalties	(11.85)	(10.60)	(6.10)	12%	94%	(11.28)	(6.08)	86%
Transportation	(3.40)	(3.59)	(3.60)	(5)%	(6)%	(3.49)	(3.53)	(1)%
Operating	(13.17)	(14.78)	(11.86)	(11)%	11%	(13.90)	(12.36)	12%
General and administration	(3.29)	(3.95)	(3.62)	(17)%	(9)%	(3.59)	(3.56)	1%
Current income taxes	(4.92)	(2.31)	(1.79)	113%	175%	(3.73)	(3.58)	4%
Fund flows from operations netback	58.50	46.47	35.12	26%	67%	53.02	35.64	49%
Reference prices								
Dated Brent (US $/bbl)	74.35	66.76	49.83	11%	49%	70.55	51.81	36%
Dated Brent ($/bbl)	95.99	84.44	67.01	14%	43%	90.16	69.10	30%

Production

- Q2 2018 production increased 6% compared to the prior quarter and 3% year-over-year primarily due to production additions from our Q1 2018 drilling program in the Neocomian and Champotran fields. Production also benefited from less downtime and successful execution of our planned workovers in the quarter.

Activity review

- We have completed our 2018 drilling program, which included the drilling and completion of two (2.0 net) Neocomian wells and three (3.0 net) Champotran wells.
- In addition to the drilling and completion activity, we plan to continue our workover and optimization programs in the Aquitaine and Paris Basins throughout 2018.

Sales

- Crude oil in France is priced with reference to Dated Brent.
- Q2 2018 sales per boe increased versus all comparable periods, consistent with increases in the Dated Brent benchmark price.

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 12.5% in Q2 2018 was lower than 13.0% in Q1 2018 due to the impact of fixed RCDM royalties coupled with higher realized pricing in the current quarter.
- For the three and six months ended June 30, 2018, royalties as a percentage of sales of 12.5% and 12.7% increased from 9.8% and 9.4% in the comparable periods in the prior year due to the impact of a royalty rate increase enacted in 2017.

Transportation

- Transportation expense increased in Q2 2018 compared to Q1 2018 due to the impact of three vessel-based shipments in the current quarter compared to two shipments in the prior quarter.
- Transportation expense for the three and six months ended June 30, 2018 was relatively consistent with the comparable periods in the prior year.

Operating

- Operating expense increased in Q2 2018 versus Q1 2018 due to the impact of higher sales volumes. On a per unit basis, operating expense decreased due to the impact of higher sales volumes on fixed costs.
- For the three and six months ended June 30, 2018, operating expense increased on both a dollar and per unit basis versus the comparable periods in the prior year due primarily to the impact of a stronger Euro versus the Canadian dollar and the timing of activity.

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%.
- Full year effective tax rates are estimated each quarter based on forecasted commodity prices and operational results. The estimated full year effective tax rate is applied on a pro-rata basis to quarterly results. As such, fluctuations between the reporting periods occur due to changes in estimated tax rates.
- For 2018, the effective rate on current taxes, inclusive of corporate allocations, is expected to be between 9% to 13% 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.
- On December 21, 2017, the French Parliament approved the Finance Bill for 2018. The Finance Bill for 2018 provides for a progressive decrease of the French corporate income tax rate from 34.4% to 25.8% by 2022, with the first reduction planned for 2019 to 32.0%.

Netherlands Business Unit

Overview

- Entered the Netherlands in 2004.
- Second largest onshore operator.
- Interests include 25 onshore licenses (all operated) and one offshore license (non-operated).
- Licenses include more than 800,000 net acres of land, 95% of which is undeveloped.

Operational and financial review

Netherlands business unit ($M except as indicated)	Q2 2018	Q1 2018	Q2 2017	Q2/18 vs. Q1/18	Q2/18 vs. Q2/17	YTD 2018	YTD 2017	2018 vs. 2017
Production and sales								
Condensate (bbls/d)	87	77	104	13%	(16)%	82	90	(9)%
Natural gas (mmcf/d)	43.49	44.79	31.58	(3)%	38%	44.13	35.73	24%
Total (boe/d)	7,335	7,541	5,368	(3)%	37%	7,438	6,044	23%
Activity								
Capital expenditures	6,695	3,278	5,973	104%	12%	9,973	7,685	30%
Acquisitions	139	2,760	(16)			2,899	—	
Financial results								
Sales	35,000	36,186	19,126	(3)%	83%	71,186	45,888	55%
Royalties	(745)	(850)	(296)	(12)%	152%	(1,595)	(715)	123%
Operating	(6,488)	(7,757)	(4,892)	(16)%	33%	(14,245)	(9,733)	46%
General and administration	(331)	(968)	(560)	(66)%	(41)%	(1,299)	(1,156)	12%
Current income taxes	(4,993)	(5,805)	(754)	(14)%	562%	(10,798)	(1,661)	550%
Fund flows from operations	22,443	20,806	12,624	8%	78%	43,249	32,623	33%
Netbacks ($/boe)								
Sales	52.43	53.31	39.16	(2)%	34%	52.88	41.94	26%
Royalties	(1.12)	(1.25)	(0.61)	(10)%	84%	(1.19)	(0.65)	83%
Operating	(9.72)	(11.43)	(10.01)	(15)%	(3)%	(10.58)	(8.90)	19%
General and administration	(0.50)	(1.43)	(1.14)	(65)%	(56)%	(0.96)	(1.06)	(9)%
Current income taxes	(7.48)	(8.55)	(1.54)	(13)%	386%	(8.02)	(1.52)	428%
Fund flows from operations netback	33.61	30.65	25.86	10%	30%	32.13	29.81	8%
Realized prices								
Condensate ($/bbl)	79.40	68.64	49.59	16%	60%	74.40	53.26	40%
Natural gas ($/mmbtu)	8.68	8.86	6.49	(2)%	34%	8.77	6.96	26%
Total ($/boe)	52.43	53.31	39.16	(2)%	34%	52.88	41.94	26%
Reference prices								
TTF ($/mmbtu)	9.50	9.59	6.74	(1)%	41%	9.54	7.21	32%
TTF (€/mmbtu)	6.17	6.17	4.56	—%	35%	6.17	4.99	24%

Production

- Q2 2018 production was relatively consistent with the prior quarter. Near the end of Q4 2017, we temporarily shut-in the Eesveen-02 well following an inline production test. The test rate from the Eesveen-02 well (60% working interest) was approximately 10 mmcf/d net during the test period, which lasted approximately two months. The well is expected to be brought on production in August 2018 as we have received the necessary permits and approvals to proceed. Production increased 37% year-over-year as various permitting delays restricted production through the first half of 2017.

Activity review

- Our Q2 2018 capital activity was primarily focused on planned workovers and facilities maintenance.

Sales

- The price of our natural gas in the Netherlands is based on the TTF index.
- Q2 2018 sales per boe decreased slightly versus Q1 2018 and increased versus Q2 2017, consistent with the change in the TTF reference price.

Royalties

- In the Netherlands, certain wells are subject to overriding royalties as well as royalties that take effect only when specified production levels are exceeded. As such, fluctuations in royalty expense in the periods presented result from the amount of production from those wells. Royalties in Q2 2018 represented less than 3% of sales.

Transportation

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

Operating

- Q2 2018 operating expense decreased on both a dollar and per unit basis versus Q1 2018 due to lower activity levels in the current quarter and the implementation of various cost efficiencies.
- For the three and six months ended June 30, 2018, operating expense increased versus the comparable periods in the prior year on a dollar basis, consistent with higher production volumes. For the three months ended June 30, 2018, per unit operating expense was relatively consistent versus the comparable period in the prior year. For the six months ended June 30, 2018, per unit operating expense increased due primarily to higher electricity charges in the current quarter.

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 asset retirement obligations, at a tax rate of 50%.
- Full year effective tax rates are estimated each quarter based on forecasted commodity prices and operational results. The estimated full year effective tax rate is applied on a pro-rata basis to quarterly results. As such, fluctuations between the reporting periods occur due to changes in estimated tax rates.
- For 2018, the effective rate on current taxes, inclusive of corporate allocations, is expected to be between 18% to 22% 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.

Germany Business Unit

Overview

- Entered Germany in February 2014 through the acquisition of a non-operated natural gas producing property.
- Executed a significant exploration license farm-in agreement in 2015 and acquired operated producing properties in 2016.
- Producing assets consist of seven gas and five oil producing fields with extensive infrastructure in place.
- Significant land position of approximately 1.3 million net acres (97% undeveloped).

Operational and financial review

Germany business unit ($M except as indicated)	Q2 2018	Q1 2018	Q2 2017	Q2/18 vs. Q1/18	Q2/18 vs. Q2/17	YTD 2018	YTD 2017	2018 vs. 2017
Production								
Crude oil (bbls/d)	1,008	1,078	1,047	(6)%	(4)%	1,043	1,018	2%
Natural gas (mmcf/d)	14.63	16.19	19.86	(10)%	(26)%	15.41	19.63	(21)%
Total (boe/d)	3,447	3,777	4,357	(9)%	(21)%	3,611	4,289	(16)%
Sales								
Crude oil (bbls/d)	1,058	1,307	923	(19)%	15%	1,182	956	24%
Natural gas (mmcf/d)	14.63	16.19	19.86	(10)%	(26)%	15.41	19.63	(21)%
Total (boe/d)	3,497	4,006	4,234	(13)%	(17)%	3,750	4,227	(11)%
Production mix (% of total)								
Crude oil	29%	29%	24%			29%	24%	
Natural gas	71%	71%	76%			71%	76%	
Activity								
Capital expenditures	2,314	2,415	326	(4)%	610%	4,729	1,232	284%
Financial results								
Sales	18,999	20,501	16,167	(7)%	18%	39,500	34,135	16%
Royalties	(1,251)	(1,737)	(1,228)	(28)%	2%	(2,988)	(2,596)	15%
Transportation	(1,779)	(1,998)	(1,955)	(11)%	(9)%	(3,777)	(3,440)	10%
Operating	(5,384)	(6,186)	(5,753)	(13)%	(6)%	(11,570)	(10,674)	8%
General and administration	(1,499)	(1,596)	(2,099)	(6)%	(29)%	(3,095)	(3,979)	(22)%
Fund flows from operations	9,086	8,984	5,132	1%	77%	18,070	13,446	34%
Netbacks ($/boe)								
Sales	59.69	56.86	41.96	5%	42%	58.19	44.61	30%
Royalties	(3.93)	(4.82)	(3.19)	(18)%	23%	(4.40)	(3.39)	30%
Transportation	(5.59)	(5.54)	(5.07)	1%	10%	(5.56)	(4.50)	24%
Operating	(16.92)	(17.16)	(14.93)	(1)%	13%	(17.04)	(13.95)	22%
General and administration	(4.71)	(4.43)	(5.45)	6%	(14)%	(4.56)	(5.20)	(12)%
Fund flows from operations netback	28.54	24.91	13.32	15%	114%	26.63	17.57	52%
Realized prices								
Crude oil ($/bbl)	91.00	79.04	61.34	15%	48%	84.42	63.54	33%
Natural gas ($/mmbtu)	7.68	7.69	6.09	—%	26%	7.69	6.51	18%
Total ($/boe)	59.69	56.86	41.96	5%	42%	58.19	44.61	30%
Reference prices								
Dated Brent (US $/bbl)	74.35	66.76	49.83	11%	49%	70.55	51.81	36%
Dated Brent ($/bbl)	95.99	84.44	67.01	14%	43%	90.16	69.10	30%
TTF ($/mmbtu)	9.50	9.59	6.74	(1)%	41%	9.54	7.21	32%
TTF (€/mmbtu)	6.17	6.17	4.56	—%	35%	6.17	4.99	24%

Production

- Q2 2018 production decreased 9% quarter-over-quarter and 21% year-over-year due to downtime at a non-operated sour gas processing plant resulting in 22 days of downtime. A portion of the volumes were brought back on-line mid-June; however, approximately two-thirds of the volumes affected by the downtime are not anticipated to come back on-line until late in the third quarter. Production was also negatively impacted by higher than normal downtime on some of our oil-producing wells.

Activity review

- Q2 2018 activity focused on workover and optimization opportunities on the assets acquired in late 2016.
- In 2018, we plan to continue permitting and pre-drill activities associated with our first operated well in Germany, Burgmoor Z5 (45.8% working interest) in the Dümmersee-Uchte area, which we expect to drill in early 2019.

Sales

- The price of our natural gas in Germany is based on the NCG and GPL indexes, which are both highly correlated to the TTF benchmark. Crude oil in Germany is priced with reference to Dated Brent.
- Q2 2018 sales per boe increased versus Q1 2018 due to higher Dated Brent prices.
- Sales per boe for the three and six months ended June 30, 2018 increased versus the comparable periods in the prior year, consistent with increases in both crude oil and natural gas benchmark prices.

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 6.6% in Q2 2018 was lower than 8.5% in Q1 2018 and 7.6% in Q2 2017 due to the impact of a prior period adjustment recorded in the current quarter.
- For the six months ended June 30, 2018, royalties as a percentage of sales was consistent with 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.
- Transportation expense in Q2 2018 was lower than both Q1 2018 and Q2 2017 due to the impact of lower volumes.
- Transportation expense for the six months ended June 30, 2018 was higher than the comparable period in the period year due to the timing of transportation cost adjustments.

Operating

- Operating expense on a per unit basis in Q2 2018 was relatively consistent with Q1 2018.
- Operating expense on a per unit basis increased for the three and six months ended June 30, 2018, versus the comparable periods in the prior year. The increase was primarily due to the impact of a stronger Euro relative to the Canadian dollar year-over-year, as well as the impact of fixed costs on lower 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 Germany, we do not expect to incur current income taxes in the German Business Unit for the foreseeable future.

Ireland Business Unit

Overview

- Entered Ireland in 2009 with an investment in the offshore Corrib gas field.
- The Corrib gas field is located offshore northwest Ireland and comprises six offshore wells, offshore and onshore sales and transportation pipeline segments, as well as a natural gas processing facility.
- Vermilion currently holds an 18.5% non-operated interest.
- Vermilion has a strategic partnership with Canada Pension Plan Investment Board ("CPPIB") that is expected to result in Vermilion increasing ownership in Corrib to 20% and assuming operatorship. This is expected to occur in the second half of 2018.

Operational and financial review

Ireland business unit ($M except as indicated)	Q2 2018	Q1 2018	Q2 2017	Q2/18 vs. Q1/18	Q2/18 vs. Q2/17	YTD 2018	YTD 2017	2018 vs. 2017
Production and sales								
Natural gas (mmcf/d)	56.56	60.87	63.81	(7)%	(11)%	58.70	64.31	(9)%
Total (boe/d)	9,426	10,144	10,634	(7)%	(11)%	9,783	10,718	(9)%
Activity								
Capital expenditures	87	47	(73)	85%	N/A	134	(877)	N/A
Financial results								
Sales	47,862	53,675	36,671	(11)%	31%	101,537	81,319	25%
Transportation	(1,268)	(1,286)	(1,258)	(1)%	1%	(2,554)	(2,457)	4%
Operating	(4,306)	(3,209)	(4,903)	34%	(12)%	(7,515)	(8,902)	(16)%
General and administration	(1,443)	(1,309)	(695)	10%	108%	(2,752)	(1,133)	143%
Fund flows from operations	40,845	47,871	29,815	(15)%	37%	88,716	68,827	29%
Netbacks ($/boe)								
Sales	55.80	58.79	37.90	(5)%	47%	57.34	41.92	37%
Transportation	(1.48)	(1.41)	(1.30)	5%	14%	(1.44)	(1.27)	13%
Operating	(5.02)	(3.51)	(5.07)	43%	(1)%	(4.24)	(4.59)	(8)%
General and administration	(1.68)	(1.43)	(0.72)	17%	133%	(1.55)	(0.58)	167%
Fund flows from operations netback	47.62	52.44	30.81	(9)%	55%	50.11	35.48	41%
Reference prices								
NBP ($/mmbtu)	9.42	9.96	6.52	(5)%	44%	9.69	7.26	33%
NBP (€/mmbtu)	6.12	6.41	4.41	(5)%	39%	6.27	5.02	25%

Production

- Q2 2018 production decreased 7% quarter-over-quarter and 11% year-over-year primarily due to natural declines and some minor plant downtime related to external electricity supply issues.

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 current production expectations for Corrib. The acquisition has an effective date of January 1, 2017 and is anticipated to close in the second half of 2018.

Sales

- The price of our natural gas in Ireland is based on the NBP index.
- Q2 2018 sales per boe decreased slightly versus Q1 2018, consistent with the decrease in the NBP reference price.
- Sales per boe for the three and six months ended June 30, 2018 increased versus 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.
- Transportation expense for the three and six months ended June 30, 2018 was relatively consistent versus all comparable periods.

Operating

- For the three and six months ended June 30, 2018, fluctuations in operating expense on a per unit and dollar basis against all comparable periods were due to the timing of maintenance work, as well as the impact of fixed costs on lower production volumes resulting from natural declines.

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 incur current income taxes in the Ireland Business Unit 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

Australia business unit ($M except as indicated)	Q2 2018	Q1 2018	Q2 2017	Q2/18 vs. Q1/18	Q2/18 vs. Q2/17	YTD 2018	YTD 2017	2018 vs. 2017
Production								
Crude oil (bbls/d)	4,132	4,971	6,054	(17)%	(32)%	4,549	6,316	(28)%
Sales								
Crude oil (bbls/d)	4,164	4,878	7,400	(15)%	(44)%	4,519	6,227	(27)%
Inventory (mbbls)								
Opening crude oil inventory	142	134	253			134	115	
Crude oil production	376	447	550			823	1,143	
Crude oil sales	(379)	(439)	(672)			(818)	(1,127)	
Closing crude oil inventory	139	142	131			139	131	
Activity								
Capital expenditures	11,469	4,555	9,158	152%	25%	16,024	12,596	27%
Financial results								
Sales	37,364	38,170	48,061	(2)%	(22)%	75,534	83,048	(9)%
Operating	(12,910)	(13,150)	(15,639)	(2)%	(17)%	(26,060)	(25,675)	1%
General and administration	(989)	(1,534)	(896)	(36)%	10%	(2,523)	(3,326)	(24)%
Current income taxes	(5,006)	(5,518)	(7,660)	(9)%	(35)%	(10,524)	(14,490)	(27)%
Fund flows from operations	18,459	17,968	23,866	3%	(23)%	36,427	39,557	(8)%
Netbacks ($/boe)								
Sales	98.61	86.94	71.37	13%	38%	92.35	73.68	25%
Operating	(34.07)	(29.95)	(23.22)	14%	47%	(31.86)	(22.78)	40%
General and administration	(2.61)	(3.49)	(1.33)	(25)%	96%	(3.08)	(2.95)	4%
PRRT	(7.00)	(11.04)	(9.61)	(37)%	(27)%	(9.17)	(10.56)	(13)%
Corporate income taxes	(6.21)	(1.53)	(1.77)	306%	251%	(3.70)	(2.30)	61%
Fund flows from operations netback	48.72	40.93	35.44	19%	37%	44.54	35.09	27%
Reference prices								
Dated Brent (US $/bbl)	74.35	66.76	49.83	11%	49%	70.55	51.81	36%
Dated Brent ($/bbl)	95.99	84.44	67.01	14%	43%	90.16	69.10	30%

Production

- Q2 2018 production decreased 17% quarter-over-quarter and 24% year-over-year due to higher than normal downtime to perform workovers on three of our wells.
- 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

- Q2 2018 efforts were largely focused on well workover activity, which resulted in two wells being offline for part of the quarter to optimize electric submersible pump completions.
- 2018 activity will be focused on adding value through asset optimization and targeted proactive maintenance, in addition to preparing for our planned two (2.0 net) well drilling campaign, now scheduled to occur in the fourth quarter of 2018.

Sales

- Crude oil in Australia is priced with reference to Dated Brent.
- Sales per boe for the three and six months ended June 30, 2018 increased versus all comparable periods, consistent with increases in the Dated Brent reference price. These increases in sales per boe were more than offset by lower sales volumes versus all comparable periods, resulting in decreases to 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

- For the three and six months ended June 30, 2018, per unit operating expense increased versus all comparable periods due to the impact of fixed costs on lower volumes, partially offset by lower operating costs due to lower maintenance activities.

General and administration

- Fluctuations in general and administration expense for all comparable periods are primarily 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.
- Full year effective tax rates are estimated each quarter based on forecasted commodity prices and operational results. The estimated full year effective tax rate is applied on a pro-rata basis to quarterly results. As such, fluctuations between the reporting periods occur due to changes in estimated tax rates.
- For 2018, the effective rate on current taxes, inclusive of corporate allocations, is expected to be between 20% to 24% 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.

United States Business Unit

Overview

- Entered the United States in September 2014.
- Interests include approximately 97,100 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 ($M except as indicated)	Q2 2018	Q1 2018	Q2 2017	Q2/18 vs. Q1/18	Q2/18 vs. Q2/17	YTD 2018	YTD 2017	2018 vs. 2017
Production and sales								
Crude oil (bbls/d)	655	574	747	14%	(12)%	615	557	10%
NGLs (bbls/d)	62	20	76	210%	(18)%	41	50	(18)%
Natural gas (mmcf/d)	0.40	0.15	0.44	167%	(9)%	0.28	0.32	(13)%
Total (boe/d)	784	618	896	27%	(13)%	702	660	6%
Activity								
Capital expenditures	10,702	15,868	5,155	(33)%	108%	26,570	16,694	59%
Acquisitions	11	68	49			79	2,062	
Gross wells drilled	—	5.00	—			5.00	3.00	
Net wells drilled	—	5.00	—			5.00	3.00	
Financial results								
Sales	5,230	4,059	4,108	29%	27%	9,289	6,234	49%
Royalties	(1,451)	(1,122)	(1,160)	29%	25%	(2,573)	(1,759)	46%
Operating	(374)	(566)	(387)	(34)%	(3)%	(940)	(672)	40%
General and administration	(1,482)	(1,317)	(1,127)	13%	31%	(2,799)	(2,132)	31%
Fund flows from operations	1,923	1,054	1,434	82%	34%	2,977	1,671	78%
Netbacks ($/boe)								
Sales	73.30	72.94	50.37	—%	46%	73.14	52.15	40%
Royalties	(20.35)	(20.16)	(14.21)	1%	43%	(20.26)	(14.71)	38%
Operating	(5.24)	(10.18)	(4.74)	(49)%	11%	(7.40)	(5.62)	32%
General and administration	(20.77)	(23.67)	(13.82)	(12)%	50%	(22.04)	(17.83)	24%
Fund flows from operations netback	26.94	18.93	17.60	42%	53%	23.44	13.99	68%
Realized prices								
Crude oil ($/bbl)	83.85	76.56	58.05	10%	44%	80.47	59.23	36%
NGLs ($/bbl)	30.93	36.24	14.70	(15)%	110%	32.21	17.32	86%
Natural gas ($/mmbtu)	1.59	3.00	1.55	(47)%	3%	1.96	1.84	7%
Total ($/boe)	73.30	72.94	50.37	—%	46%	73.14	52.15	40%
Reference prices								
WTI (US $/bbl)	67.88	62.87	48.28	8%	41%	65.37	50.10	30%
WTI ($/bbl)	87.63	79.52	64.92	10%	35%	83.54	66.82	25%
Henry Hub (US $/mmbtu)	2.80	3.00	3.18	(7)%	(12)%	2.90	3.25	(11)%
Henry Hub ($/mmbtu)	3.61	3.80	4.28	(5)%	(16)%	3.70	4.33	(15)%

Production

- Q2 2018 production increased 27% from the prior quarter primarily due to the contribution from two (2.0 net) of our five (5.0 net) wells drilled in Q1 2018 and resumption of gas sales following the restart of a third-party gas facility in mid-Q1 2018. The two wells placed on production averaged peak 30-day production rates of 280 boe/d (84% oil). Two (2.0 net) wells are in the process of being completed and one (1.0 net) well was shut-in after initial testing due to uneconomic production levels. Production decreased 13% year-over-year as a result of natural declines and the above mentioned production delays.

Activity

- In Q2 2018, we completed and brought on production two (2.0 net) our five (5.0 net) well 2018 drilling program.

Sales

- The price of crude oil in the United States is directly linked to WTI, subject to local market differentials within the United States.
- Q2 2018 sales per boe were consistent with Q1 2018.
- For the three and six months ended June 30, 2018, sales per boe increased versus the comparable periods in the prior year, consistent with an increase in the WTI reference price.

Royalties

- Our production in the United States is subject to federal and private royalties, severance tax, and ad valorem tax.
- Royalties as a percentage of sales were consistent in all periods presented at approximately 28%.

Operating

- Fluctuations in operating expense versus all comparable periods were due to the timing of activity.

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 US 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. Gains or losses relating to Vermilion's global hedging program are allocated to Vermilion's business units for statutory reporting and income tax purposes.

Operational and financial review

Corporate ($M)	Q2 2018	Q1 2018	Q2 2017	YTD 2018	YTD 2017
Activity					
Capital expenditures	3,080	3,366	1,055	6,446	1,780
Acquisitions	—	—	25	—	40
Gross wells drilled	—	1.00	—	1.00	—
Net wells drilled	—	1.00	—	1.00	—
Financial results					
General and administration expense	(4,278)	(2,440)	(950)	(6,718)	(2,984)
Current income taxes	(111)	(186)	(271)	(297)	(465)
Interest expense	(15,333)	(14,334)	(15,508)	(29,667)	(30,203)
Realized (loss) gain on derivatives	(27,859)	(17,715)	5,342	(45,574)	3,491
Realized foreign exchange (loss) gain	(4,105)	1,554	981	(2,551)	3,527
Realized other income	230	201	252	431	294
Fund flows from operations	(51,456)	(32,920)	(10,154)	(84,376)	(26,340)

Activity review

- In Q2 2018, we continued to prepare to bring on production our first exploratory well (100% working interest) in the South Battonya concession, which we drilled and tested in the first quarter of this year. We expect to bring the well on production during Q3 2018.

General and administration

- Fluctuations in general and administration expense for the three and six months ended June 30, 2018 versus all comparable periods were due to allocations to the various business unit segments.
- On a consolidated basis, general and administration expense increased 12% quarter-over-quarter to $16.2 million in Q2 2018 (compared to $14.5 million in Q1 2018), primarily due to transaction costs incurred on our Spartan acquisition. Acquisition-related costs of $1.3 million were incurred in the six months ended June 30, 2018.

Current income taxes

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

Interest expense

- The increase in interest expense in Q2 2018 versus Q1 2018 was due to higher drawings on the revolving credit facility.
- For the three and six months ended June 30, 2018, interest expense was relatively consistent with the comparative periods in the prior year.

Realized gain or loss on derivatives

- The realized loss on derivatives for the three and six months ended June 30, 2018 is related primarily to amounts paid on crude oil and European natural gas hedges.
- A listing of derivative positions as at June 30, 2018 is included in “Supplemental Table 2” of this MD&A.

Financial Performance Review

($M except per share)	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016
Petroleum and natural gas sales	394,498	318,269	317,341	248,505	271,391	261,601	259,891	232,660
Net (loss) earnings	(60,224)	25,139	8,645	(39,191)	48,264	44,540	(4,032)	(14,475)
Net earnings (loss) per share								
Basic	(0.45)	0.21	0.07	(0.32)	0.40	0.38	(0.03)	(0.12)
Diluted	(0.45)	0.20	0.07	(0.32)	0.39	0.37	(0.03)	(0.12)

The following table shows the calculation of fund flows from operations:

	Q2 2018		Q1 2018		Q2 2017		YTD 2018		YTD 2017	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Petroleum and natural gas sales	394,498	53.72	318,269	51.13	271,391	43.63	712,767	52.53	532,992	45.19
Royalties	(31,512)	(4.29)	(22,995)	(3.69)	(17,736)	(2.85)	(54,507)	(4.02)	(33,941)	(2.88)
Petroleum and natural gas revenues	362,986	49.43	295,274	47.44	253,655	40.78	658,260	48.51	499,051	42.31
Transportation	(11,851)	(1.61)	(11,019)	(1.77)	(10,843)	(1.74)	(22,870)	(1.69)	(20,662)	(1.75)
Operating	(79,493)	(10.82)	(68,375)	(10.99)	(63,074)	(10.14)	(147,868)	(10.90)	(115,195)	(9.77)
General and administration	(16,241)	(2.21)	(14,544)	(2.34)	(13,167)	(2.12)	(30,785)	(2.27)	(26,318)	(2.23)
PRRT	(2,652)	(0.36)	(4,848)	(0.78)	(6,468)	(1.04)	(7,500)	(0.55)	(11,902)	(1.01)
Corporate income taxes	(12,692)	(1.73)	(8,714)	(1.40)	(4,047)	(0.65)	(21,406)	(1.58)	(11,526)	(0.98)
Interest expense	(15,333)	(2.09)	(14,334)	(2.30)	(15,508)	(2.49)	(29,667)	(2.19)	(30,203)	(2.56)
Realized (loss) gain on derivative instruments	(27,859)	(3.79)	(17,715)	(2.85)	5,342	0.86	(45,574)	(3.36)	3,491	0.30
Realized foreign exchange (loss) gain	(4,105)	(0.56)	1,554	0.25	981	0.16	(2,551)	(0.19)	3,527	0.30
Realized other income	230	0.03	201	0.03	252	0.04	431	0.03	294	0.02
Fund flows from operations	192,990	26.29	157,480	25.29	147,123	23.66	350,470	25.81	290,557	24.63

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 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.

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

	Q2 2018	Q1 2018	Q2 2017	YTD 2018	YTD 2017
Fund flows from operations	192,990	157,480	147,123	350,470	290,557
Equity based compensation	(10,961)	(19,750)	(13,896)	(30,711)	(32,634)
Unrealized (loss) gain on derivative instruments	(105,284)	17,343	23,283	(87,941)	103,148
Unrealized foreign exchange (loss) gain	(12,458)	8,625	38,616	(3,833)	34,098
Unrealized other expense	(199)	(195)	(210)	(394)	(240)
Accretion	(7,819)	(7,154)	(6,748)	(14,973)	(13,130)
Depletion and depreciation	(140,045)	(121,559)	(126,269)	(261,604)	(241,678)
Deferred tax	23,552	(9,651)	(13,635)	13,901	(47,317)
Net (loss) earnings	(60,224)	25,139	48,264	(35,085)	92,804

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

Equity based compensation

Equity based compensation expense relates primarily to non-cash compensation expense attributable to long-term incentives granted to directors, officers, and employees under the Vermilion Incentive Plan ("VIP").

Equity based compensation expense decreased in Q2 2018 compared to Q1 2018 and Q2 2017 due to the absence of the settlement of bonuses in Q1 2018 under the employee bonus plan.

Unrealized gain or loss on derivative instruments

Unrealized gain or loss on derivative instruments arise as a result of changes in future commodity price forecasts. 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 future commodity price forecasts decline and vice-versa. As derivative instruments are settled, the unrealized gain or loss previously recognized is reversed, and the settlement results in a realized gain or loss on derivative instruments.

For the three and six months ended June 30, 2018, we recognized unrealized losses on derivative instruments of $105.3 million and $98.9 million, respectively. The unrealized loss primarily related to European natural gas and crude oil derivative instruments for 2018 and 2019. As of June 30, 2018, our European natural gas swaps and collars for provide an average floor of $7.26/mmbtu for 74,802 mmcf/d for the remainder of 2018, $7.53/mmbtu for 63,835 mmcf/d for 2019, and $7.64/mmbtu for 29,544 mmcf/d for 2020. Our crude oil swaps and collars provide an average floor of $72.46/bbl for 8,792 bbls/d for the remainder of 2018 and $90.40/bbl for 2,388 bbls/d for 2019. Subsequent to June 30, 2018, we have entered into additional swap contracts at higher prices.

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. These monetary assets primarily relate to Euro denominated intercompany loans from Vermilion Energy Inc. to our international subsidiaries. These monetary liabilities primarily relate to our US$300.0 million senior unsecured notes.

Unrealized foreign exchange gains and losses result from translating these monetary assets and liabilities from their underlying currency to the Canadian dollar. Unrealized foreign exchange primarily results from the translation of Euro denominated intercompany loans and US dollar denominated long-term debt. 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 June 30, 2018, the Canadian dollar weakened against the US dollar and strengthened against the Euro, resulting in an unrealized loss on foreign exchange of $12.5 million. For the six months ended June 30, 2018, the impact of the Canadian dollar weakening against the US dollar was more significant than the impact of the Canadian dollar weakening against the Euro, resulting in an unrealized loss on foreign exchange of $3.8 million.

As at June 30, 2018, a $0.01 appreciation of the Euro against the Canadian dollar would result in a $3.7 million increase to net earnings as a result of an unrealized gain on foreign exchange. In contrast, a $0.01 appreciation of the US dollar against the Canadian dollar would result in a $2.3 million decrease to net earnings as a result of an unrealized loss on foreign exchange.

Accretion

Accretion expense is recognized to update the present value of the asset retirement obligation balance. The increase in accretion expense was primarily attributable to new obligations recognized following acquisitions in 2018.

Depletion and depreciation

Depletion and depreciation expense is recognized to allocate the cost of capital assets over the useful life of the respective assets. Depletion and depreciation expense per unit of production is determined for each depletion unit (which are groups of assets within a specific production area that have similar economic lives) by dividing the sum of the net book value of capital assets and future development costs by total proved plus probable reserves.

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

Depletion and depreciation on a per boe basis for Q2 2018 of $19.07 was consistent with $19.53 in Q1 2018. For the three and six months ended June 30, 2018, depletion and depreciation on a per boe basis of $19.07 and $19.28, respectively, were lower than $20.30 and $20.49 for the respective comparable periods in the prior year due to reduced depletion and depreciation rates as a result of increased reserves and lower estimated future development costs.

Deferred tax

On the balance sheet, deferred tax assets arise when the tax basis of an asset exceeds its accounting basis (known as a deductible temporary difference). Conversely, deferred tax liabilities arise when the tax basis of an asset is less than its accounting basis (known as a taxable temporary difference). Deferred tax assets are recognized only to the extent that it is probable that there are future taxable profits against which the deductible temporary difference can be utilized. Deferred tax assets and liabilities are measured at the enacted or substantively tax rate that is expected to apply when the asset is realized or the liability is settled.

As such, fluctuations in deferred tax expenses and recoveries primarily arise as a result of: changes in the accounting basis of an asset or liability without a corresponding tax basis change (e.g. when derivative assets and liabilities are marked-to-market or when accounting depletion differs from tax depletion), changes in available tax losses (e.g. if they are utilized to offset taxable income), changes in estimated future taxable profits resulting in a de-recognition or re-recognition of deferred tax assets, and changes in enacted or substantively enacted tax rates.

For the three and six months ended June 30, 2018, deferred tax recoveries of $23.6 million and $13.9 million resulted from unrealized losses on derivative instruments.

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. As at June 30, 2018 our ratio of net debt to annualized fund flows from operations was 2.6 (2017 - 2.3) .

We remain focused on maintaining and strengthening our balance sheet by aligning our exploration and development capital budget with forecasted fund flows from operations to target a payout ratio (a non-GAAP financial measure) of at or less than 100%. We continually monitor for changes in forecasted fund flows from operations as a result of changes to forward commodity prices and as appropriate we will make adjustments to our exploration and development capital plans. As a result of our focus on this payout ratio target, we intend for the ratio of net debt to fund flows from operations to trend towards 1.5 over time.

Net debt

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

	As at	
($M)	Jun 30, 2018	Dec 31, 2017
Long-term debt	1,605,561	1,270,330
Current liabilities	501,604	363,306
Current assets	(319,562)	(261,846)
Net debt	1,787,603	1,371,790
Ratio of net debt to annualized fund flows from operations	2.6	2.3

As at June 30, 2018, net debt increased to $1.79 billion (December 31, 2017 - $1.37 billion) due to the impact of the acquisitions closed in the first half of 2018 and a $63.7 million increase in net current derivative liability. Included in this increase was the assumption of approximately $175 million in net debt from the acquisition of Spartan. As the acquisition closed in late May, Q2 2018 fund flows from operations did not fully benefit from the contribution of Spartan. As such, the ratio of net debt to annualized fund flows from operations increased from 2.3 for 2017 to 2.6 for the current period.

Long-term debt

The balances recognized on our balance sheet are as follows:

	As at	
($M)	Jun 30, 2018	Dec 31, 2017
Revolving credit facility	1,216,006	899,595
Senior unsecured notes	389,555	370,735
Long-term debt	1,605,561	1,270,330

Revolving Credit Facility

In Q2 2018, we negotiated an increase in our revolving credit facility from $1.4 billion to $1.6 billion and an extension of the maturity to May 31, 2022.

As at June 30, 2018, Vermilion had in place a bank revolving credit facility maturing May 31, 2022 with the below terms, outstanding positions, and covenants.

($M)	As at Jun 30, 2018	Dec 31, 2017
Total facility amount	1,600,000	1,400,000
Amount drawn	(1,216,006)	(899,595)
Letters of credit outstanding	(10,600)	(7,400)
Unutilized capacity	373,394	493,005

As at June 30, 2018, the revolving credit facility was subject to the following covenants:

Financial covenant	Limit	As at Jun 30, 2018	Dec 31, 2017
Consolidated total debt to consolidated EBITDA	4.0	1.70	1.87
Consolidated total senior debt to consolidated EBITDA	3.5	1.30	1.30
Consolidated total senior debt to total capitalization	55%	29%	32%

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

- Consolidated total debt: Includes all amounts classified as "Long-term debt", "Current portion of long-term debt", and "Finance lease obligation" (including the current portion included within "Accounts payable and accrued liabilities" but excluding operating leases as defined under IAS 17) 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, adjusted for the impact of the acquisition of a material subsidiary.
- 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, 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 senior unsecured 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%

Shareholders' capital

Beginning with the April 2018 dividend paid on May 15, 2018, we increased our monthly dividend by 7%, to $0.23 per share from $0.215 per share. The dividend increase in Q2 2018 was our fourth dividend increase (previously Vermilion's distribution in the income trust era) since we began paying a distribution in 2003.

In total, dividends declared in 2018 were $177.6 million.

The following table outlines our dividend payment history:

Date	Monthly dividend per unit or share
January 2003 to December 2007	$0.170
January 2008 to December 2012	$0.190
January 2013 to December 2013	$0.200
January 2014 to March 2018	$0.215
April 2018 onwards	$0.230

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 at December 31, 2017	122,119	2,650,706
Shares issued for corporate acquisition	27,883	1,234,676
Shares issued for the Dividend Reinvestment Plan	932	39,616
Vesting of equity based awards	1,025	54,057
Equity based compensation	220	9,044
Share-settled dividends on vested equity based awards	184	7,773
Balance as at June 30, 2018	152,363	3,995,872

As at June 30, 2018, there were approximately 1.8 million VIP awards outstanding. As at July 27, 2018, there were approximately 152.4 million common shares issued and outstanding.

Asset Retirement Obligations

As at June 30, 2018, asset retirement obligations were $607.4 million compared to $517.2 million as at December 31, 2017.

The increase in asset retirement obligations is largely attributable to additional obligations recognized as a result of acquisitions completed in 2018.

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 June 30, 2018.

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 discussion of these risks, please see Vermilion's MD&A and Annual Information Form, each for the year ended December 31, 2017 available on SEDAR at www.sedar.com or on Vermilion's website at www.vermilionenergy.com.

Critical Accounting Estimates

The preparation of financial statements in accordance with IFRS requires management to make estimates, judgments and assumptions that affect reported assets, liabilities, revenues and expenses, gains and losses, and disclosures of any possible contingencies. These estimates and assumptions are developed based on the best available information which management believed to be reasonable at the time such estimates and assumptions were made. As such, these assumptions are uncertain at the time estimates are made and could change, resulting in a material impact on Vermilion's consolidated financial statements. Estimates are reviewed by management on an ongoing basis and as a result may change from period to period due to the availability of new information or changes in circumstances. Additionally, as a result of the unique circumstances of each jurisdiction that Vermilion operates in, the critical accounting estimates may affect one or more jurisdictions. There have been no material changes to our critical accounting estimates used in applying accounting policies for the three and six months ended June 30, 2018. 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, 2017, 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 ("ICFR") during the period covered by this MD&A that materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

Vermilion has limited the scope of design controls and procedures ("DC&P") and internal controls over financial reporting to exclude controls, policies and procedures of Spartan Energy Corp, which was acquired on May 28, 2018. The scope limitation is in accordance with section 3.3(1)(b) of NI 52-109 which allows an issuer to limit the design of DC&P and ICFR to exclude controls, policies, and procedures of a business that the issuer acquired not more than 365 days before the end of the fiscal period.

The table below presents the summary financial information of Spartan included in Vermilion's financial statements as at and for the six months ended June 30, 2018:

($MM)	As at June 30, 2018
Non-current assets	1,542
Non-current liabilities	115
Net assets	1,392

($MM)	Six months ended June 30, 2018
Revenue	40
Net earnings	10

Accounting Pronouncements

Recently adopted

IFRS 9 "Financial instruments"

On January 1, 2018, Vermilion adopted IFRS 9 *"Financial Instruments"* as issued by the IASB. IFRS 9 includes a new classification and measurement approach for financial assets and a forward-looking 'expected credit loss' model. The adoption of IFRS 9 did not have a material impact on Vermilion's consolidated financial statements.

IFRS 15 "Revenue from contracts with customers"

On January 1, 2018, Vermilion adopted IFRS 15 "Revenue from Contracts with Customers" IFRS 15 establishes a comprehensive framework for determining whether, how much, and when revenue from contracts with customers is recognized. Vermilion's revenue relates to the sale of petroleum and natural gas to customers at specified delivery points at benchmark prices.

Vermilion adopted IFRS 15 using the modified retrospective approach. Under this transitional provision, the cumulative effect of initially applying IFRS 15 is recognized on the date of initial application as an adjustment to retained earnings. No adjustment to retained earnings was required upon adoption of IFRS 15.

Issued but not yet adopted

IFRS 16 "Leases"

Vermilion is required to adopt IFRS 16 "Leases" by January 1, 2019. IFRS 16 requires lessees to recognize a lease obligation and right-of-use asset for the majority of leases. On adoption, non-current assets, current liabilities, and non-current liabilities on Vermilion's consolidated balance sheet will increase. Interest expense will be recognized on the lease obligation and lease payments will be applied against the lease obligation.

The primary impact of adopting IFRS 16 is expected to be the addition of right-of-use assets and lease obligations relating to the Company's office leases. Upon adoption, the office leases are expected to increase assets and liabilities by $55 million to $65 million. This is estimated to result in annual increases to depletion and depreciation expense of $5 million to $13 million and interest expense of $2 million to $5 million, and an annual decrease to general and administration expense of $5 million to $8 million. Vermilion is currently in the process of completing its assessment of applicable lease contracts and intends on adopting IFRS 16 when this assessment is completed, on or before January 1, 2019.

Supplemental Table 1: Netbacks

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

	Q2 2018 $/boe	Q1 2018 $/boe	Q2 2017 $/boe	YTD 2018 $/boe	YTD 2017 $/boe
Canada					
Sales	37.35	32.19	32.18	35.18	32.85
Royalties	(3.88)	(3.41)	(3.39)	(3.68)	(3.57)
Transportation	(1.30)	(1.57)	(1.52)	(1.41)	(1.66)
Operating	(9.04)	(8.43)	(7.44)	(8.78)	(7.43)
Operating netback	23.13	18.78	19.83	21.31	20.19
General and administration	(0.68)	(0.65)	(1.20)	(0.67)	(1.00)
Fund flows from operations netback	22.45	18.13	18.63	20.64	19.19
France					
Sales	95.13	81.70	62.09	89.01	64.75
Royalties	(11.85)	(10.60)	(6.10)	(11.28)	(6.08)
Transportation	(3.40)	(3.59)	(3.60)	(3.49)	(3.53)
Operating	(13.17)	(14.78)	(11.86)	(13.90)	(12.36)
Operating netback	66.71	52.73	40.53	60.34	42.78
General and administration	(3.29)	(3.95)	(3.62)	(3.59)	(3.56)
Current income taxes	(4.92)	(2.31)	(1.79)	(3.73)	(3.58)
Fund flows from operations netback	58.50	46.47	35.12	53.02	35.64
Netherlands					
Sales	52.43	53.31	39.16	52.88	41.94
Royalties	(1.12)	(1.25)	(0.61)	(1.19)	(0.65)
Operating	(9.72)	(11.43)	(10.01)	(10.58)	(8.90)
Operating netback	41.59	40.63	28.54	41.11	32.39
General and administration	(0.50)	(1.43)	(1.14)	(0.96)	(1.06)
Current income taxes	(7.48)	(8.55)	(1.54)	(8.02)	(1.52)
Fund flows from operations netback	33.61	30.65	25.86	32.13	29.81
Germany					
Sales	59.69	56.86	41.96	58.19	44.61
Royalties	(3.93)	(4.82)	(3.19)	(4.40)	(3.39)
Transportation	(5.59)	(5.54)	(5.07)	(5.56)	(4.50)
Operating	(16.92)	(17.16)	(14.93)	(17.04)	(13.95)
Operating netback	33.25	29.34	18.77	31.19	22.77
General and administration	(4.71)	(4.43)	(5.45)	(4.56)	(5.20)
Fund flows from operations netback	28.54	24.91	13.32	26.63	17.57
Ireland					
Sales	55.80	58.79	37.90	57.34	41.92
Transportation	(1.48)	(1.41)	(1.30)	(1.44)	(1.27)
Operating	(5.02)	(3.51)	(5.07)	(4.24)	(4.59)
Operating netback	49.30	53.87	31.53	51.66	36.06
General and administration	(1.68)	(1.43)	(0.72)	(1.55)	(0.58)
Fund flows from operations netback	47.62	52.44	30.81	50.11	35.48

	Q2 2018 $/boe	Q1 2018 $/boe	Q2 2017 $/boe	YTD 2018 $/boe	YTD 2017 $/boe
Australia					
Sales	98.61	86.94	71.37	92.35	73.68
Operating	(34.07)	(29.95)	(23.22)	(31.86)	(22.78)
PRRT [1]	(7.00)	(11.04)	(9.61)	(9.17)	(10.56)
Operating netback	57.54	45.95	38.54	51.32	40.34
General and administration	(2.61)	(3.49)	(1.33)	(3.08)	(2.95)
Corporate income taxes	(6.21)	(1.53)	(1.77)	(3.70)	(2.30)
Fund flows from operations netback	48.72	40.93	35.44	44.54	35.09
United States					
Sales	73.30	72.94	50.37	73.14	52.15
Royalties	(20.35)	(20.16)	(14.21)	(20.26)	(14.71)
Operating	(5.24)	(10.18)	(4.74)	(7.40)	(5.62)
Operating netback	47.71	42.60	31.42	45.48	31.82
General and administration	(20.77)	(23.67)	(13.82)	(22.04)	(17.83)
Fund flows from operations netback	26.94	18.93	17.60	23.44	13.99
Total Company					
Sales	53.72	51.13	43.63	52.53	45.19
Realized hedging (loss) gain	(3.79)	(2.85)	0.86	(3.36)	0.30
Royalties	(4.29)	(3.69)	(2.85)	(4.02)	(2.88)
Transportation	(1.61)	(1.77)	(1.74)	(1.69)	(1.75)
Operating	(10.82)	(10.99)	(10.14)	(10.90)	(9.77)
PRRT [1]	(0.36)	(0.78)	(1.04)	(0.55)	(1.01)
Operating netback	32.85	31.05	28.72	32.01	30.08
General and administration	(2.21)	(2.34)	(2.12)	(2.27)	(2.23)
Interest expense	(2.09)	(2.30)	(2.49)	(2.19)	(2.56)
Realized foreign exchange (loss) gain	(0.56)	0.25	0.16	(0.19)	0.30
Other income	0.03	0.03	0.04	0.03	0.02
Corporate income taxes	(1.73)	(1.40)	(0.65)	(1.58)	(0.98)
Fund flows from operations netback	26.29	25.29	23.66	25.81	24.63

(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 June 30, 2018:

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 (bbld) (2)
Dated Brent												
Swap	Jan 2018 - Dec 2018		CAD	—	—	—	—	—	—	500	76.25	—
Swap	Jan 2019 - Dec 2019		USD	—	—	—	—	—	—	1,350	91.76	—
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	—	—	—
Collar	Jan 2018 - Dec 2018		USD	1,000	50.00	1,000	57.50	—	—	—	—	—
Swap	Jan 2018 - Dec 2018		USD	—	—	—	—	—	—	1,000	55.00	—
Swap	Apr 2018 - Mar 2019		USD	—	—	—	—	—	—	750	61.33	—
Swap	Jul 2018 - Jun 2019		USD	—	—	—	—	—	—	1,500	68.52	—
Swaption	Jan 2019 - Dec 2019	Aug 31, 2018	USD	—	—	—	—	—	—	750	76.67	—
Swaption	Jan 2019 - Dec 2019	Sep 28, 2018	USD	—	—	—	—	—	—	500	77.50	—
WTI												
Swap	Jul 2018 - Aug 2018		CAD	—	—	—	—	—	—	3,000	89.45	—
Swap	Jul 2018 - Sep 2018		CAD	—	—	—	—	—	—	500	83.91	—
Swap	Jul 2018 - Dec 2018		CAD	—	—	—	—	—	—	500	83.45	—
Swap	Jan 2019 - Dec 2019		CAD	—	—	—	—	—	—	1,050	81.41	—
Collar	Jan 2018 - Dec 2018		USD	500	50.00	500	55.00	—	—	—	—	—
Swap	Jan 2018 - Dec 2018		USD	—	—	—	—	—	—	1,000	54.00	—
Swap	Apr 2018 - Mar 2019		USD	—	—	—	—	—	—	250	54.00	—
Swaption	Oct 2018 - Sep 2019	Sep 28, 2018	USD	—	—	—	—	—	—	750	69.67	—
Swaption	Jan 2019 - Dec 2019	Aug 31, 2018	USD	—	—	—	—	—	—	1,000	68.50	—

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												
Swap	Jan 2018 - Dec 2018		CAD	—	—	—	—	—	—	9,478	2.80	—
AECO Basis (AECO less NYMEX HH)												
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	Apr 2018 - Dec 2018		USD	—	—	—	—	—	—	10,000	3.10	—

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

(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	Apr 2018 - Sep 2018		EUR	4,913	4.73	4,913	5.42	4,913	3.52	—	—	—
3-Way Collar	Jan 2019 - Dec 2019		EUR	17,197	4.97	17,197	5.65	17,197	3.79	—	—	—
3-Way Collar	Jan 2019 - Dec 2020		EUR	7,370	4.96	7,370	5.76	7,370	3.74	—	—	—
3-Way Collar	Jan 2020 - Dec 2020		EUR	17,197	4.91	17,197	5.70	17,197	3.87	—	—	—
Call	Oct 2018 - Mar 2019		EUR	—	—	12,327	6.28	—	—	—	—	—
Put	Apr 2018 - Sep 2018		EUR	—	—	—	—	9,870	4.82	—	—	—
Put	Jul 2018 - Sep 2018		EUR	—	—	—	—	4,913	4.76	—	—	—
Swap	Jul 2018		EUR	—	—	—	—	—	—	2,457	6.54	
Swap	Aug 2018		EUR	—	—	—	—	—	—	3,685	6.38	
Swaption	Oct 2018 - Mar 2019	Sep 28, 2018	EUR	—	—	—	—	—	—	4,913	5.86	—
Swaption	Jul 2019 - Jun 2021	Oct 31, 2018	EUR	—	—	—	—	—	—	9,827	5.47	—
Swaption	Oct 2019 - Mar 2020	Sep 28, 2018	EUR	—	—	—	—	—	—	4,913	5.86	—
Swaption	Oct 2020 - Mar 2021	Sep 28, 2018	EUR	—	—	—	—	—	—	4,913	5.86	—
Collar	Jan 2018 - Dec 2018		GBP	2,500	3.15	2,500	3.82	—	—	—	—	—
Swap	Jan 2018 - Dec 2018		GBP	—	—	—	—	—	—	2,500	4.04	5,000
NBP Basis (NBP less NYMEX HH)												
Collar	Jan 2018 - Dec 2018		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	12,284	5.05	12,284	5.72	12,284	3.69	—	—	—
3-Way Collar	Jan 2020 - Dec 2020		EUR	7,370	5.37	7,370	6.25	7,370	3.81	—	—	—
Collar	Jan 2018 - Dec 2018		EUR	4,913	4.40	4,913	5.31	—	—	—	—	—
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	Jul 2018 - Dec 2019		EUR	—	—	—	—	—	—	4,913	4.98	—
Swap	Jan 2019 - Dec 2019		EUR	—	—	—	—	—	—	2,457	4.92	—

Cross Currency Interest Rate		Receive Notional Amount (USD)	Rate (LIBOR +)	Pay Notional Amount (CAD)	Rate (CDOR +)
Swap	Jul 2018	927,437,382	1.70%	1,234,900,000	1.50%

(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)	Q2 2018	Q1 2018	Q2 2017	YTD 2018	YTD 2017
Drilling and development	76,854	124,811	57,681	201,665	152,845
Exploration and evaluation	3,275	3,807	1,194	7,082	1,919
Capital expenditures	80,129	128,618	58,875	208,747	154,764
Acquisitions	57,590	56,355	993	113,945	3,613
Shares issued for acquisition	1,235,221	—	—	1,235,221	—
Long-term debt net of working capital assumed	175,834	36,723	—	212,557	—
Acquisitions	1,468,645	93,078	993	1,561,723	3,613

By category ($M)	Q2 2018	Q1 2018	Q2 2017	YTD 2018	YTD 2017
Drilling, completion, new well equip and tie-in, workovers and recompletions	56,154	108,893	37,196	165,047	117,684
Production equipment and facilities	10,224	16,142	13,963	26,366	24,538
Seismic, studies, land and other	13,751	3,583	7,716	17,334	12,542
Capital expenditures	80,129	128,618	58,875	208,747	154,764
Acquisitions	1,468,645	93,078	993	1,561,723	3,613
Total capital expenditures and acquisitions	1,548,774	221,696	59,868	1,770,470	158,377

Capital expenditures by country ($M)	Q2 2018	Q1 2018	Q2 2017	YTD 2018	YTD 2017
Canada	28,694	69,117	20,599	97,811	78,056
France	17,088	29,972	16,682	47,060	37,598
Netherlands	6,695	3,278	5,973	9,973	7,685
Germany	2,314	2,415	326	4,729	1,232
Ireland	87	47	(73)	134	(877)
Australia	11,469	4,555	9,158	16,024	12,596
United States	10,702	15,868	5,155	26,570	16,694
Corporate	3,080	3,366	1,055	6,446	1,780
Total capital expenditures	80,129	128,618	58,875	208,747	154,764

Acquisitions by country ($M)	Q2 2018	Q1 2018	Q2 2017	YTD 2018	YTD 2017
Canada	1,468,495	90,250	935	1,558,745	1,511
Netherlands	139	2,760	(16)	2,899	—
United States	11	68	49	79	2,062
Corporate	—	—	25	—	40
Total acquisitions	1,468,645	93,078	993	1,561,723	3,613

Supplemental Table 4: Production

	Q2/18	Q1/18	Q4/17	Q3/17	Q2/17	Q1/17	Q4/16	Q3/16	Q2/16	Q1/16	Q4/15	Q3/15
Canada												
Crude oil & condensate (bbls/d)	17,009	9,272	9,703	9,288	9,205	7,987	7,945	8,984	9,453	10,317	10,413	11,030
NGLs (bbls/d)	5,589	5,106	5,235	4,891	3,745	2,670	2,444	2,448	2,687	2,633	2,710	2,678
Natural gas (mmcf/d)	127.32	106.21	107.91	103.92	93.68	85.74	75.12	77.62	87.44	97.16	87.90	71.94
Total (boe/d)	43,817	32,078	32,923	31,499	28,563	24,947	22,910	24,368	26,713	29,141	27,773	25,698
% of consolidated	55%	46%	45%	46%	43%	38%	38%	37%	42%	44%	45%	47%
France												
Crude oil (bbls/d)	11,683	11,037	11,215	10,918	11,368	10,834	11,220	11,827	12,326	12,220	12,537	12,310
Natural gas (mmcf/d)	—	—	—	—	—	0.01	0.38	0.42	0.54	0.44	1.36	1.47
Total (boe/d)	11,683	11,037	11,215	10,918	11,368	10,836	11,283	11,897	12,416	12,293	12,763	12,555
% of consolidated	14%	16%	15%	16%	17%	17%	19%	19%	19%	19%	21%	22%
Netherlands												
Condensate (bbls/d)	87	77	105	74	104	76	57	86	96	114	110	109
Natural gas (mmcf/d)	43.49	44.79	55.66	34.90	31.58	39.92	41.15	47.62	49.18	53.40	56.34	53.56
Total (boe/d)	7,335	7,541	9,381	5,890	5,368	6,729	6,915	8,023	8,293	9,015	9,500	9,035
% of consolidated	9%	11%	13%	9%	8%	10%	11%	13%	13%	14%	16%	16%
Germany												
Crude oil (bbls/d)	1,008	1,078	1,148	1,054	1,047	989	—	—	—	—	—	—
Natural gas (mmcf/d)	14.63	16.19	18.19	20.12	19.86	19.39	14.80	14.52	14.31	15.96	16.17	14.00
Total (boe/d)	3,447	3,777	4,180	4,407	4,357	4,220	2,467	2,420	2,385	2,660	2,695	2,333
% of consolidated	4%	5%	6%	7%	6%	7%	4%	4%	4%	4%	4%	4%
Ireland												
Natural gas (mmcf/d)	56.56	60.87	56.23	49.04	63.81	64.82	62.92	59.28	47.26	33.90	0.12	—
Total (boe/d)	9,426	10,144	9,372	8,173	10,634	10,803	10,486	9,879	7,877	5,650	20	—
% of consolidated	12%	14%	13%	12%	16%	17%	17%	16%	12%	9%	—	—
Australia												
Crude oil (bbls/d)	4,132	4,971	4,993	5,473	6,054	6,581	6,388	6,562	6,083	6,180	7,824	6,433
% of consolidated	5%	7%	7%	8%	9%	10%	10%	10%	9%	9%	13%	11%
United States												
Crude oil (bbls/d)	655	574	667	880	747	365	362	383	458	368	420	226
NGLs (bbls/d)	62	20	43	56	76	24	23	30	26	39	29	—
Natural gas (mmcf/d)	0.40	0.15	0.29	0.64	0.44	0.20	0.18	0.20	0.20	0.26	0.20	—
Total (boe/d)	784	618	758	1,043	896	422	414	447	518	450	483	226
% of consolidated	1%	1%	1%	2%	1%	1%	1%	1%	1%	1%	1%	—
Consolidated												
Crude oil, condensate & NGLs (bbls/d)	40,225	32,134	33,109	32,634	32,346	29,526	28,439	30,320	31,129	31,871	34,043	32,786
% of consolidated	50%	46%	45%	48%	48%	46%	47%	48%	48%	49%	56%	58%
Natural gas (mmcf/d)	242.40	228.20	238.28	208.62	209.36	210.07	194.54	199.65	198.93	201.11	162.09	140.97
% of consolidated	50%	54%	55%	52%	52%	54%	53%	52%	52%	51%	44%	42%
Total (boe/d)	80,625	70,167	72,821	67,403	67,240	64,537	60,863	63,596	64,285	65,389	61,058	56,280

	YTD 2018	2017	2016	2015	2014	2013
Canada						
Crude oil & condensate (bbls/d)	13,161	9,051	9,171	11,357	12,491	8,387
NGLs (bbls/d)	5,349	4,144	2,552	2,301	1,233	1,666
Natural gas (mmcf/d)	116.82	97.89	84.29	71.65	55.67	42.39
Total (boe/d)	37,980	29,510	25,771	25,598	23,001	17,117
% of consolidated	50%	45%	40%	46%	47%	41%
France						
Crude oil (bbls/d)	11,362	11,084	11,896	12,267	11,011	10,873
Natural gas (mmcf/d)	—	—	0.44	0.97	—	3.40
Total (boe/d)	11,362	11,085	11,970	12,429	11,011	11,440
% of consolidated	15%	16%	19%	23%	22%	28%
Netherlands						
Condensate (bbls/d)	82	90	88	99	77	64
Natural gas (mmcf/d)	44.13	40.54	47.82	44.76	38.20	35.42
Total (boe/d)	7,438	6,847	8,058	7,559	6,443	5,967
% of consolidated	10%	10%	13%	14%	13%	15%
Germany						
Crude oil (bbls/d)	1,043	1,060	—	—	—	—
Natural gas (mmcf/d)	15.41	19.39	14.90	15.78	14.99	—
Total (boe/d)	3,611	4,291	2,483	2,630	2,498	—
% of consolidated	5%	6%	4%	5%	5%	—
Ireland						
Natural gas (mmcf/d)	58.70	58.43	50.89	0.03	—	—
Total (boe/d)	9,783	9,737	8,482	5	—	—
% of consolidated	13%	14%	13%	—	—	—
Australia						
Crude oil (bbls/d)	4,549	5,770	6,304	6,454	6,571	6,481
% of consolidated	6%	8%	10%	12%	13%	16%
United States						
Crude oil (bbls/d)	615	666	393	231	49	—
NGLs (bbls/d)	41	50	29	7	—	—
Natural gas (mmcf/d)	0.28	0.39	0.21	0.05	—	—
Total (boe/d)	702	781	457	247	49	—
% of consolidated	1%	1%	1%	—	—	—
Consolidated						
Crude oil, condensate & NGLs (bbls/d)	36,202	31,915	30,433	32,716	31,432	27,471
% of consolidated	48%	47%	48%	60%	63%	67%
Natural gas (mmcf/d)	235.34	216.64	198.55	133.24	108.85	81.21
% of consolidated	52%	53%	52%	40%	37%	33%
Total (boe/d)	75,425	68,021	63,526	54,922	49,573	41,005

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 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 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:

Acquisitions: The sum of acquisitions from the Consolidated Statement of Cash Flows plus the assumption of the acquiree's outstanding long-term debt plus or net of acquired working capital deficit or surplus.

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 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:

($M)	Q2 2018	Q1 2018	Q2 2017	YTD 2018	YTD 2017
Dividends declared	98,604	79,005	77,858	177,609	154,451
Shares issued for the Dividend Reinvestment Plan	(19,975)	(19,641)	(29,241)	(39,616)	(64,747)
Net dividends	78,629	59,364	48,617	137,993	89,704
Drilling and development	76,854	124,811	57,681	201,665	152,845
Exploration and evaluation	3,275	3,807	1,194	7,082	1,919
Asset retirement obligations settled	2,626	3,591	2,120	6,217	4,369
Payout	161,384	191,573	109,612	352,957	248,837
% of fund flows from operations	84%	122%	75%	101%	86%

('000s of shares)	Q2 2018	Q1 2018	Q2 2017
Shares outstanding	152,363	122,769	120,947
Potential shares issuable pursuant to the VIP	2,992	3,025	2,847
Diluted shares outstanding	155,355	125,794	123,794

DIRECTORS

Lorenzo Donadeo [1]
Calgary, Alberta

Larry J. Macdonald [2, 4, 6, 8]
Chairman & CEO, Point Energy Ltd.
Calgary, Alberta

Stephen P. Larke [4, 6]
Calgary, Alberta

Loren M. Leiker [10]
Houston, Texas

Timothy R. Marchant [7, 10]
Calgary, Alberta

Anthony Marino
Calgary, Alberta

Robert Michaleski [4, 5]
Calgary, Alberta

William Roby [8, 9]
Katy, Texas

Catherine L. Williams [3, 6]
Calgary, Alberta

1 Chairman of the Board
2 Lead Director
3 Audit Committee Chair (Independent)
4 Audit Committee Member
5 Governance and Human Resources Committee Chair (Independent)
6 Governance and Human Resources Committee Member
7 Health, Safety and Environment Committee Chair (Independent)
8 Health, Safety and Environment Committee Member
9 Independent Reserves Committee Chair (Independent)
10 Independent Reserves Committee Member

ABBREVIATIONS

$M	thousand dollars
$MM	million dollars
AECO	the daily average benchmark price for natural gas at the AECO 'C' hub in Alberta
bbl(s)	barrel(s)
bbls/d	barrels per day
boe	barrel of oil equivalent, including: crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe for six mcf of natural gas)
boe/d	barrel of oil equivalent per day
GJ	gigajoules
HH	Henry Hub, a reference price paid for natural gas in US dollars at Erath, Louisiana
mbbls	thousand barrels
mcf	thousand cubic feet
mmbtu	million British thermal units
mmcf/d	million cubic feet per day
MWh	megawatt hour
NBP	the reference price paid for natural gas in the United Kingdom at the National Balancing Point Virtual Trading Point.
NGLs	natural gas liquids, which includes butane, propane, and ethane
PRRT	Petroleum Resource Rent Tax, a profit based tax levied on petroleum projects in Australia
TTF	the price for natural gas in the Netherlands at the Title Transfer Facility Virtual Trading Point.
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma

OFFICERS AND KEY PERSONNEL

CANADA

Anthony Marino
President & Chief Executive Officer

Lars Glemser
Vice President & Chief Financial Officer

Mona Jasinski
Executive Vice President, People and Culture

Michael Kaluza
Executive Vice President & Chief Operating Officer

Dion Hatcher
Vice President Canada Business Unit

Terry Hergott
Vice President Marketing

Jenson Tan
Vice President Business Development

Daniel Goulet
Director Corporate HSE

Jeremy Kalanuk
Director Operations Accounting

Bryce Kremnica
Director Field Operations - Canada Business Unit

Kyle Preston
Director Investor Relations

Mike Prinz
Director Information Technology & Information Systems

Robert (Bob) J. Engbloom
Corporate Secretary

UNITED STATES
Scott Seatter
Managing Director - U.S. Business Unit

Timothy R. Morris
Director U.S. Business Development - U.S. Business Unit

EUROPE
Gerard Schut
Vice President European Operations

Sylvain Nothhelfer
Managing Director - France Business Unit

Sven Tummers
Managing Director - Netherlands Business Unit

Bill Liutkus
Managing Director - Germany Business Unit

Darcy Kerwin
Managing Director - Ireland Business Unit

Bryan Sralla
Managing Director - Central & Eastern Europe Business Unit

AUSTRALIA
Bruce D. Lake
Managing Director - Australia Business Unit

AUDITORS

Deloitte LLP
Calgary, Alberta

BANKERS

The Toronto-Dominion Bank

Bank of Montreal

Canadian Imperial Bank of Commerce

National Bank of Canada

The Bank of Nova Scotia

Royal Bank of Canada

Alberta Treasury Branches

Bank of America N.A., Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

HSBC Bank Canada

JPMorgan Chase Bank, N.A., Toronto Branch

La Caisse Centrale Desjardins du Québec

Wells Fargo Bank N.A., Canadian Branch

Barclays Bank PLC

Canadian Western Bank

Goldman Sachs Lending Partners LLC

Export Development Canada

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Calgary, Alberta

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TRANSFER AGENT

Computershare Trust Company of Canada

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The New York Stock Exchange ("VET")

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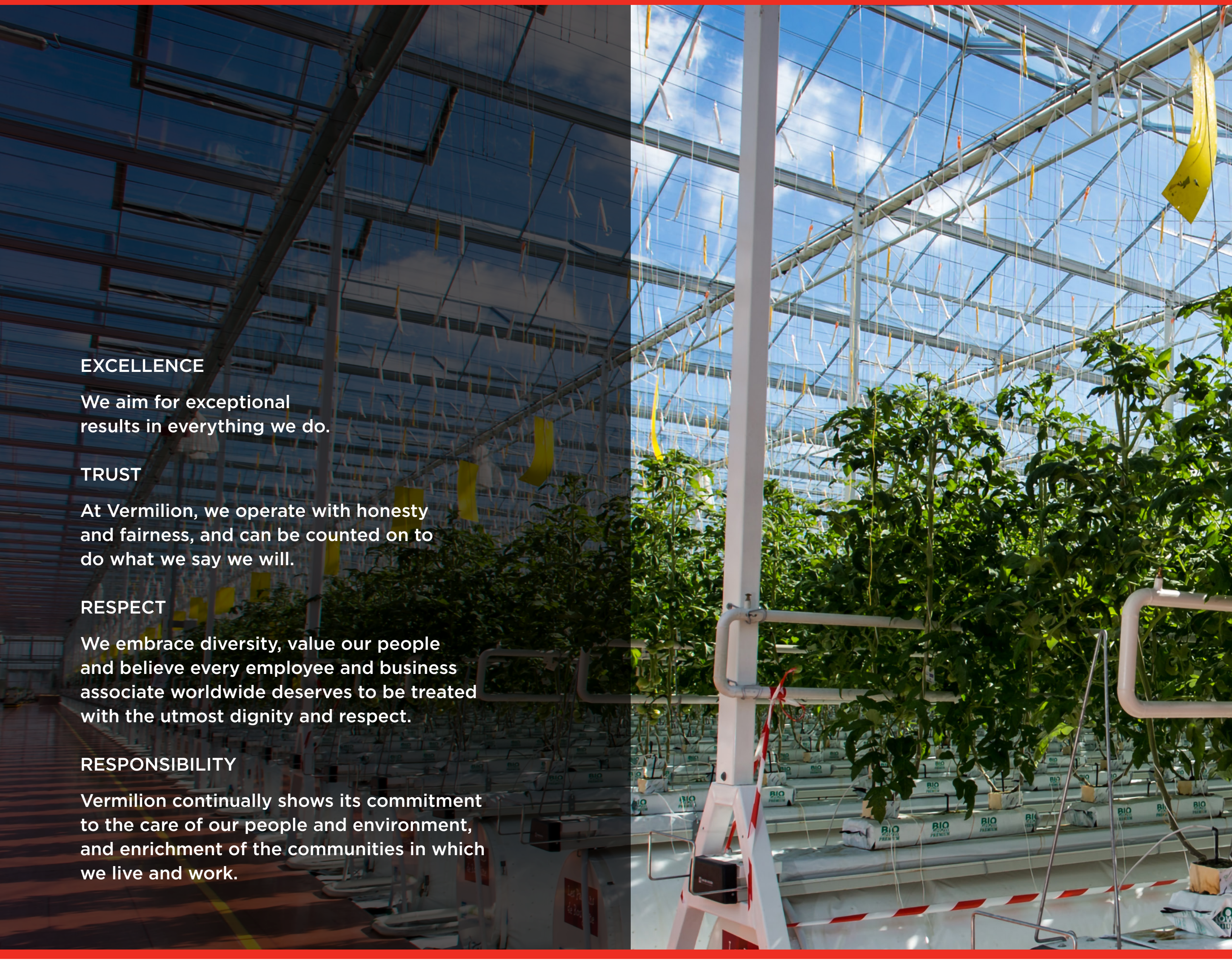

EXCELLENCE

We aim for exceptional results in everything we do.

TRUST

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

RESPECT

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

RESPONSIBILITY

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

VERMILION ENERGY

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