

Q3 2021

MANAGEMENT'S DISCUSSION AND ANALYSIS

EXCELLENCE. TRUST. RESPECT. RESPONSIBILITY.



INTERNATIONALLY DIVERSIFIED | FREE CASH FLOW FOCUSED

VERMILION
ENERGY



Disclaimer

Certain statements included or incorporated by reference in this document may constitute forward looking statements or financial outlooks under applicable securities legislation. Such forward looking statements or information typically contain statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", "project", or similar words suggesting future outcomes or statements regarding an outlook. Forward looking statements or information in this document may include, but are not limited to: capital expenditures; business strategies and objectives; operational and financial performance; estimated reserve quantities and the discounted net present value of future net revenue from such reserves; petroleum and natural gas sales; future production levels (including the timing thereof) and rates of average annual production growth; exploration and development plans; acquisition and disposition plans and the timing thereof; operating and other expenses, including the payment and amount of future dividends; royalty and income tax rates; and the timing of regulatory proceedings and approvals.

Such forward looking statements or information are based on a number of assumptions, all or any of which may prove to be incorrect. In addition to any other assumptions identified in this document, assumptions have been made regarding, among other things: the ability of Vermilion to obtain equipment, services and supplies in a timely manner to carry out its activities in Canada and internationally; the ability of Vermilion to market crude oil, natural gas liquids, and natural gas successfully to current and new customers; the timing and costs of pipeline and storage facility construction and expansion and the ability to secure adequate product transportation; the timely receipt of required regulatory approvals; the ability of Vermilion to obtain financing on acceptable terms; foreign currency exchange rates and interest rates; future crude oil, natural gas liquids, and natural gas prices; and management's expectations relating to the timing and results of exploration and development activities.

Although Vermilion believes that the expectations reflected in such forward looking statements or information are reasonable, undue reliance should not be placed on forward looking statements because Vermilion can give no assurance that such expectations will prove to be correct. Financial outlooks are provided for the purpose of understanding Vermilion's financial position and business objectives, and the information may not be appropriate for other purposes. Forward looking statements or information are based on current expectations, estimates, and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by Vermilion and described in the forward looking statements or information. These risks and uncertainties include, but are not limited to: the ability of management to execute its business plan; the risks of the oil and gas industry, both domestically and internationally, such as operational risks in exploring for, developing and producing crude oil, natural gas liquids, and natural gas; risks and uncertainties involving geology of crude oil, natural gas liquids, and natural gas deposits; risks inherent in Vermilion's marketing operations, including credit risk; the uncertainty of reserves estimates and reserves life and estimates of resources and associated expenditures; the uncertainty of estimates and projections relating to production and associated expenditures; potential delays or changes in plans with respect to exploration or development projects; Vermilion's ability to enter into or renew leases on acceptable terms; fluctuations in crude oil, natural gas liquids, and natural gas prices, foreign currency exchange rates and interest rates; health, safety, and environmental risks; uncertainties as to the availability and cost of financing; the ability of Vermilion to add production and reserves through exploration and development activities; the possibility that government policies or laws may change or governmental approvals may be delayed or withheld; uncertainty in amounts and timing of royalty payments; risks associated with existing and potential future law suits and regulatory actions against Vermilion; and other risks and uncertainties described elsewhere in this document or in Vermilion's other filings with Canadian securities regulatory authorities.

The forward looking statements or information contained in this document are made as of the date hereof and Vermilion undertakes no obligation to update publicly or revise any forward looking statements or information, whether as a result of new information, future events, or otherwise, unless required by applicable securities laws.

This document contains metrics commonly used in the oil and gas industry. These oil and gas metrics do not have any standardized meaning or standard methods of calculation and therefore may not be comparable to similar measures presented by other companies where similar terminology is used and should therefore not be used to make comparisons. Natural gas volumes have been converted on the basis of six thousand cubic feet of natural gas to one barrel of oil equivalent. Barrels of oil equivalent (boe) may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Financial data contained within this document are reported in Canadian dollars, unless otherwise stated.

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
LSB	light sour blend crude oil reference price
mbbls	thousand barrels
mcf	thousand cubic feet
mmcf/d	million cubic feet per day
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
tCO ₂ e	tonnes of carbon dioxide equivalent
TTF	the price for natural gas in the Netherlands, quoted in megawatt hours of natural gas, 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

Management's Discussion and Analysis

The following is Management's Discussion and Analysis ("MD&A"), dated November 9, 2021, of Vermilion Energy Inc.'s ("Vermilion", "we", "our", "us" or the "Company") operating and financial results as at and for the three and nine months ended September 30, 2021 compared with the corresponding periods in the prior year.

This discussion should be read in conjunction with the unaudited condensed consolidated interim financial statements for the three and nine months ended September 30, 2021 and the audited consolidated financial statements for the years ended December 31, 2020 and 2019, 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 nine months ended September 30, 2021 and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with IAS 34, "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.
- **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.
- **Net debt:** Net debt is a capital management measure in accordance with IAS 1 "Presentation of Financial Statements". Net debt is comprised of long-term debt (excluding unrealized foreign exchange on swapped USD borrowings) plus adjusted working capital (defined as current assets less current liabilities, excluding current derivatives and current lease liabilities), and represents Vermilion's net financing obligations after adjusting for the timing of working capital fluctuations. Net debt excludes lease obligations which are secured by a corresponding right-of-use asset. Please see "Capital disclosures" in the "Notes to the Condensed Consolidated Interim Financial Statements" for additional information.
- **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".

Product Type Disclosure

Under National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities", disclosure of production volumes should include segmentation by product type as defined in the instrument. In this report, references to "crude oil" and "light and medium crude oil" mean "light crude oil and medium crude oil" and references to "natural gas" mean "conventional natural gas".

In addition, in Supplemental Table 4 "Production", Vermilion provides a reconciliation from total production volumes to product type and also a reconciliation of "crude oil and condensate" and "NGLs" to the product types "light crude oil and medium crude oil" and "natural gas liquids".

Production volumes reported are based on quantities as measured at the first point of sale.

Guidance

On January 18, 2021, we released our 2021 capital budget and associated production guidance. On November 9, 2021, we increased our 2021 capital expenditure guidance to \$375 million and our 2021 annual production guidance to 84,500 to 85,500 boe/d.

The following table summarizes our guidance:

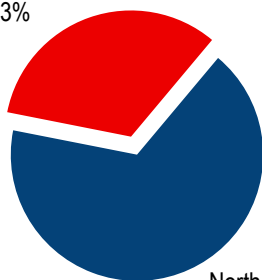
	Date	Capital Expenditures (\$MM)	Production (boe/d)
2021 Guidance			
2021 Guidance	January 18, 2021	300	83,000 to 85,000
2021 Guidance	November 9, 2021	375	84,500 to 85,500

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.

2021 YTD production of 85,742 boe/d

International: 33%



North America: 67%

2021 YTD capital expenditures of \$229.0MM

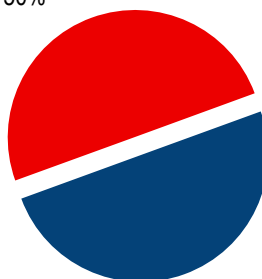
International: 42%



North America: 58%

2021 YTD fund flows from operations of \$597.7MM

International: 50%



North America: 50%

Consolidated Results Overview

	Q3 2021	Q3 2020	Q3/21 vs. Q3/20	YTD 2021	YTD 2020	2021 vs. 2020
Production ⁽¹⁾						
Crude oil and condensate (bbls/d)	38,777	43,240	(10)%	38,777	44,383	(13)%
NGLs (bbls/d)	8,068	9,509	(15)%	8,279	9,041	(8)%
Natural gas (mmcf/d)	226.73	256.34	(12)%	232.12	265.39	(13)%
Total (boe/d)	84,633	95,471	(11)%	85,742	97,656	(12)%
(Draw) build in inventory (mbbls)	(112)	(68)		187	(144)	
Financial metrics						
Fund flows from operations (\$M)	262,696	114,776	129%	597,689	366,853	63%
Per share (\$/basic share)	1.62	0.73	122%	3.72	2.33	60%
Net (loss) earnings (\$M)	(147,130)	(69,926)	110%	804,108	(1,459,720)	N/A
Per share (\$/basic share)	(0.91)	(0.44)	107%	5.00	(9.26)	N/A
Free cash flow	196,246	83,446	135%	368,700	59,545	519%
Net debt (\$M) ⁽²⁾	1,778,052	2,083,317	(15)%	1,778,052	2,083,317	(15)%
Activity						
Capital expenditures (\$M)	66,450	31,330	112%	228,989	307,308	(26)%
Acquisitions (\$M)	94,420	6,720		107,332	20,989	

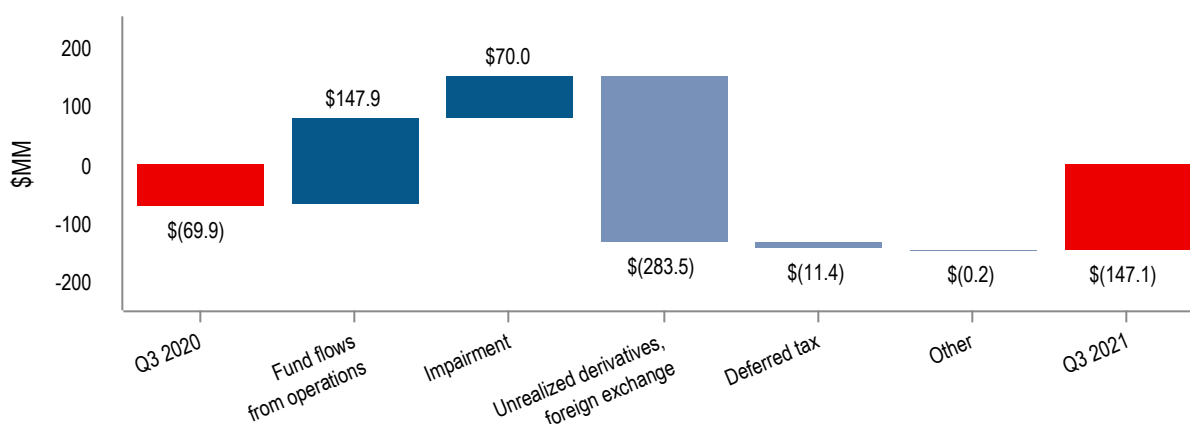
⁽¹⁾ Please refer to Supplemental Table 4 "Production" for disclosure by product type.

⁽²⁾ Prior period comparatives have been revised. Net debt is defined as long-term debt (excluding unrealized foreign exchange on swapped USD borrowings) plus adjusted working capital (defined as current assets less current liabilities, excluding current derivatives and current lease liabilities).

Financial performance review

Q3 2021 vs. Q3 2020

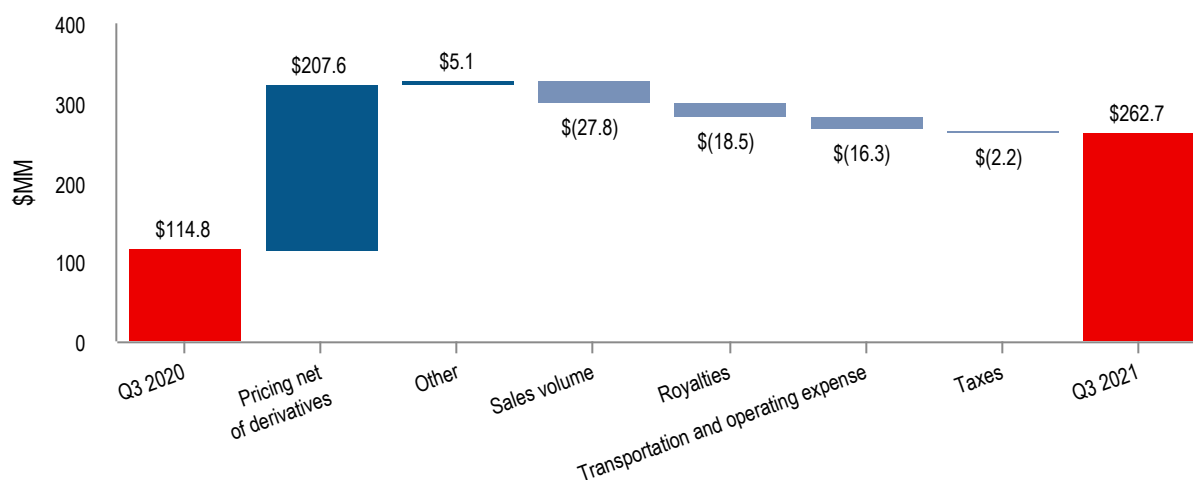
Net loss of \$147.1MM in Q3 2021 compared to a net loss of \$69.9MM in Q3 2020



"Other" contains equity based compensation, accretion, depletion and depreciation, and unrealized other

- We recorded a net loss of \$147.1 million (\$0.91/basic share) for Q3 2021 compared to a net loss of \$69.9 million (\$0.44/basic share) in Q3 2020. The increase in net loss was primarily driven by unrealized losses on derivatives due to increased commodity prices. These losses were partially offset by an increase in FFO which was predominantly driven by an increase in realized pricing, as well as a decrease in impairment reversals recognized versus the prior quarter.

Fund flows from operations of \$262.7MM in Q3 2021 compared to \$114.8MM in Q3 2020

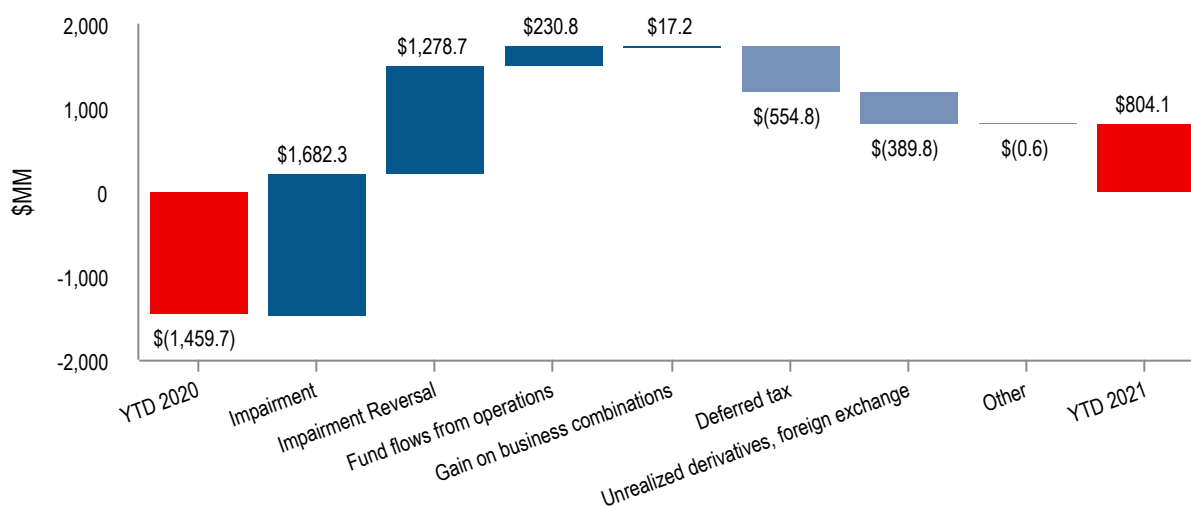


"Other" contains general and administration, interest, and realized foreign exchange

- We generated fund flows from operations of \$262.7 million in Q3 2021, an increase from \$114.8 million in Q3 2020 primarily as a result of higher commodity prices, which is reflected in our consolidated realized price per boe increasing from \$31.86/boe in Q3 2020 to \$68.19/boe in Q3 2021. This was partially offset by a decrease in sales volumes, primarily driven by natural decline and planned maintenance activity; increased royalties, due to increased pricing; and increases in transportation and operating expenses driven by increased transportation costs in France due to incremental trucking costs and higher maintenance activity in North America.

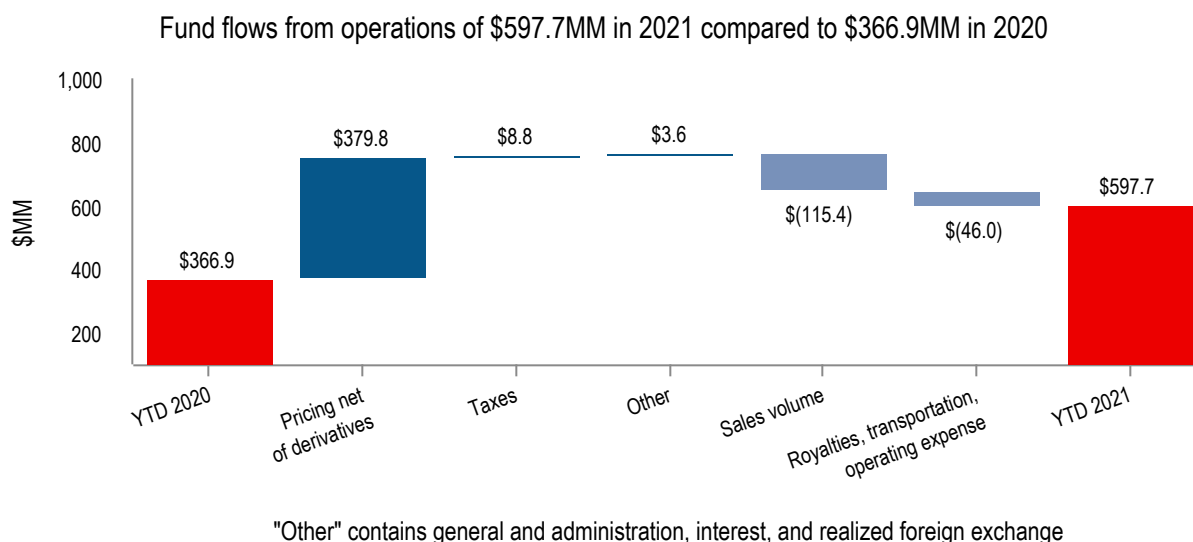
YTD 2021 vs. YTD 2020

Net earnings of \$804.1MM in 2021 compared to net loss of \$1,459.7MM in 2020



"Other" contains equity based compensation, accretion, depletion and depreciation, and unrealized other

- For the nine months ended September 30, 2021, we achieved net earnings of \$804.1 million compared to a net loss of \$1,459.7 million for the comparable period in 2020. The increase in net earnings was primarily due to impairment charges we recorded in 2020 of \$1,272.1 million (net of \$410.2 million income tax recovery), impairment reversal charges we recorded in 2021 of \$969.3 million (net of \$309.4 million income tax expense) and higher fund flows from operations driven by increased consolidated realized pricing. These increases were partially offset by higher unrealized derivative losses driven by increased commodity prices.



- Fund flows from operations increased by 63% for the nine months ended September 30, 2021 versus the same period in 2020, primarily driven by a 90% increase in our consolidated realized price from \$29.86/boe to \$56.58/boe. Sales volumes decreased year-over-year primarily due to natural decline in North America, Ireland, and Netherlands, as well as timing of liftings in Australia, while royalties increased as a result of higher benchmark prices.

Production review

Q3 2021 vs. Q3 2020

- Consolidated average production of 84,633 boe/d in Q3 2021 represented a decrease of 11% from Q3 2020 production of 95,471 boe/d. Production decreases in Canada of 8,088 boe/d were primarily due to reduced capital activity as we are focused on maximizing free cash flow and reducing debt in 2021, and in Ireland of 2,075 boe/d which were primarily due to a planned turnaround.

YTD 2021 vs. YTD 2020

- Consolidated average production of 85,742 boe/d for the nine months ended September 30, 2021 represented a decrease of 12% from the prior year comparable period of 97,656 boe/d. Production decreases were mainly in Canada of 7,929 boe/d and in Ireland of 1,564 boe/d due to reduced capital activity and natural decline, respectively.

Activity review

- For the three months ended September 30, 2021, capital expenditures of \$66.5 million were incurred.
- In our North America core region, capital expenditures of \$35.2 million were incurred during Q3 2021. In Canada, \$29.7 million was incurred primarily related to drilling and facility activity. In southeast Saskatchewan we drilled 19 (19.0 net) wells and completed 20 (19.5 net) wells. Eighteen (17.5 net) wells were brought on production during the quarter. In addition, we completed one (0.2 net) and brought one (0.2 net) Mannville natural gas wells on production in Alberta. In the United States, we completed and brought on production two (2.0 net) wells in the quarter.
- In our International core region, capital expenditures of \$31.3 million were incurred during Q3 2021. Our activities included \$9.3 million in Central and Eastern Europe mainly related to facility expenditures in Croatia, \$8.9 million in France mainly due to increased activity on subsurface maintenance and facilities, \$6.1 million incurred in Australia primarily for facility work, and \$3.3 million in Germany mainly related to tie-in and workover activity.

Financial sustainability review

Free cash flow

- Free cash flow of \$368.7 million increased by \$309.2 million for the nine months ended September 30, 2021 compared to the prior year period. This was primarily the result of a 90% increase in consolidated realized prices, as well as lower capital spending due to a focus on generating free cash flow and reducing debt in 2021.

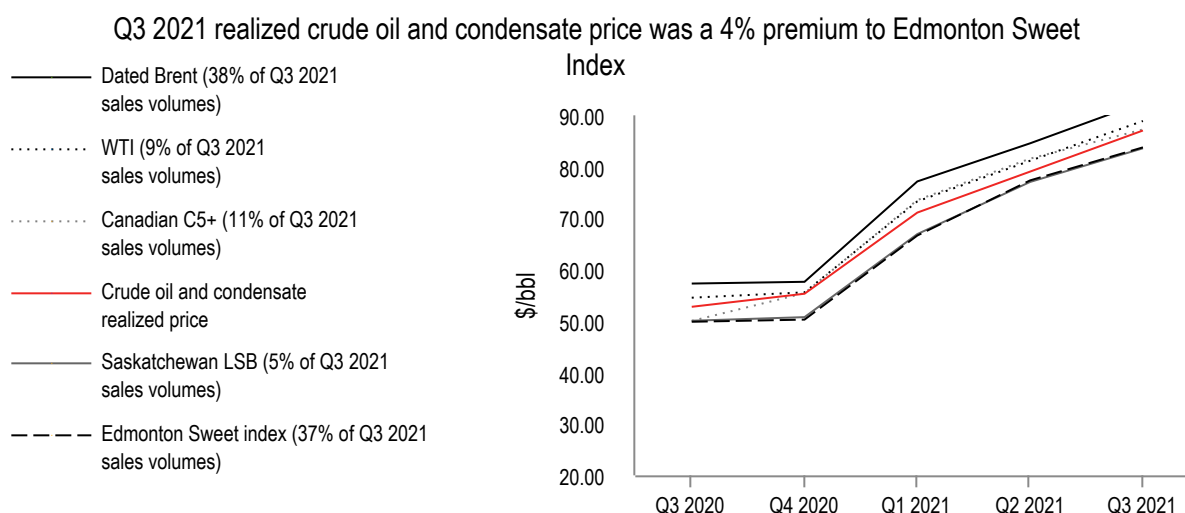
Long-term debt and net debt

- Long-term debt decreased to \$1.8 billion as at September 30, 2021 from \$1.9 billion as at December 31, 2020.
- Net debt decreased to \$1.8 billion as at September 30, 2021 from \$2.0 billion as at December 31, 2020 (revised), mainly due to a decrease in long-term debt as a result of debt repayments of \$238.1 million.
- In Q3 2021, we adjusted our net debt calculation in order to provide more meaningful and comparable information. The revised net debt definition has been adjusted as long-term debt (excluding unrealized foreign exchange on swapped USD borrowings) plus adjusted working capital (defined as current assets less current liabilities, excluding current derivatives and current lease liabilities).
- The ratio of net debt to four quarter trailing fund flows from operations decreased to 2.43 as at September 30, 2021 (December 31, 2020 - 4.00 (revised)) mainly due to lower net debt combined with higher four quarter trailing fund flows from operations.

Benchmark Commodity Prices

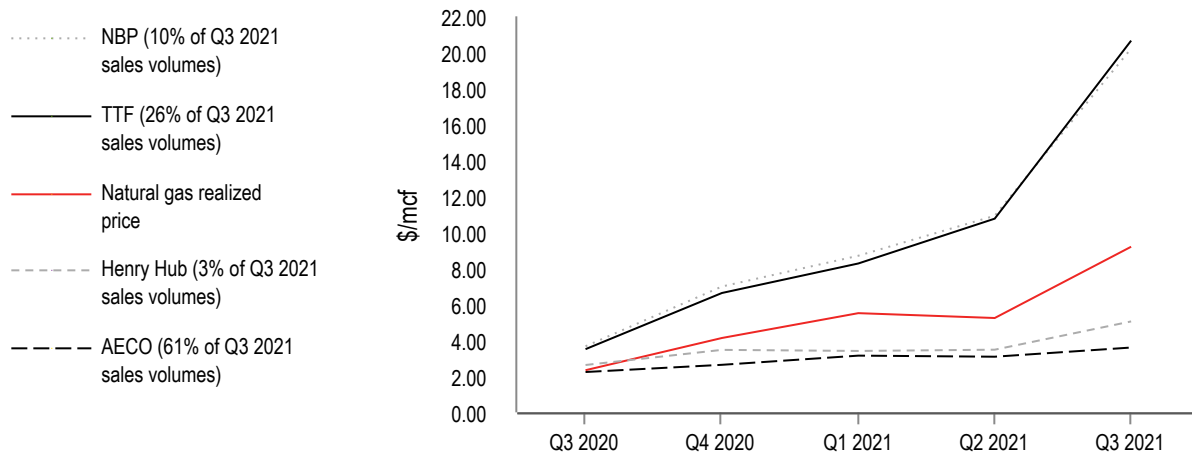
	Q3 2021	Q3 2020	Q3/21 vs. Q3/20	YTD 2021	YTD 2020	2021 vs. 2020
Crude oil						
WTI (\$/bbl)	88.90	54.54	63%	81.14	51.90	56%
WTI (US \$/bbl)	70.56	40.93	72%	64.82	38.32	69%
Edmonton Sweet index (\$/bbl)	83.77	49.86	68%	75.95	44.11	72%
Edmonton Sweet index (US \$/bbl)	66.49	37.42	78%	60.68	32.57	86%
Saskatchewan LSB index (\$/bbl)	83.59	50.06	67%	75.89	44.06	72%
Saskatchewan LSB index (US \$/bbl)	66.35	37.57	77%	60.63	32.53	86%
Canadian C5+ Condensate index (\$/bbl)	87.25	50.02	74%	80.81	47.91	69%
Canadian C5+ Condensate index (US \$/bbl)	69.25	37.54	85%	64.56	35.37	83%
Dated Brent (\$/bbl)	92.56	57.29	62%	84.78	55.29	53%
Dated Brent (US \$/bbl)	73.47	43.00	71%	67.73	40.82	66%
Natural gas						
AECO (\$/mcf)	3.60	2.24	61%	3.28	2.09	57%
NBP (\$/mcf)	20.21	3.67	451%	13.32	3.43	288%
NBP (€/mcf)	13.61	2.36	477%	8.89	2.25	295%
TTF (\$/mcf)	20.65	3.51	488%	13.27	3.38	293%
TTF (€/mcf)	13.91	2.25	518%	8.86	2.22	299%
Henry Hub (\$/mcf)	5.05	2.63	92%	3.98	2.54	57%
Henry Hub (US \$/mcf)	4.01	1.97	104%	3.18	1.88	69%
Average exchange rates						
CDN \$/US \$	1.26	1.33	(5)%	1.25	1.35	(7)%
CDN \$/Euro	1.49	1.56	(5)%	1.50	1.52	(1)%
Realized prices						
Crude oil and condensate (\$/bbl)	87.05	52.77	65%	79.40	49.03	62%
NGLs (\$/bbl)	35.55	15.04	136%	30.03	11.09	171%
Natural gas (\$/mcf)	9.20	2.34	293%	6.63	2.37	180%
Total (\$/boe)	68.19	31.86	114%	56.58	29.86	90%

As an internationally diversified producer, we are exposed to a range of commodity prices. In our North America core region, our crude oil is sold at benchmarks linked to WTI (including the Edmonton Sweet index, the Saskatchewan LSB index, and the Canadian C5+ index) and our natural gas is sold at the AECO index (in Canada) or the Henry Hub index (in the United States). In our International core region, our crude oil is sold with reference to Dated Brent and our natural gas is sold with reference to NBP, TTF, or indices highly correlated to TTF.



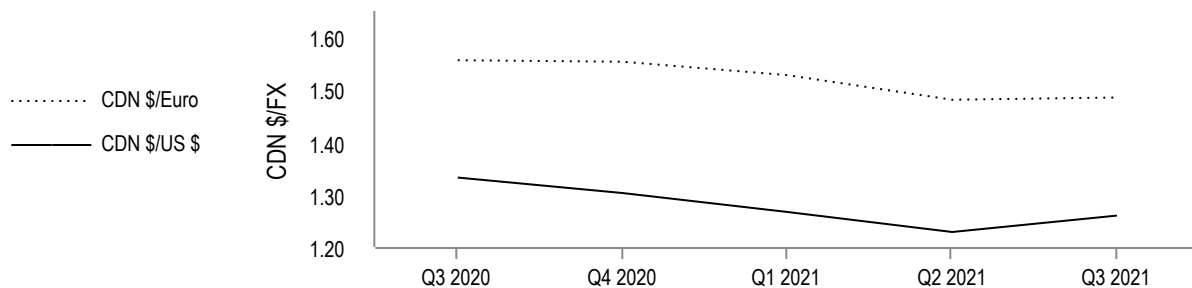
- Crude oil prices increased in Q3 2021 relative to Q3 2020 due to continued global demand recovery, OPEC+ group's adherence to moderated supply increase schedule, and continued capital discipline leading to muted US shale production growth. Year-over-year, Canadian dollar WTI and Brent prices rose 72% and 71% respectively.
- In Canadian dollar terms, year-over-year, the Edmonton Sweet differential widened by \$0.45/bbl to a discount of \$5.13/bbl against WTI, and the Saskatchewan LSB differential widened by \$0.83/bbl to a discount of \$5.31/bbl against WTI.
- Approximately 38% of Vermilion's Q3 2021 crude oil and condensate production was priced at the Dated Brent index (which averaged a premium to WTI of US\$2.91/bbl), while the remainder of our crude oil and condensate production was priced at the Saskatchewan LSB, Canadian C5+, Edmonton Sweet, and WTI indices.

Q3 2021 realized natural gas price was a \$5.60/mcf premium to AECO



- In Canadian dollar terms, prices for European natural gas (NBP and TTF) rose by 451% and 488%, respectively, in Q3 2021 compared to Q3 2020. Lower than average supply balances leading into winter have been driven by the continued demand recovery along with lower supply from both pipeline flows and LNG imports. Prices have also increased due to higher Asian LNG, global coal and European carbon prices.
- Natural gas prices at AECO in Q3 2021 increased by 61% compared to Q3 2020, with seasonal demand and supportive storage balances improving prices.
- For Q3 2021, average European natural gas prices represented a \$16.83/mcf premium to AECO. Approximately 36% of our natural gas production in Q3 2021 benefited from this premium European pricing.

Quarter-over-quarter, the Canadian dollar weakened versus the US Dollar



- For the three months ended September 30, 2021, the Canadian dollar remained flat against the Euro quarter-over-quarter.
- For the three months ended September 30, 2021, the Canadian dollar weakened 3% against the US dollar quarter-over-quarter.

North America

	Q3 2021	Q3 2020	YTD 2021	YTD 2020
Production ⁽¹⁾				
Crude oil and condensate (bbls/d)	24,757	28,296	24,573	29,912
NGLs (bbls/d)	8,068	9,508	8,279	9,041
Natural gas (mmcf/d)	145.18	163.09	147.20	164.46
Total production volume (boe/d)	57,022	64,986	57,386	66,363

⁽¹⁾ Please refer to Supplemental Table 4 "Production" for disclosure by product type.

	Q3 2021		Q3 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Sales	264,393	50.40	173,029	28.94	709,136	45.26	459,829	25.29
Royalties	(37,444)	(7.14)	(21,423)	(3.58)	(97,279)	(6.21)	(52,737)	(2.90)
Transportation	(10,085)	(1.92)	(10,413)	(1.74)	(30,653)	(1.96)	(32,485)	(1.79)
Operating	(57,834)	(11.02)	(46,762)	(7.82)	(172,945)	(11.04)	(177,542)	(9.76)
General and administration ⁽¹⁾	(5,990)	(1.14)	(4,688)	(0.78)	(17,663)	(1.13)	(19,300)	(1.06)
Corporate income tax (expense) ⁽¹⁾	(276)	(0.05)	(108)	(0.02)	(689)	(0.04)	(443)	(0.02)
Fund flows from operations	152,764	29.12	89,635	14.99	389,907	24.89	177,322	9.75
Capital expenditures	(35,179)		(9,575)		(133,139)		(231,480)	
Free cash flow	117,585		80,060		256,768		(54,158)	

⁽¹⁾ Includes amounts from Corporate segment.

In North America, production averaged 57,022 boe/d in Q3 2021, a decrease of 12% year-over-year primarily due to natural decline and reduced capital activity as we focused on maximizing free cash flow and reducing debt. The production decline was partially offset by a small acquisition completed in the United States during Q3 2021.

In Canada, we continued with our two-rig drilling program in southeast Saskatchewan where we drilled 19 (19.0 net) wells and completed 20 (19.5 net) wells in the quarter. Activity in Alberta was primarily focused on plant turnarounds and maintenance and preparing for our Q4 2021 condensate-rich Mannville drilling program. Our operations were affected by an unplanned outage at the Plains Midstream Fort Saskatchewan facility late in the quarter, but we were able to minimize the impact by optimizing our marketing logistics and rerouting our production to other facilities. The net impact for Q3 2021 related to this event was approximately 550 boe/d.

In the United States, we completed and brought on production the remaining two (2.0 net) wells from our four (4.0 net) well Q2 2021 drilling program. The results from our 2021 drilling program have exceeded expectations from both a cost and production performance basis. We completed a strategic acquisition in the United States during the third quarter. The acquisition includes 20,000 net acres of land adjacent to our Hilight field in Wyoming with current production of approximately 1,500 boe/d (72% liquids) and we have identified up to 40 drilling locations in the Turner sands. Total consideration for the acquisition was US\$76 million which was funded through our credit facility.

Sales

	Q3 2021		Q3 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Canada	228,519	48.54	153,374	28.13	631,175	43.85	408,472	24.58
United States	35,874	66.61	19,655	37.28	77,961	61.29	51,357	32.84
North America	264,393	50.40	173,029	28.94	709,136	45.26	459,829	25.29

Sales in North America increased on a dollar and per unit basis for the three and nine months ended September 30, 2021 versus the comparable prior periods due to higher benchmark prices across all products, partially offset by lower production volumes.

Royalties

	Q3 2021		Q3 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Canada	(27,812)	(5.91)	(16,259)	(2.98)	(76,587)	(5.32)	(39,721)	(2.39)
United States	(9,632)	(17.89)	(5,164)	(9.80)	(20,692)	(16.27)	(13,016)	(8.32)
North America	(37,444)	(7.14)	(21,423)	(3.58)	(97,279)	(6.21)	(52,737)	(2.90)

Royalties in North America increased on a dollar and per unit basis for the three and nine months ended September 30, 2021 versus the comparable prior periods primarily due to higher benchmark prices. Royalties as a percentage of sales for the three and nine months ended September 30, 2021 of 14.2% and 13.7% increased versus comparable periods in the prior year primarily due to the effect of higher commodity prices on sliding scale royalties.

Transportation

	Q3 2021		Q3 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Canada	(9,526)	(2.02)	(9,904)	(1.82)	(29,630)	(2.06)	(31,507)	(1.90)
United States	(559)	(1.04)	(509)	(0.97)	(1,023)	(0.80)	(978)	(0.63)
North America	(10,085)	(1.92)	(10,413)	(1.74)	(30,653)	(1.96)	(32,485)	(1.79)

Transportation expense in North America remained relatively consistent for the three and nine months ended September 30, 2021 versus the comparable prior periods. On a per unit basis for the three and nine months ended September 30, 2021, transportation expense increased slightly versus the comparable prior periods primarily due to higher pipeline tariffs partially offset by lower volumes shipped through pipelines.

Operating expense

	Q3 2021		Q3 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Canada	(53,076)	(11.27)	(42,405)	(7.78)	(160,683)	(11.16)	(163,871)	(9.86)
United States	(4,758)	(8.84)	(4,357)	(8.26)	(12,262)	(9.64)	(13,671)	(8.74)
North America	(57,834)	(11.02)	(46,762)	(7.82)	(172,945)	(11.04)	(177,542)	(9.76)

Operating expenses in North America increased on a dollar basis for the three months ended September 30, 2021 versus the comparable prior period primarily due to higher maintenance activity in Q3 2021. For the nine months ended September 30, 2021, operating expenses remained relatively consistent versus the comparable prior period. On a per unit basis, operating expenses increased for the three and nine months ended September 30, 2021 versus the comparable prior periods primarily due to lower production volumes and the resulting impact of fixed costs.

International

	Q3 2021	Q3 2020	YTD 2021	YTD 2020
Production ⁽¹⁾				
Crude oil and condensate (bbls/d)	14,020	14,943	14,203	14,471
Natural gas (mmcf/d)	81.55	93.25	84.92	100.93
Total production volume (boe/d)	27,612	30,484	28,356	31,292
Total sales volume (boe/d)	28,820	31,229	27,669	31,817

⁽¹⁾ Please refer to Supplemental Table 4 "Production" for disclosure by product type.

	Q3 2021		Q3 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Sales	274,137	103.39	108,991	37.94	604,710	80.06	343,518	39.40
Royalties	(11,991)	(4.52)	(9,546)	(3.32)	(30,058)	(3.98)	(25,709)	(2.95)
Transportation	(9,188)	(3.47)	(6,546)	(2.28)	(27,475)	(3.64)	(18,169)	(2.08)
Operating	(46,521)	(17.55)	(43,600)	(15.18)	(127,388)	(16.86)	(133,133)	(15.27)
General and administration	(6,351)	(2.40)	(7,281)	(2.53)	(17,840)	(2.36)	(22,898)	(2.63)
Corporate income tax recovery (expense)	1,690	0.64	118	0.04	2,757	0.36	(279)	(0.03)
PRRT	(7,271)	(2.74)	(3,638)	(1.27)	(10,144)	(1.34)	(16,113)	(1.85)
Fund flows from operations	194,505	73.36	38,498	13.40	394,562	52.23	127,217	14.59
Capital expenditures	(31,271)		(21,755)		(95,850)		(75,828)	
Free cash flow	163,234		16,743		298,712		51,389	

Production from our International assets averaged 27,612 boe/d in Q3 2021, representing a decrease of 9% year-over-year primarily due to natural decline and a planned turnaround in Ireland.

Most of the activity in Europe during the third quarter was focused on completing and tying in the Nijega (1.0 net) and Blesdijke (0.5 net) gas wells in the Netherlands and the Burgmoor Z-5 gas well (46% working interest) in Germany. In the Netherlands, the Nijega well (1.0 net) was tied in during the third quarter, while the Blesdijke well (0.5 net) is currently undergoing stimulation operations and is expected to be tested in Q4 2021. In Germany, the Burgmoor Z-5 well (46% working interest) was brought on production during the third quarter.

Progress on the gas plant for the SA-10 block in Croatia also continued during the quarter. We took physical delivery of the gas plant that was shipped from the Netherlands and we continue to advance the detailed design work with construction planned for 2022 and first production anticipated in 2023.

Sales

	Q3 2021		Q3 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Australia	44,044	105.17	30,537	68.63	102,682	99.77	111,304	76.89
France	79,817	91.60	48,976	53.55	199,454	84.11	129,094	54.35
Netherlands	69,247	104.68	12,351	17.29	130,353	69.67	42,608	19.54
Germany	32,943	94.41	6,507	26.17	66,312	69.97	23,529	27.44
Ireland	47,817	137.58	10,472	19.45	105,073	79.75	35,328	20.18
Central and Eastern Europe	269	81.22	148	12.19	836	49.39	1,655	15.65
International	274,137	103.39	108,991	37.94	604,710	80.06	343,518	39.40

As a result of changes in inventory levels, our sales volumes for crude oil in Australia, France, and Germany may differ from our production volumes in those business units. The following table provides the crude oil sales volumes (consisting entirely of "light crude oil and medium crude oil") for those jurisdictions.

Crude oil sales volumes (bbls/d)	Q3 2021	Q3 2020	YTD 2021	YTD 2020
Australia	4,552	4,836	3,770	5,283
France	9,471	9,941	8,687	8,669
Germany	1,094	828	959	958
International	15,117	15,605	13,416	14,910

Sales increased on a dollar and per boe basis for the three and nine months ended September 30, 2021 versus the prior year comparable periods due to higher realized prices across all business units, and were offset by lower sales volumes in Ireland, Netherlands, and Central Eastern Europe driven by natural decline, a planned turnaround in Ireland and the timing of liftings in France and Australia.

Royalties

	Q3 2021		Q3 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
France	(11,089)	(12.73)	(8,902)	(9.73)	(27,492)	(11.59)	(22,653)	(9.54)
Netherlands	(229)	(0.35)	(96)	(0.13)	(454)	(0.24)	(294)	(0.13)
Germany	(616)	(1.77)	(443)	(1.78)	(1,938)	(2.05)	(2,180)	(2.54)
Central and Eastern Europe	(57)	(17.21)	(105)	(8.65)	(174)	(10.28)	(582)	(5.50)
International	(11,991)	(4.52)	(9,546)	(3.32)	(30,058)	(3.98)	(25,709)	(2.95)

Royalties in our International core region are primarily incurred in France, where royalties include charges based on a percentage of sales and fixed per boe charges. Our production in Australia and Ireland is not subject to royalties.

Royalties increased in our International core region for the three and nine months ended September 30, 2021 versus the prior year comparable periods mainly due to increases in France as a result of an RCDM rate increase and higher R31 royalties as a result of higher commodity prices increasing sales. Royalties as a percentage of sales for the three and nine months ended September 30, 2021 of 4.4% and 5.0% decreased versus the prior year comparable periods of 8.8% and 7.5% primarily due to the impact of RCDM royalties in France, which are levied on units of production and not subject to changes in commodity prices.

Transportation

	Q3 2021		Q3 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
France	(6,400)	(7.34)	(3,868)	(4.23)	(19,923)	(8.40)	(10,340)	(4.35)
Germany	(1,708)	(4.89)	(1,475)	(5.93)	(4,283)	(4.52)	(4,302)	(5.02)
Ireland	(1,080)	(3.11)	(1,203)	(2.23)	(3,269)	(2.48)	(3,527)	(2.01)
International	(9,188)	(3.47)	(6,546)	(2.28)	(27,475)	(3.64)	(18,169)	(2.08)

Transportation expense increased for the three and nine months ended September 30, 2021 versus the comparable prior year periods. This increase was primarily in France relating to the use of incremental trucking in the Paris Basin following the conversion of the Grandpuits refinery. Our production in Australia, Netherlands and Central and Eastern Europe is not subject to transportation expense.

Operating expense

	Q3 2021		Q3 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Australia	(14,684)	(35.06)	(12,111)	(27.22)	(34,830)	(33.84)	(40,143)	(27.73)
France	(13,523)	(15.52)	(14,983)	(16.38)	(37,905)	(15.98)	(40,898)	(17.22)
Netherlands	(8,514)	(12.87)	(8,197)	(11.48)	(23,820)	(12.73)	(24,638)	(11.30)
Germany	(6,717)	(19.25)	(4,262)	(17.14)	(19,826)	(20.92)	(15,089)	(17.60)
Ireland	(2,968)	(8.54)	(3,936)	(7.31)	(10,782)	(8.18)	(12,000)	(6.85)
Central and Eastern Europe	(115)	(34.72)	(111)	(9.14)	(225)	(13.29)	(365)	(3.45)
International	(46,521)	(17.55)	(43,600)	(15.18)	(127,388)	(16.86)	(133,133)	(15.27)

Operating expenses on a dollar and per boe basis increased for Q3 2021 versus Q3 2020. This increase was primarily due to higher inventory draws in Australia where operating expenses are deferred on the balance sheet until crude oil is sold at which point the related expenses are recognized into income and in Germany due to increased activity in Q3 2021.

For the nine months ended September 30, 2021 versus the comparable prior year period, operating expenses decreased mainly due to larger inventory builds in Australia and France. Operating expenses on a per boe basis for the same periods increased mainly due to timing of inventory draws and higher facility costs in Germany combined with natural declines in Ireland and the Netherlands.

Consolidated Financial Performance Review

Fund flows from operations

	Q3 2021		Q3 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Sales	538,530	68.19	282,020	31.86	1,313,846	56.58	803,347	29.86
Royalties	(49,435)	(6.26)	(30,969)	(3.50)	(127,337)	(5.48)	(78,446)	(2.92)
Transportation	(19,273)	(2.44)	(16,959)	(1.92)	(58,128)	(2.50)	(50,654)	(1.88)
Operating	(104,355)	(13.21)	(90,362)	(10.21)	(300,333)	(12.93)	(310,675)	(11.55)
General and administration	(12,341)	(1.56)	(11,969)	(1.35)	(35,503)	(1.53)	(42,198)	(1.57)
Corporate income tax recovery (expense)	1,414	0.18	10	—	2,068	0.09	(722)	(0.03)
PRRT	(7,271)	(0.92)	(3,638)	(0.41)	(10,144)	(0.44)	(16,113)	(0.60)
Interest expense	(18,699)	(2.37)	(17,400)	(1.97)	(56,796)	(2.45)	(55,269)	(2.05)
Realized (loss) gain on derivatives	(72,579)	(9.19)	4,180	0.47	(137,786)	(5.93)	108,303	4.03
Realized foreign exchange gain (loss)	2,921	0.37	(2,714)	(0.31)	(4,218)	(0.18)	9,781	0.36
Realized other income (expense)	3,784	0.48	2,577	0.29	12,020	0.52	(501)	(0.02)
Fund flows from operations	262,696	33.27	114,776	12.95	597,689	25.75	366,853	13.63

Fluctuations in fund flows from operations may occur as a result of changes in production levels, 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 within profit or loss.

General and administration

- General and administration expense remained relatively consistent in Q3 2021 versus Q3 2020, and decreased for the nine months ended September 30, 2021 versus the comparable prior year period primarily due to work-force reductions made in Q4 2020.

PRRT and corporate income taxes

- PRRT increased for the three months ended September 30, 2021 versus the prior year comparable period primarily due to higher sales in Australia.
- PRRT decreased for the nine months ended September 30, 2021 versus the prior year comparable period due to lower sales and higher capital expenditures in Australia.
- Corporate income taxes for the three and nine months ended September 30, 2021 decreased versus the prior year comparable periods primarily due to the application of tax losses in France and Australia.

Interest expense

- Interest expense remained relatively consistent for the three and nine months ended September 30, 2021 versus the prior year comparable periods.

Realized gain or loss on derivatives

- For the three and nine months ended September 30, 2021, we recorded realized losses on our crude oil and natural gas hedges due to higher commodity pricing compared to the strike prices on our hedges. Realized gains on derivatives for the prior year comparable periods relate to receipts for European natural gas and crude oil hedges.
- A listing of derivative positions as at September 30, 2021 is included in "Supplemental Table 2" of this MD&A.

Realized other income

- Realized other income for the three and nine months ended September 30, 2021 primarily relates to amounts for funding under the Saskatchewan Accelerated Site Closure program to complete abandonment and reclamation on inactive oil and gas wells and facilities.

Net earnings

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

(\$M)	Q3 2021	Q3 2020	YTD 2021	YTD 2020
Fund flows from operations	262,696	114,776	597,689	366,853
Equity based compensation	(7,823)	(9,733)	(34,899)	(31,894)
Unrealized loss on derivative instruments	(279,393)	(39,637)	(353,359)	(34,092)
Unrealized foreign exchange (loss) gain	(27,877)	15,885	(72,085)	(1,507)
Accretion	(11,199)	(9,158)	(32,569)	(26,184)
Depletion and depreciation	(167,808)	(167,728)	(423,472)	(432,242)
Deferred tax recovery (expense)	62,245	73,653	(172,509)	382,321
Gain on business combinations	—	—	17,198	—
Impairment reversal (expense)	22,225	(47,777)	1,278,697	(1,682,344)
Unrealized other expense	(196)	(207)	(583)	(631)
Net (loss) earnings	(147,130)	(69,926)	804,108	(1,459,720)

Fluctuations in net earnings from period-to-period are caused by changes in both cash and non-cash based income and charges. Cash based items are reflected in fund flows from operations. 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 security-based arrangements. Equity based compensation expense decreased for the three months ended September 30, 2021 due to lower performance factor applied to grants, while equity based compensation increased for the nine months ended September 30, 2021 due to settlement of bonuses in Q1 2021 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 forecasts for future prices and rates. 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.

USD-to-CAD cross currency interest rate swaps and foreign exchange swaps may be entered into to hedge the foreign exchange movements on USD borrowings on our revolving credit facility. As such, unrealized gains and losses on our cross currency interest swaps are offset by unrealized losses and gains on foreign exchange relating to the underlying USD borrowings from our revolving credit facility.

For the three months ended September 30, 2021, we recognized a net unrealized loss on derivative instruments of \$279.4 million. This consists of unrealized losses of \$306.3 million on our European natural gas commodity derivative instruments and \$7.7 million on our crude oil commodity derivative instruments, partially offset by unrealized gains of \$20.9 million on our USD-to-CAD foreign exchange swaps, \$7.5 million on our North American natural gas commodity derivative instruments and \$6.5 million on our equity swaps.

For the nine months ended September 30, 2021, we recognized a net unrealized loss on derivative instruments of \$353.4 million. This consists of unrealized losses of \$431.2 million on our European natural gas commodity derivative instruments, \$8.7 million on our crude oil commodity derivative instruments, and \$3.1 million on our North American natural gas commodity derivative instruments, partially offset by unrealized gains of \$63.7 million on our USD-to-CAD foreign exchange swaps and \$25.6 million on our equity swaps.

Unrealized foreign exchange gains or losses

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. Unrealized foreign exchange gains and losses result from translating these monetary assets and liabilities from their underlying currency to the Canadian dollar.

In 2021, unrealized foreign exchange gains and losses primarily resulted from:

- The translation of Euro denominated intercompany loans from Vermilion Energy Inc. to our international subsidiaries. An appreciation in the Euro against the Canadian dollar will result in an unrealized foreign exchange gain (and vice-versa). Under IFRS, the offsetting foreign exchange loss or gain is recorded as a currency translation adjustment within other comprehensive income. As a result, consolidated comprehensive income reflects the offsetting of these translation adjustments while net earnings reflects only the parent company's side of the translation.
- The translation of USD borrowings on our revolving credit facility. The unrealized foreign exchange gains or losses on these borrowings are offset by unrealized derivative gains or losses on associated USD-to-CAD cross currency interest rate swaps (discussed further below).
- The translation of our USD denominated senior unsecured notes prior to June 12, 2019 and from May 5, 2020 onward. During the period between June 12, 2019 and May 5, 2020 the USD senior notes were hedged by a USD-to-CAD cross currency interest rate swap. Subsequent to the termination of these instruments, amounts previously recognized in the hedge accounting reserve will be recognized into earnings through unrealized foreign exchange loss over the period of the hedged cash flows.

For the three months ended September 30, 2021, we recognized a net unrealized foreign exchange loss of \$27.9 million due to unrealized losses of \$29.3 million on our USD borrowings from our revolving credit facility and the impact of the US dollar strengthening 2.8% against the Canadian dollar in Q3 2021 resulting in an unrealized loss of \$10.2 million on our senior unsecured notes. These were partially offset by an unrealized gain of \$4.2 million on intercompany loans due to the Euro strengthening 0.7% against the Canadian dollar in Q3 2021.

For the nine months ended September 30, 2021, we recognized a net unrealized foreign exchange loss of \$72.1 million. This was due to unrealized losses of \$73.5 million on our USD borrowings from our revolving credit facility and \$10.2 million on intercompany loans due to the Euro weakening 5.3% against the Canadian dollar. These were partially offset by the impact of the US dollar weakening 0.7% against the Canadian dollar resulting in an unrealized gain of \$2.8 million on our senior unsecured notes.

As at September 30, 2021, a \$0.01 appreciation of the Euro against the Canadian dollar would result in a \$0.7 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 \$2.8 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. For the three and nine months ended September 30, 2021 versus the comparable prior year periods accretion expense increased primarily due to additional obligations recognized at the end of 2020 through 2021 partially offset by the weakening of the Euro against the Canadian dollar.

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, depletable base (net book value of capital assets and future development costs), and relative production mix.

Depletion and depreciation on a per boe basis for the three and nine months ended September 30, 2021 of \$21.25 and \$18.24 increased from \$18.95 and \$16.07 in the prior year comparable periods primarily due to impairment reversals recorded in the first half of 2021.

Deferred tax

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 enacted 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 derecognition or recognition of deferred tax assets, and changes in enacted or substantively enacted tax rates.

For the three and nine months ended September 30, 2021, the Company recorded a deferred tax recovery of \$62.2 million and deferred tax expense of \$172.5 million, respectively compared to deferred tax recoveries of \$73.7 million and \$382.3 million for the prior year comparable periods. The deferred tax expense for the nine months ended September 30, 2021 is primarily due to impairment reversals in the first half of 2021, partially offset by the recognition of a portion of non-expiring tax loss pools in Ireland that are expected to be utilized due to an increase in forecast commodity prices.

Impairment

Impairment losses are recognized when indicators of impairment arise and the carrying amount of a cash generating unit ("CGU") exceeds its recoverable amount, determined as the higher of fair value less costs of disposal or value-in-use.

In the third quarter of 2021, indicators of impairment reversal were present in our Ireland CGU due to an increase and stabilization in forecast gas prices. As a result of the indicators of impairment reversal, the Company performed impairment reversal calculations on the Ireland CGU and the recoverable amount was determined using fair value less costs to sell, which considered future after-tax cash flows from proved plus probable reserves and an after-tax discount rate of 12.0%. Based on the results of the impairment reversal calculations completed, the recoverable amount was determined to be greater than the carrying value and \$16.7 million (net of \$5.5 million deferred income tax expense) of impairment reversal was recorded.

In the second quarter of 2021, indicators of impairment reversal were present in our Alberta, Saskatchewan, Germany, Ireland and United States CGUs due to an increase and stabilization in forecast oil and gas prices. As a result of the indicators of impairment reversal, the Company performed impairment reversal calculations on the identified CGUs and the recoverable amounts were determined using fair value less costs to sell, which considered future after-tax cash flows from proved plus probable reserves and an after-tax discount rate of 12.0%. Based on the results of the impairment reversal calculations completed, recoverable amounts were determined to be greater than the carrying values of the CGUs tested and \$460.4 million (net of \$133.2 million deferred income tax expense) of impairment reversal was recorded.

In the first quarter of 2021, indicators of impairment reversal were present in our Australia, Alberta, Saskatchewan, and United States CGUs due to an increase and stabilization in forecast crude oil prices versus 2020 when impairment charges were taken. As a result of the indicators of impairment reversal, the Company performed impairment reversal tests on the identified CGUs and the recoverable amounts were determined using fair value less costs to sell, which considered future after-tax cash flows from proved plus probable reserves and an after-tax discount rate of 12.0%. Based on the results of the impairment reversal calculations completed, recoverable amounts were determined to be greater than the carrying values of the CGUs tested and \$492.2 million (net of \$170.7 million deferred income tax expense) of impairment reversal was recorded.

In the first quarter of 2020, indicators of impairment were present due to global commodity price forecasts deteriorating from decreases in demand and an increase of supply around the world. As a result of the indicators of impairment, the Company performed impairment tests across all CGUs. The recoverable amounts were determined using fair value less costs to sell, which considered future after-tax cash flows from proved plus probable reserves and an after-tax discount rate of 11.5%. Based on the results of the impairment calculations completed, the Company recognized non-cash impairment charges of \$1.2 billion (net of \$0.4 billion income tax recovery).

In the second quarter of 2020, indicators of impairment were present due to the Company's market capitalization falling below the carrying value of its net assets as at June 30, 2020. As a result of the indicators of impairment, the Company performed an impairment test. The recoverable amount was determined using fair value less costs to sell, which considered future after-tax cash flows from proved plus probable reserves and an after-tax discount rate of 11.5%. Based on the results of the impairment calculations completed, the Company recognized non-cash impairment charges of \$53.1 million (net of \$16.6 million income tax recovery).

Inputs used in the measurement of capital assets are not based on observable market data and fall within level 3 of the fair value hierarchy.

Gain on business combinations

A gain on business combination is recognized when the total consideration paid in a business combination is less than the fair value of the net assets acquired. For the nine months ended September 30, 2021, a gain of \$17.2 million was recognized on our purchase of assets in Germany in the second quarter of 2021.

Financial Position Review

Balance sheet strategy

We regularly review whether our forecast of fund flows from operations is sufficient to finance planned capital expenditures, dividends, and abandonment and reclamation expenditures. To the extent that fund flows from operations forecasts are not expected to be sufficient to fulfill such expenditures, we will evaluate our ability to finance any shortfall by reducing some or all categories of expenditures, with issuances of equity, or with debt (including borrowing using the unutilized capacity of our existing revolving credit facility). We have a long-term goal of achieving and maintaining a ratio of net debt to fund flows from operations of less than 1.5.

As at September 30, 2021, we have a ratio of net debt to fund flows from operations of 2.43. We will continue to monitor for changes in forecasted fund flows from operations and, as appropriate, will adjust our exploration and development capital plans (and associated growth targets) to minimize any further increase to debt. We intend to strengthen our balance sheet through debt reduction, and as commodity prices improve, may implement a return of capital in the form of dividends and/or share buybacks.

Net debt

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

(\$M)	As at	
	Sep 30, 2021	Dec 31, 2020 (revised)
Long-term debt	1,760,342	1,933,848
Adjusted working capital deficiency ⁽¹⁾	41,168	35,258
Unrealized foreign exchange on swapped USD borrowings	(23,458)	40,219
Net debt	1,778,052	2,009,325

Ratio of net debt to four quarter trailing fund flows from operations	2.43	4.00
--	-------------	-------------

(1) Adjusted working capital is defined as current assets (excluding current derivatives), less current liabilities (excluding current derivatives and current lease liabilities)

In Q3 2021, the Company adjusted the calculation for net debt in order to provide more meaningful and comparable information to users. The revised definition of net debt is long-term debt (excluding unrealized foreign exchange on swapped USD borrowings) plus adjusted working capital (defined as current assets less current liabilities, excluding current derivatives and current lease liabilities).

As at September 30, 2021, net debt decreased to \$1.8 billion (December 31, 2020 - \$2.0 billion (revised)) primarily as a result of debt repayments of \$238.1 million funded by free cash flow generated for the nine months ended September 30, 2021 of \$368.7 million. We will draw on unutilized capacity of the revolving credit facility to fund working capital deficiencies. The ratio of net debt to four quarter trailing fund flows from operations decreased to 2.43 (December 31, 2020 - 4.00 (revised)) mainly due to the decrease in net debt combined with higher four quarter trailing fund flows from operations.

Long-term debt

The balances recognized on our balance sheet are as follows:

(\$M)	As at	
	Sep 30, 2021	Dec 31, 2020
Revolving credit facility	1,383,946	1,555,215
Senior unsecured notes	376,396	378,633
Long-term debt	1,760,342	1,933,848

Revolving Credit Facility

As at September 30, 2021, Vermilion had in place a bank revolving credit facility maturing May 31, 2024 with terms and outstanding positions as follows:

(\$M)	As at	
	Sep 30, 2021	Dec 31, 2020
Total facility amount	2,100,000	2,100,000
Amount drawn	(1,383,946)	(1,555,215)
Letters of credit outstanding	(16,022)	(23,210)
Unutilized capacity	700,032	521,575

As at September 30, 2021, the revolving credit facility was subject to the following financial covenants:

Financial covenant	Limit	As at	
		Sep 30, 2021	Dec 31, 2020
Consolidated total debt to consolidated EBITDA	Less than 4.0	2.20	3.48
Consolidated total senior debt to consolidated EBITDA	Less than 3.5	1.72	2.82
Consolidated EBITDA to consolidated interest expense	Greater than 2.5	11.00	8.12

Our financial 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 "Lease obligations" (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 interest expense: Includes all amounts classified as "Interest expense", but excludes interest on operating leases as defined under IAS 17.

In addition, our revolving credit facility has provisions relating to our liability management ratings in Alberta and Saskatchewan whereby if our security adjusted liability management ratings fall below specified limits in a province, a portion of the asset retirement obligations are included in the definitions of consolidated total debt and consolidated total senior debt. An event of default occurs if our security adjusted liability management ratings breach additional lower limits for a period greater than 90 days. As of September 30, 2021, Vermilion's liability management ratings were higher than the specified levels, and as such, no amounts relating to asset retirement obligations were included in the calculation of consolidated total debt and consolidated total senior debt.

Senior Unsecured Notes

On March 13, 2017, Vermilion issued US \$300.0 million of senior unsecured notes at par. The notes bear interest at a rate of 5.625% per annum, 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 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, if redeemed during the twelve-month period beginning on March 15 of each of the years indicated below:

Year	Redemption price
2021	102.813 %
2022	101.406 %
2023 and thereafter	100.000 %

Shareholders' capital

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 to February 2020	\$0.230
March 2020	\$0.115

In April 2020, we suspended our monthly dividend to strengthen the financial position of the Company. Our ability to restore a dividend will be dependent upon stronger commodity prices combined with a balance sheet that reflects the Company's ability to sustain such dividend over the long-term.

The following table reconciles the change in shareholders' capital:

Shareholders' Capital	Number of Shares ('000s)	Amount (\$M)
Balance at December 31, 2020	158,724	4,181,160
Vesting of equity based awards	2,132	45,051
Equity based compensation	911	8,364
Share-settled dividends on vested equity based awards	218	1,926
Balance at September 30, 2021	161,985	4,236,501

As at September 30, 2021, there were approximately 7.2 million equity based compensation awards outstanding. As at November 9, 2021, there were approximately 162.3 million common shares issued and outstanding.

Asset Retirement Obligations

As at September 30, 2021, asset retirement obligations were \$876.9 million compared to \$467.7 million as at December 31, 2020. The increase in asset retirement obligations is primarily attributable to a decrease in the credit-adjusted risk-free rate from December 31, 2020 to September 30, 2021. This increase was partially offset by the Euro weakening against the Canadian dollar and obligations settled.

The present value of the obligation is calculated using a credit-adjusted risk-free rate, calculated using a credit spread added to risk-free rates based on long-term, risk-free government bonds. Vermilion's credit spread is determined as the yield to maturity on its senior unsecured notes at the end of the reporting period.

The risk-free rates and credit spread used as inputs to discount the obligations were as follows:

	Sep 30, 2021	Dec 31, 2020	Change
Credit spread added to below noted risk-free rates	4.3 %	9.5 %	(5.2)%
Country specific risk-free rate			
Canada	2.0 %	1.2 %	0.8 %
United States	2.0 %	1.6 %	0.4 %
France	0.8 %	0.3 %	0.5 %
Netherlands	(0.4)%	(0.6)%	0.2 %
Germany	0.2 %	(0.2)%	0.4 %
Ireland	0.5 %	(0.1)%	0.6 %
Australia	1.7 %	1.3 %	0.4 %

Risks and Uncertainties

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, 2020 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 nine months ended September 30, 2021. 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, 2020, available on SEDAR at www.sedar.com or on Vermilion's website at www.vermilionenergy.com.

Off Balance Sheet Arrangements

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

Internal Control Over Financial Reporting

Other than Vermilion's response to COVID-19, there has been 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.

As a result of COVID-19, our global workforce shifted to a primarily work from home environment beginning in March 2020. This change to remote working was rapid and included both our employees as well as a large extended workforce across all regions in which we operate. While pre-existing controls were not specifically designed to operate in our current work from home operating environment, we believe that our internal controls over financial reporting continue to be effective. We took precautionary actions to re-evaluate and refine our financial reporting process to provide reasonable assurance that we could report our financial results accurately and timely. During 2021, portions of our workforce returned to a work from the office arrangement.

Recently Adopted Accounting Pronouncements

Vermilion did not adopt any new accounting pronouncements as at September 30, 2021.

Disclosure Controls and Procedures

Our officers have established and maintained disclosure controls and procedures and evaluated the effectiveness of these controls in conjunction with our filings.

As of September 30, 2021, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures. Based on this evaluation, the President, for this specific purpose of acting in the capacity of Chief Executive Officer, and Chief Financial Officer have concluded and certified that our disclosure controls and procedures are effective.

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.

	Q3 2021			YTD 2021			Q3 2020	YTD 2020
	Liquids \$/bbl	Natural Gas \$/mcf	Total \$/boe	Liquids \$/bbl	Natural Gas \$/mcf	Total \$/boe	Total \$/boe	Total \$/boe
Canada								
Sales	69.83	3.77	48.54	62.94	3.36	43.85	28.13	24.58
Royalties	(9.81)	(0.19)	(5.91)	(8.77)	(0.17)	(5.32)	(2.98)	(2.39)
Transportation	(2.72)	(0.20)	(2.02)	(2.73)	(0.20)	(2.06)	(1.82)	(1.90)
Operating	(14.58)	(1.21)	(11.27)	(13.91)	(1.29)	(11.16)	(7.78)	(9.86)
Operating netback	42.72	2.17	29.34	37.53	1.70	25.31	15.55	10.43
General and administration			(1.01)			(1.05)	(1.10)	(1.05)
Fund flows from operations netback			28.33			24.26	14.45	9.38
United States								
Sales	76.25	4.36	66.61	67.64	6.40	61.29	37.28	32.84
Royalties	(20.39)	(1.23)	(17.89)	(17.76)	(1.81)	(16.27)	(9.80)	(8.32)
Transportation	(1.29)	—	(1.04)	(1.03)	—	(0.80)	(0.97)	(0.63)
Operating	(8.99)	(1.37)	(8.84)	(9.73)	(1.55)	(9.64)	(8.26)	(8.74)
Operating netback	45.58	1.76	38.84	39.12	3.04	34.58	18.25	15.15
General and administration			(2.51)			(2.34)	(2.44)	(3.23)
Fund flows from operations netback			36.33			32.24	15.81	11.92
France								
Sales	91.60	—	91.60	84.11	—	84.11	53.55	54.35
Royalties	(12.72)	—	(12.73)	(11.59)	—	(11.59)	(9.73)	(9.54)
Transportation	(7.34)	—	(7.34)	(8.40)	—	(8.40)	(4.23)	(4.35)
Operating	(15.52)	—	(15.52)	(15.98)	—	(15.98)	(16.38)	(17.22)
Operating netback	56.02	—	56.01	48.14	—	48.14	23.21	23.24
General and administration			(3.35)			(3.60)	(3.05)	(4.10)
Current income taxes			14.23			5.23	—	—
Fund flows from operations netback			66.89			49.77	20.16	19.14
Netherlands								
Sales	79.70	17.51	104.68	62.50	11.63	69.67	17.29	19.54
Royalties	—	(0.06)	(0.35)	—	(0.04)	(0.24)	(0.13)	(0.13)
Operating	—	(2.18)	(12.87)	—	(2.15)	(12.73)	(11.48)	(11.30)
Operating netback	79.70	15.27	91.46	62.50	9.44	56.70	5.68	8.11
General and administration			(0.23)			(0.28)	(0.64)	(0.56)
Current income taxes			(16.06)			(6.94)	0.49	0.28
Fund flows from operations netback			75.17			49.48	5.53	7.83
Germany								
Sales	82.31	16.55	94.41	78.17	11.14	69.97	26.17	27.44
Royalties	(1.53)	(0.31)	(1.77)	(1.17)	(0.40)	(2.05)	(1.78)	(2.54)
Transportation	(12.49)	(0.30)	(4.89)	(10.76)	(0.36)	(4.52)	(5.93)	(5.02)
Operating	(25.26)	(2.80)	(19.25)	(24.24)	(3.28)	(20.92)	(17.14)	(17.60)
Operating netback	43.03	13.14	68.50	42.00	7.10	42.48	1.32	2.28
General and administration			(3.33)			(3.95)	(5.97)	(5.29)
Fund flows from operations netback			65.17			38.53	(4.65)	(3.01)
Ireland								
Sales	—	22.93	137.58	—	13.29	79.75	19.45	20.18
Transportation	—	(0.52)	(3.11)	—	(0.41)	(2.48)	(2.23)	(2.01)
Operating	—	(1.42)	(8.54)	—	(1.36)	(8.18)	(7.31)	(6.85)
Operating netback	—	20.99	125.93	—	11.52	69.09	9.91	11.32
General and administration			(0.88)			0.29	(0.51)	(0.32)
Fund flows from operations netback			125.05			69.38	9.40	11.00

	Liquids \$/bbl	Q3 2021 Natural Gas \$/mcf	Total \$/boe	Liquids \$/bbl	YTD 2021 Natural Gas \$/mcf	Total \$/boe	Q3 2020 Total \$/boe	YTD 2020 Total \$/boe
Australia								
Sales	105.17	—	105.17	99.77	—	99.77	68.63	76.89
Operating	(35.06)	—	(35.06)	(33.84)	—	(33.84)	(27.22)	(27.73)
PRRT ⁽¹⁾	(17.36)	—	(17.36)	(9.86)	—	(9.86)	(8.18)	(11.13)
Operating netback	52.75	—	52.75	56.07	—	56.07	33.23	38.03
General and administration			(2.09)			(2.29)	(2.39)	(1.95)
Current income taxes			(0.21)			3.25	(0.53)	(0.61)
Fund flows from operations netback			50.45			57.03	30.31	35.47

Total Company								
Sales	78.41	9.20	68.19	70.58	6.63	56.58	31.86	29.86
Realized hedging (loss) gain	(0.51)	(3.37)	(9.19)	(3.22)	(1.53)	(5.93)	0.47	4.03
Royalties	(10.28)	(0.19)	(6.26)	(9.11)	(0.19)	(5.48)	(3.50)	(2.92)
Transportation	(3.45)	(0.19)	(2.44)	(3.59)	(0.20)	(2.50)	(1.92)	(1.88)
Operating	(16.37)	(1.53)	(13.21)	(15.77)	(1.59)	(12.93)	(10.21)	(11.55)
PRRT ⁽¹⁾	(1.64)	—	(0.92)	(0.80)	—	(0.44)	(0.41)	(0.60)
Operating netback	46.16	3.92	36.17	38.09	3.12	29.30	16.29	16.94
General and administration			(1.56)			(1.53)	(1.35)	(1.57)
Interest expense			(2.37)			(2.45)	(1.97)	(2.05)
Realized foreign exchange loss			0.37			(0.18)	(0.31)	0.36
Other income			0.48			0.52	0.29	(0.02)
Corporate income taxes			0.18			0.09	—	(0.03)
Fund flows from operations netback			33.27			25.75	12.95	13.63

⁽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 with foreign currency amounts translated to the disclosure currency using forward rates as at the month-end date. The weighted average price for the portfolio of options listed below may not have the same payoff profile as the individual contracts. As such, the presentation of the weighted average prices is purely for indicative purposes.

The following tables outline Vermilion's outstanding risk management positions as at September 30, 2021:

	Unit	Currency	Daily Bought Put Volume	Weighted Average Bought Put Price	Daily Sold Call Volume	Weighted Average Sold Call Price	Daily Sold Put Volume	Weighted Average Sold Put Price	Daily Sold Swap Volume	Weighted Average Sold Swap Price	Daily Bought Swap Volume	Weighted Average Bought Swap Price
Dated Brent												
Q4 2021	bbl	USD	—	—	—	—	—	—	1,342	59.97	—	—
Q1 2022	bbl	USD	2,700	62.50	2,700	81.01	2,700	47.50	500	52.00	—	—
Q2 2022	bbl	USD	2,700	62.50	2,700	81.01	2,700	47.50	—	—	—	—
Q3 2022	bbl	USD	1,850	62.50	1,850	81.35	1,850	47.50	—	—	—	—
Q4 2022	bbl	USD	1,850	62.50	1,850	81.35	1,850	47.50	—	—	—	—
WTI												
Q4 2021	bbl	USD	1,000	60.00	1,000	80.50	1,000	50.00	1,853	62.32	—	—
Q1 2022	bbl	USD	6,300	60.00	6,300	77.31	6,300	45.00	—	—	—	—
Q2 2022	bbl	USD	6,300	60.00	6,300	77.31	6,300	45.00	—	—	—	—
Q3 2022	bbl	USD	2,500	60.00	2,500	80.86	2,500	45.00	—	—	—	—
Q4 2022	bbl	USD	2,500	60.00	2,500	80.86	2,500	45.00	—	—	—	—
AECO												
Q4 2021	mcf	CAD	—	—	—	—	—	—	3,194	2.12	—	—
AECO Basis (AECO less NYMEX Henry Hub)												
Q4 2021	mcf	USD	—	—	—	—	—	—	35,054	(1.09)	—	—
Q1 2022	mcf	USD	—	—	—	—	—	—	30,000	(1.10)	—	—
Q2 2022	mcf	USD	—	—	—	—	—	—	35,000	(1.09)	—	—
Q3 2022	mcf	USD	—	—	—	—	—	—	35,000	(1.09)	—	—
Q4 2022	mcf	USD	—	—	—	—	—	—	11,793	(1.09)	—	—
NYMEX Henry Hub												
Q4 2021	mcf	USD	31,685	2.72	31,685	3.12	—	—	21,870	2.78	—	—
Q2 2022	mcf	USD	10,000	3.00	10,000	4.04	—	—	—	—	—	—
Q3 2022	mcf	USD	10,000	3.00	10,000	4.04	—	—	—	—	—	—
Q4 2022	mcf	USD	3,370	3.00	3,370	4.04	—	—	—	—	—	—
Ventura Basis (Ventura less NYMEX Henry Hub)												
Q4 2021	mcf	USD	—	—	—	—	—	—	—	—	3,370	0.05
Conway Propane												
Q4 2021	bbl	USD	—	—	—	—	—	—	168	50% WTI	—	—

	Unit	Currency	Daily Bought Put Volume	Weighted Average Bought Put Price	Daily Sold Call Volume	Weighted Average Sold Call Price	Daily Sold Put Volume	Weighted Average Sold Put Price	Daily Sold Swap Volume	Weighted Average Sold Swap Price	Daily Bought Swap Volume	Weighted Average Bought Swap Price
NBP												
Q4 2021	mcf	EUR	58,962	5.37	58,962	5.68	58,962	3.88	2,457	4.69	—	—
Q1 2022	mcf	EUR	36,851	6.04	36,851	7.54	34,394	3.63	4,913	4.91	—	—
Q2 2022	mcf	EUR	27,024	5.07	27,024	5.78	27,024	3.50	4,913	4.91	—	—
Q3 2022	mcf	EUR	19,654	5.11	19,654	6.20	19,654	3.66	4,913	4.91	—	—
Q4 2022	mcf	EUR	19,654	5.11	19,654	6.20	19,654	3.66	4,913	4.91	—	—
Q1 2023	mcf	EUR	12,284	5.19	12,284	6.39	12,284	3.75	—	—	—	—
Q2 2023	mcf	EUR	4,913	5.86	4,913	8.24	4,913	4.40	—	—	—	—
TTF												
Q1 2022	mcf	EUR	2,457	4.84	2,457	5.64	2,457	3.52	—	—	—	—
Q2 2022	mcf	EUR	2,457	4.84	2,457	5.64	2,457	3.52	—	—	—	—
Q3 2022	mcf	EUR	2,457	4.84	2,457	5.64	2,457	3.52	—	—	—	—
Q4 2022	mcf	EUR	2,457	4.84	2,457	5.64	2,457	3.52	—	—	—	—
Q1 2023	mcf	EUR	2,457	4.84	2,457	5.64	2,457	3.52	—	—	—	—

VET Equity Swaps				Initial Share Price		Share Volume
Swap	Jan 2020 - Apr 2023			20.9788	CAD	2,250,000
Swap	Jan 2020 - Apr 2023			22.4587	CAD	1,500,000

Foreign Currency Swaps		Notional Amount		Notional Amount		Average Rate
Swap	October 2021	1,045,016,080	USD	1,300,000,000	CAD	1.2440

Supplemental Table 3: Capital Expenditures and Acquisitions

By classification (\$M)	Q3 2021	Q3 2020	YTD 2021	YTD 2020
Drilling and development	63,173	29,762	220,388	299,578
Exploration and evaluation	3,277	1,568	8,601	7,730
Capital expenditures	66,450	31,330	228,989	307,308
Acquisitions	92,191	6,720	104,780	20,989
Contingent consideration	—	—	330	—
Long-term debt net of working capital assumed	2,229	—	2,222	—
Acquisitions	94,420	6,720	107,332	20,989

By category (\$M)	Q3 2021	Q3 2020	YTD 2021	YTD 2020
Drilling, completion, new well equip and tie-in, workovers and recompletions	38,666	13,220	154,901	243,338
Production equipment and facilities	26,092	15,800	62,982	48,617
Seismic, studies, land and other	1,692	2,310	11,106	15,353
Capital expenditures	66,450	31,330	228,989	307,308
Acquisitions	94,420	6,720	107,332	20,989
Total capital expenditures and acquisitions	160,870	38,050	336,321	328,297

Capital expenditures by country (\$M)	Q3 2021	Q3 2020	YTD 2021	YTD 2020
Canada	29,660	3,837	104,191	166,199
United States	5,519	5,738	28,948	65,281
France	8,886	12,638	24,678	29,498
Netherlands	2,789	1,553	14,605	6,688
Germany	3,318	1,558	9,424	12,692
Ireland	918	928	1,156	1,612
Australia	6,073	3,926	26,030	20,128
Central and Eastern Europe	9,287	1,152	19,957	5,210
Total capital expenditures	66,450	31,330	228,989	307,308

Acquisitions by country (\$M)	Q3 2021	Q3 2020	YTD 2021	YTD 2020
Canada	150	6,621	508	12,320
United States	94,170	90	94,170	6,697
France	—	—	—	—
Netherlands	—	—	—	—
Germany	100	9	12,654	592
Ireland	—	—	—	—
Australia	—	—	—	—
Central and Eastern Europe	—	—	—	1,380
Total acquisitions	94,420	6,720	107,332	20,989

Supplemental Table 4: Production

	Q3/21	Q2/21	Q1/21	Q4/20	Q3/20	Q2/20	Q1/20	Q4/19	Q3/19	Q2/19	Q1/19	Q4/18
Canada												
Light and medium crude oil (bbls/d)	16,809	16,868	17,767	19,301	19,847	22,545	22,767	23,259	23,610	23,973	25,067	25,640
Condensate ⁽¹⁾ (bbls/d)	4,426	5,558	4,556	4,662	5,200	5,047	4,634	4,140	4,072	4,872	4,096	3,918
Other NGLs ⁽¹⁾ (bbls/d)	6,862	7,767	7,016	7,334	8,350	8,248	6,943	7,005	6,632	7,352	6,968	6,816
NGLs (bbls/d)	11,288	13,325	11,572	11,996	13,550	13,295	11,577	11,145	10,704	12,224	11,064	10,734
Conventional natural gas (mmcf/d)	138.42	146.55	138.41	135.27	155.15	164.08	151.16	145.14	145.14	151.87	151.37	146.65
Total (boe/d)	51,168	54,618	52,407	53,840	59,256	63,187	59,537	58,593	58,504	61,507	61,360	60,814
United States												
Light and medium crude oil (bbls/d)	3,520	1,888	2,322	2,495	3,243	3,971	2,481	3,149	2,717	2,421	1,750	1,582
Condensate ⁽¹⁾ (bbls/d)	2	2	—	1	6	6	6	12	4	63	(8)	23
Other NGLs ⁽¹⁾ (bbls/d)	1,206	928	1,058	1,294	1,158	1,340	1,079	1,156	1,140	754	929	998
NGLs (bbls/d)	1,208	930	1,058	1,295	1,164	1,346	1,085	1,168	1,144	817	921	1,021
Conventional natural gas (mmcf/d)	6.75	5.51	5.95	6.87	7.94	8.35	6.72	8.20	6.38	7.06	5.89	5.65
Total (boe/d)	5,854	3,736	4,373	4,934	5,730	6,708	4,685	5,683	4,925	4,414	3,653	3,545
France												
Light and medium crude oil (bbls/d)	8,677	9,013	9,062	9,255	9,347	7,046	9,957	10,264	10,347	9,800	11,342	11,317
Conventional natural gas (mmcf/d)	—	—	—	—	—	—	—	—	—	—	0.77	0.82
Total (boe/d)	8,677	9,013	9,062	9,255	9,347	7,046	9,957	10,264	10,347	9,800	11,470	11,454
Netherlands												
Light and medium crude oil (bbls/d)	6	1	6	1	—	1	3	4	1	9	—	—
Condensate ⁽¹⁾ (bbls/d)	104	95	92	99	83	86	84	86	81	91	93	112
NGLs (bbls/d)	104	95	92	99	83	86	84	86	81	91	93	112
Conventional natural gas (mmcf/d)	42.48	37.59	41.45	42.95	46.09	47.31	48.33	47.99	44.08	52.90	51.51	51.82
Total (boe/d)	7,190	6,362	7,006	7,257	7,764	7,972	8,143	8,088	7,429	8,917	8,677	8,749
Germany												
Light and medium crude oil (bbls/d)	1,043	1,093	911	960	964	1,039	909	800	845	1,047	978	913
Conventional natural gas (mmcf/d)	16.19	15.60	13.40	11.50	11.25	13.23	14.64	15.44	14.54	14.56	16.71	16.94
Total (boe/d)	3,741	3,694	3,144	2,876	2,839	3,244	3,349	3,373	3,269	3,474	3,763	3,736
Ireland												
Conventional natural gas (mmcf/d)	22.67	30.19	34.14	34.76	35.12	38.57	41.38	42.30	43.21	49.21	51.71	52.03
Total (boe/d)	3,778	5,031	5,690	5,793	5,853	6,428	6,896	7,049	7,202	8,201	8,619	8,672
Australia												
Light and medium crude oil (bbls/d)	4,190	3,835	4,489	3,781	4,549	5,299	4,041	4,548	5,564	6,689	5,862	4,174
Total (boe/d)	4,190	3,835	4,489	3,781	4,549	5,299	4,041	4,548	5,564	6,689	5,862	4,174
Central and Eastern Europe												
Conventional natural gas (mmcf/d)	0.22	0.28	0.63	0.67	0.80	2.89	3.27	1.66	—	—	—	2.86
Total (boe/d)	36	46	104	111	132	483	546	276	—	—	—	477
Consolidated												
Light and medium crude oil (bbls/d)	34,245	32,698	34,556	35,793	37,951	39,899	40,157	42,024	43,084	43,938	45,001	43,625
Condensate ⁽¹⁾ (bbls/d)	4,532	5,656	4,648	4,762	5,289	5,142	4,724	4,237	4,158	5,026	4,181	4,053
Other NGLs ⁽¹⁾ (bbls/d)	8,068	8,695	8,074	8,627	9,509	9,588	8,022	8,160	7,772	8,107	7,897	7,815
NGLs (bbls/d)	12,600	14,351	12,722	13,389	14,798	14,730	12,746	12,397	11,930	13,133	12,078	11,868
Conventional natural gas (mmcf/d)	226.73	235.72	233.98	232.00	256.34	274.42	265.51	260.72	253.36	275.60	277.96	276.77
Total (boe/d)	84,633	86,335	86,276	87,848	95,471	100,366	97,154	97,875	97,239	103,003	103,404	101,621

	YTD 2021	2020	2019	2018	2017	2016
Canada						
Light and medium crude oil (bbls/d)	17,144	21,106	23,971	17,400	6,015	6,657
Condensate ⁽¹⁾ (bbls/d)	4,846	4,886	4,295	3,754	3,036	2,514
Other NGLs ⁽¹⁾ (bbls/d)	7,214	7,719	6,988	5,914	4,144	2,552
NGLs (bbls/d)	12,060	12,605	11,283	9,668	7,180	5,066
Conventional natural gas (mmcf/d)	141.13	151.38	148.35	129.37	97.89	84.29
Total (boe/d)	52,726	58,942	59,979	48,630	29,510	25,771
United States						
Light and medium crude oil (bbls/d)	2,581	3,046	2,514	1,069	662	393
Condensate ⁽¹⁾ (bbls/d)	2	5	18	8	4	—
Other NGLs ⁽¹⁾ (bbls/d)	1,065	1,218	996	452	50	29
NGLs (bbls/d)	1,067	1,223	1,014	460	54	29
Conventional natural gas (mmcf/d)	6.08	7.47	6.89	2.78	0.39	0.21
Total (boe/d)	4,660	5,514	4,675	1,992	781	457
France						
Light and medium crude oil (bbls/d)	8,916	8,903	10,435	11,362	11,084	11,896
Conventional natural gas (mmcf/d)	—	—	0.19	0.21	—	0.44
Total (boe/d)	8,916	8,903	10,467	11,396	11,085	11,970
Netherlands						
Light and medium crude oil (bbls/d)	4	1	3	—	—	—
Condensate ⁽¹⁾ (bbls/d)	97	88	88	90	90	88
NGLs (bbls/d)	97	88	88	90	90	88
Conventional natural gas (mmcf/d)	40.51	46.16	49.10	46.13	40.54	47.82
Total (boe/d)	6,853	7,782	8,274	7,779	6,847	8,058
Germany						
Light and medium crude oil (bbls/d)	1,016	968	917	1,004	1,060	—
Conventional natural gas (mmcf/d)	15.08	12.65	15.31	15.66	19.39	14.90
Total (boe/d)	3,529	3,076	3,468	3,614	4,291	2,483
Ireland						
Conventional natural gas (mmcf/d)	28.96	37.44	46.57	55.17	58.43	50.89
Total (boe/d)	4,826	6,240	7,762	9,195	9,737	8,482
Australia						
Light and medium crude oil (bbls/d)	4,170	4,416	5,662	4,494	5,770	6,304
Total (boe/d)	4,170	4,416	5,662	4,494	5,770	6,304
Central and Eastern Europe						
Conventional natural gas (mmcf/d)	0.37	1.90	0.42	1.02	—	—
Total (boe/d)	62	317	70	169	—	—
Consolidated						
Light and medium crude oil (bbls/d)	33,832	38,441	43,502	35,329	24,591	25,250
Condensate ⁽¹⁾ (bbls/d)	4,945	4,980	4,400	3,853	3,130	2,602
Other NGLs ⁽¹⁾ (bbls/d)	8,279	8,937	7,984	6,366	4,194	2,582
NGLs (bbls/d)	13,224	13,917	12,384	10,219	7,324	5,184
Conventional natural gas (mmcf/d)	232.12	256.99	266.82	250.33	216.64	198.55
Total (boe/d)	85,742	95,190	100,357	87,270	68,021	63,526

⁽¹⁾ Under National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities", disclosure of production volumes should include segmentation by product type as defined in the instrument. This table provides a reconciliation from "crude oil and condensate", "NGLs" and "natural gas" to the product types. In this report, references to "crude oil" and "light and medium crude oil" mean "light crude oil and medium crude oil" and references to "natural gas" mean "conventional natural gas". Production volumes reported are based on quantities as measured at the first point of sale.

Supplemental Table 5: Operational and Financial Data by Core Region

Production volumes ⁽¹⁾

	Q3/21	Q2/21	Q1/21	Q4/20	Q3/20	Q2/20	Q1/20	Q4/19	Q3/19	Q2/19	Q1/19	Q4/18
North America												
Crude oil and condensate (bbls/d)	24,757	24,316	24,645	26,459	28,296	31,569	29,888	30,560	30,403	31,329	30,905	31,163
NGLs (bbls/d)	8,068	8,695	8,074	8,628	9,508	9,588	8,022	8,161	7,772	8,106	7,897	7,814
Natural gas (mmcf/d)	145.18	152.06	144.36	142.13	163.09	172.43	157.88	153.34	151.52	158.93	157.26	152.30
Total (boe/d)	57,022	58,354	56,780	58,774	64,986	69,895	64,222	64,276	63,429	65,921	65,013	64,359
International												
Crude oil and condensate (bbls/d)	14,020	14,037	14,560	14,096	14,943	13,471	14,994	15,702	16,838	17,636	18,275	16,516
Natural gas (mmcf/d)	81.55	83.66	89.62	89.86	93.25	101.99	107.63	107.38	101.83	116.67	120.70	124.48
Total (boe/d)	27,612	27,981	29,495	29,073	30,484	30,472	32,932	33,598	33,811	37,081	38,391	37,262
Consolidated												
Crude oil and condensate (bbls/d)	38,777	38,354	39,204	40,555	43,240	45,041	44,881	46,261	47,242	48,964	49,182	47,678
NGLs (bbls/d)	8,068	8,695	8,074	8,627	9,509	9,588	8,022	8,160	7,772	8,107	7,897	7,815
Natural gas (mmcf/d)	226.73	235.72	233.98	232.00	256.34	274.42	265.51	260.72	253.36	275.60	277.96	276.77
Total (boe/d)	84,633	86,335	86,276	87,848	95,471	100,366	97,154	97,875	97,239	103,003	103,404	101,621

⁽¹⁾ Please refer to Supplemental Table 4 "Production" for disclosure by product type.

Sales volumes

	Q3/21	Q2/21	Q1/21	Q4/20	Q3/20	Q2/20	Q1/20	Q4/19	Q3/19	Q2/19	Q1/19	Q4/18
North America												
Crude oil and condensate (bbls/d)	24,757	24,316	24,645	26,459	28,297	31,569	29,888	30,560	30,404	31,327	30,906	31,162
NGLs (bbls/d)	8,068	8,695	8,074	8,628	9,508	9,588	8,022	8,161	7,772	8,106	7,897	7,814
Natural gas (mmcf/d)	145.18	152.06	144.36	142.13	163.09	172.43	157.88	153.34	151.52	158.93	157.26	152.30
Total (boe/d)	57,022	58,354	56,780	58,774	64,986	69,895	64,222	64,276	63,429	65,921	65,013	64,359
International												
Crude oil and condensate (bbls/d)	15,227	13,859	11,421	15,359	15,689	12,202	17,090	13,864	18,575	16,009	20,163	16,458
Natural gas (mmcf/d)	81.55	83.66	89.62	89.86	93.25	101.99	107.63	107.38	101.83	116.67	120.70	124.48
Total (boe/d)	28,820	27,802	26,357	30,336	31,229	29,201	35,028	31,760	35,547	35,454	40,279	37,204
Consolidated												
Crude oil and condensate (bbls/d)	39,985	38,174	36,066	41,818	43,985	43,771	46,977	44,423	48,979	47,337	51,068	47,620
NGLs (bbls/d)	8,068	8,695	8,074	8,627	9,509	9,588	8,022	8,160	7,772	8,107	7,897	7,815
Natural gas (mmcf/d)	226.73	235.72	233.98	232.00	256.34	274.42	265.51	260.72	253.36	275.60	277.96	276.77
Total (boe/d)	85,841	86,156	83,138	89,111	96,217	99,096	99,250	96,037	98,976	101,377	105,291	101,563

Financial results

	Q3/21	Q2/21	Q1/21	Q4/20	Q3/20	Q2/20	Q1/20	Q4/19	Q3/19	Q2/19	Q1/19	Q4/18
North America												
Crude oil and condensate sales (\$/bbl)	82.23	75.43	66.31	51.06	49.79	28.94	50.25	66.31	66.67	72.40	65.95	54.90
NGL sales (\$/bbl)	35.55	25.43	29.39	19.20	15.04	8.94	8.92	14.63	6.14	11.25	22.49	25.70
Natural gas sales (\$/mcf)	3.80	2.72	3.98	2.77	2.02	1.60	1.92	2.29	1.18	1.15	2.52	1.79
Sales (\$/boe)	50.40	42.30	43.08	32.51	28.94	18.24	29.22	38.86	35.52	38.56	40.17	33.94
Royalties (\$/boe)	(7.14)	(5.98)	(5.49)	(3.64)	(3.58)	(1.67)	(3.54)	(4.98)	(4.93)	(4.22)	(5.00)	(5.01)
Transportation (\$/boe)	(1.92)	(1.90)	(2.05)	(1.92)	(1.74)	(1.72)	(1.91)	(1.76)	(1.78)	(1.63)	(1.83)	(1.88)
Operating (\$/boe)	(11.02)	(10.89)	(11.21)	(10.94)	(7.82)	(9.60)	(11.93)	(11.15)	(10.67)	(10.66)	(11.46)	(10.96)
General and administration (\$/boe)	(1.14)	(0.91)	(1.34)	(1.94)	(0.78)	(1.52)	(0.84)	(0.97)	(0.60)	(1.04)	(0.83)	(0.28)
Corporate income taxes (\$/boe)	(0.05)	(0.04)	(0.04)	0.04	(0.02)	(0.02)	(0.04)	(0.11)	0.09	(0.02)	(0.03)	0.10
PRRT (\$/boe)	—	—	—	—	—	—	—	—	—	—	—	—
Fund flows netback (\$/boe)	29.12	22.58	22.94	14.12	14.99	3.72	10.96	19.89	17.63	20.99	21.03	15.91
Fund flows from operations	152,764	119,916	117,227	76,375	89,635	23,639	64,048	117,623	102,867	125,893	123,071	94,200
Capital expenditures	(35,179)	(38,847)	(59,113)	(33,781)	(9,575)	(23,979)	(197,926)	(69,775)	(91,027)	(42,047)	(148,091)	(93,092)
Free cash flow	117,585	81,069	58,114	42,594	80,060	(340)	(133,878)	47,848	11,840	83,846	(25,020)	1,108
International												
Crude oil and condensate sales (\$/bbl)	94.91	85.41	81.40	62.65	58.19	50.27	73.35	82.14	84.55	93.28	84.95	87.56
Natural gas sales (\$/mcf)	18.82	9.83	7.98	6.27	2.91	2.28	4.44	5.49	4.29	5.73	8.46	10.78
Sales (\$/boe)	103.39	72.16	62.39	50.30	37.94	28.98	49.42	54.42	56.46	60.98	67.87	74.80
Royalties (\$/boe)	(4.52)	(3.83)	(3.53)	(3.02)	(3.32)	(2.16)	(3.27)	(3.85)	(3.89)	(3.97)	(3.89)	(4.16)
Transportation (\$/boe)	(3.47)	(4.64)	(2.76)	(2.40)	(2.28)	(2.04)	(1.94)	(1.77)	(2.76)	(3.40)	(1.66)	(1.70)
Operating (\$/boe)	(17.55)	(16.56)	(16.42)	(16.99)	(15.18)	(14.35)	(16.13)	(15.28)	(13.13)	(11.76)	(15.28)	(13.89)
General and administration (\$/boe)	(2.40)	(2.61)	(2.06)	(2.92)	(2.53)	(2.72)	(2.63)	(3.70)	(3.10)	(2.93)	(2.27)	(3.27)
Corporate income taxes (\$/boe)	0.64	(0.19)	0.66	2.25	0.04	(0.02)	(0.11)	2.22	(1.55)	(3.63)	(4.30)	(2.49)
PRRT (\$/boe)	(2.74)	(0.58)	(0.60)	(1.45)	(1.27)	(1.21)	(2.90)	(0.50)	(1.78)	(2.56)	(2.87)	0.71
Fund flows netback (\$/boe)	73.36	43.74	37.69	25.77	13.40	6.47	22.44	31.54	30.26	32.73	37.60	49.99
Fund flows from operations	194,505	110,654	89,403	71,934	38,498	17,193	71,526	92,160	98,955	105,600	136,298	171,119
Capital expenditures	(31,271)	(40,329)	(24,250)	(26,113)	(21,755)	(18,295)	(35,778)	(30,850)	(36,852)	(50,560)	(53,962)	(70,488)
Free cash flow	163,234	70,325	65,153	45,821	16,743	(1,102)	35,748	61,310	62,103	55,040	82,336	100,631
Consolidated												
Crude oil and condensate sales (\$/bbl)	87.05	79.06	71.09	55.31	52.79	34.89	58.66	71.25	73.45	79.46	73.45	66.19
NGL sales (\$/bbl)	35.55	25.43	29.39	19.20	15.04	8.94	8.92	14.63	6.14	11.25	22.49	25.69
Natural gas sales (\$/mcf)	9.20	5.24	5.51	4.13	2.34	1.85	2.94	3.61	2.43	3.09	5.10	5.83
Sales (\$/boe)	68.19	51.93	49.20	38.57	31.86	21.40	36.35	44.01	43.04	46.40	50.77	48.90
Royalties (\$/boe)	(6.26)	(5.29)	(4.87)	(3.43)	(3.50)	(1.81)	(3.45)	(4.60)	(4.56)	(4.13)	(4.58)	(4.70)
Transportation (\$/boe)	(2.44)	(2.78)	(2.27)	(2.08)	(1.92)	(1.81)	(1.92)	(1.76)	(2.13)	(2.25)	(1.76)	(1.81)
Operating (\$/boe)	(13.21)	(12.72)	(12.86)	(13.00)	(10.21)	(11.00)	(13.41)	(12.52)	(11.55)	(11.04)	(12.92)	(12.04)
General and administration (\$/boe)	(1.56)	(1.46)	(1.57)	(2.27)	(1.35)	(1.88)	(1.47)	(1.88)	(1.50)	(1.70)	(1.38)	(1.37)
Corporate income taxes (\$/boe)	0.18	(0.09)	0.18	0.80	—	(0.02)	(0.06)	0.66	(0.50)	(1.28)	(1.66)	(0.85)
PRRT (\$/boe)	(0.92)	(0.19)	(0.19)	(0.49)	(0.41)	(0.36)	(1.02)	(0.16)	(0.64)	(0.90)	(1.10)	0.26
Interest (\$/boe)	(2.37)	(2.41)	(2.57)	(2.42)	(1.97)	(1.98)	(2.21)	(2.17)	(2.16)	(2.34)	(2.21)	(2.23)
Realized derivatives (\$/boe)	(9.19)	(5.05)	(3.43)	0.10	0.47	6.07	5.47	2.57	4.06	1.54	1.09	(3.03)
Realized foreign exchange (\$/boe)	0.37	(0.25)	(0.69)	0.16	(0.31)	0.44	0.94	0.23	(0.37)	(0.17)	(0.22)	0.63
Realized other (\$/boe)	0.48	0.35	0.73	0.56	0.29	0.03	(0.37)	0.03	0.04	0.02	0.73	0.03
Fund flows netback (\$/boe)	33.26	22.06	21.66	16.49	12.97	9.08	18.85	24.40	23.74	24.14	26.76	23.80
Fund flows from operations	262,696	172,942	162,051	135,212	114,776	81,852	170,225	215,592	216,153	222,738	253,572	222,342
Capital expenditures	(66,450)	(79,176)	(83,363)	(59,894)	(31,330)	(42,274)	(233,704)	(100,625)	(127,879)	(92,607)	(202,053)	(163,580)
Free cash flow	196,246	93,766	78,688	75,318	83,446	39,578	(63,479)	114,967	88,274	130,131	51,519	58,762

Non-GAAP Financial Measures

This MD&A includes references to certain financial measures which do not have standardized meanings and may not be comparable to similar measures presented by other issuers. These financial measures include fund flows from operations, a measure of profit or loss in accordance with IFRS 8 "Operating Segments" (please see Segmented Information in the Notes to the Condensed Consolidated Interim Financial Statements) and net debt, a measure of capital in accordance with IAS 1 "Presentation of Financial Statements" (please see Capital Disclosures in the Notes to the Condensed Consolidated Interim Financial Statements).

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

Acquisitions: The sum of acquisitions from the Consolidated Statements of Cash Flows, Vermilion common shares issued as consideration, the estimated value of contingent consideration, the amount of acquiree's outstanding long-term debt assumed plus or net of acquired working capital deficit or surplus. We believe that including these components provides a useful measure of the economic investment associated with our acquisition activity.

Capital expenditures: The sum of drilling and development and exploration and evaluation from the Consolidated Statements 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 equity based compensation plans 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 **payout or sustainability ratio**) to assess the amount of cash distributed back to shareholders and re-invested in the business for maintaining production and organic growth.

Return on capital employed (ROCE): ROCE is a measure that we use to analyze our profitability and the efficiency of our capital allocation process. ROCE is calculated by dividing net earnings before interest and taxes ("EBIT") by average capital employed over the preceding twelve months. Capital employed is calculated as total assets less current liabilities while average capital employed is calculated using the balance sheets at the beginning and end of the twelve-month period.

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)	Q3 2021	Q3 2020	YTD 2021	YTD 2020
Dividends declared	—	—	—	90,067
Shares issued for the Dividend Reinvestment Plan	—	—	—	(8,277)
Net dividends	—	—	—	81,790
Drilling and development	63,173	29,762	220,388	299,578
Exploration and evaluation	3,277	1,568	8,601	7,730
Asset retirement obligations settled	5,142	2,305	15,486	7,007
Payout	71,592	33,635	244,475	396,105
% of fund flows from operations	27 %	29 %	41 %	108 %

('000s of shares)	Q3 2021	Q3 2020
Shares outstanding	161,985	158,308
Potential shares issuable pursuant to the VIP	7,027	5,492
Diluted shares outstanding	169,012	163,800

The following table reconciles the calculation of return on capital employed:

(\$M)	Twelve Months Ended	
	Sep 30, 2021	Sep 30, 2020
Net earnings (loss)	746,401	(1,458,243)
Taxes	186,099	(348,533)
Interest expense	76,604	74,438
EBIT	1,009,104	(1,732,338)
Average capital employed	4,324,592	4,679,796
Return on capital employed	23 %	(37)%

DIRECTORS

Lorenzo Donadeo ¹
Calgary, Alberta

Larry J. Macdonald ^{2, 4, 8, 10}
Calgary, Alberta

James J. Kleckner Jr. ^{8, 10}
Edwards, Colorado

Carin Knickel ^{5, 8, 12}
Golden, Colorado

Stephen P. Larke ^{4, 6, 12}
Calgary, Alberta

Timothy R. Marchant ^{7, 10, 11}
Calgary, Alberta

Robert Michaleski ^{3, 6}
Calgary, Alberta

William Roby ^{8, 9, 12}
Katy, Texas

Manjit Sharma ^{4, 8}
Toronto, Ontario

Judy Steele ^{6, 12}
Halifax, Nova Scotia

¹ Executive Chairman

² Lead Director (Independent)

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

¹¹ Sustainability Committee Chair (Independent)

¹² Sustainability Committee Member

OFFICERS / CORPORATE SECRETARY

Lorenzo Donadeo ^{*}
Executive Chairman

Curtis Hicks ^{*}
President (to December 31, 2021)

Dion Hatcher ^{*}
Vice President North America / President (effective January 1, 2022)

Lars Glemser ^{*}
Vice President & Chief Financial Officer

Terry Hergott
Vice President Marketing

Yvonne Jeffery
Vice President Sustainability

Darcy Kerwin ^{*}
Vice President International & HSE

Bryce Kremnica ^{*}
Vice President North America

Geoff MacDonald
Vice President Geosciences

Kyle Preston
Vice President Investor Relations

Averyl Schraven
Vice President People and Culture

Jenson Tan ^{*}
Vice President Business Development

Gerard Schut ^{*}
Vice President European Operations

Robert (Bob) J. Engbloom
Corporate Secretary

^{*} Executive Committee

AUDITORS

Deloitte LLP
Calgary, Alberta

BANKERS

The Toronto-Dominion Bank

Bank of Montreal

Canadian Imperial Bank of Commerce

Export Development Canada

National Bank of Canada

Royal Bank of Canada

The Bank of Nova Scotia

Wells Fargo Bank N.A., Canadian Branch

Bank of America N.A., Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

JPMorgan Chase Bank, N.A., Toronto Branch

La Caisse Centrale Desjardins du Québec

Alberta Treasury Branches

Canadian Western Bank

Goldman Sachs Lending Partners LLC

EVALUATION ENGINEERS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL

Norton Rose Fulbright Canada LLP
Calgary, Alberta

TRANSFER AGENT

Odyssey Trust Company

STOCK EXCHANGE LISTINGS

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

INVESTOR RELATIONS

Kyle Preston
Vice President Investor Relations
403-476-8431 TEL
403-476-8100 FAX
1-866-895-8101 IR TOLL FREE
investor_relations@vermilionenergy.com