

Q1 2026

# MANAGEMENT'S DISCUSSION AND ANALYSIS

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VERMILION  
ENERGY



# Disclaimer

Certain statements included or incorporated by reference in this document may constitute forward-looking statements or information under applicable securities legislation. Such forward-looking statements or information typically contain statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", 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, including Vermilion's 2026 guidance and outlook, and Vermilion's ability to fund such expenditures; the flexibility of Vermilion's capital program and operations; business strategies and objectives; operational and financial performance; wells expected to be drilled and the timing thereof; exploration and development plans and the timing thereof; future drilling prospects; the ability of our asset base to deliver modest production growth; the evaluation of international acquisition opportunities; statements regarding the return of capital; our asset petroleum and natural gas sales; future production levels and the timing thereof, including Vermilion's 2026 guidance, and rates of average annual production growth; the effect of changes in crude oil and natural gas prices, changes in exchange and inflation rates; the payment and amount of future dividends, including management's intention to increase the Company's dividend and the timing thereof; the effect of possible changes in critical accounting estimates; the Company's review of the impact of potential changes to financial reporting standards; the potential financial impact of climate-related risks; Vermilion's goals regarding its debt levels, including maintenance of a ratio of net debt to four quarter trailing fund flows from operations; statements regarding Vermilion's hedging program and the stability of our cash flows; operating and other expenses; royalty and income tax rates and Vermilion's expectations regarding future taxes and taxability and the timing of regulatory proceedings and approvals; and timing of the divestitures of certain of the Company's operations and the use of such sale proceeds.

Such forward-looking statements or information are based on a number of current expectations and assumptions, all or any of which may prove to be incorrect. In addition to any other assumptions identified in this document, assumptions that have been made include, but are not limited to: 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; management's expectations relating to the timing and results of exploration and development activities; the impact of Vermilion's dividend policy on its future cash flows; credit ratings; hedging program; expected earnings/(loss) and adjusted earnings/(loss); expected earnings/(loss) or adjusted earnings/(loss) per share; expected future cash flows and free cash flow and expected future cash flow and free cash flow per share; estimated future dividends; financial strength and flexibility; debt and equity market conditions; general economic and competitive conditions; ability of management to execute key priorities; and the effectiveness of various actions resulting from the Vermilion's strategic priorities.

Although Vermilion believes that the expectations reflected in such forward-looking statements or information are reasonable as of the date hereof, 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, interest rates and inflation; 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 or involving Vermilion; and other risks and uncertainties described elsewhere in this document or in Vermilion's other filings with Canadian securities regulatory authorities. In particular, please also see Vermilion's MD&A and Annual Information Form, each for the year ended December 31, 2025, available on SEDAR+ at [www.sedarplus.ca](http://www.sedarplus.ca) or on Vermilion's website at [www.vermilionenergy.com](http://www.vermilionenergy.com). References to Vermilion or the Company in this document include Westbrick Energy Ltd. ("Westbrick" or "Westbrick Energy") which was acquired by Vermilion Energy Inc. on February 26, 2025.

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 may disclose certain oil and gas metrics, including capital spent to drill, complete, equip and tie-in a well ("DCET costs"), which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included in this MD&A to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the Company's future performance and future performance may not compare to the Company's performance in previous periods and therefore such metrics should not be unduly relied upon. Additional oil and gas metrics in this document may include, but are not limited to:

**Boe Equivalency:** Per barrel of oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil equivalent (6:1). Barrel of oil equivalents (boe) may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, as the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

**Estimates of Drilling Locations:** Unbooked drilling locations are the internal estimates of Vermilion based on Vermilion's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by Vermilion's management as an estimation of Vermilion's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that Vermilion will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and natural gas reserves, resources or production. The drilling locations on which Vermilion will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While a certain number of the unbooked drilling locations have been de-risked by Vermilion drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management of Vermilion has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

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)
bbl(s)/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
CO <sub>2</sub>	carbon dioxide
CO <sub>2</sub> e	carbon dioxide equivalent
GHG	greenhouse gas
GJ	gigajoules
mbbl(s)	thousand barrel(s)
mmboe	thousand barrels of oil equivalent
MMBtu	million British Thermal Units
mcf	thousand cubic feet
mmcf/d	million cubic feet per day
MD	measured depth
NBP	the reference price paid for natural gas in the United Kingdom at the National Balancing Point Virtual Trading Point
NCIB	normal course issuer bid
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
psi	pounds per square inch
tCO <sub>2</sub> e	tonne of carbon dioxide equivalent
Tcf	trillion cubic feet
THE	the price for natural gas in Germany, quoted in megawatt hours of natural gas, at the Trading Hub Europe
TTF	the price for natural gas in the Netherlands, quoted in megawatt hours of natural gas, at the Title Transfer Facility Virtual Trading Point
US	the United States of America
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 May 5, 2026, of Vermilion Energy Inc.'s ("Vermilion", "we", "our", "us" or the "Company") operating and financial results as at and for the three months ended March 31, 2026 compared with the corresponding period in the prior year.

This discussion should be read in conjunction with the unaudited condensed consolidated interim financial statements for the three months ended March 31, 2026, and the audited consolidated financial statements for the years ended December 31, 2025 and 2024, together with the accompanying notes. Additional information relating to Vermilion, including its Annual Information Form, is available on SEDAR+ at [www.sedarplus.ca](http://www.sedarplus.ca) or on Vermilion's website at [www.vermilionenergy.com](http://www.vermilionenergy.com).

The unaudited condensed consolidated interim financial statements for the three months ended March 31, 2026, 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").

The operating results attributable to the Company's Saskatchewan, United States and block SA-07 in Croatia operations have been classified and presented as discontinued operations, with all other operating results presented as continuing operations. The prior period results have been presented to conform with current period presentation. See Note 3 "Discontinued operations" of the condensed consolidated interim financial statements for the three months ended March 31, 2026, for additional information.

This MD&A includes references to certain financial measures which are not specified, defined, or determined under IFRS® Accounting Standards as issued by the IASB ("IFRS Accounting Standards") and are therefore considered non-GAAP and other specified financial measures. These financial measures are unlikely to be comparable to similar financial measures presented by other issuers. For a full description of these non-GAAP and other specified financial measures and a reconciliation of these measures to their most directly comparable GAAP measures, please refer to "Non-GAAP and Other Specified 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", "tight oil" and "heavy oil" and references to "natural gas" mean "conventional natural gas", "shale gas" and "coal bed methane".

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 November 5, 2025, the Company released the 2026 capital budget and associated production guidance. The Company's guidance for 2026 is as follows:

Category	2026 Current <sup>(1)</sup>
Production (boe/d)	118,000 - 122,000
E&D capital expenditures (\$MM)	\$600 - 630
Operating (\$/boe)	\$12.25 - 13.25
General and administration (\$/boe) <sup>(2)</sup>	\$1.65 - 2.15
Transportation (\$/boe)	\$3.00 - 3.50
Royalty rate (% of sales)	7 - 9 %
Cash taxes (% of pre-tax FFO)	2 - 6 %
Asset retirement obligations settled (\$MM)	\$55
Payments on lease obligations (\$MM)	\$10

<sup>(1)</sup> Current 2026 guidance reflects foreign exchange assumptions of CAD/USD 1.38, CAD/EUR 1.63, and CAD/AUD 0.91.

<sup>(2)</sup> General and administration expense exclusive of expected cash-settled equity based compensation of \$0.15 - 0.20/boe.

## Consolidated Results Overview

	Q1 2026	Q1 2025	Q1/26 vs. Q1/25
<b>Production <sup>(1)</sup></b>			
Crude oil and condensate (bbls/d)	23,692	32,386	(27)%
NGLs (bbls/d)	12,044	9,167	31%
Natural gas (mmcf/d)	539.29	369.36	46%
<b>Total (boe/d)</b>	<b>125,618</b>	<b>103,115</b>	<b>22%</b>
(Draw) build in inventory (mbbls)	(112)	62	
<b>Financial metrics</b>			
Fund flows from continuing operations (\$M) <sup>(2)</sup>	232,429	210,942	10%
Fund flows from discontinued operations (\$M) <sup>(2)</sup>	(152)	45,087	N/A
Fund flows from operations (\$M) <sup>(2)</sup>	232,277	256,029	(9)%
Fund flows from operations per share	1.52	1.66	(8)%
Net (loss) earnings from continuing operations	(141,206)	3,849	N/A
Net (loss) earnings from discontinued operations	(4,332)	11,104	N/A
Net (loss) earnings (\$M)	(145,538)	14,953	N/A
Net (loss) earnings per share - continuing operations	(0.92)	0.03	N/A
Net (loss) earnings per share - discontinued operations	(0.03)	0.07	N/A
Net loss per share	(0.95)	0.10	N/A
Cash flows from operating activities (\$M)	227,398	280,384	(19)%
Free cash flow (\$M) <sup>(3)</sup>	97,697	73,910	32%
Long-term debt (\$M)	1,254,333	1,874,033	(33)%
Net debt (\$M) <sup>(4)</sup>	1,292,567	2,062,805	(37)%
Cash dividends (\$/share)	0.135	0.130	4%
<b>Activity</b>			
Capital expenditures (\$M) <sup>(5)</sup>	134,580	182,119	(26)%
Acquisitions (\$M) <sup>(6)</sup>	6,035	1,120,998	(100)%

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

<sup>(2)</sup> Fund flows from operations (FFO) and FFO per share are a total of segments measure and supplementary financial measure most directly comparable to net (loss) earnings and net (loss) earnings per share, respectively. The measures do not have a standardized meaning under IFRS Accounting Standards and therefore may not be comparable to similar measures presented by other issuers. FFO is comprised of sales less royalties, transportation, operating, general and administrative (G&A), corporate income tax, PRRT, interest expense, equity based compensation settled in cash, realized gain (loss) on derivatives, plus realized gain (loss) on foreign exchange and realized other income (expense). The measure is used to assess the contribution of each business unit to Vermilion's ability to generate income necessary to pay dividends, repay debt, fund asset retirement obligations and make capital investments. A reconciliation to the primary financial statement measures can be found within the "Non-GAAP and Other Specified Financial Measures" section of this MD&A. Fund flows from continuing operations and fund flows from discontinued operations are calculated in the same manner as FFO and are most directly comparable to net earnings (loss) from continuing operations and net earnings (loss) discontinued operations, respectively.

<sup>(3)</sup> Free cash flow (FCF) is a non-GAAP financial measure most directly comparable to cash flows from operating activities; it does not have a standardized meaning under IFRS Accounting Standards and therefore may not be comparable to similar measures presented by other issuers. FCF is comprised of fund flows from operations less drilling and development costs and exploration and evaluation costs. FCF is used to determine the funding available for investing and financing activities including payment of dividends, repayment of long-term debt, reallocation into existing business units and deployment into new ventures. A reconciliation to primary financial statement measures can be found within the "Non-GAAP and Other Specified Financial Measures" section of this MD&A.

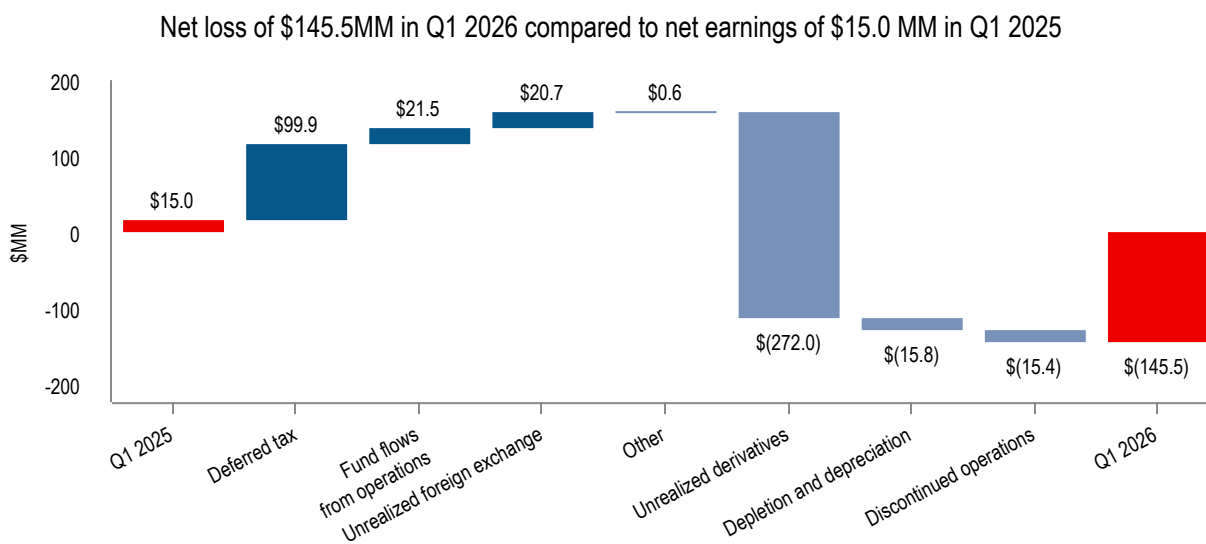
<sup>(4)</sup> Net debt is a capital management measure in accordance with IAS 1 "Presentation of Financial Statements" and is most directly comparable to long-term debt. Net debt is comprised of long-term debt (excluding unrealized foreign exchange on swapped USD borrowings) plus adjusted working capital (defined as current assets less current liabilities, excluding current derivatives, current asset retirement obligations 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. A reconciliation to the primary financial statement measures can be found within the "Financial Position Review" section of this MD&A.

<sup>(5)</sup> Capital expenditures is a non-GAAP financial measure that does not have a standardized meaning under IFRS Accounting Standards and therefore may not be comparable to similar measures presented by other issuers. The measure is calculated as the sum of drilling and development costs and exploration and evaluation costs 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. A reconciliation to the primary financial statement measures can be found within the "Non-GAAP and Other Specified Financial Measures" section of this MD&A.

<sup>(6)</sup> Acquisitions is a non-GAAP financial measure that does not have a standardized meaning under IFRS Accounting Standards and therefore may not be comparable to similar measures presented by other issuers. The measure is calculated as the sum of acquisitions, net of cash and acquisitions of securities 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, and net 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. A reconciliation to the acquisitions line item in the Consolidated Statements of Cash Flows can be found in "Supplemental Table 3: Capital Expenditures and Acquisitions" section of this MD&A.

## Financial performance review

Q1 2026 vs. Q1 2025

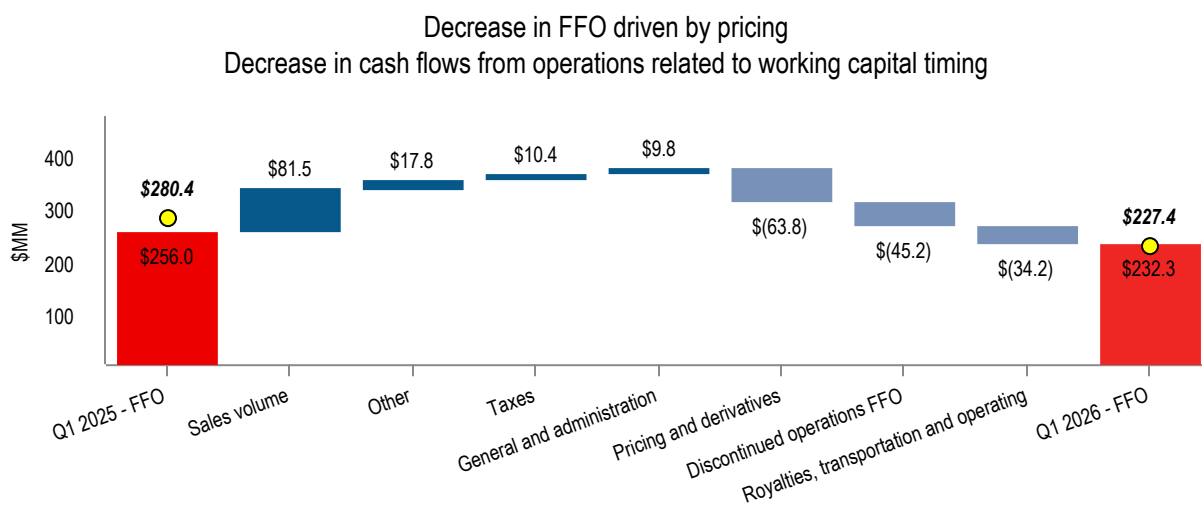


"Other" contains equity based compensation, accretion, and unrealized other.

"Discontinued operations" contains net loss from the United States, Saskatchewan, and SA-07 block disposal groups.

All other items presented above are attributable to continuing operations.

- We recorded a net loss of \$145.5 million (\$0.95/basic share) for Q1 2026 compared to net earnings of \$15.0 million (\$0.10/basic share) in Q1 2025. The change was primarily due to unfavourable changes in our non-cash mark-to-market unrealized derivative position driven by European gas and crude oil contracts, partially offset by deferred tax recovery on mark-to-market losses coupled with increased tax asset valuation in Canada and Ireland on forward pricing and higher fund flows from continuing operations attributable to increased production on acquisition and drilling activities.



"Sales volume" is the sum of sales volume variance from continuing operations.

"Pricing, net of derivatives" is the sum of pricing variance received on sales volumes from continuing operations, net of realized derivatives.

"Other" contains interest, realized FX and other realized expense.

"Discontinued operations" contains fund flows from the United States, Saskatchewan, and SA-07 block operations.

All other items reconciling FFO are attributable to continuing operations.

● Cash flows from operating activities

- Cash flows from operating activities decreased to \$227.4 million in Q1 2026 compared to \$280.4 million in Q1 2025, while fund flows from operations decreased to \$232.3 million from \$256.0 million over the same period. The decrease in FFO was primarily due to a \$15.9 million loss on derivative contracts versus a gain of \$11.1 million in 2025 and lower North American gas pricing, partially offset by higher sales volumes, net of operating costs, driven by new production in the Deep Basin and Montney and lower general and administration expenses. Variances between cash flows from operating activities and fund flows from operations are primarily driven by working capital timing differences.

## Production review

### Q1 2026 vs. Q1 2025

- Consolidated average production increased 22% to 125,618 boe/d in Q1 2026 compared to Q1 2025 production of 103,115 boe/d primarily due to higher production from assets acquired in February 2025 and new wells brought on production in the Deep Basin and Montney. The increase was partially offset by the United States and Saskatchewan dispositions, cyclone-related downtime in Australia and natural well decline across International business units.

## Activity review

For the three months ended March 31, 2026, capital expenditures were \$134.6 million.

- In Canada, we invested capital expenditures of \$113.9 million in our liquids-rich gas assets:
  - In the Deep Basin, we drilled ten (9.3 net), completed fourteen (13.8 net), and brought on production eighteen (18.0 net) liquids-rich conventional natural gas wells.
  - In the Montney, we drilled five (5.0 net), completed six (6.0 net), and brought on production six (6.0 net) liquids-rich shale gas wells.
- Internationally, capital expenditures of \$20.7 million were invested:
  - In Germany, we invested \$3.3 million, primarily on subsurface maintenance and facilities activities, including progressing infrastructure to facilitate production from the Wisselshorst well, which is expected to be brought online by mid-2026.
  - In the Netherlands, we invested \$2.7 million, primarily on facilities and maintenance capital.
  - In France, we invested \$7.0 million, primarily on subsurface maintenance.
  - In Australia, \$5.6 million was invested primarily on facilities activities, as we worked to resume operations following cyclone-related downtime.
  - In Ireland, \$2.0 million was invested on facilities activities.

## Financial sustainability review

### Free cash flow

- Free cash flow increased by \$23.8 million to \$97.7 million for the three months ended March 31, 2026 compared to the prior year primarily driven by increased funds flow from continuing operations and lower capital expenditures, partially offset by lower funds flow from discontinued operations.

### Long-term debt and net debt

- As at March 31, 2026, long-term debt increased to \$1.3 billion (December 31, 2025 - \$1.2 billion) primarily due to the foreign exchange impact of the US dollar strengthening against the Canadian dollar on our US denominated senior unsecured notes, partially offset by the repayment of long-term debt from excess cash flows generated during the quarter.
- As at March 31, 2026, net debt totaled \$1.3 billion, a decrease from December 31, 2025 of approximately \$50 million. The decrease was primarily due to funds from continuing operations and the inclusion of expected proceeds from the dispositions of assets held for sale. The decrease was partially offset by capital expenditures, asset retirement obligations settled during the quarter and the US dollar strengthening by 2% against the Canadian dollar on our US denominated notes.
- The ratio of net debt to four quarter trailing fund flows from operations<sup>(1)</sup> remained at 1.4 as at March 31, 2026 (December 31, 2025 - 1.4) due to slightly lower four quarter trailing funds from continuing operations, mainly impacted by pricing, partially offset by lower net debt.

<sup>(1)</sup> Net debt to four quarter trailing fund flows from operations is a supplementary financial measure that does not have a standardized meaning under IFRS Accounting Standards and therefore may not be comparable to similar measures presented by other issuers. It is calculated as net debt (capital measure) over the FFO from the preceding four quarters (total of segments measure). The measure is used to assess our ability to repay debt. Subsequent to February 26, 2025, net debt to four quarter trailing fund flows from operations is calculated inclusive of Westbrick Energy's pre-acquisition four quarter trailing fund flows from operations, as if the acquisition of Westbrick Energy occurred at the beginning of the four quarter trailing period, and exclusive of the four quarter trailing fund flows from discontinued operations to reflect the Company's ability to repay debt on a pro forma basis.

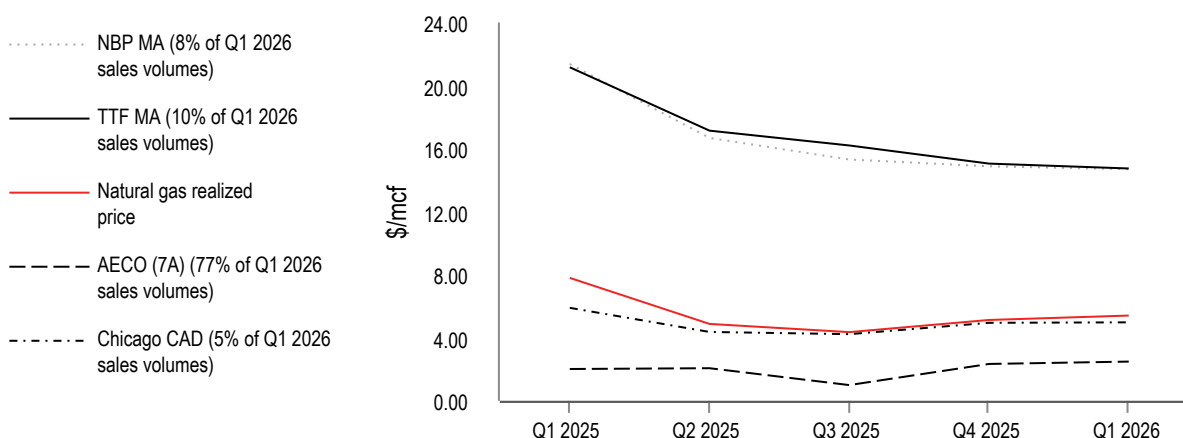
## Benchmark Commodity Prices

	Q1 2026	Q1 2025	Q1/26 vs. Q1/25
<b>Natural gas</b>			
<b>North America</b>			
AECO 7A (CAD/Mcf)	2.49	2.02	23%
Henry Hub (USD/Mcf)	5.04	3.65	38%
Chicago (USD/Mcf)	3.63	4.11	(12)%
<b>Europe <sup>(1)</sup></b>			
TTF MA (CAD/MMBtu)	14.74	21.16	(30)%
TTF MA (EUR/MMBtu)	9.18	14.00	(34)%
NBP MA (CAD/MMBtu)	14.69	21.37	(31)%
NBP MA (EUR/MMBtu)	9.15	14.14	(35)%
THE MA (CAD/MMBtu)	15.60	21.55	(28)%
THE MA (EUR/MMBtu)	9.72	14.26	(32)%
<b>Crude oil</b>			
Dated Brent (USD/bbl)	80.61	75.66	7%
WTI (USD/bbl)	71.93	71.42	1%
Edmonton Sweet index (CAD/bbl)	93.48	95.35	(2)%
Canadian C5+ Condensate index (CAD/bbl)	97.93	100.31	(2)%
<b>Average exchange rates</b>			
CAD/USD	1.37	1.44	(5)%
CAD/EUR	1.61	1.51	7%
<b>Realized prices</b>			
Crude oil and condensate (\$/bbl)	100.61	99.36	1%
NGLs (\$/bbl)	23.00	31.56	(27)%
Natural gas (\$/mcf)	5.41	7.80	(31)%
<b>Total (\$/boe)</b>	<b>44.96</b>	<b>61.71</b>	<b>(27)%</b>

<sup>(1)</sup> Natural gas in the Netherlands and Germany is benchmarked to the TTF and THE and production is generally equally split between day ahead ("DA") and month ahead ("MA") contracts. Natural gas in Ireland is benchmarked to the NBP and is sold on DA contracts.

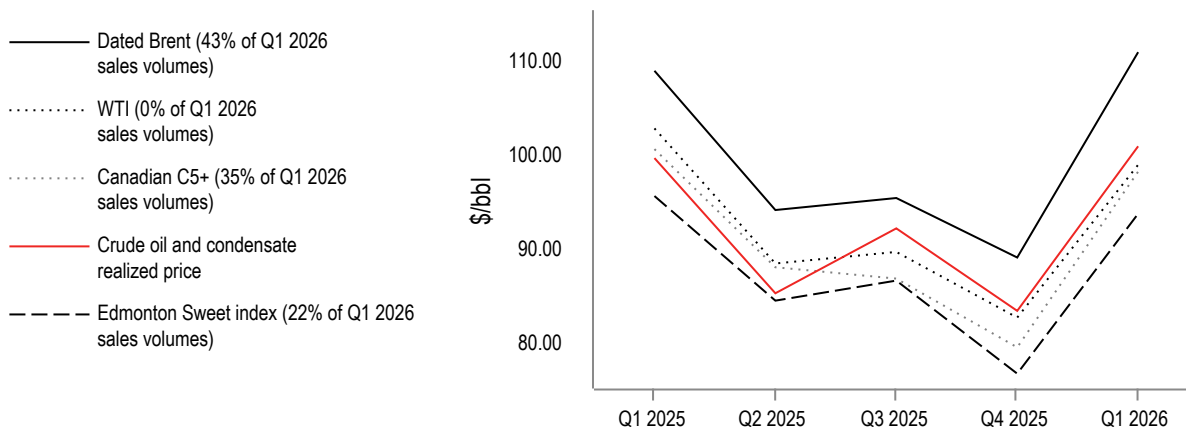
As an internationally diversified producer, we are exposed to a range of commodity prices. In Canada, our crude oil is sold at benchmarks linked to WTI (including the Edmonton Sweet index and the Canadian C5+ index) and our natural gas is sold at benchmarks linked to the AECO index (in Canada) and a combination of Chicago Daily and Henry Hub ("HH") indices (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 TTF, NBP, THE, or indices highly correlated to TTF.

Q1 2026 realized natural gas price was a \$2.92/mcf premium to AECO 7A



- In Canadian dollar terms, year-over-year, prices for European natural gas at NBP and TTF decreased by 31% and 30% respectively on a month ahead basis. Prices over the first two months of 2026 were depressed in response to weaker demand outlooks from Asia and growing LNG flows from the United States. However, March 2026 started to heavily price in LNG outages from Qatar and seasonally low storage across Europe entering Summer 2026.
- Year-over-year, natural gas prices in Canadian dollar terms at NYMEX HH increased by 32% and AECO 7A increased by 23%. AECO prices increased in Q1 2026 due to strong winter storage withdrawals, pulls to satisfy strong demand in Eastern Canada and the US Midwest. LNG growth and Winter Storm Fern across Canada and the US also helped support demand to start 2026.
- For Q1 2026, average European natural gas prices represented a \$12.23/mcf premium to AECO 7A. Approximately 18% of our natural gas production in Q1 2026 benefited from this premium European pricing (Q1 2025 - 28%). The decrease in our realized natural gas price from the prior period is primarily due to increased North American natural gas exposure via the Westbrick acquisition in Q1 2025.

Q1 2026 realized crude oil and condensate price was a \$7.13/bbl premium to Edmonton Sweet Index



- Crude oil prices increased in Q1 2026 relative to Q1 2025 primarily due to the turmoil in the Middle East sparking a late rally across March 2026 on Strait of Hormuz closures and record production shut-ins. Across the quarterly average, USD WTI increased by 1% and Dated Brent increased by 7% in Q1 2026 relative to Q1 2025.
- In Canadian dollar terms, year-over-year, the Edmonton Sweet differential tightened by \$1.98/bbl to a discount of \$5.17/bbl against WTI. This is due to decreased supply in Western Canadian storage as well as strong flows towards the US markets and the Canadian West coast. MSW differentials were also supported heading into peak driving season.
- Approximately 43% of Vermilion's Q1 2026 crude oil and condensate production was priced at the Dated Brent index, which averaged a premium to WTI of US\$8.68/bbl; in Australia sales were executed at an \$3.70/bbl premium to Dated Brent index in February 2026, prior to the late quarter increase in Dated Brent. The remainder of our crude oil and condensate production was priced at the Canadian C5+, Edmonton Sweet, and WTI indices.

## Canada

The continuing operations in Canada consist of our Deep Basin and Mica Montney Canadian assets. The comparative period includes the operating results for non-core assets in Saskatchewan and the United States disposed of in 2025, presented as discontinued operations throughout this MD&A in accordance with IFRS 5 "Non-current Assets Held for Sale and Discontinued Operations". Please refer to Note 3 "Discontinued operations" of the consolidated interim financial statements for the three months ended March 31, 2026 for additional information.

	Q1 2026	Q1 2025
<b>Production <sup>(1)</sup></b>		
Crude oil and condensate (bbls/d)	14,300	9,904
NGLs (bbls/d)	12,044	7,695
Natural gas (mmcf/d)	440.41	249.02
<b>Production from continuing operations (boe/d)</b>	<b>99,746</b>	<b>59,104</b>
Production from discontinued operations (boe/d)	—	14,656
<b>Total production volume (boe/d)</b>	<b>99,746</b>	<b>73,760</b>

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

## Fund Flows from Operations

### Continuing Operations

	Q1 2026		Q1 2025	
	\$M	\$/boe	\$M	\$/boe
Sales	263,907	29.40	166,264	31.26
Royalties	(20,014)	(2.23)	(18,657)	(3.51)
Transportation	(21,700)	(2.42)	(16,295)	(3.06)
Operating	(58,802)	(6.55)	(42,941)	(8.07)
General and administration <sup>(1)</sup>	(7,437)	(0.83)	(17,688)	(3.33)
Corporate income tax recovery (expense) <sup>(1)</sup>	(1,941)	(0.22)	(435)	(0.08)
<b>Fund flows from continuing operations</b>	<b>154,013</b>	<b>17.15</b>	<b>70,248</b>	<b>13.21</b>
Drilling and development	(113,897)		(121,851)	
<b>Free cash flow from continuing operations</b>	<b>40,116</b>		<b>(51,603)</b>	

<sup>(1)</sup> General and administration and corporate income tax include amounts from our Corporate segment. General and administration expenses previously presented within the Corporate segment have been reclassified to our Canadian segment and the prior period results have been presented to conform with current period presentation. The decrease in general and administration was primarily due to non-recurring acquisition costs in 2025. Corporate income tax expense primarily relates to income taxes on Corporate segment activities.

### Discontinued Operations

	Q1 2026		Q1 2025	
	\$M	\$/boe	\$M	\$/boe
Sales	—	—	100,153	75.93
Royalties	—	—	(19,199)	(14.56)
Transportation	—	—	(2,945)	(2.23)
Operating	—	—	(27,879)	(21.14)
General and administration	—	—	(4,872)	(3.69)
<b>Fund flows from discontinued operations</b>	<b>—</b>	<b>—</b>	<b>45,258</b>	<b>34.31</b>
Drilling and development	—		(8,959)	
<b>Free cash flow from discontinued operations</b>	<b>—</b>		<b>36,299</b>	

Production in Canada averaged 99,746 boe/d, representing a 10% increase from the prior quarter. The increase was primarily due to continued strong performance from our Deep Basin drilling program and production from new wells in the Montney brought online in the quarter.

In Q1 2026, the Company maintained a three-rig drilling program in the Deep Basin, drilling ten (9.3 net), completing fourteen (13.8 net), and bringing on production eighteen (18.0 net) liquids-rich gas wells. In the Montney, Vermilion drilled five (5.0 net), completed six (6.0 net), and brought on production six (6.0 net) liquids-rich shale gas wells.

## Sales

	Q1 2026		Q1 2025	
	\$M	\$/boe	\$M	\$/boe
Canada	263,907	29.40	166,264	31.26
Discontinued operations:				
Canada	—	—	74,135	77.59
United States	—	—	26,018	71.57
Total discontinued operations	—	—	100,153	75.93
<b>Total</b>	<b>263,907</b>	<b>29.40</b>	<b>266,417</b>	<b>40.13</b>

Sales in Canada continuing operations decreased 6% on a per boe basis for the three months ended March 31, 2026, compared to the same period in 2025 primarily due to change in product mix on the acquisition and disposition activity, which was partially offset by higher natural gas prices. On a dollar basis, sales in Canada continuing operations increased for three months ended March 31, 2026 compared to the prior year period primarily due a full month more of production from assets acquired in late February 2025 and new gas wells brought online in the Deep Basin and in the Montney.

## Royalties

	Q1 2026		Q1 2025	
	\$M	\$/boe	\$M	\$/boe
Canada	(20,014)	(2.23)	(18,657)	(3.51)
Discontinued operations:				
Canada	—	—	(11,932)	(12.49)
United States	—	—	(7,267)	(19.99)
Total discontinued operations	—	—	(19,199)	(14.56)
<b>Total</b>	<b>(20,014)</b>	<b>(2.23)</b>	<b>(37,856)</b>	<b>(5.70)</b>
Royalty rate (% of sales)				
Canada	7.6 %		11.2 %	
Discontinued operations	— %		19.2 %	

Royalties in Canada continuing operations decreased 36% on a per unit basis for the three months ended March 31, 2026, compared to same period in 2025 primarily due to the higher gas weighting in our production mix, which is subject to lower royalty rates relative to liquids and a higher proportion of our production on royalty holiday. Royalties in Canada continuing operations increased on a dollar basis for the three months ended March 31, 2026 compared to the prior period primarily due to royalties on higher production.

## Transportation

	Q1 2026		Q1 2025	
	\$M	\$/boe	\$M	\$/boe
Canada	(21,700)	(2.42)	(16,295)	(3.06)
Discontinued operations:				
Canada	—	—	(2,820)	(2.95)
United States	—	—	(125)	(0.34)
Total discontinued operations	—	—	(2,945)	(2.23)
<b>Total</b>	<b>(21,700)</b>	<b>(2.42)</b>	<b>(19,240)</b>	<b>(2.90)</b>

On a per boe basis, transportation expense in Canada continuing operations decreased 21% for the three months ended March 31, 2026 compared to same period in the prior year primarily due to higher utilization of contracted natural gas transportation capacity on Deep Basin production and lower crude oil trucking costs. Transportation expense in Canada continuing operations increased on a dollar basis for the three months ended March 31, 2026 compared to the prior year period primarily due to more transportation costs in the current year on assets acquired in late February 2025.

## Operating expense

	Q1 2026		Q1 2025	
	\$M	\$/boe	\$M	\$/boe
Canada	(58,802)	(6.55)	(42,941)	(8.07)
Discontinued operations:				
Canada	—	—	(20,937)	(21.91)
United States	—	—	(6,942)	(19.10)
Total discontinued operations	—	—	(27,879)	(21.14)
<b>Total</b>	<b>(58,802)</b>	<b>(6.55)</b>	<b>(70,820)</b>	<b>(10.67)</b>

Operating expenses in Canada continuing operations decreased 19% to \$6.55 per boe compared to \$8.07 per boe in the first quarter of 2025 due to increased operational scale in the Deep Basin and Montney as increased volumes are more than offset by costs related to gas processing, maintenance and other costs as we utilized existing infrastructure to facilitate production growth, which is weighted to a variable cost structure.

## International

During the first quarter of 2026, Vermilion entered into an agreement for the sale of the SA-07 assets in Croatia. As a result of this agreement, the operating results for the assets held for sale have been presented as discontinued operations throughout this MD&A in accordance with IFRS 5 "Non-current Assets Held for Sale and Discontinued Operations". Please refer to Note 3 "Discontinued operations" of the condensed consolidated interim financial statements for the three months ended March 31, 2026, for additional information.

	Q1 2026	Q1 2025
<b>Production <sup>(1)</sup></b>		
Crude oil and condensate (bbls/d)	9,392	11,835
Natural gas (mmcf/d)	98.88	105.12
<b>Total production volume (boe/d)</b>	<b>25,872</b>	<b>29,355</b>
Total sales volume (boe/d)	27,121	28,668

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

## Fund Flows from Operations

### Continuing Operations

	Q1 2026		Q1 2025	
	\$M	\$/boe	\$M	\$/boe
Sales	249,424	102.19	302,429	117.22
Royalties	(11,256)	(4.61)	(11,434)	(4.43)
Transportation	(11,607)	(4.76)	(11,946)	(4.63)
Operating	(82,903)	(33.99)	(70,839)	(27.50)
General and administration	(12,528)	(5.16)	(12,047)	(4.69)
Corporate income tax expense	(9,723)	(3.98)	(18,624)	(7.22)
PRRT	—	—	(3,018)	(1.17)
<b>Fund flows from continuing operations</b>	<b>121,407</b>	<b>49.69</b>	<b>174,521</b>	<b>67.58</b>
Drilling and development	(20,375)		(36,565)	
Exploration and evaluation	(120)		(14,373)	
<b>Free cash flow from continuing operations</b>	<b>100,912</b>		<b>123,583</b>	

### Discontinued Operations

	Q1 2026		Q1 2025	
	\$M	\$/boe	\$M	\$/boe
Operating	(74)	—	(118)	—
General and administration	(78)	—	(53)	—
<b>Fund flows from discontinued operations</b>	<b>(152)</b>	<b>—</b>	<b>(171)</b>	<b>—</b>
Drilling and development	126		(89)	
Exploration and evaluation	(314)		(282)	
<b>Free cash flow from discontinued operations</b>	<b>(340)</b>		<b>(542)</b>	

Production from Vermilion's International operations averaged 25,872 boe/d in Q1 2025, a decrease of 14% from the prior quarter primarily driven by cyclone-related downtime in Australia, as well as natural declines across International business units.

In Germany, the Company progressed infrastructure build-out on the Wisselshorst well during Q1 2026 and expects first production from this well by mid-2026. In Australia, production operations at Wandoo safely resumed in mid-March 2026 following downtime related to Cyclone Mitchell in February 2026, and was subsequently shut-in due to Cyclone Narelle in late March 2026. Production resumed subsequent to the quarter following necessary repair work. Despite production operations being shut-in, Vermilion exported approximately 300,000 barrels of oil in February 2026.

## Sales

	Q1 2026		Q1 2025	
	\$M	\$/boe	\$M	\$/boe
Australia	32,317	102.34	30,832	124.40
France	50,928	111.08	61,062	103.78
Netherlands	30,742	88.04	42,886	118.54
Germany	56,223	98.65	53,335	111.23
Ireland	72,488	108.50	100,986	127.21
Central and Eastern Europe	6,726	84.61	13,328	122.54
<b>International</b>	<b>249,424</b>	<b>102.19</b>	<b>302,429</b>	<b>117.22</b>

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)	Q1 2026	Q1 2025
Australia	3,509	2,754
France	5,094	6,538
Germany	2,013	1,819
<b>International</b>	<b>10,616</b>	<b>11,111</b>

Sales in our International core region for the three months ended March 31, 2026 decreased by 13% on a per boe basis compared to the prior period, primarily due to 20% lower realized European natural gas pricing, partially offset by 1% higher realized European crude oil pricing. International sales decreased on a dollar basis for the three months ended March 31, 2026 compared to the same period in the prior year primarily due to lower realized European natural gas pricing combined with lower sales volumes.

## Royalties

	Q1 2026		Q1 2025	
	\$M	\$/boe	\$M	\$/boe
France	(5,646)	(12.31)	(7,466)	(12.69)
Netherlands	—	—	(10)	(0.03)
Germany	(3,679)	(6.46)	(2,338)	(4.88)
Central and Eastern Europe	(1,931)	(24.29)	(1,620)	(14.89)
<b>International</b>	<b>(11,256)</b>	<b>(4.61)</b>	<b>(11,434)</b>	<b>(4.43)</b>
Royalty rate (% of sales)	4.5 %		3.8 %	

Royalties in our International core region are primarily incurred in France, the Netherlands, Germany and Croatia, where royalties, depending on jurisdiction, 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 4% from \$4.43 to \$4.61 per boe for the three months ended March 31, 2026 mainly due to higher royalties on the Osterheide startup volumes in Germany. Royalties on a dollar basis remained relatively flat for the three months ended March 31, 2026 compared to the prior year comparable period primarily due to lower sales volumes in France, partially offset by higher royalties on the Osterheide startup volumes in Germany.

## Transportation

	Q1 2026		Q1 2025	
	\$M	\$/boe	\$M	\$/boe
France	(6,109)	(13.32)	(5,478)	(9.31)
Germany	(3,612)	(6.34)	(4,269)	(8.90)
Ireland	(1,886)	(2.82)	(2,199)	(2.77)
<b>International</b>	<b>(11,607)</b>	<b>(4.76)</b>	<b>(11,946)</b>	<b>(4.63)</b>

Transportation expense on a dollar and per boe basis remained relatively flat for the three months ended March 31, 2026 primarily due to lower tariffs in Germany, partially offset by the timing of sales and vessel costs in France.

Our production in Australia, Netherlands and Central and Eastern Europe is not subject to transportation expense.

## Operating expense

	Q1 2026		Q1 2025	
	\$M	\$/boe	\$M	\$/boe
Australia	(33,978)	(107.60)	(14,985)	(60.46)
France	(12,849)	(28.03)	(16,043)	(27.27)
Netherlands	(9,113)	(26.10)	(9,608)	(26.56)
Germany	(14,187)	(24.89)	(15,177)	(31.65)
Ireland	(11,768)	(17.61)	(14,242)	(17.94)
Central and Eastern Europe	(1,008)	(12.68)	(784)	(7.21)
Discontinued operations:				
Central and Eastern Europe	(74)	—	(118)	—
<b>International</b>	<b>(82,977)</b>	<b>(33.99)</b>	<b>(70,957)</b>	<b>(27.50)</b>

Operating expenses increased 24% from \$27.50 to \$33.99 per boe for the three months ended March 31, 2026 primarily due the timing of liftings and maintenance costs in Australia, partially offset by lower gas processing fees in Germany. Operating expenses increased on a dollar basis for the three months ended March 31, 2026 compared to the same period in the prior year primarily due to the timing of liftings and maintenance costs in Australia, partially offset by the timing of sales volumes in France and Ireland.

# Consolidated Financial Performance Review

## Continuing Operations

	Q1 2026		Q1 2025	
	\$M	\$/boe	\$M	\$/boe
Sales	513,331	44.96	468,693	59.33
Royalties	(31,270)	(2.74)	(30,091)	(3.81)
Transportation	(33,307)	(2.92)	(28,241)	(3.58)
Operating	(141,705)	(12.41)	(113,780)	(14.40)
General and administration <sup>(1)</sup>	(19,965)	(1.75)	(29,735)	(3.76)
Corporate income tax expense	(11,664)	(1.02)	(19,059)	(2.41)
Petroleum resource rent tax	—	—	(3,018)	(0.38)
Interest expense	(26,697)	(2.34)	(32,979)	(4.17)
Realized (loss) gain on derivatives	(15,885)	(1.39)	11,119	1.41
Realized foreign exchange (loss) gain	(544)	(0.05)	2,499	0.32
Realized other income (expense)	135	0.01	(14,466)	(1.83)
<b>Fund flows from continuing operations</b>	<b>232,429</b>	<b>20.35</b>	<b>210,942</b>	<b>26.72</b>
Equity based compensation	(2,451)		(5,931)	
Unrealized loss on derivative instruments <sup>(2)</sup>	(285,648)		(13,675)	
Unrealized foreign exchange loss <sup>(2)</sup>	(15,273)		(36,016)	
Accretion	(18,838)		(15,793)	
Depletion and depreciation	(164,130)		(148,282)	
Deferred tax recovery	112,789		12,923	
Unrealized other expense <sup>(2)</sup>	(84)		(319)	
<b>Net (loss) earnings from continuing operations</b>	<b>(141,206)</b>		<b>3,849</b>	

<sup>(1)</sup> General and administration expenses previously presented within the Corporate segment have been reclassified to our Canadian segment. The prior period results have been presented to conform with current period presentation.

<sup>(2)</sup> Unrealized loss on derivative instruments, Unrealized foreign exchange loss, and Unrealized other expense are line items from the respective Consolidated Statements of Cash Flows.

## Discontinued Operations

	Q1 2026		Q1 2025	
	\$M	\$/boe	\$M	\$/boe
Sales	—	—	100,153	75.93
Royalties	—	—	(19,199)	(14.56)
Transportation	—	—	(2,945)	(2.23)
Operating	(74)	—	(27,997)	(21.23)
General and administration	(78)	—	(4,925)	(3.73)
<b>Fund flows from discontinued operations</b>	<b>(152)</b>	<b>—</b>	<b>45,087</b>	<b>34.18</b>
Unrealized foreign exchange gain <sup>(1)</sup>	6		117	
Accretion	—		(2,087)	
Depletion and depreciation	(5,137)		(28,106)	
Deferred tax recovery (expense)	951		(3,907)	
<b>Net (loss) earnings from discontinued operations</b>	<b>(4,332)</b>		<b>11,104</b>	
<b>Fund flows from operations</b>	<b>232,277</b>	<b>20.33</b>	<b>256,029</b>	<b>27.78</b>
<b>Net (loss) earnings</b>	<b>(145,538)</b>		<b>14,953</b>	

<sup>(1)</sup> Unrealized foreign exchange gain is a line item from the respective Consolidated Statements of Cash Flows.

## Consolidated Financial Performance Review

Fluctuations in fund flows from operations, including fund flows from continuing operations and fund flows from discontinued 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

- For the three months ended March 31, 2026, total general and administration expense decreased compared to the same period in the prior year due to transaction costs related to the Westbrick acquisition combined with the impact of restructuring in Canada and more efficient operations resulting in lower costs.

### PRRT and corporate income taxes

- PRRT decreased to zero for the three months ended March 31, 2026 compared to a PRRT expense in Q1 2025 due to cyclone-related downtime in Australia.
- Corporate income taxes for the three months ended March 31, 2026 decreased compared to the prior year comparable period mainly due to lower revenues in Germany and in the Netherlands.

### Interest expense

- Interest expense for the three months ended March 31, 2026 decreased due to lower debt levels compared to the same period in 2025 driven by the repayment of the \$450 million term loan, which was drawn in Q1 2025 and subsequently repaid in 2025. In addition, buybacks of the 2030 and 2033 senior unsecured notes has reduced interest expense.

### Realized gain or loss on derivatives

- For the three months ended March 31, 2026, we recorded realized losses on our crude oil and European natural gas hedges due to higher commodity pricing compared to the strike prices, partially offset by realized gains on our North American natural gas hedges due to lower commodity pricing compared to the strike prices.
- A listing of derivative positions as at March 31, 2026 is included in "Supplemental Table 2" of this MD&A.

### Realized other income or expense

- Realized other expense for the three months ended March 31, 2026 remained relatively flat compared to the prior year comparable period. For the three months ended March 31, 2026, realized other expense increased primarily related to an estimated provision recognized to satisfy work commitments.

## Net earnings (loss)

Fluctuations in net (loss) 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 or losses resulting from acquisition or disposition activity or charges resulting from impairment or impairment reversals.

### *Equity based compensation*

Equity based compensation expense relates included within net (loss) earnings and excluded from funds flow from operations relates 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 March 31, 2026 versus the same period in the prior year primarily due to a decrease in the performance factor on LTIP awards vesting in 2026.

### *Unrealized gain or loss on derivative instruments*

Unrealized gain or loss on derivative instruments arises 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.

Cross currency interest rate swaps and foreign exchange swaps may be entered into to manage foreign exchange and interest rate exposures on USD denominated debt. Unrealized gains and losses on these instruments are partially offset by the unrealized foreign exchange losses and gains on the underlying debt.

For the three months ended March 31, 2026, we recognized a net unrealized loss on derivative instruments of \$285.6 million. This consists of unrealized losses of \$218.5 million on our European natural gas commodity derivative instruments, \$149.3 million on our crude oil and liquids commodity derivative instruments, partially offset by unrealized gains of \$41.9 million on our North America gas commodity derivative instruments, \$30.1 million on our equity swaps and \$10.5 million on rate 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 2026, unrealized foreign exchange gains and losses primarily resulted from:

- The translation of Euro and US dollar denominated intercompany loans to and from our international subsidiaries to Vermilion Energy Inc. An appreciation in the Euro and/or the US dollar against the Canadian dollar will result in an unrealized foreign exchange loss (and vice-versa). Under IFRS Accounting Standards, 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 (loss) earnings reflects only the parent company's side of the translation.
- The translation of our USD denominated 2030 senior unsecured notes and USD denominated 2033 senior unsecured notes.
- 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.

For the three months ended March 31, 2026, we recognized a net unrealized foreign exchange loss of \$15.3 million, primarily driven by the effects of the US dollar strengthening 1.7% against the Canadian dollar on our US denominated debt, partially offset by the impact on our US dollar denominated intercompany loans.

### *Accretion*

Accretion expense is recognized to update the present value of asset retirement obligations. For the three months ended March 31, 2026, accretion expense increased primarily due to the impact of the Euro and Australian dollar strengthening against the Canadian dollar partially offset by lower asset retirement obligation driven by dispositions in the prior year.

### *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 months ended March 31, 2026 of \$14.82 decreased from \$19.13 in the same period of the prior year primarily due to decreases in the depletable base on impairment taken at the end of 2025 in Australia, Ireland and France, partially offset by higher production in Canada and reserve additions in 2025.

### 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.

The Company recorded a deferred tax recovery of \$112.8 million on continuing operations for the three months ended March 31, 2026 compared to a deferred tax recovery of \$12.9 million for the same period in the prior year. The deferred tax recovery was driven by the recognition of deferred tax assets in Ireland and Canada from increased valuation driven by forward pricing and on unrealized derivative losses.

For the three months ended March 31, 2026, the Company recorded a deferred tax recovery of \$1.0 million on discontinued operations compared to deferred tax expense of \$3.9 million for the same period in the prior year. The deferred tax recovery for the three months ended March 31, 2026 was driven by the depreciation recorded for the SA-07 block assets held for sale.

## 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, share buy-backs, 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, and/or with debt (including borrowing using the unutilized capacity of our existing revolving credit facility). We have a long-term goal of maintaining a ratio of net debt to four quarter trailing fund flows from operations of approximately 1.0.

As at March 31, 2026, we have a ratio of net debt to four quarter trailing fund flows from operations of 1.4.

### Net debt

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

(\$M)	As at	
	Mar 31, 2026	Dec 31, 2025
Long-term debt	1,254,333	1,243,397
Adjusted working capital <sup>(1)</sup>	41,208	96,091
Unrealized FX on swapped USD borrowings <sup>(2)</sup>	(2,974)	2,902
<b>Net debt</b>	<b>1,292,567</b>	<b>1,342,390</b>
<b>Ratio of net debt to four quarter trailing fund flows from operations <sup>(3)</sup></b>	<b>1.4</b>	<b>1.4</b>

- (1) Adjusted working capital is a non-GAAP financial measure that is not standardized under IFRS Accounting Standards and may not be comparable to similar measures disclosed by other issuers. It is defined as current assets less current liabilities, excluding current derivatives, current asset retirement obligations and current lease liabilities. The measure is used to calculate net debt, a capital measure disclosed above. Reconciliation to the primary financial statement measures can be found in the "Non-GAAP and Other Specified Financial Measures" section of this document.
- (2) Vermilion may enter into cross currency interest rate swaps to hedge the foreign exchange movements on USD borrowings on our revolving credit facility. Unrealized FX on swapped USD borrowings relates to the unrealized gains and losses on our cross currency interest swaps. At March 31, 2026, there was \$203.4 million of USD borrowings on our revolving credit facility. (December 31, 2025 - \$196.7 million).
- (3) Subsequent to February 26, 2025, net debt to four quarter trailing fund flows from operations is calculated inclusive of Westbrick Energy's pre-acquisition four quarter trailing fund flows from operations, as if the acquisition of Westbrick Energy occurred at the beginning of the four quarter trailing period, and exclusive of the four quarter trailing fund flows from discontinued operations to reflect the Company's ability to repay debt on a pro forma basis.

As at March 31, 2026, net debt decreased slightly to \$1.29 billion (December 31, 2025 - \$1.34 billion) primarily due to increased funds from continuing operations and the inclusion of the expected proceeds from the disposition of the SA-07 assets held for sale in Croatia. The decrease was partially offset by capital expenditures, asset retirement obligations settled during the quarter and the US dollar strengthening by 2% against the Canadian dollar on our US denominated notes.

The ratio of net debt to four quarter trailing fund flows from operations<sup>(1)</sup> remained flat at 1.4 as at March 31, 2026 (December 31, 2025 - 1.4) due to slightly lower four quarter trailing funds from continuing operations, mainly impacted by pricing, net of derivatives and lower net debt on inclusion of the expected proceeds on assets held for sale.

## Long-term debt

The balances recognized on our balance sheet are as follows:

	As at	
	Mar 31, 2026	Dec 31, 2025
Revolving credit facility	229,491	222,724
2030 senior unsecured notes	513,962	504,962
2033 senior unsecured notes	510,880	515,711
<b>Long-term debt</b>	<b>1,254,333</b>	<b>1,243,397</b>

### Revolving credit facility

As at March 31, 2026, Vermilion had in place a bank revolving credit facility maturing May 25, 2029 with terms and outstanding positions as follows:

(\$M)	As at	
	Mar 31, 2026	Dec 31, 2025
Total facility amount	1,350,000	1,350,000
Amount drawn	(229,491)	(222,724)
Letters of credit outstanding	(42,153)	(49,263)
<b>Unutilized capacity</b>	<b>1,078,356</b>	<b>1,078,013</b>

The facility is secured by various fixed and floating charges against the subsidiaries of Vermilion. As at March 31, 2026, \$229.5 million of the revolving credit facility was drawn (December 31, 2025 - \$222.7 million).

Subsequent to March 31, 2026, the maturity date of the revolving credit facility was extended to May 30, 2030 with no other changes to the existing terms and conditions.

As at March 31, 2026, the revolving credit facility was subject to the following financial covenants:

Financial covenant	Limit	As at	
		Mar 31, 2026	Dec 31, 2025
Consolidated total debt to consolidated EBITDA	Less than 4.0	1.17	1.14
Consolidated total senior debt to consolidated EBITDA	Less than 3.5	0.21	0.21
Consolidated EBITDA to consolidated interest expense	Greater than 2.5	8.77	8.44

Our financial covenants include financial measures defined within our revolving credit facility agreement that are not defined under IFRS Accounting Standards. 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 consolidated balance sheet.
- Consolidated total senior debt: Consolidated total debt excluding unsecured and subordinated debt.
- Consolidated EBITDA: Consolidated net (loss) 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.

As at March 31, 2026 and December 31, 2025, Vermilion was in compliance with the above covenants.

### *Term loan*

Concurrent with the completion of the Westbrick acquisition on February 26, 2025, Vermilion's credit facility agreement was amended to incorporate a new \$450.0 million term loan (the “Term Loan”) which was immediately drawn. The Term Loan balance was repaid in full in 2025.

### *2025 senior unsecured notes*

On March 13, 2017, Vermilion issued US \$300.0 million of senior unsecured notes at par. The notes bore interest at a rate of 5.625% per annum and were paid semi-annually on March 15 and September 15. During the year ended December 31, 2024, Vermilion purchased \$31.6 million of senior unsecured notes on the open market which were subsequently cancelled. The notes matured on March 15, 2025 and the balance was repaid in full.

### *2030 senior unsecured notes*

On April 26, 2022, Vermilion closed a private offering of US \$400.0 million of senior unsecured notes, priced at 99.241% of par. The notes bear interest at a rate of 6.875% per annum, to be paid semi-annually on May 1 and November 1. The notes mature on May 1, 2030. As direct senior unsecured obligations of Vermilion, the notes rank equally with existing and future senior unsecured indebtedness of the Company.

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

- On or after May 1, 2025, Vermilion may redeem some or all of the senior unsecured notes at the redemption prices set forth below, together with accrued and unpaid interest.

Year	Redemption price
2025	103.438 %
2026	102.292 %
2027	101.146 %
2028 and thereafter	100.000 %

### *2033 senior unsecured notes*

On February 11, 2025 Vermilion closed a private offering of US \$400.0 million of senior unsecured notes at par. The notes bear interest at a rate of 7.250% per annum, to be paid semi-annually on February 15 and August 15. The notes mature on February 15, 2033. As direct senior unsecured obligations of Vermilion, the notes rank equally with existing and future senior unsecured indebtedness of the Company.

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

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

- Prior to February 15, 2028, Vermilion may redeem up to 40% of the original principal amount of the notes with an amount of cash not greater than the net cash proceeds of certain equity offerings at a redemption price of 107.250% of the principal amount of the notes, together with accrued and unpaid interest.
- Prior to February 15, 2028, Vermilion may also redeem some or all of the notes at a price equal to 100% of the principal amount of the notes, plus a “make-whole premium,” together with applicable premium, accrued and unpaid interest.
- On or after February 15, 2028, Vermilion may redeem some or all of the senior unsecured notes at the redemption prices set forth below, together with accrued and unpaid interest.

Year	Redemption price
2028	103.625 %
2029	101.813 %
2030 and thereafter	100.000 %

During the three months ended March 31, 2026, Vermilion purchased \$13.5 million of the 2033 senior unsecured notes at a rate of 99.0% on the open market which were subsequently cancelled.

## Shareholders' capital

The following table outlines our dividend payment history:

Date	Frequency	Dividend per unit or share
April 2022 to July 2022	Quarterly	\$0.06
August 2022 to March 2023	Quarterly	\$0.08
April 2023 to March 2024	Quarterly	\$0.10
April 2024 to March 2025	Quarterly	\$0.12
April 2025 to March 2026	Quarterly	\$0.13
April 2026 onwards	Quarterly	\$0.135

The following table reconciles the change in shareholders' capital:

Shareholders' Capital	Shares ('000s)	Amount (\$M)
<b>Balance at January 1</b>	<b>152,950</b>	<b>3,871,914</b>
Repurchase of shares	(350)	(8,955)
<b>Balance at March 31</b>	<b>152,600</b>	<b>3,862,959</b>

As at March 31, 2026, there were approximately 4.9 million equity based compensation awards outstanding. As at May 5, 2026, there were approximately 153.2 million common shares issued and outstanding.

On July 9, 2025, the Toronto Stock Exchange approved the Company's notice of intention to renew its normal course issuer bid ("the NCIB"). The NCIB renewal allows Vermilion to purchase up to 15,259,187 common shares (representing approximately 10% of outstanding common shares) beginning July 12, 2025 and ending July 11, 2026. Common shares purchased under the NCIB will be cancelled.

In the first quarter of 2026, Vermilion purchased 0.3 million common shares under the NCIB for total consideration of \$4.7 million. The common shares purchased under the NCIB were cancelled.

Subsequent to March 31, 2026, Vermilion purchased and cancelled 0.1 million shares under the NCIB for total consideration of \$1.3 million.

## Asset Retirement Obligations

As at March 31, 2026, asset retirement obligations were \$1.1 billion compared to \$1.0 billion as at December 31, 2025. The increase in asset retirement obligations is primarily attributable to changes in rates. The credit spread decreased to 3.1% at March 31, 2026 compared to 4.4% at December 31, 2025, primarily due to a higher expected cost of borrowing.

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 using the Company's expected cost of borrowing at the end of the reporting period.

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

	Mar 31, 2026	Dec 31, 2025	Change
Credit spread added to below noted risk-free rates	3.1 %	4.4 %	(1.3)%
<b>Country specific risk-free rate</b>			
Canada	3.9 %	3.9 %	— %
France	4.6 %	4.5 %	0.1 %
Netherlands	3.7 %	3.2 %	0.5 %
Germany	3.5 %	3.4 %	0.1 %
Ireland	3.4 %	3.2 %	0.2 %
Australia	5.2 %	4.9 %	0.3 %
Central and Eastern Europe	5.2 %	4.8 %	0.4 %

Current cost estimates are inflated to the estimated time of abandonment using inflation rates of between 1.4% and 3.5% (as at December 31, 2025 - between 1.4% and 3.5%).

## 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, 2025 available on SEDAR+ at [www.sedarplus.ca](http://www.sedarplus.ca) or on Vermilion's website at [www.vermilionenergy.com](http://www.vermilionenergy.com).

## Critical Accounting Estimates

The preparation of consolidated financial statements in accordance with IFRS Accounting Standards requires management to make estimates, judgments and assumptions that affect reported assets, liabilities, revenues and expenses, gains and losses, and disclosures of any possible contingencies. These estimates and assumptions are developed based on the best available information which management believed to be reasonable at the time such estimates and assumptions were made. As such, these assumptions are uncertain at the time estimates are made and could change, resulting in a material impact on Vermilion's consolidated financial statements. Estimates are reviewed by management on an ongoing basis and as a result may change from period to period due to the availability of new information or changes in circumstances. Additionally, as a result of the unique circumstances of each jurisdiction that Vermilion operates in, the critical accounting estimates may affect one or more jurisdictions. There have been no material changes to our critical accounting estimates used in applying accounting policies for the three months ended March 31, 2026. 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, 2025, available on SEDAR+ at [www.sedarplus.ca](http://www.sedarplus.ca) or on Vermilion's website at [www.vermilionenergy.com](http://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

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, our internal control over financial reporting.

## Recently Adopted Accounting Pronouncements

### *Amendments to IFRS 9 - Financial Instruments and IFRS 7 Financial Instruments: Disclosure*

On January 1, 2026, Vermilion adopted the amendments to IFRS 9 - Financial Instruments and IFRS 7 Financial Instruments: Disclosure, as issued by the international Accounting Standards Board ("IASB") that contained guidance related to settling financial liabilities using an electronic payment system and assessing contractual cash flow characteristics of financial assets. There was no impact to Vermilion's financial statements.

Vermilion did not adopt any new accounting pronouncements as at March 31, 2026 that would have a material impact on the Consolidated Interim Financial Statements.

## Regulatory Pronouncements Not Yet Adopted

### *Issuance of IFRS Sustainability Standards - IFRS S1 "General Requirements for Disclosure of Sustainability-related Financial Information" and IFRS S2 "Climate-related Disclosures" and European Corporate Sustainability Reporting Directive (CSRD)*

In June 2023, the International Sustainability Standards Board (ISSB) issued its inaugural standards – IFRS S1 and IFRS S2, and is currently discussing its approach to nature-related disclosure. In March 2026, the European Corporate Sustainability Reporting Directive's Omnibus 1 entered into force.

The Canadian Sustainability Standards Board has issued Canada-specific version of IFRS S1 and S2 as Canadian Sustainability Disclosure Standards 1 and 2. While Canadian securities regulators have not mandated these standards, they have referenced them as a useful voluntary disclosure framework for sustainability and climate-related disclosure, and noted that securities legislation already requires issuers to disclose material climate-related risks. Australia has mandated the Australian version of IFRS S2 as Australian Accounting Standards Board S2 with mandatory disclosure for Vermilion in 2025, reporting in 2026. Under the Omnibus, Vermilion may be required to report as a non-EU parent company; however, the regulations for this reporting are not yet finalized. Vermilion's reporting date is currently projected as 2029 for the 2028 fiscal year, depending on EU subsidiary revenue for fiscal years 2026 and 2027. Vermilion is continuing to review the impact of the standards on its financial reporting.

### *IFRS 18 "Presentation and Disclosure in Financial Statements issued"*

In April 2024, the IASB issued the new accounting standard, IFRS 18 'Presentation and Disclosure in Financial Statements'. IFRS 18 will replace IAS 1 'Presentation of Financial Statements' and provides a defined structure to the statement of net earnings (loss) and comprehensive income and related disclosure requirements. Key changes include a new operating profit subtotal and require income and expenses to be classified into operating, investing, and financing categories, based on the entity's main business activities. The new standard is effective for annual reporting periods beginning on or after January 1, 2027 and is required to be adopted retrospectively. Vermilion is currently reviewing income and expense classifications, management-defined performance measures, and contractual arrangements to assess the impact the standard will have on the consolidated financial statements.

## 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 March 31, 2026, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures. Based on this evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded and certified that our disclosure controls and procedures are effective.

## Supplemental Table 1: Operating 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.

	Q1 2026			Q1 2025		
	Liquids \$/bbl	Natural Gas \$/mcf	Total \$/boe	Liquids \$/bbl	Natural Gas \$/mcf	Total \$/boe
<b>Continuing Operations</b>						
<b>Canada</b>						
Sales	62.14	2.94	29.40	65.76	2.77	31.26
Royalties	(6.61)	(0.11)	(2.23)	(7.95)	(0.27)	(3.51)
Transportation	(4.65)	(0.27)	(2.42)	(5.63)	(0.33)	(3.06)
Operating	(13.89)	(0.65)	(6.55)	(17.08)	(0.71)	(8.07)
<b>Operating netback</b>	36.99	1.91	18.20	35.10	1.46	16.62
General and administration <sup>(1)</sup>			(0.83)			(3.33)
Corporate income taxes (\$/boe)			(0.22)			(0.08)
<b>Fund flows from operations (\$/boe)</b>			17.15			13.21
<b>France</b>						
Sales	111.08	—	111.08	103.78	—	103.78
Royalties	(12.31)	—	(12.31)	(12.69)	—	(12.69)
Transportation	(13.32)	—	(13.32)	(9.31)	—	(9.31)
Operating	(28.03)	—	(28.03)	(27.27)	—	(27.27)
<b>Operating netback</b>	57.42	—	57.42	54.51	—	54.51
General and administration			(8.52)			(6.13)
Current income taxes			(0.82)			(0.81)
<b>Fund flows from operations (\$/boe)</b>			48.08			47.57
<b>Netherlands</b>						
Sales	85.53	14.68	88.04	107.21	19.77	118.54
Royalties	—	—	—	—	—	(0.03)
Operating	(46.05)	(4.33)	(26.10)	(31.19)	(4.42)	(26.56)
<b>Operating netback</b>	39.48	10.35	61.94	76.02	15.35	91.95
General and administration			(3.40)			(3.66)
Current income taxes			(16.68)			(31.34)
<b>Fund flows from operations (\$/boe)</b>			41.86			56.95
<b>Germany</b>						
Sales	110.47	15.52	98.65	103.94	19.17	111.23
Royalties	(2.36)	(1.39)	(6.46)	(2.59)	(1.01)	(4.88)
Transportation	(10.51)	(0.73)	(6.34)	(17.55)	(0.74)	(8.90)
Operating	(28.18)	(3.89)	(24.89)	(29.66)	(5.45)	(31.65)
<b>Operating netback</b>	69.42	9.51	60.96	54.14	11.97	65.80
General and administration			(6.03)			(6.43)
Current income taxes			(5.31)			(12.79)
<b>Fund flows from operations (\$/boe)</b>			49.62			46.58
<b>Ireland</b>						
Sales	—	18.08	108.50	—	21.19	127.21
Transportation	—	(0.47)	(2.82)	—	(0.46)	(2.77)
Operating	—	(2.94)	(17.61)	—	(2.99)	(17.94)
<b>Operating netback</b>	—	14.67	88.07	—	17.74	106.50
General and administration			(1.58)			(2.11)
Current income taxes			(0.22)			(0.24)
<b>Fund flows from operations (\$/boe)</b>			86.27			104.15

	Q1 2026			Q1 2025		
	Liquids	Natural Gas	Total	Liquids	Natural Gas	Total
	\$/bbl	\$/mcf	\$/boe	\$/bbl	\$/mcf	\$/boe
<b>Australia</b>						
Sales	102.34	—	102.34	124.40	—	124.40
Operating	(107.60)	—	(107.60)	(60.46)	—	(60.46)
PRRT <sup>(2)</sup>	—	—	—	(12.18)	—	(12.18)
<b>Operating netback</b>	(5.26)	—	(5.26)	51.76	—	51.76
General and administration			(4.52)			(4.80)
Current income taxes			—			(0.59)
<b>Fund flows from operations (\$/boe)</b>			<b>(9.78)</b>			<b>46.37</b>
<b>Central and Eastern Europe</b>						
Sales	13.04	14.14	84.61	96.15	20.43	122.54
Royalties	—	(4.06)	(24.29)	—	(2.49)	(14.89)
Operating	—	(1.96)	(12.68)	—	(1.20)	(7.21)
<b>Operating netback</b>	13.04	8.12	47.64	96.15	16.74	100.44
General and administration			(19.00)			(10.74)
Current income taxes			(4.35)			(3.14)
<b>Fund flows from operations (\$/boe)</b>			<b>24.29</b>			<b>86.56</b>
<b>Discontinued Operations</b>						
<b>United States</b>						
Sales	—	—	—	85.82	4.35	71.57
Royalties	—	—	—	(23.98)	(1.21)	(19.99)
Transportation	—	—	—	(0.45)	—	(0.34)
Operating	—	—	—	(22.83)	(1.20)	(19.10)
<b>Operating netback</b>	—	—	—	38.56	1.94	32.14
General and administration			—			(5.15)
<b>Fund flows from operations (\$/boe)</b>			<b>—</b>			<b>26.99</b>
<b>Canada - Saskatchewan</b>						
Sales	—	—	—	88.81	2.18	77.59
Royalties	—	—	—	(17.54)	2.76	(12.49)
Transportation	—	—	—	(3.17)	(0.28)	(2.95)
Operating	—	—	—	(25.21)	(0.49)	(21.91)
<b>Operating netback</b>	—	—	—	42.89	4.17	40.24
General and administration			—			(3.14)
<b>Fund flows from operations (\$/boe)</b>			<b>—</b>			<b>37.10</b>
<b>Total Company</b>						
Sales	75.33	5.41	44.96	84.15	7.80	61.71
Realized hedging gain	(4.20)	(0.04)	(1.39)	0.42	0.29	1.21
Royalties	(6.54)	(0.20)	(2.74)	(11.26)	(0.24)	(5.35)
Transportation	(5.81)	(0.29)	(2.92)	(5.47)	(0.33)	(3.38)
Operating	(20.87)	(1.49)	(12.42)	(20.82)	(1.96)	(15.38)
PRRT <sup>(2)</sup>	—	—	—	(0.82)	—	(0.33)
<b>Operating netback</b>	37.91	3.39	25.49	46.20	5.56	38.48
General and administration			(1.76)			(3.75)
Interest expense			(2.34)			(3.58)
Realized foreign exchange gain			(0.05)			0.27
Realized other income (expense)			0.01			(1.57)
Corporate income taxes			(1.02)			(2.07)
<b>Fund flows from operations (\$/boe)</b>			<b>20.33</b>			<b>27.78</b>

(1) General and administration expenses previously presented within the Corporate segment have been reclassified to our Canadian segment. The prior period results have been presented to conform with current period presentation.

(2) 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 March 31, 2026:

	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
<b>AECO</b>												
Q2 2026	mcf	CAD	4,739	3.17	4,739	4.22	—	—	151,651	3.12	—	—
Q3 2026	mcf	CAD	4,739	3.17	4,739	4.22	—	—	151,651	3.12	—	—
Q4 2026	mcf	CAD	39,304	2.76	39,304	4.57	—	—	113,944	3.24	—	—
Q1 2027	mcf	CAD	52,130	2.71	52,130	4.61	—	—	99,521	3.16	—	—
Q2 2027	mcf	CAD	—	—	—	—	—	—	127,955	2.88	—	—
Q3 2027	mcf	CAD	—	—	—	—	—	—	127,955	2.88	—	—
Q4 2027	mcf	CAD	37,707	2.37	37,707	4.40	—	—	102,818	3.02	—	—
Q1 2028	mcf	CAD	56,869	2.37	56,869	4.40	—	—	28,435	3.15	—	—
Q2 2028	mcf	CAD	—	—	—	—	—	—	18,956	2.43	—	—
Q3 2028	mcf	CAD	—	—	—	—	—	—	18,956	2.43	—	—
Q4 2028	mcf	CAD	—	—	—	—	—	—	6,387	2.43	—	—
<b>NYMEX Henry Hub</b>												
Q2 2026	mcf	USD	24,000	4.00	24,000	4.00	—	—	—	—	—	—
Q3 2026	mcf	USD	24,000	3.50	24,000	4.49	—	—	—	—	—	—
Q4 2026	mcf	USD	24,000	3.50	24,000	4.49	—	—	—	—	—	—
Q1 2027	mcf	USD	—	—	—	—	—	—	24,000	4.00	—	—
Q2 2027	mcf	USD	—	—	—	—	—	—	24,000	4.00	—	—
Q3 2027	mcf	USD	—	—	—	—	—	—	24,000	4.00	—	—
Q4 2027	mcf	USD	—	—	—	—	—	—	24,000	4.00	—	—
Q1 2028	mcf	USD	—	—	24,000	6.00	—	—	—	—	—	—
Q2 2028	mcf	USD	—	—	24,000	6.00	—	—	—	—	—	—
Q3 2028	mcf	USD	—	—	24,000	6.00	—	—	—	—	—	—
Q4 2028	mcf	USD	—	—	24,000	6.00	—	—	—	—	—	—
<b>TTF</b>												
Q2 2026	mcf	EUR	27,980	8.00	27,980	13.26	24,567	3.00	25,796	10.00	—	—
Q3 2026	mcf	EUR	26,785	8.00	26,785	12.84	24,567	3.00	23,338	9.00	—	—
Q4 2026	mcf	EUR	34,736	8.00	34,736	14.08	28,253	3.00	17,197	9.00	—	—
Q1 2027	mcf	EUR	28,253	7.43	28,253	11.66	28,253	2.93	9,827	9.87	—	—
Q2 2027	mcf	EUR	—	—	2,457	7.74	—	—	25,523	8.69	—	—
Q3 2027	mcf	EUR	—	—	2,457	7.74	—	—	25,523	8.69	—	—
Q4 2027	mcf	EUR	—	—	2,457	7.74	—	—	25,523	8.69	—	—
Q1 2028	mcf	EUR	—	—	—	—	—	—	14,740	7.43	—	—
<b>WTI</b>												
Q2 2026	bbl	USD	11,000	62.73	12,500	69.91	11,000	50.70	7,000	63.00	500	62.00
Q3 2026	bbl	USD	11,000	62.82	11,000	71.29	11,000	50.80	1,000	63.00	—	—
Q4 2026	bbl	USD	11,000	62.82	11,000	71.29	11,000	51.00	1,000	62.50	—	—
Q1 2027	bbl	USD	4,000	62.50	4,000	70.30	4,000	53.00	—	—	—	—
Q2 2027	bbl	USD	4,000	62.50	4,000	70.30	4,000	53.00	—	—	—	—
Q3 2027	bbl	USD	4,000	67.75	4,000	79.59	4,000	58.00	—	—	—	—
Q4 2027	bbl	USD	4,000	67.75	4,000	79.59	4,000	58.00	—	—	—	—

	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
<b>Dated Brent</b>												
Q3 2026	bbl	USD	2,000	66.50	2,000	74.38	2,000	56.50	—	—	—	—
Q4 2026	bbl	USD	2,000	66.50	2,000	74.38	2,000	56.50	—	—	—	—
Q1 2027	bbl	USD	3,000	67.17	3,000	77.33	3,000	57.17	—	—	—	—
Q2 2027	bbl	USD	3,000	67.17	3,000	77.33	3,000	57.17	—	—	—	—
Q3 2027	bbl	USD	3,000	70.67	3,000	84.14	3,000	60.67	—	—	—	—
Q4 2027	bbl	USD	3,000	70.67	3,000	84.14	3,000	60.67	—	—	—	—
<b>C5-WTI Differential</b>												
Q2 2026	bbl	USD	—	—	—	—	—	—	659	0.05	—	—
<b>Conway</b>												
Q2 2026	bbl	USD	—	—	—	—	—	—	1,000	31.13	—	—
<b>FEI</b>												
Q2 2026	bbl	USD	—	—	—	—	—	—	500	48.30	—	—
Q3 2026	bbl	USD	—	—	—	—	—	—	500	45.72	—	—

VET Equity Swaps		Initial Share Price	Share Volume
Swap	Jan 2020 - Apr 2027	20.9788 CAD	1,650,000
Swap	Jan 2020 - Jul 2027	22.4587 CAD	1,500,000

Foreign Exchange	Period	Monthly Bought Put Amount	Weighted Average Bought Put Price	Monthly Sold Call Amount	Weighted Average Sold Call Price	Monthly Sold Swap Amount	Weighted Average Sold Swap Price
Collar	Sell USD, Buy CAD	Apr - Jun 2026	11,000,000 USD	1.3500	11,000,000 USD	1.4403	—
Collar	Sell USD, Buy CAD	Apr - Dec 2026	2,000,000 USD	1.3500	2,000,000 USD	1.4355	—

Cross Currency Interest Rate		Receive Notional Amount	Receive Rate	Pay Notional Amount	Pay Rate
Swap	Feb 2033	250,000,000 USD	7.250%	357,870,000 CAD	6.099%
Swap	Mar - Apr 2026	145,879,871 USD	SOFR + 2.350%	200,000,000 CAD	CORRA + 2.269%

The following sold option instruments allow the counterparties, at the specified date, to enter into a derivative instrument contract with Vermilion at the detailed terms:

Period if Option Exercised	Unit	Currency	Option Expiration Date	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
<b>WTI</b>											
Jul 2026 - Dec 2026	bbl	USD	30-Jun-2026	—	—	—	—	—	—	1,000	70.00
Jul 2026 - Jun 2027	bbl	USD	30-Jun-2026	—	—	—	—	—	—	2,000	70.00
Jan 2027 - Dec 2027	bbl	USD	30-Sep-2026	—	—	—	—	—	—	1,000	70.00
<b>TTF</b>											
Jan 2027 - Dec 2027	mcf	EUR	30-Jun-2026	—	—	—	—	—	—	2,457	10.26
Jan 2027 - Dec 2027	mcf	EUR	31-Dec-2026	—	—	—	—	—	—	4,913	10.26
Apr 2027 - Dec 2027	mcf	EUR	30-Sep-2026	—	—	—	—	—	—	4,913	10.26
Jan 2028 - Dec 2028	mcf	EUR	30-Sep-2027	—	—	—	—	—	—	4,913	8.79
Jan 2028 - Dec 2028	mcf	EUR	24-Dec-2027	—	—	—	—	—	—	4,913	8.79
Jan 2028 - Dec 2028	mcf	EUR	30-Dec-2027	—	—	—	—	—	—	4,913	8.06

## Supplemental Table 3: Capital Expenditures and Acquisitions

By classification (\$M)	Q1 2026	Q1 2025
Drilling and development	134,146	167,464
Exploration and evaluation	434	14,655
<b>Capital expenditures</b>	<b>134,580</b>	<b>182,119</b>
Acquisitions (\$M)	Q1 2026	Q1 2025
Acquisitions, net of cash acquired	6,035	1,084,456
Shares issued for acquisition	—	13,363
Acquired working capital deficit	—	23,179
<b>Acquisitions</b>	<b>6,035</b>	<b>1,120,998</b>
By category (\$M)	Q1 2026	Q1 2025
Drilling, completion, new well equip and tie-in, workovers and recompletions	116,291	117,696
Production equipment and facilities	14,955	55,300
Seismic, studies, land and other	3,334	9,123
Capital expenditures	134,580	182,119
Acquisitions	6,035	1,120,998
<b>Total capital expenditures and acquisitions</b>	<b>140,615</b>	<b>1,303,117</b>
Capital expenditures by country (\$M)	Q1 2026	Q1 2025
Canada	113,897	120,152
France	6,978	6,756
Netherlands	2,707	7,747
Germany	3,274	25,235
Ireland	1,970	328
Australia	5,601	9,702
Central and Eastern Europe	(35)	1,170
Capital expenditures on continuing operations	134,392	171,090
Canada	—	5,491
United States	—	5,167
Central and Eastern Europe	188	371
Capital expenditures on discontinued operations	188	11,029
<b>Capital expenditures</b>	<b>134,580</b>	<b>182,119</b>
Acquisitions by country (\$M)	Q1 2026	Q1 2025
Canada	6,035	1,120,998
<b>Acquisitions</b>	<b>6,035</b>	<b>1,120,998</b>

## Supplemental Table 4: Production

	Q1/26	Q4/25	Q3/25	Q2/25	Q1/25	Q4/24	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23
<b>Continuing Operations</b>												
<b>Canada</b>												
Light and medium crude oil (bbls/d)	5,592	5,494	6,092	5,812	4,136	4,102	4,843	4,288	3,252	3,294	3,572	869
Condensate <sup>(1)</sup> (bbls/d)	8,708	8,230	7,804	8,366	5,768	3,546	3,338	3,595	3,815	3,696	4,046	3,194
Other NGLs <sup>(1)</sup> (bbls/d)	12,044	12,099	10,579	11,072	7,695	4,980	5,715	5,374	5,200	5,390	5,333	4,215
<b>NGLs (bbls/d)</b>	<b>20,752</b>	<b>20,329</b>	<b>18,383</b>	<b>19,438</b>	<b>13,463</b>	<b>8,526</b>	<b>9,053</b>	<b>8,969</b>	<b>9,015</b>	<b>9,086</b>	<b>9,379</b>	<b>7,409</b>
Conventional natural gas (mmcf/d)	440.41	391.39	367.34	394.06	249.02	151.64	148.38	148.37	140.93	148.20	150.97	141.80
<b>Total (boe/d)</b>	<b>99,746</b>	<b>91,053</b>	<b>85,698</b>	<b>90,926</b>	<b>59,104</b>	<b>37,898</b>	<b>38,625</b>	<b>37,987</b>	<b>35,753</b>	<b>37,081</b>	<b>38,113</b>	<b>31,912</b>
<b>France</b>												
Light and medium crude oil (bbls/d)	6,729	6,985	6,811	6,827	6,810	7,083	7,115	7,246	7,308	7,395	7,578	7,788
<b>Total (boe/d)</b>	<b>6,729</b>	<b>6,985</b>	<b>6,811</b>	<b>6,827</b>	<b>6,810</b>	<b>7,083</b>	<b>7,115</b>	<b>7,246</b>	<b>7,308</b>	<b>7,395</b>	<b>7,578</b>	<b>7,788</b>
<b>Netherlands</b>												
Condensate <sup>(1)</sup> (bbls/d)	22	45	27	35	34	44	39	51	165	119	39	61
<b>NGLs (bbls/d)</b>	<b>22</b>	<b>45</b>	<b>27</b>	<b>35</b>	<b>34</b>	<b>44</b>	<b>39</b>	<b>51</b>	<b>165</b>	<b>119</b>	<b>39</b>	<b>61</b>
Conventional natural gas (mmcf/d)	23.15	25.20	20.12	22.25	23.91	24.20	25.06	26.84	31.02	32.06	24.32	27.28
<b>Total (boe/d)</b>	<b>3,880</b>	<b>4,245</b>	<b>3,381</b>	<b>3,744</b>	<b>4,020</b>	<b>4,078</b>	<b>4,216</b>	<b>4,524</b>	<b>5,336</b>	<b>5,462</b>	<b>4,091</b>	<b>4,607</b>
<b>Germany</b>												
Light and medium crude oil (bbls/d)	1,593	1,650	1,717	1,731	1,512	1,596	1,598	1,698	1,722	1,775	1,713	1,715
Conventional natural gas (mmcf/d)	25.91	28.61	26.21	25.49	21.05	21.71	21.41	18.41	22.87	19.62	20.29	22.05
<b>Total (boe/d)</b>	<b>5,912</b>	<b>6,419</b>	<b>6,086</b>	<b>5,979</b>	<b>5,020</b>	<b>5,215</b>	<b>5,167</b>	<b>4,766</b>	<b>5,533</b>	<b>5,046</b>	<b>5,095</b>	<b>5,391</b>
<b>Ireland</b>												
Conventional natural gas (mmcf/d)	44.54	47.04	48.83	47.75	52.92	55.32	59.06	57.70	60.34	64.04	47.96	67.51
<b>Total (boe/d)</b>	<b>7,423</b>	<b>7,840</b>	<b>8,139</b>	<b>7,959</b>	<b>8,820</b>	<b>9,220</b>	<b>9,844</b>	<b>9,616</b>	<b>10,057</b>	<b>10,673</b>	<b>7,993</b>	<b>11,251</b>
<b>Australia</b>												
Light and medium crude oil (bbls/d)	1,045	2,941	3,693	3,460	3,477	3,778	2,040	3,713	4,264	4,715	1,204	—
<b>Total (boe/d)</b>	<b>1,045</b>	<b>2,941</b>	<b>3,693</b>	<b>3,460</b>	<b>3,477</b>	<b>3,778</b>	<b>2,040</b>	<b>3,713</b>	<b>4,264</b>	<b>4,715</b>	<b>1,204</b>	<b>—</b>
<b>Central and Eastern Europe</b>												
Conventional natural gas (mmcf/d)	5.28	10.22	13.13	9.90	7.24	11.21	11.13	0.69	0.29	0.54	0.05	0.30
<b>Total (boe/d)</b>	<b>881</b>	<b>1,707</b>	<b>2,189</b>	<b>1,654</b>	<b>1,208</b>	<b>1,869</b>	<b>1,855</b>	<b>122</b>	<b>48</b>	<b>90</b>	<b>8</b>	<b>50</b>

	Q1/26	Q4/25	Q3/25	Q2/25	Q1/25	Q4/24	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23
<b>Discontinued Operations</b>												
<b>United States</b>												
Light and medium crude oil (bbls/d)	—	3	1,151	2,977	2,261	2,449	2,909	3,817	3,483	3,187	4,404	3,349
Condensate <sup>(1)</sup> (bbls/d)	—	9	4	12	19	34	12	27	29	27	15	22
Other NGLs <sup>(1)</sup> (bbls/d)	—	39	308	792	795	848	1,064	988	1,078	1,131	1,124	1,025
<b>NGLs (bbls/d)</b>	—	48	312	804	814	882	1,076	1,015	1,107	1,158	1,139	1,047
Conventional natural gas (mmcf/d)	—	0.11	2.83	5.83	5.78	5.88	7.08	7.27	8.23	7.49	7.25	7.23
<b>Total (boe/d)</b>	—	70	1,934	4,752	4,039	4,311	5,164	6,044	5,962	5,593	6,751	5,601
<b>Canada - Saskatchewan</b>												
Light and medium crude oil (bbls/d)	—	44	862	7,961	8,039	7,512	7,682	8,180	8,397	8,320	8,482	12,032
Condensate <sup>(1)</sup> (bbls/d)	—	—	36	266	328	182	260	258	260	338	364	312
Other NGLs <sup>(1)</sup> (bbls/d)	—	1	98	792	677	784	768	834	768	891	887	1,298
<b>NGLs (bbls/d)</b>	—	1	134	1,058	1,005	966	1,028	1,092	1,028	1,229	1,251	1,610
Conventional natural gas (mmcf/d)	—	0.02	0.80	10.09	9.44	9.63	8.62	10.11	10.91	11.96	12.97	17.46
<b>Total (boe/d)</b>	—	48	1,131	10,701	10,617	10,084	10,147	10,956	11,244	11,542	11,894	16,552
<b>Consolidated</b>												
Light and medium crude oil (bbls/d)	<b>14,962</b>	17,117	20,326	28,768	26,235	26,521	26,188	28,948	28,426	28,685	26,952	25,753
Condensate <sup>(1)</sup> (bbls/d)	<b>8,730</b>	8,284	7,871	8,681	6,151	3,806	3,649	3,931	4,269	4,180	4,463	3,589
Other NGLs <sup>(1)</sup> (bbls/d)	<b>12,044</b>	12,140	10,985	12,656	9,167	6,612	7,547	7,196	7,046	7,412	7,344	6,538
<b>NGLs (bbls/d)</b>	<b>20,774</b>	20,424	18,856	21,337	15,318	10,418	11,196	11,127	11,315	11,592	11,807	10,127
Conventional natural gas (mmcf/d)	<b>539.29</b>	502.60	479.28	515.38	369.36	279.59	280.73	269.39	274.59	283.91	263.80	283.63
<b>Total (boe/d)</b>	<b>125,618</b>	121,308	119,062	136,002	103,115	83,536	84,173	84,974	85,505	87,597	82,727	83,152
						YTD 2026	2025	2024	2023	2022	2021	
<b>Continuing Operations</b>												
<b>Canada</b>												
Light and medium crude oil (bbls/d)						<b>5,592</b>	5,389	4,124	558	2,713	2,136	
Condensate <sup>(1)</sup> (bbls/d)						<b>8,708</b>	7,550	3,573	3,761	4,280	4,475	
Other NGLs <sup>(1)</sup> (bbls/d)						<b>12,044</b>	10,374	5,317	4,981	5,772	5,857	
<b>NGLs (bbls/d)</b>						<b>20,752</b>	17,924	8,890	8,742	10,052	10,332	
Conventional natural gas (mmcf/d)						<b>440.41</b>	350.89	147.35	144.26	130.44	122.90	
<b>Total (boe/d)</b>						<b>99,746</b>	81,794	37,570	33,344	34,505	32,951	
<b>France</b>												
Light and medium crude oil (bbls/d)						<b>6,729</b>	6,859	7,188	7,584	7,639	8,799	
<b>Total (boe/d)</b>						<b>6,729</b>	6,859	7,188	7,584	7,639	8,799	
<b>Netherlands</b>												
Light and medium crude oil (bbls/d)						—	—	—	—	—	—	3
Condensate <sup>(1)</sup> (bbls/d)						<b>22</b>	35	75	71	66	97	
<b>NGLs (bbls/d)</b>						<b>22</b>	35	75	71	66	97	
Conventional natural gas (mmcf/d)						<b>23.15</b>	22.87	26.77	28.18	32.66	43.40	
<b>Total (boe/d)</b>						<b>3,880</b>	3,847	4,536	4,768	5,510	7,334	
<b>Germany</b>												
Light and medium crude oil (bbls/d)						<b>1,593</b>	1,653	1,653	1,654	1,435	1,044	
Conventional natural gas (mmcf/d)						<b>25.91</b>	25.36	21.10	21.93	26.18	15.81	
<b>Total (boe/d)</b>						<b>5,912</b>	5,880	5,170	5,310	5,798	3,679	
<b>Ireland</b>												
Conventional natural gas (mmcf/d)						<b>44.54</b>	49.12	58.10	51.12	27.48	29.25	
<b>Total (boe/d)</b>						<b>7,423</b>	8,187	9,683	8,520	4,579	4,875	

	YTD 2026	2025	2024	2023	2022	2021
<b>Australia</b>						
Light and medium crude oil (bbls/d)	1,045	3,392	3,446	1,492	3,995	3,810
<b>Total (boe/d)</b>	<b>1,045</b>	<b>3,392</b>	<b>3,446</b>	<b>1,492</b>	<b>3,995</b>	<b>3,810</b>
<b>Central and Eastern Europe</b>						
Conventional natural gas (mmcf/d)	5.28	10.14	5.86	0.38	0.57	0.31
<b>Total (boe/d)</b>	<b>883</b>	<b>1,692</b>	<b>978</b>	<b>63</b>	<b>95</b>	<b>51</b>
<b>Discontinued Operations</b>						
<b>United States</b>						
Light and medium crude oil (bbls/d)	—	1,591	3,162	3,445	2,908	2,597
Condensate <sup>(1)</sup> (bbls/d)	—	11	25	21	34	8
Other NGLs <sup>(1)</sup> (bbls/d)	—	481	994	1,076	1,066	1,146
<b>NGLs (bbls/d)</b>	<b>—</b>	<b>492</b>	<b>1,019</b>	<b>1,097</b>	<b>1,100</b>	<b>1,154</b>
Conventional natural gas (mmcf/d)	—	3.62	7.11	7.28	7.20	6.84
<b>Total (boe/d)</b>	<b>—</b>	<b>2,686</b>	<b>5,367</b>	<b>5,754</b>	<b>5,207</b>	<b>4,890</b>
<b>Canada - Saskatchewan</b>						
Light and medium crude oil (bbls/d)	—	4,195	7,941	12,735	14,117	14,818
Condensate <sup>(1)</sup> (bbls/d)	—	156	240	405	341	356
Other NGLs <sup>(1)</sup> (bbls/d)	—	389	789	1,239	1,123	1,322
<b>NGLs (bbls/d)</b>	<b>—</b>	<b>545</b>	<b>1,029</b>	<b>1,644</b>	<b>1,464</b>	<b>1,678</b>
Conventional natural gas (mmcf/d)	—	5.05	9.81	16.68	13.66	15.13
<b>Total (boe/d)</b>	<b>—</b>	<b>5,582</b>	<b>10,605</b>	<b>17,159</b>	<b>17,859</b>	<b>19,017</b>
<b>Consolidated</b>						
Light and medium crude oil (bbls/d)	14,962	23,079	27,514	27,469	32,809	33,208
Condensate <sup>(1)</sup> (bbls/d)	8,730	7,753	3,913	4,258	4,721	4,936
Other NGLs <sup>(1)</sup> (bbls/d)	12,044	11,244	7,100	7,296	7,961	8,325
<b>NGLs (bbls/d)</b>	<b>20,774</b>	<b>18,997</b>	<b>11,013</b>	<b>11,554</b>	<b>12,682</b>	<b>13,261</b>
Conventional natural gas (mmcf/d)	539.29	467.06	276.10	269.83	238.18	233.64
<b>Total (boe/d)</b>	<b>125,618</b>	<b>119,919</b>	<b>84,543</b>	<b>83,994</b>	<b>85,187</b>	<b>85,408</b>

<sup>(1)</sup> 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 <sup>(1)</sup>

	Q1/26	Q4/25	Q3/25	Q2/25	Q1/25	Q4/24	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23
<b>Continuing operations:</b>												
<b>Canada</b>												
Crude oil and condensate (bbls/d)	14,300	13,726	13,894	14,178	9,904	7,648	8,181	7,883	7,067	6,990	7,618	4,063
NGLs (bbls/d)	12,044	12,099	10,579	11,072	7,695	4,980	5,715	5,374	5,200	5,390	5,333	4,215
Natural gas (mmcf/d)	440.40	391.39	367.34	394.06	249.02	151.64	148.38	148.37	140.93	148.20	150.97	141.80
<b>Total (boe/d)</b>	<b>99,746</b>	<b>91,056</b>	<b>85,696</b>	<b>90,926</b>	<b>59,104</b>	<b>37,898</b>	<b>38,625</b>	<b>37,987</b>	<b>35,753</b>	<b>37,081</b>	<b>38,113</b>	<b>31,912</b>
<b>International</b>												
Crude oil and condensate (bbls/d)	9,389	11,621	12,248	12,055	11,835	12,502	10,792	12,714	13,459	14,004	10,534	9,564
Natural gas (mmcf/d)	98.88	111.07	108.29	105.39	105.12	112.44	116.66	103.64	114.52	116.27	92.61	117.14
<b>Total (boe/d)</b>	<b>25,870</b>	<b>30,137</b>	<b>30,299</b>	<b>29,623</b>	<b>29,355</b>	<b>31,243</b>	<b>30,237</b>	<b>29,987</b>	<b>32,546</b>	<b>33,381</b>	<b>25,969</b>	<b>29,087</b>
<b>Discontinued operations:</b>												
Crude oil and condensate (bbls/d)	—	56	2,052	11,216	10,647	10,177	10,863	12,282	12,169	11,872	13,265	15,715
NGLs (bbls/d)	—	40	406	1,584	1,472	1,632	1,832	1,822	1,846	2,022	2,011	2,323
Natural gas (mmcf/d)	—	0.13	3.63	15.93	15.22	15.51	15.70	17.38	19.14	19.45	20.22	24.69
<b>Total (boe/d)</b>	<b>—</b>	<b>117</b>	<b>3,065</b>	<b>15,452</b>	<b>14,656</b>	<b>14,395</b>	<b>15,311</b>	<b>17,000</b>	<b>17,206</b>	<b>17,135</b>	<b>18,645</b>	<b>22,153</b>
<b>Consolidated</b>												
Crude oil and condensate (bbls/d)	23,692	25,401	28,197	37,449	32,386	30,327	29,837	32,879	32,695	32,866	31,416	29,341
NGLs (bbls/d)	12,044	12,140	10,985	12,656	9,167	6,612	7,547	7,196	7,046	7,412	7,344	6,538
Natural gas (mmcf/d)	539.29	502.60	479.28	515.38	369.36	279.59	280.73	269.39	274.59	283.92	263.80	283.63
<b>Total (boe/d)</b>	<b>125,618</b>	<b>121,308</b>	<b>119,062</b>	<b>136,002</b>	<b>103,115</b>	<b>83,536</b>	<b>84,173</b>	<b>84,974</b>	<b>85,505</b>	<b>87,597</b>	<b>82,727</b>	<b>83,152</b>

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

### Sales volumes

	Q1/26	Q4/25	Q3/25	Q2/25	Q1/25	Q4/24	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23
<b>Continuing operations:</b>												
<b>Canada</b>												
Crude oil and condensate (bbls/d)	14,300	13,726	13,894	14,178	9,904	7,648	8,181	7,883	7,067	6,990	7,618	4,063
NGLs (bbls/d)	12,044	12,099	10,579	11,072	7,695	4,980	5,715	5,374	5,200	5,390	5,333	4,215
Natural gas (mmcf/d)	440.40	391.39	367.34	394.06	249.02	151.64	148.38	148.37	140.93	148.20	150.97	141.80
<b>Total (boe/d)</b>	<b>99,746</b>	<b>91,056</b>	<b>85,696</b>	<b>90,926</b>	<b>59,104</b>	<b>37,898</b>	<b>38,625</b>	<b>37,987</b>	<b>35,753</b>	<b>37,081</b>	<b>38,113</b>	<b>31,912</b>
<b>International</b>												
Crude oil and condensate (bbls/d)	10,641	12,168	14,018	10,344	11,145	11,360	12,580	11,998	15,938	9,221	9,950	10,302
Natural gas (mmcf/d)	98.88	111.07	108.29	105.39	105.12	112.44	116.66	103.64	114.52	116.27	92.61	117.14
<b>Total (boe/d)</b>	<b>27,121</b>	<b>30,681</b>	<b>32,069</b>	<b>27,911</b>	<b>28,668</b>	<b>30,101</b>	<b>32,024</b>	<b>29,271</b>	<b>35,026</b>	<b>28,598</b>	<b>25,386</b>	<b>29,824</b>
<b>Discontinued operations:</b>												
Crude oil and condensate (bbls/d)	—	56	2,052	11,216	10,647	10,177	10,863	12,282	12,169	11,872	13,265	15,715
NGLs (bbls/d)	—	40	406	1,584	1,472	1,632	1,832	1,822	1,846	2,022	2,011	2,323
Natural gas (mmcf/d)	—	0.13	3.63	15.93	15.22	15.51	15.70	17.38	19.14	19.45	20.22	24.69
<b>Total (boe/d)</b>	<b>—</b>	<b>117</b>	<b>3,065</b>	<b>15,452</b>	<b>14,656</b>	<b>14,395</b>	<b>15,311</b>	<b>17,000</b>	<b>17,206</b>	<b>17,135</b>	<b>18,645</b>	<b>22,153</b>
<b>Consolidated</b>												
Crude oil and condensate (bbls/d)	24,941	25,946	29,968	35,738	31,698	29,185	31,624	32,163	35,174	28,083	30,833	30,080
NGLs (bbls/d)	12,044	12,140	10,985	12,656	9,167	6,612	7,547	7,196	7,046	7,412	7,344	6,538
Natural gas (mmcf/d)	539.29	502.60	479.28	515.38	369.36	279.59	280.73	269.39	274.59	283.92	263.80	283.63
<b>Total (boe/d)</b>	<b>126,867</b>	<b>121,852</b>	<b>120,833</b>	<b>134,290</b>	<b>102,427</b>	<b>82,394</b>	<b>85,960</b>	<b>84,258</b>	<b>87,985</b>	<b>82,814</b>	<b>82,144</b>	<b>83,889</b>

## Financial results

	Q1/26	Q4/25	Q3/25	Q2/25	Q1/25	Q4/24	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23
<b>Continuing operations:</b>												
<b>Canada</b>												
Crude oil and condensate sales (\$/bbl)	95.10	78.32	85.25	83.86	91.67	93.50	94.81	101.35	89.71	99.69	94.82	156.65
NGL sales (\$/bbl)	23.00	20.99	22.63	23.37	29.75	27.76	25.96	27.93	31.21	30.77	27.34	26.83
Natural gas sales (\$/mcf)	2.94	2.60	1.37	2.25	2.77	1.99	0.97	1.31	2.11	2.64	2.47	2.33
Sales (\$/boe)	29.40	25.75	22.51	25.67	31.26	30.81	28.11	30.60	31.01	34.46	33.20	35.09
Royalties (\$/boe)	(2.23)	(2.14)	(1.39)	(1.97)	(3.51)	(1.96)	(3.22)	(2.83)	(3.42)	(3.98)	(3.39)	(2.31)
Transportation (\$/boe)	(2.42)	(2.66)	(2.96)	(2.77)	(3.06)	(3.42)	(3.46)	(3.07)	(2.47)	(2.56)	(2.04)	(1.43)
Operating (\$/boe)	(6.55)	(6.49)	(6.97)	(7.55)	(8.07)	(11.10)	(8.88)	(11.98)	(10.39)	(9.47)	(11.12)	(7.80)
General and administration (\$/boe) <sup>(1)</sup>	(0.83)	(1.17)	(0.90)	(1.42)	(3.33)	(0.99)	0.20	(1.86)	(0.60)	2.94	0.71	1.65
Corporate income taxes (\$/boe)	(0.22)	0.06	(0.27)	(0.28)	(0.08)	0.60	(0.47)	1.19	(0.97)	0.34	(0.01)	(0.17)
<b>Fund flows from operations (\$/boe)</b>	<b>17.15</b>	<b>13.35</b>	<b>10.02</b>	<b>11.68</b>	<b>13.21</b>	<b>13.94</b>	<b>12.28</b>	<b>12.05</b>	<b>13.16</b>	<b>21.73</b>	<b>17.35</b>	<b>25.03</b>
Fund flows from operations	154,013	111,763	79,036	96,654	70,248	48,598	43,633	41,638	42,856	74,171	60,866	72,684
Drilling and development	(113,897)	(134,523)	(92,293)	(45,211)	(121,851)	(85,682)	(54,522)	(43,594)	(110,864)	(40,674)	(39,245)	(53,352)
<b>Free cash flow</b>	<b>40,116</b>	<b>(22,760)</b>	<b>(13,257)</b>	<b>51,443</b>	<b>(51,603)</b>	<b>(37,084)</b>	<b>(10,889)</b>	<b>(1,956)</b>	<b>(68,008)</b>	<b>33,497</b>	<b>21,621</b>	<b>19,332</b>
<b>International</b>												
Crude oil and condensate sales (\$/bbl)	108.00	88.68	98.71	90.82	108.97	110.31	114.16	116.24	119.68	123.77	114.26	100.23
Natural gas sales (\$/mcf)	16.40	14.07	14.53	15.22	20.41	18.11	14.55	12.72	11.63	16.92	13.34	14.58
Sales (\$/boe)	102.19	86.09	92.21	91.13	117.22	109.27	97.85	92.68	92.48	108.70	93.46	91.89
Royalties (\$/boe)	(4.61)	(5.12)	(5.58)	(5.10)	(4.43)	(5.38)	(4.16)	(4.49)	(4.60)	(3.41)	3.55	(7.43)
Transportation (\$/boe)	(4.76)	(4.92)	(3.91)	(4.22)	(4.63)	(3.37)	(3.81)	(4.20)	(3.65)	(3.91)	(4.53)	(5.23)
Operating (\$/boe)	(33.96)	(27.86)	(28.29)	(23.80)	(27.46)	(25.08)	(27.11)	(26.56)	(25.30)	(22.64)	(25.58)	(28.24)
General and administration (\$/boe)	(5.13)	(5.52)	(3.98)	(4.67)	(4.67)	(6.21)	(5.56)	(5.20)	(4.86)	(9.18)	(7.37)	(7.58)
Corporate income taxes (\$/boe)	(3.98)	2.96	(0.86)	(3.46)	(7.22)	(6.53)	(3.74)	(6.08)	(7.06)	(7.81)	(13.42)	(6.79)
PRRT (\$/boe)	—	2.97	(0.56)	(0.30)	(1.17)	1.16	(0.17)	(1.37)	(3.38)	7.93	—	—
<b>Fund flows from operations (\$/boe)</b>	<b>49.74</b>	<b>48.60</b>	<b>49.03</b>	<b>49.58</b>	<b>67.64</b>	<b>63.86</b>	<b>53.30</b>	<b>44.78</b>	<b>43.63</b>	<b>69.68</b>	<b>46.11</b>	<b>36.62</b>
Fund flows from operations	121,407	137,175	144,615	125,955	174,521	176,883	157,048	119,310	139,054	183,351	107,706	99,377
Drilling and development	(20,375)	(59,785)	(54,418)	(53,055)	(36,565)	(42,341)	(40,638)	(47,830)	(45,789)	(73,604)	(49,701)	(28,347)
Exploration and evaluation	(120)	2,011	(601)	(4,210)	(14,373)	(22,161)	(260)	(1,260)	(5,123)	(7,612)	(5,766)	(2,504)
<b>Free cash flow</b>	<b>100,912</b>	<b>79,401</b>	<b>89,596</b>	<b>68,690</b>	<b>123,583</b>	<b>112,381</b>	<b>116,150</b>	<b>70,220</b>	<b>88,142</b>	<b>102,135</b>	<b>52,239</b>	<b>68,526</b>
<b>Discontinued operations</b>												
Crude oil and condensate sales (\$/bbl)	—	88.70	90.96	81.28	93.64	91.88	95.57	104.51	90.61	97.61	105.81	75.66
NGL sales (\$/bbl)	—	77.17	32.39	33.83	47.63	37.41	35.94	46.43	46.90	45.49	33.84	34.03
Natural gas sales (\$/mcf)	—	7.19	2.90	1.71	3.01	1.89	0.24	1.13	2.38	2.42	2.93	2.08
Sales (\$/boe)	—	76.83	68.62	64.23	75.93	71.23	72.36	81.63	71.77	75.74	82.11	59.56
Royalties (\$/boe)	—	(19.04)	(15.56)	(11.95)	(14.56)	(13.83)	(13.53)	(16.09)	(14.54)	(14.35)	(16.68)	(9.97)
Transportation (\$/boe)	—	(3.53)	(3.64)	(2.13)	(2.23)	(2.04)	(2.26)	(2.26)	(2.11)	(2.18)	(2.18)	(1.76)
Operating (\$/boe)	—	6.78	(20.06)	(18.44)	(21.23)	(23.73)	(19.44)	(18.14)	(22.27)	(15.89)	(14.08)	(18.59)
General and administration (\$/boe)	—	(78.97)	(16.98)	(7.61)	(3.73)	(5.15)	(4.36)	(4.06)	(4.00)	(3.62)	(3.64)	(2.12)
<b>Fund flows from operations (\$/boe)</b>	<b>—</b>	<b>(17.93)</b>	<b>12.38</b>	<b>24.10</b>	<b>34.18</b>	<b>26.48</b>	<b>32.77</b>	<b>41.08</b>	<b>28.85</b>	<b>39.70</b>	<b>45.53</b>	<b>27.12</b>
Fund flows from operations	(152)	(193)	3,493	33,893	45,087	35,064	46,160	63,549	45,171	62,595	78,094	54,662
Drilling and development	126	551	1,920	(12,972)	(9,048)	(48,482)	(23,649)	(17,926)	(25,645)	(18,030)	(30,458)	(82,371)
Exploration and evaluation	(314)	(6)	(170)	(41)	(282)	(1,993)	(2,200)	—	(3,021)	(2,967)	(469)	(271)
<b>Free cash flow</b>	<b>(340)</b>	<b>352</b>	<b>5,243</b>	<b>20,880</b>	<b>35,757</b>	<b>(15,411)</b>	<b>20,311</b>	<b>45,623</b>	<b>16,505</b>	<b>41,598</b>	<b>47,167</b>	<b>(27,980)</b>

	Q1/26	Q4/25	Q3/25	Q2/25	Q1/25	Q4/24	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23
<b>Consolidated</b>												
Crude oil and condensate sales (\$/bbl)	100.61	83.21	91.93	85.07	99.36	100.06	103.55	108.93	104.26	107.91	106.94	96.64
NGL sales (\$/bbl)	23.00	21.17	22.99	24.68	31.56	29.38	27.49	31.61	34.16	33.38	27.77	28.11
Natural gas sales (\$/mcf)	5.41	5.13	4.36	4.88	7.80	8.47	6.57	5.69	6.10	8.48	6.32	7.37
Sales (\$/boe)	44.96	40.99	42.18	43.71	61.71	66.54	61.97	62.46	63.45	68.64	62.92	61.74
Royalties (\$/boe)	(2.74)	(2.91)	(2.86)	(3.77)	(5.35)	(5.28)	(5.40)	(6.08)	(6.06)	(5.93)	(4.26)	(6.16)
Transportation (\$/boe)	(2.92)	(3.23)	(3.23)	(3.00)	(3.38)	(3.16)	(3.38)	(3.30)	(2.87)	(2.95)	(2.84)	(2.87)
Operating (\$/boe)	(12.42)	(11.86)	(12.96)	(12.18)	(15.38)	(18.41)	(17.55)	(18.29)	(18.65)	(15.35)	(16.26)	(17.91)
General and administration (\$/boe)	(1.76)	(2.34)	(2.13)	(2.80)	(3.76)	(3.62)	(2.76)	(3.46)	(2.96)	(2.60)	(2.77)	(2.63)
Corporate income taxes (\$/boe)	(1.02)	0.79	(0.42)	(0.91)	(2.07)	(2.11)	(1.61)	(1.58)	(3.20)	(2.57)	(7.05)	(7.04)
PRRT (\$/boe)	—	0.75	(0.15)	(0.06)	(0.33)	0.43	(0.06)	(0.47)	(1.35)	2.74	—	—
Interest (\$/boe)	(2.34)	(2.47)	(3.10)	(3.08)	(3.58)	(3.16)	(2.68)	(2.75)	(2.30)	(3.01)	(2.68)	(2.65)
Equity based compensation (\$/boe)	—	(0.06)	—	(0.47)	—	—	—	(1.87)	—	—	—	—
Realized derivatives (\$/boe)	(1.39)	1.88	5.56	3.90	1.21	3.80	6.31	6.00	27.55	10.33	9.74	8.86
Realized foreign exchange (\$/boe)	(0.05)	0.01	(0.08)	(0.04)	0.27	0.32	0.15	0.30	0.23	(0.73)	0.28	0.48
Realized other (\$/boe)	0.01	(0.08)	0.01	(0.05)	(1.57)	(0.68)	(0.21)	(0.09)	0.02	0.26	(1.32)	0.53
<b>Fund flows from operations (\$/boe)</b>	<b>20.33</b>	<b>21.47</b>	<b>22.82</b>	<b>21.25</b>	<b>27.77</b>	<b>34.67</b>	<b>34.78</b>	<b>30.87</b>	<b>53.86</b>	<b>48.83</b>	<b>35.76</b>	<b>32.35</b>
Fund flows from operations	232,277	240,734	253,810	259,678	256,029	262,698	275,024	236,703	431,358	372,117	270,218	247,109
Drilling and development	(134,146)	(193,757)	(144,791)	(111,238)	(167,464)	(176,505)	(118,809)	(109,350)	(182,298)	(132,308)	(119,404)	(164,070)
Exploration and evaluation	(434)	2,005	(771)	(4,251)	(14,655)	(24,154)	(2,460)	(1,260)	(8,144)	(10,579)	(6,235)	(2,775)
<b>Free cash flow</b>	<b>97,697</b>	<b>48,982</b>	<b>108,248</b>	<b>144,189</b>	<b>73,910</b>	<b>62,039</b>	<b>153,755</b>	<b>126,093</b>	<b>240,916</b>	<b>229,230</b>	<b>144,579</b>	<b>80,264</b>

(1) General and administration expenses previously presented within the Corporate segment have been reclassified to our Canadian segment. The prior period results have been presented to conform with current period presentation.

## Non-GAAP and Other Specified 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 total of segments measure of profit or loss in accordance with IFRS 8 “Operating Segments” (please see Segmented Information in the Notes to the Consolidated Interim Financial Statements) and net debt, a capital management measure in accordance with IAS 1 “Presentation of Financial Statements” (please see Capital Disclosures in the Notes to the Consolidated Interim Financial Statements).

In addition, this MD&A includes financial measures which are not specified, defined, or determined under IFRS Accounting Standards 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:

### Total of Segments Measure

**Fund flows from operations (FFO):** Most directly comparable to net (loss) earnings, FFO is a non-GAAP financial measure and total of segments measure comprised of sales less royalties, transportation, operating, G&A, corporate income tax, PRRT, interest expense, equity based compensation settled in cash, realized gain (loss) on derivatives, realized foreign exchange gain (loss), and realized other income (expense). The measure is used by management to assess the contribution of each business unit to Vermilion's ability to generate income necessary to pay dividends, repay debt, fund asset retirement obligations and make capital investments. Reconciliation to the most directly comparable primary financial statement measures can be found below. Fund flows from continuing operations and fund flows from discontinued operations are calculated in the same manner as FFO and are most directly comparable to net (loss) earnings from continuing operations and net (loss) earnings discontinued operations, respectively.

#### Reconciliation of fund flows from continuing operations to net (loss) earnings from continuing operations:

	Q1 2026		Q1 2025	
	\$M	\$/boe	\$M	\$/boe
Sales	513,331	44.96	468,693	59.33
Royalties	(31,270)	(2.74)	(30,091)	(3.81)
Transportation	(33,307)	(2.92)	(28,241)	(3.58)
Operating	(141,705)	(12.41)	(113,780)	(14.40)
General and administration <sup>(1)</sup>	(19,965)	(1.75)	(29,735)	(3.76)
Corporate income tax expense	(11,664)	(1.02)	(19,059)	(2.41)
Petroleum resource rent tax	—	—	(3,018)	(0.38)
Interest expense	(26,697)	(2.34)	(32,979)	(4.17)
Realized (loss) gain on derivatives	(15,885)	(1.39)	11,119	1.41
Realized foreign exchange (loss) gain	(544)	(0.05)	2,499	0.32
Realized other expense	135	0.01	(14,466)	(1.83)
<b>Fund flows from continuing operations</b>	<b>232,429</b>	<b>20.35</b>	<b>210,942</b>	<b>26.72</b>
Equity based compensation	(2,451)		(5,931)	
Unrealized loss on derivative instruments <sup>(2)</sup>	(285,648)		(13,675)	
Unrealized foreign exchange loss <sup>(2)</sup>	(15,273)		(36,016)	
Accretion	(18,838)		(15,793)	
Depletion and depreciation	(164,130)		(148,282)	
Deferred tax recovery	112,789		12,923	
Unrealized other expense <sup>(2)</sup>	(84)		(319)	
<b>Net (loss) earnings from continuing operations</b>	<b>(141,206)</b>		<b>3,849</b>	

<sup>(1)</sup> General and administration expenses previously presented within the Corporate segment have been reclassified to our Canadian segment. The prior period results have been presented to conform with current period presentation.

<sup>(2)</sup> Unrealized loss on derivative instruments, Unrealized foreign exchange loss, and Unrealized other expense are line items from the respective Consolidated Statements of Cash Flows.

Reconciliation of fund flows from discontinued operations to net earnings (loss) earnings) from discontinued operations:

	Q1 2026		Q1 2025	
	\$M	\$/boe	\$M	\$/boe
Sales	—	—	100,153	75.93
Royalties	—	—	(19,199)	(14.56)
Transportation	—	—	(2,945)	(2.23)
Operating	(74)	—	(27,997)	(21.23)
General and administration	(78)	—	(4,925)	(3.73)
<b>Fund flows from discontinued operations</b>	<b>(152)</b>	<b>—</b>	<b>45,087</b>	<b>34.18</b>
Unrealized foreign exchange gain <sup>(1)</sup>	6		117	
Accretion	—		(2,087)	
Depletion and depreciation	(5,137)		(28,106)	
Deferred tax recovery (expense)	951		(3,907)	
<b>Net (loss) earnings from discontinued operations</b>	<b>(4,332)</b>		<b>11,104</b>	
<b>Fund flows from operations</b>	<b>232,277</b>	<b>20.33</b>	<b>256,029</b>	<b>27.78</b>
<b>Net (loss) earnings</b>	<b>(145,538)</b>		<b>14,953</b>	

<sup>(1)</sup> Unrealized foreign exchange gain is a line item from the respective Consolidated Statements of Cash Flows.

## Non-GAAP Financial Measures and Non-GAAP Ratios

**Fund flows from operations per basic and diluted share:** FFO per share and diluted share are non-GAAP ratios. 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 (total of segments measure) by the basic weighted average shares outstanding as defined under IFRS Accounting Standards. 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. Fund flows from continuing operations per basic and diluted share and fund flows from discontinued operations per basic and diluted share are calculated in the same manner as FFO per basic and diluted share.

**Fund flows from operations per boe:** Management uses fund flows from operations per boe to assess the profitability of our business units and Vermilion as a whole. Fund flows from operations per boe is calculated by dividing fund flows from operations (total of segments measure) by boe production. Fund flows from continuing operations per boe and fund flows from discontinued operations per boe are calculated in the same manner as FFO per boe.

**Free cash flow (FCF):** Most directly comparable to cash flows from operating activities, FCF is a non-GAAP financial measure calculated as fund flows from operations less drilling and development costs and exploration and evaluation costs. FCF is used by management to determine the funding available for investing and financing activities including payment of dividends, repayment of long-term debt, reallocation into existing business units and deployment into new ventures. Reconciliation to the primary financial statement measures can be found in the following table.

(\$M)	Q1 2026	Q1 2025
Cash flows from operating activities	227,398	280,384
Changes in non-cash operating working capital	(7,923)	(33,702)
Asset retirement obligations settled	12,802	9,347
<b>Fund flows from operations</b>	<b>232,277</b>	<b>256,029</b>
Drilling and development	(134,146)	(167,464)
Exploration and evaluation	(434)	(14,655)
<b>Free cash flow</b>	<b>97,697</b>	<b>73,910</b>

**Capital expenditures:** Most directly comparable to cash flows used in investing activities, capital expenditures is a non-GAAP financial measure calculated as the sum of drilling and development costs and exploration and evaluation costs as derived 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. Reconciliation to the primary financial statement measures can be found below.

(\$M)	Q1 2026	Q1 2025
Drilling and development	134,146	167,464
Exploration and evaluation	434	14,655
<b>Capital expenditures</b>	<b>134,580</b>	<b>182,119</b>

**Payout and payout % of FFO:** Payout and payout % of FFO are, respectively, a non-GAAP financial measure and non-GAAP ratio. Payout is most directly comparable to dividends declared. Payout is comprised of dividends declared plus drilling and development costs, exploration and evaluation costs, and asset retirement obligations settled, and payout % of FFO is calculated as payout divided by FFO. The measure is used by management to assess the amount of cash distributed back to shareholders and reinvested in the business for maintaining production and organic growth. Payout as a percentage of FFO is also referred to as the payout ratio or sustainability ratio. The reconciliation of the measure to the primary financial statement measure can be found below.

(\$M)	Q1 2026	Q1 2025
Dividends declared	20,601	20,043
Drilling and development	134,146	167,464
Exploration and evaluation	434	14,655
Asset retirement obligations settled	12,802	9,347
<b>Payout</b>	<b>167,983</b>	<b>211,509</b>
<b>% of fund flows from operations</b>	<b>72 %</b>	<b>83 %</b>

**Return on capital employed (ROCE):** A non-GAAP ratio, ROCE is a measure that management uses to analyze our profitability and the efficiency of our capital allocation process; the comparable primary financial statement measure is earnings before income taxes. ROCE is calculated by dividing net (loss) 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.

(\$M)	Twelve Months Ended	
	Mar 31, 2026	Mar 31, 2025
Net loss	(814,092)	(34,091)
Taxes	(129,629)	144
Interest expense	126,466	99,193
<b>EBIT</b>	<b>(817,255)</b>	<b>65,246</b>
Average capital employed <sup>(1)</sup>	5,547,531	5,914,151
<b>Return on capital employed</b>	<b>(15)%</b>	<b>1 %</b>

<sup>(1)</sup> Average capital employed includes the current portion of asset retirement obligations, previously presented on a combined basis as long-term. The prior period results have been presented to conform with current period presentation.

**Adjusted working capital (deficit):** Adjusted working capital (deficit) is a non-GAAP financial measure calculated as current assets less current liabilities, excluding current derivatives, current asset retirement obligations and current lease liabilities. The measure is used by management to calculate net debt, a capital management measure disclosed below.

(\$M)	As at	
	Mar 31, 2026	Dec 31, 2025
Current assets	484,784	467,286
Current liabilities	(765,072)	(554,547)
Current derivative asset	(68,409)	(78,694)
Current asset retirement obligation <sup>(1)</sup>	55,937	54,504
Current lease liability	8,298	9,206
Current derivative liability	243,254	6,154
<b>Adjusted working capital deficit</b>	<b>(41,208)</b>	<b>(96,091)</b>

<sup>(1)</sup> Asset retirement obligations previously presented as a combined balance have been reclassified into current and long-term portion of asset retirement obligations. The prior period results have been presented to conform with current period presentation.

**Acquisitions:** Acquisitions is a non-GAAP financial measure and is calculated as the sum of acquisitions, net of cash acquired and acquisitions of securities 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, and net acquired working capital deficit or surplus. Management believes that including these components provides a useful measure of the economic investment associated with our acquisition activity and is most directly comparable to cash flows used in investing activities. A reconciliation to the acquisitions line items in the Consolidated Statements of Cash Flows can be found below.

(\$M)	Q1 2026	Q1 2025
Acquisitions, net of cash acquired	6,035	1,084,456
Shares issued for acquisition	—	13,363
Acquired working capital deficit	—	23,179
<b>Acquisitions</b>	<b>6,035</b>	<b>1,120,998</b>

**Operating netback:** Operating netback is non-GAAP financial measure and is calculated as sales less royalties, operating expense, transportation costs, PRRT, and realized hedging gains and losses, and when presented on a per unit basis, is a non-GAAP ratio. Operating netback is most directly comparable to net (loss) earnings. Management assesses operating netback as a measure of the profitability and efficiency of our field operations.

**Net debt to four quarter trailing fund flows from operations:** Management uses net debt (a capital management measure, as defined below) to four quarter trailing fund flows from operations to assess the Company's ability to repay debt. Net debt to four quarter trailing fund flows from operations is a non-GAAP ratio and is calculated as net debt (capital management measure) divided by fund flows from operations (total of segments measure) from the preceding four quarters.

## Capital Management Measure

**Net debt:** Net debt is a capital management measure in accordance with IAS 1 "Presentation of Financial Statements" that is most directly comparable to long-term debt. 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, current asset retirement obligations and current lease liabilities), and represents Vermilion's net financing obligations after adjusting for the timing of working capital fluctuations.

(\$M)	As at	
	Mar 31, 2026	Dec 31, 2025
Long-term debt	1,254,333	1,243,397
Adjusted working capital <sup>(1)</sup>	41,208	96,091
Unrealized FX on swapped USD borrowings <sup>(2)</sup>	(2,974)	2,902
<b>Net debt</b>	<b>1,292,567</b>	<b>1,342,390</b>
<b>Ratio of net debt to four quarter trailing fund flows from operations <sup>(3)</sup></b>	<b>1.4</b>	<b>1.4</b>

<sup>(1)</sup> Adjusted working capital is defined as current assets less current liabilities (excluding current derivatives, current asset retirement obligations and current lease liabilities).

<sup>(2)</sup> Vermilion may enter into cross currency interest rate swaps to hedge the foreign exchange movements on USD borrowings on our revolving credit facility. Unrealized FX on swapped USD borrowings relates to the unrealized gains and losses on our cross currency interest swaps. At March 31, 2026, there was \$203.4 million of USD borrowings on our revolving credit facility. (December 31, 2025 - \$196.7 million).

<sup>(3)</sup> Subsequent to February 26, 2025, net debt to four quarter trailing fund flows from operations is calculated inclusive of Westbrick Energy's pre-acquisition four quarter trailing fund flows from operations, as if the acquisition of Westbrick Energy occurred at the beginning of the four quarter trailing period, and exclusive of the four quarter trailing fund flows from discontinued operations to reflect the Company's ability to repay debt on a pro forma basis.

## Supplementary Financial Measures

**Diluted shares outstanding:** The sum of shares outstanding at the period end plus outstanding awards under the Long-term Incentive Plan ("LTIP"), based on current estimates of future performance factors and forfeiture rates.

(*000s of shares)	Q1 2026	Q1 2025
Shares outstanding	152,600	154,177
Potential shares issuable pursuant to the LTIP	4,433	3,488
<b>Diluted shares outstanding</b>	<b>157,033</b>	<b>157,665</b>

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Judy Steele<sup>3,7</sup>  
Halifax, Nova Scotia

<sup>1</sup> Chairman (Independent)

<sup>2</sup> Audit Committee Chair (Independent)

<sup>3</sup> Audit Committee Member (Independent)

<sup>4</sup> Governance and Human Resources Committee Chair (Independent)

<sup>5</sup> Governance and Human Resources Committee Member (Independent)

<sup>6</sup> Safety & Sustainability Committee Chair (Independent)

<sup>7</sup> Safety & Sustainability Committee Member (Independent)

<sup>8</sup> Technical Committee Chair (Independent)

<sup>9</sup> Technical Committee Member (Independent)

**OFFICERS / CORPORATE SECRETARY**

Dion Hatcher  
President & Chief Executive Officer

Lars Glemser  
Vice President & Chief Financial Officer

Lara Conrad  
Vice President Business Development

Tamar Epstein  
General Counsel & Corporate Secretary

Yvonne Jeffery  
Vice President Sustainability

Darcy Kerwin  
Vice President International & HSE

Geoff MacDonald  
Vice President Geosciences

Randy McQuaig  
Vice President North America

Averyl Schraven  
Vice President People & Culture

Gerard Schut  
Vice President European Operations

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Canadian Imperial Bank of Commerce

National Bank of Canada

Royal Bank of Canada

Wells Fargo Bank N.A., Canadian Branch

ATB Financial

Bank of America N.A., Canada Branch

Export Development Canada

Fédération des caisses Desjardins du Québec

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JPMorgan Chase Bank, N.A., Toronto Branch

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