Q1 2025

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 2025 guidance, 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 2025 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; 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.

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

Initial Production Rates and Short-Term Test Rates: This document discloses test rates of production for certain wells over short periods of time (i.e. 24 hours, IP30, IP60, IP90, etc.), which are preliminary and not determinative of the rates at which those or any other wells will commence production and thereafter decline. Short-term test rates are not necessarily indicative of long-term well or reservoir performance or of ultimate recovery. Although such rates are useful in confirming the presence of hydrocarbons, they are preliminary in nature, are subject to a high degree of predictive uncertainty as a result of limited data availability and may not be representative of stabilized on-stream production rates. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Production over a longer period will also experience natural decline rates, which can be high in certain plays in which the Company operates, and may not be consistent over the longer term with the decline experienced over an initial production period. Initial production or test rates may also include recovered "load" fluids used in well completion stimulation operations. Actual results will differ from those realized during an initial production period or short-term test period, and the difference may be material.

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
CO2	carbon dioxide
CO2e	carbon dioxide equivalent
GHG	greenhouse gas
GJ	gigajoules
LSB	light sour blend crude oil reference price
mbbls	thousand barrels
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
tCO2e	tonne of carbon dioxide equivalent
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 7, 2025, 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, 2025 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, 2025 and the audited consolidated financial statements for the years ended December 31, 2024 and 2023, together with the accompanying notes. Additional information relating to Vermilion, including its Annual Information Form, is available on SEDAR+ at www.sedarplus.ca or on Vermilion's website at www.vermilionenergy.com.

The unaudited condensed consolidated interim financial statements for the three months ended March 31, 2025 and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with IAS 34, "Interim Financial Reporting", as issued by the International Accounting Standards Board ("IASB").

This MD&A includes references to certain financial measures which are not specified, defined, or determined under 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" and references to "natural gas" mean "conventional natural gas".

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

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

Guidance

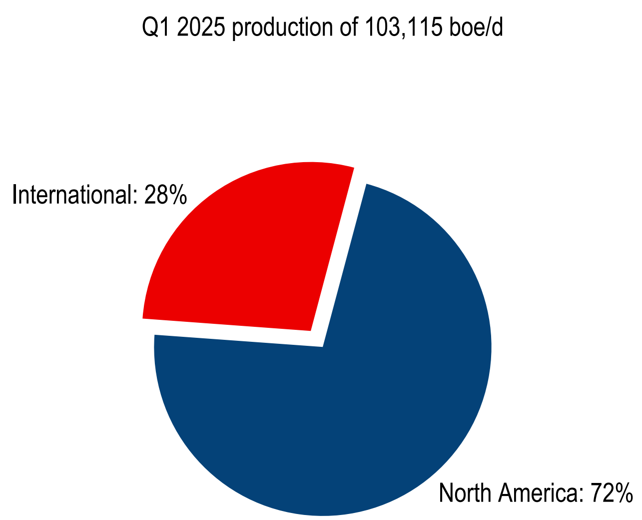
On December 19, 2024, Vermilion released the 2025 capital budget and associated production guidance. On March 5, 2025, the Company updated the 2025 capital budget and associated production guidance following the close of the acquisition of Westbrick Energy Ltd. ("Westbrick"), with incremental capital expenditures and production from the acquired assets reflected in guidance for the remainder of the year. The Company's guidance for 2025 is as follows:

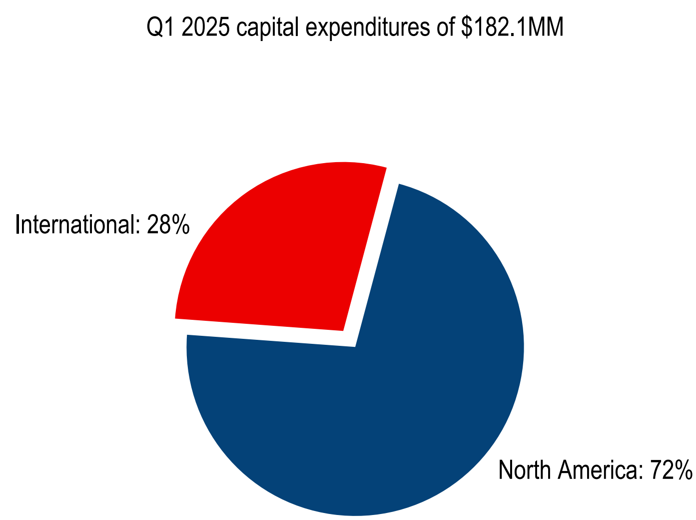
Category	2025 Prior(1)	2025 Current(1)
Production (boe/d)	84,000 - 88,000	125,000 - 130,000
E&D capital expenditures ($MM)	$600 - 625	$730 - 760
Royalty rate (% of sales)	8 - 10%	9 - 11%
Operating ($/boe)	$17.00 - 18.00	$13.50 - 14.50
Transportation ($/boe)	$3.50 - 4.00	$3.00 - 3.50
General and administration ($/boe)	$2.75 - 3.25	$2.25 - 2.75
Cash taxes (% of pre-tax FFO)	7 - 9%	6 - 10%
Asset retirement obligations settled ($MM)	$60	$60
Payments on lease obligations ($MM)	$20	$20

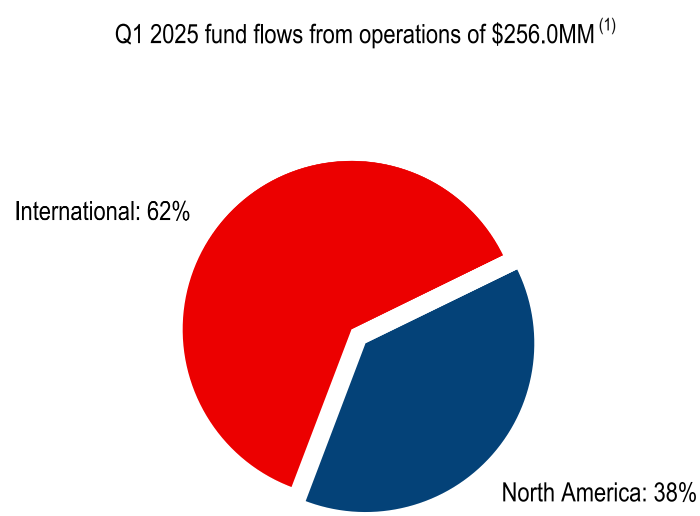
(1) Current 2025 guidance reflects foreign exchange assumptions of CAD/USD 1.43, CAD/EUR 1.51, and CAD/AUD 0.90. Prior 2025 guidance reflects foreign exchange assumptions of CAD/USD 1.40, CAD/EUR 1.48, and CAD/AUD 0.91.

Vermilion's Business

Vermilion is a Calgary, Alberta-based international oil and gas producer focused on the acquisition, exploration, development, and optimization of producing properties in North America, Europe, and Australia. We manage our business through our Calgary head office and our international business unit offices.







(1) The fund flows from operations attributable to North America and International business units above excludes $46.4M of pre-tax fund flows from operations attributable to the Corporate segment. North America includes $0.4MM of corporate income taxes and $12.2MM of general and administration expense recorded in the Corporate segment.

Consolidated Results Overview

	Q1 2025	Q1 2024	Q1/25 vs. Q1/24
Production [1]			
Crude oil and condensate (bbls/d)	**32,386**	32,695	(1)%
NGLs (bbls/d)	**9,167**	7,046	30%
Natural gas (mmcf/d)	**369.36**	274.59	35%
Total (boe/d)	**103,115**	85,505	21%
Build (draw) in inventory (mbbls)	**62**	(226)	
Financial metrics			
Fund flows from operations ($M) [2]	**256,029**	431,358	(41)%
Per share ($/basic share)	**1.66**	2.68	(38)%
Net earnings ($M)	**14,953**	2,305	549%
Per share ($/basic share)	**0.10**	0.01	900%
Cash flows from operating activities ($M)	**280,384**	354,295	(21)%
Free cash flow ($M) [3]	**73,910**	240,916	(69)%
Long-term debt ($M)	**1,874,033**	933,506	101%
Net debt ($M) [4]	**2,062,805**	944,496	118%
Activity			
Capital expenditures ($M) [5]	**182,119**	190,442	(4)%
Acquisitions ($M) [6]	**1,120,998**	9,752	11,395%

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

(2) Fund flows from operations (FFO) and FFO per share are a total of segments measure and supplementary financial measure most directly comparable to net earnings and net 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, 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.

(3) 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. The measure 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.

(4) 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 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.

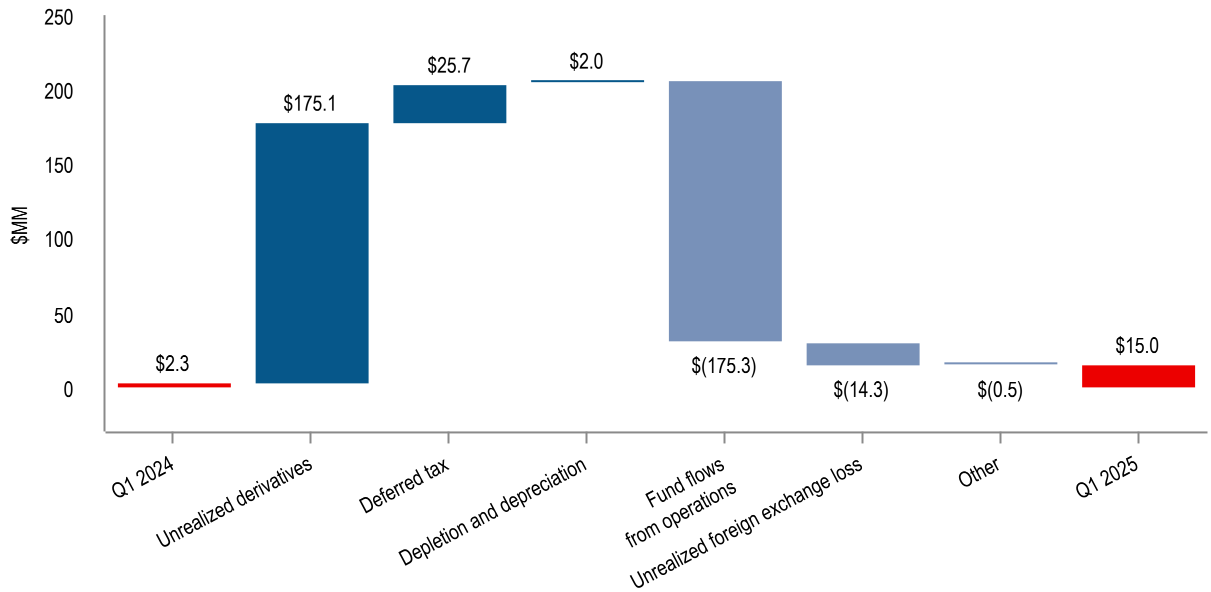
(5) Capital expenditures is a non-GAAP financial measure that does not have a standardized meaning under IFRS Accounting Standards and therefore may not be comparable to similar measures presented by other issuers. The measure is calculated as the sum of drilling and development costs and exploration 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.

(6) 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 2025 vs. Q1 2024

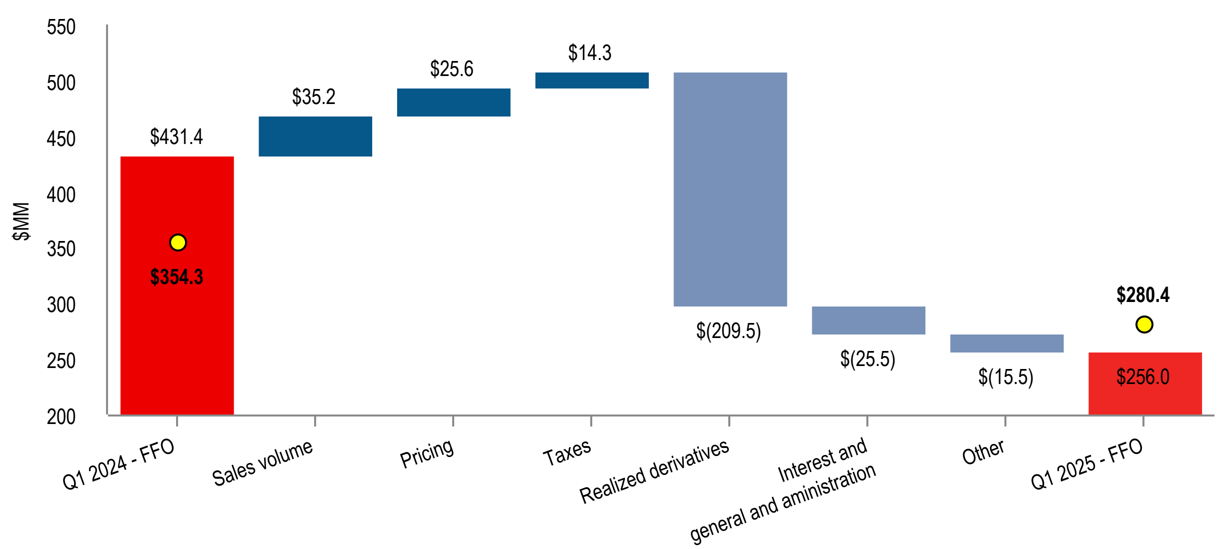
Net earnings of $15.0MM in Q1 2025 compared to net earnings of $2.3MM in Q1 2024



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

- We recorded net earnings of $15.0 million ($0.10/basic share) for Q1 2025 compared to net earnings of $2.3 million ($0.01/basic share) in Q1 2024. The change in earnings was primarily due to changes in our unrealized derivative loss of $175.1 million due to derivative gains realized in 2024 decreasing our mark-to-market position, mostly offset by decreased FFO and higher unrealized foreign exchange loss primarily due to the strengthening of the US dollar and the Euro.

Decreased cash flows from operating activities and FFO driven by changes in realized derivatives



"Sales volume" is the sum of sales volume variance in all regions. "Other" contains royalties, transportation, operating, realized foreign exchange, and other realized income.

- We generated cash flows from operating activities of $280.4 million in Q1 2025 compared to $354.3 million in Q1 2024 and fund flows from operations of $256.0 million in Q1 2025 compared to $431.4 million in Q1 2024. The decrease in fund flows from operations and cash flows from operating activities were primarily driven by lower realized gains on derivative contracts by $209.5 million, higher general and administration costs on transaction costs related to the debt issuance and Westbrick acquisition, higher interest expense on increased debt used to finance the Westbrick acquisition, partially offset by increased sales volume on new production in Canada and Germany and higher pricing.

Production review

Q1 2025 vs. Q1 2024

- Consolidated average production increased to 103,115 boe/d in Q1 2025 compared to Q1 2024 production of 85,505 boe/d. Production increased as a result of the Westbrick acquisition which closed at the end of February 2025. The increase was partially offset by lower production in the United States, the Netherlands and Ireland related to natural well decline.

Activity review

For the three months ended March 31, 2025, capital expenditures were $182.1 million.

- In our North America core region we invested capital expenditures of $130.8 million, comprised of $125.6 million of capital expenditure in Canada and $5.2 million in the United States:
    - Vermilion drilled five (5.0 net), completed seven (7.0 net), and brought on production one (1.0 net) Montney liquids-rich shale gas wells.
    - In the Deep Basin, the Company drilled two (2.0 net), completed three (3.0 net), and brought on production five (5.0 net) liquids-rich conventional natural gas wells on legacy Alberta assets and drilled two (2.0 net), completed three (3.0 net), and brought on production seven (6.5 net) liquids-rich conventional natural gas wells on acquired assets following the close of the Westbrick acquisition. Including wells that were drilled, completed, and brought on production prior to the close of the Westbrick acquisition in February 2025, nine (8.9 net) wells were drilled, 13 (12.5 net) wells completed and 16 (15.5 net) wells brought on production on Vermilion's Deep Basin land base;
    - In Saskatchewan, we drilled two (2.0 net), completed three (3.0 net), and brought on production three (3.0 net) light and medium crude oil wells;
    - In the United States, we participated in the drilling and completion of two (1.1 net) non-operated light and medium crude oil wells, while two (0.3 net) non-operated light and medium crude oil wells were brought on production.

- In our International core region, capital expenditures of $51.3 million were invested:
    - In Germany, we invested $25.2 million as we drilled two (2.0 net) wells, which included one (1.0 net) light and medium crude oil well and the completion of drilling operations on the Weissenmoor Sud deep gas exploration well (1.0 net). This well discovered hydrocarbons and was tested in Q1 2025, however testing operations did not prove commercial gas flows and the Company has elected to suspend the well while we evaluate options to improve deliverability. The Company made progress in bringing the Osterheide well (1.0 net) online in the quarter, with gas flows into the pipeline system commencing at the end of Q1 2025;
    - In Australia, $9.7 million was invested primarily on facilities activities and workovers;
    - In the Netherlands, we invested $7.7 million, primarily on the strategic gas field interconnector intended to centralize gas treatment, expected to come online in the second half of 2025;
    - In France, we invested $6.8 million primarily on subsurface maintenance in the Aquitaine basin, as well as tank and pipeline inspections and workovers;
    - In Central and Eastern Europe, $1.5 million was invested primarily on drilling preparations in Croatia and Slovakia;
    - In Ireland, $0.3 million was invested on facilities.

Financial sustainability review

Free cash flow

- Free cash flow decreased by $167.0 million to $73.9 million for the three months ended March 31, 2025 compared to the prior year period primarily due to lower fund flows from operations driven by lower realized gains on derivative contracts, partially offset by lower capital expenditures.

Long-term debt and net debt

- Long-term debt increased to $1.9 billion as at March 31, 2025 (December 31, 2024 - $1.0 billion) due to the Westbrick acquisition, including the issuance of the $565 million (US $400 million) 2033 senior unsecured notes, and the issuance of the $450 million term loan and $298 million draw on revolving credit facility, partially offset by the repayment of the $399 million (US $300 million USD) 2025 senior unsecured notes.
- As at March 31, 2025, net debt increased by $1.1 billion to $2.1 billion (December 31, 2024 - $1.0 billion) primarily due to the Westbrick acquisition.
- The ratio of net debt to four quarter trailing fund flows from operations(1) increased to 1.7 as at March 31, 2025 (December 31, 2024 - 0.8) primarily due to higher net debt as a result of the Westbrick acquisition, partially offset by the inclusion of Westbrick's four quarter trailing fund flows from operations.

(1) 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 funds flows from operations is calculated inclusive of Westbrick Energy's pre-acquisition four quarter trailing funds flow from operations, as if the acquisition of Westbrick Energy occurred at the beginning of the four-quarter trailing period, to reflect the Company's ability to repay debt on a pro forma basis..

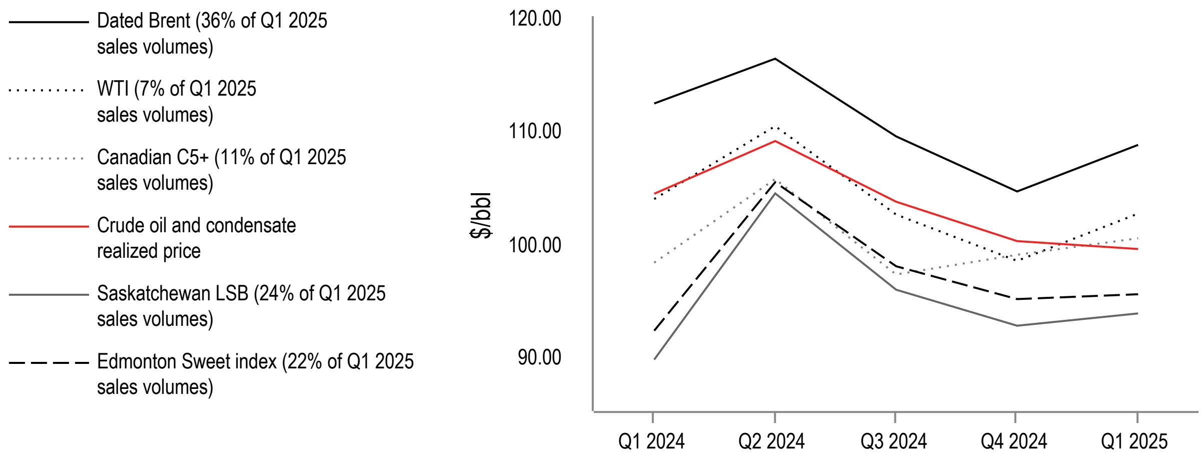
Benchmark Commodity Prices

	Q1 2025	Q1 2024	Q1/25 vs. Q1/24
Crude oil			
WTI ($/bbl)	**102.50**	103.79	(1)%
WTI (US $/bbl)	**71.42**	76.96	(7)%
Edmonton Sweet index ($/bbl)	**95.35**	92.12	4%
Edmonton Sweet index (US $/bbl)	**66.44**	68.31	(3)%
Saskatchewan LSB index ($/bbl)	**93.65**	89.56	5%
Saskatchewan LSB index (US $/bbl)	**65.25**	66.41	(2)%
Canadian C5+ Condensate index ($/bbl)	**100.31**	98.15	2%
Canadian C5+ Condensate index (US $/bbl)	**69.89**	72.78	(4)%
Dated Brent ($/bbl)	**108.59**	112.26	(3)%
Dated Brent (US $/bbl)	**75.66**	83.24	(9)%
Natural gas			
North America			
AECO 5A ($/mcf)	**2.17**	2.50	(13)%
AECO 7A ($/mcf)	**2.02**	2.05	(1)%
Henry Hub ($/mcf)	**5.24**	3.02	74%
Henry Hub (US $/mcf)	**3.65**	2.24	63%
Europe[1]			
NBP Day Ahead ($/mmbtu)	**21.06**	11.78	79%
NBP Month Ahead ($/mmbtu)	**21.37**	12.97	65%
NBP Day Ahead (€/mmbtu)	**13.94**	8.05	73%
NBP Month Ahead (€/mmbtu)	**14.14**	8.86	60%
TTF Day Ahead ($/mmbtu)	**20.81**	11.77	77%
TTF Month Ahead ($/mmbtu)	**21.16**	13.10	62%
TTF Day Ahead (€/mmbtu)	**13.77**	8.04	71%
TTF Month Ahead (€/mmbtu)	**14.00**	8.95	56%
Average exchange rates			
CDN $/US $	**1.44**	1.35	7%
CDN $/Euro	**1.51**	1.46	3%
Realized prices			
Crude oil and condensate ($/bbl)	**99.36**	104.26	(5)%
NGLs ($/bbl)	**31.56**	34.16	(8)%
Natural gas ($/mcf)	**7.80**	6.10	28%
Total ($/boe)	**61.71**	63.45	(3)%

(1) NBP and TTF pricing can occur on a day-ahead ("DA") or month-ahead ("MA") basis. DA prices in a period reflect the average current day settled price on the next days' delivery and MA prices in a period represent daily one month futures contract prices which are determined at the end of each month. In a rising price environment, the DA price will tend to be greater than the MA price and vice versa. Natural gas in the Netherlands and Germany is benchmarked to the TTF and production is generally equally split between DA and MA contracts. Natural gas in Ireland is benchmarked to the NBP and is sold on DA contracts.

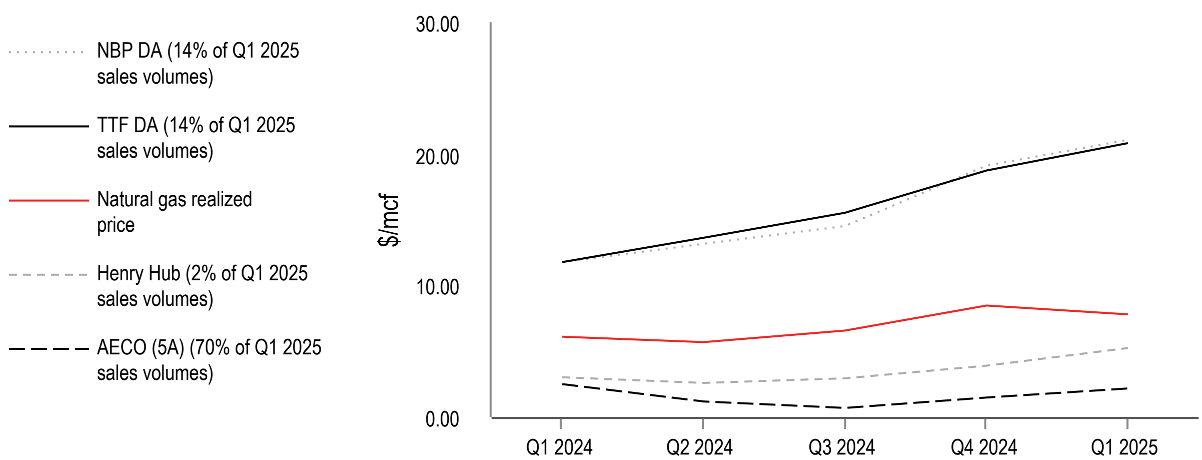
As an internationally diversified producer, we are exposed to a range of commodity prices. In our North America core region, our crude oil is sold at benchmarks linked to WTI (including the Edmonton Sweet index, the Saskatchewan LSB index, and the Canadian C5+ index) and our natural gas is sold at benchmarks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

Q1 2025 realized crude oil and condensate price was a $4.01/bbl premium to Edmonton Sweet Index



- Crude oil prices decreased in Q1 2025 relative to Q1 2024 on weaker supply-demand fundamentals and macroeconomic uncertainty. Canadian dollar WTI decreased by 1% and Dated Brent decreased by 3% in Q1 2025 relative to Q1 2024.
- In Canadian dollar terms, year-over-year, the Edmonton Sweet differential tightened by $4.53/bbl to a discount of $7.15/bbl against WTI, and the Saskatchewan LSB differential tightened by $5.39/bbl to a discount of $8.85/bbl against WTI.
- Approximately 36% of Vermilion's Q1 2025 crude oil and condensate production was priced at the Dated Brent index, which averaged a premium to WTI of US$4.24/bbl, while the remainder of our crude oil and condensate production was priced at the Saskatchewan LSB, Canadian C5+, Edmonton Sweet, and WTI indices.

Q1 2025 realized natural gas price was a $5.63/mcf premium to AECO 5A



- In Canadian dollar terms, year-over-year, prices for European natural gas at NBP and TTF increased by 79% and 77% respectively on a day-ahead basis. On a month ahead basis, NBP and TTF increased by 65% and 62% respectively. Prices increased in response to higher demand coming from the global LNG market, termination of Russian gas exports to Europe through Ukraine as of January 1, 2025, and below average storage levels due to a colder winter leading to high withdrawals.
- Year-over-year natural gas prices in Canadian dollar terms at NYMEX HH increased by 62% and AECO 7A decreased by 13%. AECO prices declined due to strong production growth and historically high storage levels, whereas NYMEX HH performed relatively better due to stronger US natural gas demand and moderate supply growth.
- For Q1 2025, average European natural gas prices represented an $18.93/mcf premium to AECO. Approximately 28% of our natural gas production in Q1 2025 benefited from this premium European pricing.

North America

	Q1 2025	Q1 2024
Production [1]		
Crude oil and condensate (bbls/d)	**20,551**	19,236
NGLs (bbls/d)	**9,167**	7,046
Natural gas (mmcf/d)	**264.24**	160.07
Total production volume (boe/d)	**73,760**	52,959

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

	Q1 2025		Q1 2024	
	$M	$/boe	$M	$/boe
Sales	**266,417**	**40.13**	213,256	44.25
Royalties	**(37,856)**	**(5.70)**	(33,880)	(7.03)
Transportation	**(19,240)**	**(2.90)**	(11,333)	(2.35)
Operating	**(70,820)**	**(10.67)**	(68,672)	(14.25)
General and administration [1]	**(22,560)**	**(3.40)**	(8,202)	(1.70)
Corporate income tax recovery (expense) [1]	**(435)**	**(0.07)**	(3,142)	(0.65)
Fund flows from operations	**115,506**	**17.39**	88,027	18.27
Drilling and development	**(130,810)**		(136,509)	
Free cash flow	**(15,304)**		(48,482)	

(1) General and administration includes amounts from our Corporate segment. Corporate income tax expense primarily relates to income taxes on Corporate segment activities.

Production from Vermilion's North American operations averaged 73,760 boe/d in Q1 2025, an increase of 41% from the previous quarter primarily due to the closing of the acquisition of Westbrick Energy Ltd. in February 2025 and the resumption of production following third-party downtime and partial shut-in of some Canadian gas production in the prior quarter.

In Q1 2025, Vermilion drilled five (5.0 net), completed seven (7.0 net), and brought on production one (1.0 net) Montney liquids-rich shale gas wells. In the Deep Basin, the Company drilled two (2.0 net), completed three (3.0 net), and brought on production five (5.0 net) liquids-rich conventional natural gas wells on legacy Alberta assets and drilled two (2.0 net), completed three (3.0 net), and brought on production seven (6.5 net) liquids-rich conventional natural gas wells on acquired assets following the close of the Westbrick acquisition. Including wells that were drilled, completed, and brought on production prior to the close of the Westbrick acquisition in February 2025, nine (8.9 net) wells were drilled, 13 (12.5 net) wells completed and 16 (15.5 net) wells brought on production on Vermilion's Deep Basin land base.

In Saskatchewan, we drilled two (2.0 net), completed three (3.0 net), and brought on production three (3.0 net) light and medium crude oil wells, while in the United States, we participated in the drilling and completion of two (1.1 net) non-operated light and medium crude oil wells, while two (0.3 net) non-operated light and medium crude oil wells were brought on production.

Sales

	Q1 2025		Q1 2024	
	$M	$/boe	$M	$/boe
Canada	**240,399**	**38.31**	175,045	40.93
United States	**26,018**	**71.57**	38,211	70.43
North America	**266,417**	**40.13**	213,256	44.25

Sales in North America increased for the three months ended March 31, 2025 compared to the prior year primarily due to increased production in Alberta from the Westbrick acquisition, and in British Columbia with 15 Mica Montney wells brought online in 2024, partially offset by decreased production in the United States.

Royalties

	Q1 2025		Q1 2024	
	$M	**$/boe**	**$M**	**$/boe**
Canada	**(30,589)**	**(4.87)**	(22,555)	(5.27)
United States	**(7,267)**	**(19.99)**	(11,325)	(20.87)
North America	**(37,856)**	**(5.70)**	(33,880)	(7.03)
Royalty rate (% of sales)	**14.2 %**		15.9 %	

Royalties in North America increased on a dollar basis for the three months ended March 31, 2025 compared to the prior year primarily due to gas royalties in Alberta on higher production from the Westbrick acquisition and crude royalties at Mica on increased production. Royalties decreased on a per unit basis for the three months ended March 31, 2025 primarily due to the change in production mix with lower royalty rates on gas relative to liquids.

Transportation

	Q1 2025		Q1 2024	
	$M	**$/boe**	**$M**	**$/boe**
Canada	**(19,115)**	**(3.05)**	(10,954)	(2.56)
United States	**(125)**	**(0.34)**	(379)	(0.70)
North America	**(19,240)**	**(2.90)**	(11,333)	(2.35)

Transportation expense in North America increased on a dollar and per boe basis for the three months ended March 31, 2025 compared to the prior year comparable periods primarily due to transportation costs on acquired Westbrick assets and increased pipeline fees in British Colombia.

Operating expense

	Q1 2025		Q1 2024	
	$M	**$/boe**	**$M**	**$/boe**
Canada	**(63,878)**	**(10.18)**	(60,458)	(14.14)
United States	**(6,942)**	**(19.10)**	(8,214)	(15.14)
North America	**(70,820)**	**(10.67)**	(68,672)	(14.25)

Operating expense in North America increased on a dollar basis for the three months ended March 31, 2025 compared to the prior year comparable period primarily due to the Westbrick acquisition, partially offset by lower trucking in British Columbia, and lower activity and production in Saskatchewan. Operating expense decreased on a per boe basis for the three months ended March 31, 2025, primarily due to lower operating expense cost per boe on our Mica assets related to Q1 2024 gas processing costs, lower operating costs on the acquired Westbrick assets and lower production in the United States.

International

	Q1 2025	Q1 2024
Production [1]		
Crude oil and condensate (bbls/d)	**11,835**	13,459
Natural gas (mmcf/d)	**105.12**	114.52
Total production volume (boe/d)	**29,355**	32,546
Total sales volume (boe/d)	**28,668**	35,026

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

	Q1 2025		Q1 2024	
	$M	$/boe	$M	$/boe
Sales	**302,429**	**117.22**	294,779	92.48
Royalties	**(11,434)**	**(4.43)**	(14,673)	(4.60)
Transportation	**(11,946)**	**(4.63)**	(11,629)	(3.65)
Operating	**(70,957)**	**(27.50)**	(80,639)	(25.30)
General and administration	**(12,100)**	**(4.69)**	(15,501)	(4.86)
Corporate income tax expense	**(18,624)**	**(7.22)**	(22,500)	(7.06)
PRRT	**(3,018)**	**(1.17)**	(10,783)	(3.38)
Fund flows from operations	**174,350**	**67.58**	139,054	43.63
Drilling and development	**(36,654)**		(45,789)	
Exploration and evaluation	**(14,655)**		(8,144)	
Free cash flow	**123,041**		85,121	

Production from Vermilion's International operations averaged 29,355 boe/d in Q1 2025, a decrease of 6% from the previous quarter primarily due to natural declines and maintenance.

In Germany, Vermilion drilled two (2.0 net) wells, which included one (1.0 net) light and medium crude oil well and the completion of drilling operations on the Weissenmoor South deep gas exploration well (1.0 net). As expected, more than 15 metres of net, gas-charged, porous sand was encountered at the expected elevation in the Rotliegend formation. During testing, the well did not achieve expected flow rates and was suspended while we evaluate options to improve deliverability. The Company made progress in bringing the Osterheide well (1.0 net) online in the quarter, with gas flows into the pipeline system commencing at the end of Q1 2025.

Sales

	Q1 2025		Q1 2024	
	$M	$/boe	$M	$/boe
Australia	**30,832**	**124.40**	74,826	131.10
France	**61,062**	**103.78**	88,996	113.24
Netherlands	**42,886**	**118.54**	34,966	72.01
Germany	**53,335**	**111.23**	31,184	73.27
Ireland	**100,986**	**127.21**	64,464	70.44
Central and Eastern Europe	**13,328**	**122.54**	343	79.27
International	**302,429**	**117.22**	294,779	92.48

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 2025	Q1 2024
Australia	**2,754**	6,272
France	**6,538**	8,636
Germany	**1,819**	865
International	**11,111**	15,773

Sales increased on a dollar and per unit basis for the three months ended March 31, 2025 compared to the prior year primarily due to higher realized sales prices on European natural gas combined with increased production from the SA-10 block in Croatia brought online in Q2 2024, partially offset by timing of transportation in France and Australia.

Royalties

	Q1 2025		Q1 2024	
	$M	**$/boe**	**$M**	**$/boe**
France	**(7,466)**	**(12.69)**	(13,052)	(16.61)
Netherlands	**(10)**	**(0.03)**	(217)	(0.45)
Germany	**(2,338)**	**(4.88)**	(1,355)	(3.18)
Central and Eastern Europe	**(1,620)**	**(14.89)**	(49)	(11.32)
International	**(11,434)**	**(4.43)**	(14,673)	(4.60)
Royalty rate (% of sales)	**3.8 %**		5.0 %	

Royalties in our International core region are primarily incurred in France, Germany, the Netherlands 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 decreased on a dollar and per unit basis for the three months ended March 31, 2025 compared to the prior year primarily due to lower sales volumes in France, partially offset by an increase in Germany due to higher sales volumes combined with increased production from the SA-10 block in Croatia brought online in Q2 2024.

Transportation

	Q1 2025		Q1 2024	
	$M	**$/boe**	**$M**	**$/boe**
France	**(5,478)**	**(9.31)**	(5,363)	(6.82)
Germany	**(4,269)**	**(8.90)**	(3,192)	(7.50)
Ireland	**(2,199)**	**(2.77)**	(3,074)	(3.36)
International	**(11,946)**	**(4.63)**	(11,629)	(3.65)

Transportation expense for the three months ended March 31, 2025 remained relatively flat on a dollar basis compared to the prior year. On a per unit basis, transportation expense increased for the three months ended March 31, 2025 compared to the prior year primarily due to higher vessel costs in France combined with increased tariffs in Germany and timing of costs recorded in Q1 2024 in Ireland.

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

Operating expense

	Q1 2025		Q1 2024	
	$M	**$/boe**	**$M**	**$/boe**
Australia	**(14,985)**	**(60.46)**	(26,786)	(46.93)
France	**(16,043)**	**(27.27)**	(21,440)	(27.28)
Netherlands	**(9,608)**	**(26.56)**	(10,610)	(21.85)
Germany	**(15,177)**	**(31.65)**	(10,761)	(25.28)
Ireland	**(14,242)**	**(17.94)**	(10,604)	(11.59)
Central and Eastern Europe	**(902)**	**(8.29)**	(438)	(101.22)
International	**(70,957)**	**(27.50)**	(80,639)	(25.30)

Operating expenses decreased on a dollar basis for the three months ended March 31, 2025 primarily due to lower sales volumes in Australia and France, partially offset by higher sales volumes and higher gas processing tariff adjustments in Germany and the timing of maintenance in Ireland. On a per unit basis, operating expenses for the three months ended March 31, 2025 remained relatively flat compared to the prior year.

Consolidated Financial Performance Review

Financial performance

	Q1 2025		Q1 2024	
	$M	$/boe	$M	$/boe
Sales	**568,846**	**61.71**	508,035	63.45
Royalties	**(49,290)**	**(5.35)**	(48,553)	(6.06)
Transportation	**(31,186)**	**(3.38)**	(22,962)	(2.87)
Operating	**(141,777)**	**(15.38)**	(149,311)	(18.65)
General and administration	**(34,660)**	**(3.76)**	(23,703)	(2.96)
Corporate income tax expense	**(19,059)**	**(2.07)**	(25,642)	(3.20)
Petroleum resource rent tax	**(3,018)**	**(0.33)**	(10,783)	(1.35)
Interest expense	**(32,979)**	**(3.58)**	(18,392)	(2.30)
Realized gain on derivatives	**11,119**	**1.21**	220,615	27.55
Realized foreign exchange gain	**2,499**	**0.27**	1,871	0.23
Realized other (expense) income	**(14,466)**	**(1.57)**	183	0.02
Fund flows from operations	**256,029**	**27.77**	431,358	53.86
Equity based compensation	**(5,931)**		(5,518)	
Unrealized loss on derivative instruments [1]	**(13,675)**		(188,744)	
Unrealized foreign exchange loss [1]	**(35,899)**		(21,641)	
Accretion	**(17,880)**		(17,934)	
Depletion and depreciation	**(176,388)**		(178,434)	
Deferred tax recovery (expense)	**9,016**		(16,645)	
Unrealized other expense [1]	**(319)**		(137)	
Net earnings	**14,953**		2,305	

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

Fluctuations in fund flows from operations may occur as a result of changes in production levels, commodity prices, and costs to produce petroleum and natural gas. In addition, fund flows from operations may be affected by the timing of crude oil shipments in Australia and France. When crude oil inventory is built up, the related operating expense, royalties, and depletion expense are deferred and carried as inventory on the consolidated balance sheet. When the crude oil inventory is subsequently drawn down, the related expenses are recognized within profit or loss.

General and administration

- General and administration expense increased for the three months ended March 31, 2025 compared to the prior year primarily due transaction costs incurred in Canada related to the Westbrick acquisition.

PRRT and corporate income taxes

- PRRT for the three months ended March 31, 2025 decreased compared to the prior year due to decreased sales in Australia.
- Corporate income taxes for the three months ended March 31, 2025 decreased compared to the same period in the prior year due to lower taxable income in France and Australia.

Interest expense

- Interest expense for the three months ended March 31, 2025 increased due to the higher debt levels, driven by the issuance of the 2033 senior notes for US $400 million, the $450 million term loan and the draw on revolving credit facility, partially offset by the repayment of the 2025 senior notes for US $300 million.

Realized gain or loss on derivatives

- For the three months ended March 31, 2025, we recorded realized gains on our natural gas and crude oil hedges due to lower commodity pricing compared to the strike prices.
- A listing of derivative positions as at March 31, 2025 is included in "Supplemental Table 2" of this MD&A.

Realized other income or expense

- Realized other expense increased for the three months ended March 31, 2025, primarily related to an estimated provision incurred to satisfy work commitments.

Net earnings (loss)

Fluctuations in net earnings from period-to-period are caused by changes in both cash and non-cash based income and charges. Cash based items are reflected in fund flows from operations. Non-cash items include: equity based compensation expense, unrealized gains and losses on derivative instruments, unrealized foreign exchange gains and losses, accretion, depletion and depreciation expense, and deferred taxes. In addition, non-cash items may also include gains or losses resulting from acquisition or disposition activity or charges resulting from impairment or impairment reversals.

Equity based compensation

Equity based compensation expense relates primarily to non-cash compensation expense attributable to long-term incentives granted to directors, officers, and employees under security-based arrangements. Equity based compensation expense for the three months ended March 31, 2025 remained relatively flat compared to the same period in the prior year.

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.

For the three months ended March 31, 2025, we recognized a net unrealized loss on derivative instruments of $13.7 million. This consists of unrealized losses of $38.8 million on our North American gas commodity derivative instruments, $7.0 million on our equity swaps, $3.6 million on our Cross Currency Interest Rate Swaps and $2.8 million on our crude oil and liquids commodity derivative instruments, offset by gains of $50.4 million on our European natural gas commodity derivative instruments and $1.5 million on our USD-to-CAD foreign exchange 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 2025, 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 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.

For the three months ended March 31, 2025, we recognized a net unrealized foreign exchange loss of $35.9 million, primarily driven by the effects of the Euro strengthening 4.1% against the Canadian dollar on our Euro denominated loans.

Accretion

Accretion expense is recognized to update the present value of the asset retirement obligation balance. For the three months ended March 31, 2025, compared to the three months ended December 31, 2024, accretion remained relatively flat.

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, 2025 of $19.13 decreased from $22.29 in the same period of the prior year primarily due to the increase in reserve estimates in British Colombia and in Alberta from the acquired Westbrick assets, partially offset by related increases to the depletable base including future development costs, and by the strengthening of the Euro against the Canadian dollar.

Deferred tax

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

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

For the three months ended March 31, 2025, the Company recorded deferred tax recovery of $9.0 million compared to deferred tax expense of $16.6 million in the comparative period in the prior year. The deferred tax recovery for the three months ended March 31, 2025 was primarily driven by the recognition of deferred tax assets in Ireland.

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, 2025, we have a ratio of net debt to four quarter trailing fund flows from operations of 1.7.

Net debt

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

	As at	
($M)	**Mar 31, 2025**	**Dec 31, 2024**
Long-term debt	**1,874,033**	963,456
Adjusted working capital [(1)]	**187,916**	3,426
Unrealized FX on swapped USD borrowings	**856**	—
Net debt	**2,062,805**	966,882
Ratio of net debt to four quarter trailing fund flows from operations [(2)]	**1.7**	0.8

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

As at March 31, 2025, net debt increased to $2.1 billion (December 31, 2024 - $1.0 billion) primarily due to the Westbrick acquisition, the working capital deficit acquired, and weaker free cash flow generation, mainly on lower realized derivative gains.

The ratio of net debt to four quarter trailing fund flows from operations as at March 31, 2025 increased to 1.7 (December 31, 2024 - 0.8) primarily due to higher net debt as a result of the Westbrick acquisition, partially offset by the inclusion of Westbrick's four quarter trailing fund flows from operations.

Long-term debt

The balances recognized on our balance sheet are as follows:

	As at	
	Mar 31, 2025	Dec 31, 2024
Revolving credit facility	**298,449**	—
Term loan	**445,392**	—
2025 senior unsecured notes	**—**	398,275
2030 senior unsecured notes	**565,078**	565,181
2033 senior unsecured notes	**565,114**	—
Long-term debt	**1,874,033**	963,456

Revolving credit facility

As at March 31, 2025, Vermilion had in place a bank revolving credit facility maturing May 26, 2028 with terms and outstanding positions as follows:

	As at	
($M)	Mar 31, 2025	Dec 31, 2024
Total facility amount	**1,350,000**	1,350,000
Amount drawn	**(298,449)**	—
Letters of credit outstanding	**(30,961)**	(22,731)
Unutilized capacity	**1,020,590**	1,327,269

The facility can be extended from time to time at the option of the lenders and upon notice from Vermilion. If no extension is granted by the lenders, the amounts owing pursuant to the facility are due at the maturity date. The facility is secured by various fixed and floating charges against the subsidiaries of Vermilion. As at March 31, 2025, $298.4 million of the revolving credit facility was drawn. As at December 31, 2024 the revolving credit facility was undrawn.

As at March 31, 2025, the revolving credit facility was subject to the following financial covenants:

		As at	
Financial covenant	Limit	Mar 31, 2025	Dec 31, 2024
Consolidated total debt to consolidated EBITDA	Less than 4.0	**1.38**	0.72
Consolidated total senior debt to consolidated EBITDA	Less than 3.5	**0.55**	—
Consolidated EBITDA to consolidated interest expense	Greater than 2.5	**13.35**	16.59

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 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, 2025 and December 31, 2024, 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 does not require principal repayments prior to its May 26, 2028 maturity, is non-revolving, and is subject to the same financial covenants as Vermilion’s revolving credit facility. The Term Loan bears interest based on a reference rate plus an applicable margin.

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. 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.

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

- Prior to May 1, 2025, Vermilion may redeem up to 35% 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 106.875% of the principal amount of the notes, together with accrued and unpaid interest.
- Prior to May 1, 2025, 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 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 %
2027 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 %

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 onwards	Quarterly	$0.12
April 2025 onwards	Quarterly	$0.13

The following table reconciles the change in shareholders' capital:

Shareholders' Capital	Shares ('000s)	Amount ($M)
Balance at January 1	**154,344**	**3,918,898**
Shares issued for acquisition	**1,104**	**13,363**
Repurchase of shares	**(1,271)**	**(32,573)**
Balance at March 31	**154,177**	**3,899,688**

As at March 31, 2025, there were approximately 3.8 million equity based compensation awards outstanding. As at May 7, 2025, there were approximately 154.5 million common shares issued and outstanding.

On July 8, 2024, the Toronto Stock Exchange approved our notice of intention to renew our normal course issuer bid ("the NCIB"). The NCIB renewal allows Vermilion to purchase up to 15,689,839 common shares (representing approximately 10% of outstanding common shares) beginning July 12, 2024 and ending July 11, 2025. Common shares purchased under the NCIB will be cancelled.

In the first quarter of 2025, Vermilion purchased 1.3 million common shares under the NCIB for total consideration of $16.6 million. The common shares purchased under the NCIB were cancelled.

Subsequent to March 31, 2025, Vermilion purchased and cancelled 0.3 million shares under the NCIB for total consideration of $2.5 million.

Contractual Obligations and Commitments

Vermilion acquired the following contractual obligations and commitments as part of the Westbrick acquisition completed on February 26, 2025, presented as at March 31, 2025:

($M)	Less than 1 year	1 - 3 years	3 - 5 years	After 5 years	Total
Lease obligations	1,692	3,666	—	—	5,358
Processing and transportation agreements	33,899	19,841	6,848	5,473	66,061
Total contractual obligations and commitments	**35,591**	**23,507**	**6,848**	**5,473**	**71,419**

The Company's contractual obligations and commitments as at December 31, 3024 remain relatively unchanged. Further information regarding the Company's contractual obligations and commitments can be found in the annual MD&A for the year ended December 31, 2024, available on SEDAR+ at www.sedarplus.ca or on Vermilion's website at www.vermilionenergy.com.

Asset Retirement Obligations

As at March 31, 2025, asset retirement obligations were $1.1 billion compared to $1.2 billion as at December 31, 2024. The decrease in asset retirement obligations is primarily attributable to changes in rates, partially offset by the acquisition of Westbrick asset retirement obligations. The credit spread increased to 3.8% at March 31, 2025 compared to 2.6% at December 31, 2024 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, 2025	Dec 31, 2024	Change
Credit spread added to below noted risk-free rates	**3.8 %**	2.6 %	1.2 %
Country specific risk-free rate			
Canada	**3.2 %**	3.2 %	— %
United States	**4.7 %**	4.8 %	(0.1)%
France	**4.1 %**	3.7 %	0.4 %
Netherlands	**3.1 %**	2.7 %	0.4 %
Germany	**3.1 %**	2.6 %	0.5 %
Ireland	**3.2 %**	2.8 %	0.4 %
Australia	**4.7 %**	4.6 %	0.1 %
Central and Eastern Europe	**5.0 %**	4.7 %	0.3 %

Current cost estimates are inflated to the estimated time of abandonment using inflation rates of between 1.5% and 3.6% (as at December 31, 2024 - between 1.5% and 3.6%).

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, 2024 available on SEDAR+ at www.sedarplus.ca or on Vermilion’s website at 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, 2025. 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, 2024, available on SEDAR+ at www.sedarplus.ca or on Vermilion’s website at www.vermilionenergy.com.

Off Balance Sheet Arrangements

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

Internal Control Over Financial Reporting

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.

Vermilion has limited the scope of design controls and procedures ("DC&P") and internal controls over financial reporting to exclude controls, policies and procedures of Westbrick Energy Ltd., which was acquired on February 26, 2025. The scope limitation is in accordance with section 3.3(1)(b) of NI 52-109 which allows an issuer to limit the design of DC&P and ICFR to exclude controls, policies, and procedures of a business that the issuer acquired not more than 365 days before the end of the fiscal period.

The table below presents the summary financial information of Westbrick Energy Ltd. included in Vermilion's financial statements as at and for the three months ended March 31, 2025:

($M)	As at March 31, 2025
Non-current assets	1,293,757
Non-current liabilities	(190,942)
Net assets	1,102,815

($M)	For the three months ended March 31, 2025
Revenue	38,491
Net earnings	4,918

Recently Adopted Accounting Pronouncements

Vermilion did not adopt any new accounting pronouncements as at March 31, 2025 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"

In June 2023, the International Sustainability Standards Board (ISSB) issued its inaugural standards - IFRS S1 and IFRS S2. The ISSB was formed as a new standard-setting board within the IFRS Foundation to issue standards that deliver a comprehensive global baseline of sustainability-related financial disclosures, operating alongside the International Accounting Standards Board.

IFRS S1 and IFRS S2 are effective for annual reporting periods beginning on or after January 1, 2024, with earlier application permitted, as long as both standards are applied. IFRS S1 provides a set of disclosure requirements designed to enable companies to communicate to investors about the sustainability-related risks and opportunities, while IFRS S2 sets out specific climate-related disclosures and is designed to be used in conjunction with IFRS S1. Canadian regulators have not yet mandated these standards; however, 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 IFRS 18 Presentation and Disclosure in Financial Statements issued which will replace IAS 1 Presentation of Financial Statements. Retrospective application of the standard is mandatory for annual reporting periods starting from January 1, 2027 onwards with earlier application is permitted. Vermilion is assessing the impacts of the standard on its financial reporting.

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, 2025, 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 2025			Q1 2024		
	Liquids $/bbl	Natural Gas $/mcf	Total $/boe	Liquids $/bbl	Natural Gas $/mcf	Total $/boe
Canada						
Sales	73.58	2.75	**38.31**	73.88	2.11	40.93
Royalties	(11.21)	(0.16)	**(4.87)**	(10.22)	(0.17)	(5.27)
Transportation	(4.80)	(0.33)	**(3.05)**	(4.54)	(0.14)	(2.56)
Operating	(19.45)	(0.74)	**(10.18)**	(25.42)	(0.74)	(14.14)
Operating netback	38.12	1.52	**20.21**	33.70	1.06	18.96
General and administration			**(1.36)**			(3.04)
Fund flows from operations ($/boe)			**18.85**			15.92
United States						
Sales	85.82	4.35	**71.57**	86.74	2.64	70.43
Royalties	(23.98)	(1.21)	**(19.99)**	(25.46)	(0.92)	(20.87)
Transportation	(0.45)	—	**(0.34)**	(0.91)	—	(0.70)
Operating	(22.83)	(1.20)	**(19.10)**	(18.68)	(0.55)	(15.14)
Operating netback	38.56	1.94	**32.14**	41.69	1.17	33.72
General and administration			**(5.15)**			(6.02)
Fund flows from operations ($/boe)			**26.99**			27.70
France						
Sales	103.78	—	**103.78**	113.24	—	113.24
Royalties	(12.69)	—	**(12.69)**	(16.61)	—	(16.61)
Transportation	(9.31)	—	**(9.31)**	(6.82)	—	(6.82)
Operating	(27.27)	—	**(27.27)**	(27.28)	—	(27.28)
Operating netback	54.51	—	**54.51**	62.53	—	62.53
General and administration			**(6.13)**			(6.60)
Current income taxes			**(0.81)**			(7.41)
Fund flows from operations ($/boe)			**47.57**			48.52
Netherlands						
Sales	107.21	19.77	**118.54**	84.76	11.93	72.01
Royalties	—	—	**(0.03)**	—	(0.08)	(0.45)
Transportation	—	—	**—**	—	—	—
Operating	(31.19)	(4.42)	**(26.56)**	(28.21)	(3.61)	(21.85)
Operating netback	76.02	15.35	**91.95**	56.55	8.24	49.71
General and administration			**(3.66)**			(3.99)
Current income taxes			**(31.34)**			(22.68)
Fund flows from operations ($/boe)			**56.95**			23.04
Germany						
Sales	103.94	19.17	**111.23**	107.68	10.91	73.27
Royalties	(2.59)	(1.01)	**(4.88)**	(2.40)	(0.56)	(3.18)
Transportation	(17.55)	(0.74)	**(8.90)**	(26.59)	(0.53)	(7.50)
Operating	(29.66)	(5.45)	**(31.65)**	(36.90)	(3.77)	(25.28)
Operating netback	54.14	11.97	**65.80**	41.79	6.05	37.31
General and administration			**(6.43)**			(6.04)
Current income taxes			**(12.79)**			(10.27)
Fund flows from operations ($/boe)			**46.58**			21.00

	Q1 2025			Q1 2024		
	Liquids	Natural Gas	Total	Liquids	Natural Gas	Total
	$/bbl	$/mcf	$/boe	$/bbl	$/mcf	$/boe
Ireland						
Sales	—	21.19	**127.21**	—	11.74	70.44
Transportation	—	(0.46)	**(2.77)**	—	(0.56)	(3.36)
Operating	—	(2.99)	**(17.94)**	—	(1.93)	(11.59)
Operating netback	—	17.74	**106.50**	—	9.25	55.49
General and administration			**(2.11)**			(2.37)
Current income taxes			**(0.24)**			(0.49)
Fund flows from operations ($/boe)			**104.15**			52.63
Australia						
Sales	124.40	—	**124.40**	131.10	—	131.10
Operating	(60.46)	—	**(60.46)**	(46.93)	—	(46.93)
PRRT [(1)]	(12.18)	—	**(12.18)**	(18.89)	—	(18.89)
Operating netback	51.76	—	**51.76**	65.28	—	65.28
General and administration			**(4.80)**			(3.05)
Current income taxes			**(0.59)**			(1.47)
Fund flows from operations ($/boe)			**46.37**			60.76
Central and Eastern Europe						
Sales	96.15	20.43	**122.54**	—	13.21	79.27
Royalties	—	(2.49)	**(14.89)**	—	(1.89)	(11.32)
Operating	—	(1.38)	**(8.29)**	—	(16.87)	(101.22)
Operating netback	96.15	16.56	**99.36**	—	(5.55)	(33.27)
General and administration			**(11.23)**			(437.71)
Current income taxes			**(3.14)**			—
Fund flows from operations ($/boe)			**84.99**			(470.98)
Total Company						
Sales	84.15	7.80	**61.71**	92.56	6.10	63.45
Realized hedging gain	0.42	0.29	**1.21**	1.20	8.64	27.55
Royalties	(11.26)	(0.24)	**(5.35)**	(11.47)	(0.18)	(6.06)
Transportation	(5.47)	(0.33)	**(3.38)**	(4.50)	(0.23)	(2.87)
Operating	(20.82)	(1.96)	**(15.38)**	(27.20)	(1.79)	(18.65)
PRRT [(2)]	(0.82)	—	**(0.33)**	(2.81)	—	(1.35)
Operating netback	46.20	5.56	**38.48**	47.78	12.54	62.07
General and administration			**(3.76)**			(2.96)
Interest expense			**(3.58)**			(2.30)
Realized foreign exchange gain			**0.27**			0.23
Other (expense) income			**(1.57)**			0.02
Corporate income taxes			**(2.07)**			(3.20)
Fund flows from operations ($/boe)			**27.77**			53.86

(1) Vermilion considers Australian PRRT to be an operating item and, accordingly, has included PRRT in the calculation of operating netbacks. Current income taxes presented above excludes PRRT.

Supplemental Table 2: Hedges

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

The following tables outline Vermilion's outstanding risk management positions as at March 31, 2025:

	Unit	Currency	Daily Bought Put Volume	Weighted Average Bought Put Price	Daily Sold Call Volume	Weighted Average Sold Call Price	Daily Sold Put Volume	Weighted Average Sold Put Price	Daily Sold Swap Volume	Weighted Average Sold Swap Price	Daily Bought Swap Volume	Weighted Average Bought Swap Price
Dated Brent												
Q2 2025	bbl	USD	—	—	—	—	—	—	7,000	75.23	—	—
Q3 2025	bbl	USD	—	—	—	—	—	—	2,500	74.34	—	—
WTI												
Q2 2025	bbl	USD	—	—	—	—	—	—	16,500	71.49	—	—
Q3 2025	bbl	USD	—	—	—	—	—	—	4,000	71.05	—	—
Conway												
Q2 2025	bbl	USD	—	—	—	—	—	—	2,000	32.86	—	—
Q3 2025	bbl	USD	—	—	—	—	—	—	2,000	32.86	—	—
Q4 2025	bbl	USD	—	—	—	—	—	—	1,500	33.32	—	—
AECO												
Q2 2025	mcf	CAD	4,739	3.17	4,739	4.22	—	—	137,433	2.72	—	—
Q3 2025	mcf	CAD	4,739	3.17	4,739	4.22	—	—	123,216	2.81	—	—
Q4 2025	mcf	CAD	4,739	3.17	4,739	4.22	—	—	72,941	3.09	—	—
Q1 2026	mcf	CAD	4,739	3.17	4,739	4.22	—	—	85,304	3.33	—	—
Q2 2026	mcf	CAD	4,739	3.17	4,739	4.22	—	—	85,304	3.33	—	—
Q3 2026	mcf	CAD	4,739	3.17	4,739	4.22	—	—	85,304	3.33	—	—
Q4 2026	mcf	CAD	4,739	3.17	4,739	4.22	—	—	85,304	3.33	—	—
Q1 2027	mcf	CAD	—	—	—	—	—	—	90,043	3.13	—	—
Q2 2027	mcf	CAD	—	—	—	—	—	—	90,043	3.13	—	—
Q3 2027	mcf	CAD	—	—	—	—	—	—	90,043	3.13	—	—
Q4 2027	mcf	CAD	—	—	—	—	—	—	90,043	3.13	—	—
AECO Basis (AECO less NYMEX Henry Hub)												
Q2 2025	mcf	USD	—	—	—	—	—	—	10,000	(1.15)	—	—
Q3 2025	mcf	USD	—	—	—	—	—	—	10,000	(1.15)	—	—
Q4 2025	mcf	USD	—	—	—	—	—	—	10,000	(1.15)	—	—
NYMEX Henry Hub												
Q2 2025	mcf	USD	24,000	3.50	24,000	4.49	—	—	10,000	3.19	—	—
Q3 2025	mcf	USD	24,000	3.50	24,000	4.49	—	—	10,000	3.19	—	—
Q4 2025	mcf	USD	24,000	3.50	24,000	4.49	—	—	10,000	3.19	—	—
Q1 2026	mcf	USD	24,000	3.50	24,000	4.49	—	—	—	—	—	—
Q2 2026	mcf	USD	24,000	3.50	24,000	4.49	—	—	—	—	—	—
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	CAD	—	—	—	—	—	—	24,000	3.76	—	—
Q2 2027	mcf	CAD	—	—	—	—	—	—	24,000	3.76	—	—
Q3 2027	mcf	CAD	—	—	—	—	—	—	24,000	3.76	—	—
Q4 2027	mcf	CAD	—	—	—	—	—	—	24,000	3.76	—	—

	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
TTF												
Q2 2025	mcf	EUR	22,111	8.31	22,111	12.88	22,111	4.01	27,024	12.81	—	—
Q3 2025	mcf	EUR	22,111	8.31	22,111	12.88	22,111	4.01	27,024	12.81	—	—
Q4 2025	mcf	EUR	31,938	8.05	31,938	12.50	31,938	3.67	23,339	11.78	—	—
Q1 2026	mcf	EUR	24,567	7.39	24,567	11.66	24,567	3.02	28,253	12.02	—	—
Q2 2026	mcf	EUR	24,567	7.39	24,567	11.66	24,567	3.02	25,796	10.42	—	—
Q3 2026	mcf	EUR	24,567	7.39	24,567	11.66	24,567	3.02	25,796	10.42	—	—
Q4 2026	mcf	EUR	28,253	7.43	28,253	11.66	28,253	2.93	12,284	10.89	—	—
Q1 2027	mcf	EUR	28,253	7.43	28,253	11.66	28,253	2.93	7,370	9.35	—	—
THE												
Q2 2025	mcf	EUR	—	—	—	—	—	—	2,457	14.95	—	—
Q3 2025	mcf	EUR	—	—	—	—	—	—	2,457	14.95	—	—

VET Equity Swaps		Initial Share Price		Share Volume
Swap	Jan 2020 - Apr 2027	20.9788	CAD	2,250,000
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 2025 - Jun 2025	5,000,000	USD	1.3740	5,000,000	USD	1.4551	—	—
Collar	Sell USD, Buy CAD	Apr 2025 - Dec 2025	12,500,000	USD	1.3637	12,500,000	USD	1.4133	—	—

Cross Currency Interest Rate		Receive Notional Amount		Receive Rate	Pay Notional Amount		Pay Rate
Swap	Feb 2033	200,000,000	USD	7.250%	288,480,000	CAD	6.060%
Swap	Mar 2025 - Apr 2025	208,100,000	USD	SOFR + 2.35%	300,000,000	CAD	CORRA + 2.27

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
WTI											
Jul 2025 - Jun 2026	bbl	USD	30-Jun-2025	—	—	—	—	—	—	1,000	70.00
Jul 2026 - Jun 2027	bbl	USD	30-Jun-2026	—	—	—	—	—	—	2,000	70.00

Supplemental Table 3: Capital Expenditures and Acquisitions

By classification ($M)	Q1 2025	Q1 2024
Drilling and development	**167,464**	182,298
Exploration and evaluation	**14,655**	8,144
Capital expenditures	**182,119**	190,442

Acquisitions ($M)	Q1 2025	Q1 2024
Acquisitions, net of cash acquired	**1,084,456**	379
Shares issued for acquisition	**13,363**	—
Acquisition of securities	**—**	9,373
Acquired working capital deficit	**23,179**	—
Acquisitions	**1,120,998**	9,752

By category ($M)	Q1 2025	Q1 2024
Drilling, completion, new well equip and tie-in, workovers and recompletions	**117,696**	138,061
Production equipment and facilities	**55,300**	48,481
Seismic, studies, land and other	**9,123**	3,900
Capital expenditures	**182,119**	190,442
Acquisitions	**1,120,998**	9,752
Total capital expenditures and acquisitions	**1,303,117**	200,194

Capital expenditures by country ($M)	Q1 2025	Q1 2024
Canada	**125,643**	124,282
United States	**5,167**	12,227
France	**6,756**	11,015
Netherlands	**7,747**	4,598
Germany	**25,235**	24,028
Ireland	**328**	3,093
Australia	**9,702**	6,171
Central and Eastern Europe	**1,541**	5,028
Capital expenditures	**182,119**	190,442

Acquisitions by country ($M)	Q1 2025	Q1 2024
Canada	**1,120,998**	9,752
Acquisitions	**1,120,998**	9,752

Supplemental Table 4: Production

	Q1/25	Q4/24	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23	Q1/23	Q4/22	Q3/22	Q2/22
Canada												
Light and medium crude oil (bbls/d)	**12,175**	11,614	12,526	12,468	11,649	11,614	12,054	12,901	16,674	17,448	16,835	17,042
Condensate [1] (bbls/d)	**6,096**	3,728	3,598	3,853	4,075	4,034	4,410	3,506	4,719	4,525	4,204	4,873
Other NGLs [1] (bbls/d)	**8,372**	5,764	6,483	6,208	5,968	6,281	6,219	5,513	6,875	6,279	6,870	7,155
NGLs (bbls/d)	**14,468**	9,492	10,081	10,061	10,043	10,315	10,629	9,019	11,594	10,804	11,074	12,028
Conventional natural gas (mmcf/d)	**258.46**	161.27	156.99	158.48	151.84	160.16	163.94	159.26	160.34	146.81	145.04	143.94
Total (boe/d)	**69,721**	47,982	48,772	48,943	46,997	48,623	50,007	48,464	54,991	52,720	52,080	53,060
United States												
Light and medium crude oil (bbls/d)	**2,261**	2,449	2,909	3,817	3,483	3,187	4,404	3,349	2,824	3,282	2,824	2,846
Condensate [1] (bbls/d)	**19**	34	12	27	29	27	15	22	20	36	35	40
Other NGLs [1] (bbls/d)	**795**	848	1,064	988	1,078	1,131	1,124	1,025	1,020	1,218	1,031	958
NGLs (bbls/d)	**814**	882	1,076	1,015	1,107	1,158	1,139	1,047	1,040	1,254	1,066	998
Conventional natural gas (mmcf/d)	**5.78**	5.88	7.08	7.27	8.23	7.49	7.25	7.23	7.14	7.45	7.03	6.74
Total (boe/d)	**4,039**	4,311	5,164	6,044	5,962	5,593	6,751	5,601	5,055	5,779	5,062	4,967
France												
Light and medium crude oil (bbls/d)	**6,810**	7,083	7,115	7,246	7,308	7,395	7,578	7,788	7,578	7,247	6,818	8,126
Total (boe/d)	**6,810**	7,083	7,115	7,246	7,308	7,395	7,578	7,788	7,578	7,247	6,818	8,126
Netherlands												
Light and medium crude oil (bbls/d)	**—**	—	—	—	—	—	—	—	—	—	—	1
Condensate [1] (bbls/d)	**34**	44	39	51	165	119	39	61	66	49	74	60
NGLs (bbls/d)	**34**	44	39	51	165	119	39	61	66	49	74	60
Conventional natural gas (mmcf/d)	**23.91**	24.20	25.06	26.84	31.02	32.06	24.32	27.28	29.07	27.41	29.15	35.22
Total (boe/d)	**4,020**	4,078	4,216	4,524	5,336	5,462	4,091	4,607	4,910	4,617	4,933	5,930
Germany												
Light and medium crude oil (bbls/d)	**1,512**	1,596	1,598	1,698	1,722	1,775	1,713	1,715	1,410	1,481	1,764	1,331
Conventional natural gas (mmcf/d)	**21.05**	21.71	21.41	18.41	22.87	19.62	20.29	22.05	25.85	25.86	26.54	25.36
Total (boe/d)	**5,020**	5,215	5,167	4,766	5,533	5,046	5,095	5,391	5,717	5,791	6,187	5,558
Ireland												
Conventional natural gas (mmcf/d)	**52.92**	55.32	59.06	57.70	60.34	64.04	47.96	67.51	24.58	26.04	25.74	27.93
Total (boe/d)	**8,820**	9,220	9,844	9,616	10,057	10,673	7,993	11,251	4,096	4,340	4,290	4,655
Australia												
Light and medium crude oil (bbls/d)	**3,477**	3,778	2,040	3,713	4,264	4,715	1,204	—	—	4,847	4,763	2,465
Total (boe/d)	**3,477**	3,778	2,040	3,713	4,264	4,715	1,204	—	—	4,847	4,763	2,465
Central and Eastern Europe												
Conventional natural gas (mmcf/d)	**7.24**	11.21	11.13	0.69	0.29	0.54	0.05	0.30	0.64	0.67	0.63	0.64
Total (boe/d)	**1,208**	1,869	1,855	122	48	90	8	50	107	111	104	106
Consolidated												
Light and medium crude oil (bbls/d)	**26,235**	26,521	26,188	28,948	28,426	28,685	26,952	25,753	28,485	34,305	33,003	31,811
Condensate [1] (bbls/d)	**6,151**	3,806	3,649	3,931	4,269	4,180	4,463	3,589	4,805	4,610	4,312	4,973
Other NGLs [1] (bbls/d)	**9,167**	6,612	7,547	7,196	7,046	7,412	7,344	6,538	7,896	7,497	7,901	8,113
NGLs (bbls/d)	**15,318**	10,418	11,196	11,127	11,315	11,592	11,807	10,127	12,701	12,107	12,213	13,086
Conventional natural gas (mmcf/d)	**369.36**	279.59	280.73	269.39	274.59	283.91	263.80	283.63	247.61	234.23	234.12	239.83
Total (boe/d)	**103,115**	83,536	84,173	84,974	85,505	87,597	82,727	83,152	82,455	85,450	84,237	84,868

	YTD 2025	2024	2023	2022	2021	2020
Canada						
Light and medium crude oil (bbls/d)	**12,175**	12,065	13,293	16,830	16,954	21,106
Condensate [1] (bbls/d)	**6,096**	3,813	4,166	4,621	4,831	4,886
Other NGLs [1] (bbls/d)	**8,372**	6,106	6,220	6,895	7,179	7,719
NGLs (bbls/d)	**14,468**	9,919	10,386	11,516	12,010	12,605
Conventional natural gas (mmcf/d)	**258.46**	157.16	160.94	144.10	138.03	151.38
Total (boe/d)	**69,721**	48,175	50,503	52,364	51,968	58,942
United States						
Light and medium crude oil (bbls/d)	**2,261**	3,162	3,445	2,908	2,597	3,046
Condensate [1] (bbls/d)	**19**	25	21	34	8	5
Other NGLs [1] (bbls/d)	**795**	994	1,076	1,066	1,146	1,218
NGLs (bbls/d)	**814**	1,019	1,097	1,100	1,154	1,223
Conventional natural gas (mmcf/d)	**5.78**	7.11	7.28	7.20	6.84	7.47
Total (boe/d)	**4,039**	5,367	5,754	5,207	4,890	5,514
France						
Light and medium crude oil (bbls/d)	**6,810**	7,188	7,584	7,639	8,799	8,903
Conventional natural gas (mmcf/d)	**—**	—	—	—	—	—
Total (boe/d)	**6,810**	7,188	7,584	7,639	8,799	8,903
Netherlands						
Light and medium crude oil (bbls/d)	**—**	—	—	—	3	1
Condensate [1] (bbls/d)	**34**	75	71	66	97	88
NGLs (bbls/d)	**34**	75	71	66	97	88
Conventional natural gas (mmcf/d)	**23.91**	26.77	28.18	32.66	43.40	46.16
Total (boe/d)	**4,020**	4,536	4,768	5,510	7,334	7,782
Germany						
Light and medium crude oil (bbls/d)	**1,512**	1,653	1,654	1,435	1,044	968
Conventional natural gas (mmcf/d)	**21.05**	21.10	21.93	26.18	15.81	12.65
Total (boe/d)	**5,020**	5,170	5,310	5,798	3,679	3,076
Ireland						
Conventional natural gas (mmcf/d)	**52.92**	58.10	51.12	27.48	29.25	37.44
Total (boe/d)	**8,820**	9,683	8,520	4,579	4,875	6,240
Australia						
Light and medium crude oil (bbls/d)	**3,477**	3,446	1,492	3,995	3,810	4,416
Total (boe/d)	**3,477**	3,446	1,492	3,995	3,810	4,416
Central and Eastern Europe						
Conventional natural gas (mmcf/d)	**7.24**	5.86	0.38	0.57	0.31	1.90
Total (boe/d)	**1,208**	978	63	95	51	317
Consolidated						
Light and medium crude oil (bbls/d)	**26,235**	27,514	27,469	32,809	33,208	38,441
Condensate [1] (bbls/d)	**6,151**	3,913	4,258	4,721	4,936	4,980
Other NGLs [1] (bbls/d)	**9,167**	7,100	7,296	7,961	8,325	8,937
NGLs (bbls/d)	**15,318**	11,013	11,554	12,682	13,261	13,917
Conventional natural gas (mmcf/d)	**369.36**	276.10	269.83	238.18	233.64	256.99
Total (boe/d)	**103,115**	84,543	83,994	85,187	85,408	95,190

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

Supplemental Table 5: Operational and Financial Data by Core Region

Production volumes [1]

	Q1/25	Q4/24	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23	Q1/23	Q4/22	Q3/22	Q2/22
North America												
Crude oil and condensate (bbls/d)	**20,551**	17,825	19,045	20,165	19,236	18,862	20,883	19,778	24,237	25,291	23,898	24,801
NGLs (bbls/d)	**9,167**	6,612	7,547	7,196	7,046	7,412	7,344	6,538	7,895	7,497	7,901	8,113
Natural gas (mmcf/d)	**264.24**	167.15	164.07	165.75	160.07	167.65	171.19	166.49	167.48	154.26	152.07	150.68
Total (boe/d)	**73,760**	52,293	53,936	54,987	52,959	54,216	56,758	54,065	60,046	58,499	57,142	58,027
International												
Crude oil and condensate (bbls/d)	**11,835**	12,502	10,792	12,714	13,459	14,004	10,534	9,564	9,054	13,624	13,419	11,983
Natural gas (mmcf/d)	**105.12**	112.44	116.66	103.64	114.52	116.27	92.61	117.14	80.13	79.97	82.05	89.15
Total (boe/d)	**29,355**	31,243	30,237	29,987	32,546	33,381	25,969	29,087	22,408	26,953	27,095	26,840
Consolidated												
Crude oil and condensate (bbls/d)	**32,386**	30,327	29,837	32,879	32,695	32,866	31,416	29,341	33,290	38,915	37,315	36,784
NGLs (bbls/d)	**9,167**	6,612	7,547	7,196	7,046	7,412	7,344	6,538	7,896	7,497	7,901	8,113
Natural gas (mmcf/d)	**369.36**	279.59	280.73	269.39	274.59	283.92	263.80	283.63	247.61	234.23	234.12	239.83
Total (boe/d)	**103,115**	83,536	84,173	84,974	85,505	87,597	82,727	83,152	82,455	85,450	84,237	84,868

[1] Please refer to Supplemental Table 4 "Production" for disclosure by product type.

Sales volumes

	Q1/25	Q4/24	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23	Q1/23	Q4/22	Q3/22	Q2/22
North America												
Crude oil and condensate (bbls/d)	**20,553**	17,825	19,044	20,166	19,235	18,862	20,883	19,778	24,237	25,291	23,897	24,801
NGLs (bbls/d)	**9,167**	6,612	7,547	7,196	7,045	7,412	7,344	6,538	7,895	7,497	7,901	8,113
Natural gas (mmcf/d)	**264.23**	167.13	164.07	165.75	160.07	167.65	171.19	166.49	167.48	154.26	152.07	150.68
Total (boe/d)	**73,759**	52,292	53,936	54,987	52,960	54,216	56,758	54,065	60,046	58,499	57,142	58,027
International												
Crude oil and condensate (bbls/d)	**11,145**	11,360	12,580	11,998	15,938	9,221	9,950	10,302	8,087	16,257	11,493	11,720
Natural gas (mmcf/d)	**105.12**	112.44	116.66	103.64	114.52	116.27	92.61	117.14	80.13	79.97	82.05	89.15
Total (boe/d)	**28,668**	30,101	32,024	29,271	35,026	28,598	25,386	29,824	21,442	29,585	25,169	26,578
Consolidated												
Crude oil and condensate (bbls/d)	**31,698**	29,185	31,624	32,163	35,174	28,083	30,833	30,080	32,324	41,547	35,391	36,522
NGLs (bbls/d)	**9,167**	6,612	7,547	7,196	7,046	7,412	7,344	6,538	7,896	7,497	7,901	8,113
Natural gas (mmcf/d)	**369.36**	279.59	280.73	269.39	274.59	283.92	263.80	283.63	247.61	234.23	234.12	239.83
Total (boe/d)	**102,427**	82,394	85,960	84,258	87,985	82,814	82,144	83,889	81,489	88,083	82,312	84,607

Financial results

	Q1/25	Q4/24	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23	Q1/23	Q4/22	Q3/22	Q2/22
North America												
Crude oil and condensate sales ($/bbl)	**94.15**	93.53	96.54	104.57	91.50	100.16	103.46	94.78	95.63	106.66	114.82	134.72
NGL sales ($/bbl)	**31.56**	29.38	27.49	31.61	34.16	33.38	27.77	28.11	36.24	39.93	44.64	51.86
Natural gas sales ($/mcf)	**2.78**	1.98	0.90	1.29	2.14	2.62	2.52	2.29	4.11	5.96	6.41	7.13
Sales ($/boe)	**40.13**	41.93	40.67	46.37	44.25	47.51	49.26	45.12	54.84	66.95	71.24	83.34
Royalties ($/boe)	**(5.70)**	(5.23)	(6.14)	(6.93)	(7.03)	(7.25)	(7.75)	(5.45)	(7.68)	(9.47)	(12.58)	(12.51)
Transportation ($/boe)	**(2.90)**	(3.04)	(3.12)	(2.82)	(2.35)	(2.44)	(2.08)	(1.57)	(2.44)	(2.42)	(2.16)	(2.15)
Operating ($/boe)	**(10.67)**	(14.58)	(11.88)	(13.89)	(14.25)	(11.50)	(12.09)	(12.22)	(14.10)	(13.51)	(14.00)	(11.58)
General and administration ($/boe)	**(3.40)**	(2.13)	(1.09)	(2.54)	(1.70)	0.87	(0.72)	0.10	(0.99)	0.10	(1.27)	(1.52)
Corporate income taxes ($/boe)	**(0.07)**	0.43	(0.34)	0.82	(0.65)	0.23	(0.01)	(0.10)	(0.12)	(0.13)	(0.03)	—
Fund flows from operations ($/boe)	**17.39**	17.38	18.10	21.01	18.27	27.42	26.61	25.88	29.51	41.52	41.20	55.58
Fund flows from operations	**115,506**	83,662	89,793	105,187	88,027	136,766	138,960	127,346	159,435	223,443	216,579	293,470
Drilling and development	**(130,810)**	(134,164)	(78,171)	(61,520)	(136,509)	(58,704)	(69,703)	(135,723)	(116,070)	(113,892)	(112,238)	(54,913)
Free cash flow	**(15,304)**	(50,502)	11,622	43,667	(48,482)	78,062	69,257	(8,377)	43,365	109,551	104,341	238,557
International												
Crude oil and condensate sales ($/bbl)	**108.97**	110.31	114.16	116.24	119.68	123.77	114.26	100.23	107.57	128.02	140.09	146.67
Natural gas sales ($/mcf)	**20.41**	18.11	14.55	12.72	11.63	16.92	13.34	14.58	24.69	39.54	58.55	32.33
Sales ($/boe)	**117.22**	109.27	97.85	92.68	92.48	108.70	93.46	91.89	132.84	177.23	254.86	173.14
Royalties ($/boe)	**(4.43)**	(5.38)	(4.16)	(4.49)	(4.60)	(3.41)	3.55	(7.43)	(13.39)	(6.38)	(7.21)	(7.23)
Transportation ($/boe)	**(4.63)**	(3.37)	(3.81)	(4.20)	(3.65)	(3.91)	(4.53)	(5.23)	(5.11)	(3.29)	(3.51)	(3.64)
Operating ($/boe)	**(27.50)**	(25.08)	(27.11)	(26.56)	(25.30)	(22.64)	(25.58)	(28.24)	(31.41)	(23.35)	(22.63)	(22.11)
General and administration ($/boe)	**(4.69)**	(6.21)	(5.56)	(5.20)	(4.86)	(9.18)	(7.37)	(7.58)	(7.52)	(5.09)	(3.34)	(3.16)
Corporate income taxes ($/boe)	**(7.22)**	(6.53)	(3.74)	(6.08)	(7.06)	(7.81)	(13.42)	(6.79)	(11.20)	(15.15)	(21.97)	(28.73)
PRRT ($/boe)	**(1.17)**	1.16	(0.17)	(1.37)	(3.38)	7.93	—	—	—	(1.85)	(1.96)	(0.83)
Fund flows from operations ($/boe)	**67.58**	63.86	53.30	44.78	43.63	69.68	46.11	36.62	64.21	122.12	194.24	107.44
Fund flows from operations	**174,350**	176,883	157,048	119,310	139,054	183,353	107,704	99,377	123,893	332,377	449,771	259,840
Drilling and development	**(36,654)**	(42,341)	(40,638)	(47,830)	(45,789)	(73,604)	(49,701)	(28,347)	(37,258)	(43,957)	(65,640)	(54,575)
Exploration and evaluation	**(14,655)**	(24,154)	(2,460)	(1,260)	(8,144)	(10,579)	(6,235)	(2,775)	(1,492)	(11,456)	(6,137)	(3,665)
Free cash flow	**123,041**	110,388	113,950	70,220	85,121	99,170	51,768	68,255	85,143	276,964	377,994	201,600

	Q1/25	Q4/24	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23	Q1/23	Q4/22	Q3/22	Q2/22
Consolidated												
Crude oil and condensate sales ($/bbl)	**99.36**	100.06	103.55	108.93	104.26	107.91	106.94	96.64	98.62	115.02	123.02	138.55
NGL sales ($/bbl)	**31.56**	29.38	27.49	31.61	34.16	33.38	27.77	28.11	36.23	39.93	44.64	51.86
Natural gas sales ($/mcf)	**7.80**	8.47	6.57	5.69	6.10	8.48	6.32	7.37	10.77	17.43	24.68	16.50
Sales ($/boe)	**61.71**	66.54	61.97	62.46	63.45	68.64	62.92	61.74	75.36	103.99	127.39	111.55
Royalties ($/boe)	**(5.35)**	(5.28)	(5.40)	(6.08)	(6.06)	(5.93)	(4.26)	(6.16)	(9.18)	(8.43)	(10.94)	(10.85)
Transportation ($/boe)	**(3.38)**	(3.16)	(3.38)	(3.30)	(2.87)	(2.95)	(2.84)	(2.87)	(3.14)	(2.71)	(2.57)	(2.62)
Operating ($/boe)	**(15.38)**	(18.41)	(17.55)	(18.29)	(18.65)	(15.35)	(16.26)	(17.91)	(18.66)	(16.81)	(16.64)	(14.89)
General and administration ($/boe)	**(3.76)**	(3.62)	(2.76)	(3.46)	(2.96)	(2.60)	(2.77)	(2.63)	(2.71)	(1.65)	(1.90)	(2.04)
Corporate income taxes ($/boe)	**(2.07)**	(2.11)	(1.61)	(1.58)	(3.20)	(2.57)	(7.05)	(7.04)	(5.96)	(32.68)	(6.74)	(9.03)
PRRT ($/boe)	**(0.33)**	0.43	(0.06)	(0.47)	(1.35)	2.74	—	—	—	(0.62)	(0.60)	(0.26)
Interest ($/boe)	**(3.58)**	(3.16)	(2.68)	(2.75)	(2.30)	(3.01)	(2.68)	(2.65)	(2.98)	(2.78)	(3.23)	(2.74)
Equity based compensation ($/boe)	**—**	—	—	(1.87)	—	—	—	—	—	—	—	—
Realized derivatives ($/boe)	**1.21**	3.80	6.31	6.00	27.55	10.33	9.74	8.86	1.95	(5.42)	(18.22)	(10.36)
Realized foreign exchange ($/boe)	**0.27**	0.32	0.15	0.30	0.23	(0.73)	0.28	0.48	(0.65)	2.33	(0.28)	(0.30)
Realized other ($/boe)	**(1.57)**	(0.68)	(0.21)	(0.09)	0.02	0.26	(1.32)	0.53	0.49	(0.14)	0.80	0.36
Fund flows from operations ($/boe)	**27.77**	34.67	34.78	30.87	53.86	48.83	35.76	32.35	34.52	35.08	67.07	58.82
Fund flows from operations	**256,029**	262,698	275,024	236,703	431,358	372,117	270,218	247,109	253,167	284,220	507,876	452,901
Drilling and development	**(167,464)**	(176,505)	(118,809)	(109,350)	(182,298)	(132,308)	(119,404)	(164,070)	(153,328)	(157,849)	(177,878)	(109,488)
Exploration and evaluation	**(14,655)**	(24,154)	(2,460)	(1,260)	(8,144)	(10,579)	(6,235)	(2,775)	(1,492)	(11,456)	(6,137)	(3,665)
Free cash flow	**73,910**	62,039	153,755	126,093	240,916	229,230	144,579	80,264	98,347	114,915	323,861	339,748

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 condensed 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 condensed 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 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.

	Q1 2025		Q1 2024	
	$M	$/boe	$M	$/boe
Sales	**568,846**	**61.71**	508,035	63.45
Royalties	**(49,290)**	**(5.35)**	(48,553)	(6.06)
Transportation	**(31,186)**	**(3.38)**	(22,962)	(2.87)
Operating	**(141,777)**	**(15.38)**	(149,311)	(18.65)
General and administration	**(34,660)**	**(3.76)**	(23,703)	(2.96)
Corporate income tax expense	**(19,059)**	**(2.07)**	(25,642)	(3.20)
Petroleum resource rent tax	**(3,018)**	**(0.33)**	(10,783)	(1.35)
Interest expense	**(32,979)**	**(3.58)**	(18,392)	(2.30)
Realized gain on derivatives	**11,119**	**1.21**	220,615	27.55
Realized foreign exchange gain	**2,499**	**0.27**	1,871	0.23
Realized other (expense) income	**(14,466)**	**(1.57)**	183	0.02
Fund flows from operations	**256,029**	**27.77**	431,358	53.86
Equity based compensation	**(5,931)**		(5,518)	
Unrealized loss on derivative instruments [(1)]	**(13,675)**		(188,744)	
Unrealized foreign exchange loss [(1)]	**(35,899)**		(21,641)	
Accretion	**(17,880)**		(17,934)	
Depletion and depreciation	**(176,388)**		(178,434)	
Deferred tax recovery (expense)	**9,016**		(16,645)	
Unrealized other expense [(1)]	**(319)**		(137)	
Net earnings	**14,953**		2,305	

(1) Unrealized loss on derivative instruments, Unrealized foreign exchange loss, and Unrealized other expense are line items 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 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.

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 2025	Q1 2024
Cash flows from operating activities	**280,384**	354,295
Changes in non-cash operating working capital	**(33,702)**	72,088
Asset retirement obligations settled	**9,347**	4,975
Fund flows from operations	**256,029**	431,358
Drilling and development	**(167,464)**	(182,298)
Exploration and evaluation	**(14,655)**	(8,144)
Free cash flow	**73,910**	240,916

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 2025	Q1 2024
Drilling and development	**167,464**	182,298
Exploration and evaluation	**14,655**	8,144
Capital expenditures	**182,119**	190,442

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 2025	Q1 2024
Dividends declared	**20,043**	19,183
Drilling and development	**167,464**	182,298
Exploration and evaluation	**14,655**	8,144
Asset retirement obligations settled	**9,347**	4,975
Payout	**211,509**	214,600
% of fund flows from operations	**83 %**	50 %

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 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.

	Twelve Months Ended	
($M)	Mar 31, 2025	Mar 31, 2024
Net loss	**(34,091)**	(615,614)
Taxes	**144**	5,139
Interest expense	**99,193**	81,729
EBIT	**65,246**	(528,746)
Average capital employed	**5,961,518**	5,904,114
Return on capital employed	**1 %**	(9)%

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

	As at	
($M)	Mar 31, 2025	Dec 31, 2024
Current assets	**509,726**	582,326
Current derivative asset	**(40,227)**	(40,312)
Current liabilities	**(718,144)**	(610,590)
Current lease liability	**12,903**	12,206
Current derivative liability	**47,826**	52,944
Adjusted working capital deficit	**(187,916)**	(3,426)

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 2025	Q1 2024
Acquisitions, net of cash acquired	**1,084,456**	379
Shares issued for acquisition	**13,363**	—
Acquisition of securities	**—**	9,373
Acquired working capital deficit	**23,179**	—
Acquisitions	**1,120,998**	9,752

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 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 and current lease liabilities), and represents Vermilion's net financing obligations after adjusting for the timing of working capital fluctuations.

	As at	
($M)	Mar 31, 2025	Dec 31, 2024
Long-term debt	**1,874,033**	963,456
Adjusted working capital deficit (1)	**187,916**	3,426
Unrealized FX on swapped USD borrowings	**856**	—
Net debt	**2,062,805**	966,882
Ratio of net debt to four quarter trailing fund flows from operations (2)	**1.7**	0.8

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

(2) Subsequent to February 26, 2025, net debt to four quarter trailing funds flows from operations is calculated inclusive of Westbrick Energy's pre-acquisition four quarter trailing funds flow from operations, as if the acquisition of Westbrick Energy occurred at the beginning of the four-quarter trailing period, 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 2025	Q1 2024
Shares outstanding	**154,177**	159,859
Potential shares issuable pursuant to the LTIP	**3,488**	4,185
Diluted shares outstanding	**157,665**	164,044

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Judy Steele [3,5,11]
Halifax, Nova Scotia

1 Chairman (Independent)
2 Audit Committee Chair (Independent)
3 Audit Committee Member (Independent)
4 Governance and Human Resources Committee Chair (Independent)
5 Governance and Human Resources Committee Member (Independent)
6 Health, Safety and Environment Committee Chair (Independent)
7 Health, Safety and Environment Committee Member (Independent)
8 Technical Committee Chair (Independent)
9 Technical Committee Member (Independent)
10 Sustainability Committee Chair (Independent)
11 Sustainability Committee Member (Independent)

OFFICERS / CORPORATE SECRETARY

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President & Chief Executive Officer

Lars Glemser *
Vice President & Chief Financial Officer

Lara Conrad
Vice President Business Development

Tamar Epstein
General Counsel & Corporate Secretary

Terry Hergott
Vice President Marketing

Yvonne Jeffery
Vice President Sustainability

Darcy Kerwin *
Vice President International & HSE

Geoff MacDonald
Vice President Geosciences

Randy McQuaig *
Vice President North America

Kyle Preston
Vice President Investor Relations

Averyl Schraven
Vice President People & Culture

Gerard Schut
Vice President European Operations

* Principal Executive Committee Member

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The Bank of Nova Scotia

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

Citibank, N.A., Canadian Branch

Canadian Western Bank

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