Q3 2024

THIRD QUARTER REPORT

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VERMILION ENERGY

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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 2024 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 2024 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 funds flow 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; the timing of regulatory proceedings and approvals; and the release of our 2025 budget and the timing thereof.

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.

This document contains references to sustainability/ESG data and performance that reflect metrics and concepts that are commonly used in such frameworks as the Global Reporting Initiative, the Task Force on Climate-related Financial Disclosures, and the Sustainability Accounting Standards Board. Vermilion has used best efforts to align with the most commonly accepted methodologies for ESG reporting, including with respect to climate data and information on potential future risks and opportunities, in order to provide a fuller context for our current and future operations. However, these methodologies are not yet standardized, are frequently based on calculation factors that change over time, and continue to evolve rapidly. Readers are particularly cautioned to evaluate the underlying definitions and measures used by other companies, as these may not be comparable to Vermilion's. While Vermilion will continue to monitor and adapt its reporting accordingly, the Company is not under any duty to update or revise the related sustainability/ESG data or statements except as required by applicable securities laws.

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)
bbls/d	barrels per day
boe	barrel of oil equivalent, including: crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe for six mcf of natural gas)
boe/d	barrel of oil equivalent per day
GJ	gigajoules
LSB	light sour blend crude oil reference price
mbbls	thousand barrels
mcf	thousand cubic feet
mmcf/d	million cubic feet per day
NBP	the reference price paid for natural gas in the United Kingdom at the National Balancing Point Virtual Trading Point
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
tCO2e	tonnes 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
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma

Highlights

- Q3 2024 fund flows from operations ("FFO")(1) was $275 million ($1.76/basic share)(2), representing a 16% increase over the prior quarter, primarily due to stronger European gas prices. Benchmark TTF Day Ahead pricing increased 14% over the prior quarter, averaging $15.52/mmbtu in Q3 2024, and European gas was the only commodity in our portfolio that increased quarter-over-quarter and year-over-year. As a result of strong European gas prices, our corporate average realized natural gas price in Q3 2024 was $6.57/mcf, compared to $0.69/mcf for the AECO 5A benchmark.
- Net earnings for Q3 2024 was $52 million ($0.33/basic share), an increase of $134 million over the prior quarter primarily due to a more normalized mark-to-market adjustment on our hedge book.
- We invested $121 million in exploration and development ("E&D") capital expenditures(3), resulting in free cash flow ("FCF")(4) of $154 million ($0.98/basic share)(5), of which $59 million was returned to shareholders, including $19 million in dividends and $40 million of share buybacks, representing 45% of excess FCF ("EFCF")(4).
- Year-to-date, we have returned $180 million ($1.13/basic share) to shareholders through dividends and share buybacks, representing 38% of EFCF, including the repurchase and cancellation of 8.0 million shares which has reduced our outstanding common shares to 155.3 million as at September 30, 2024. We continue to repurchase shares in Q4 2024 and are on track to return 10% of our market capitalization to shareholders in 2024 between our fixed dividend and variable share repurchase program, and expect to continue providing ratable dividend increases and repurchasing shares in future periods.
- Net debt(6) decreased by $73 million in Q3 2024 to $833 million, representing a net debt to trailing FFO ratio(7) of 0.6 times, the lowest in 15 years.
- Production during Q3 2024 averaged 84,173 boe/d(8) (56% natural gas and 44% crude oil and liquids), comprised of 53,936 boe/d(8) from our North American assets and 30,237 boe/d(8) from our International assets, and includes the impact from a planned turnaround in Australia and the partial shut-in of some Canadian gas production due to weak AECO pricing. Our Q3 2024 production represents an increase of 2% year-over-year, or 7% on a per share basis, reflecting the positive impact from our share repurchase program. Notably, production from our International assets has increased 16% over the prior year, including a 26% increase in natural gas production driven by new production from our SA-10 block in Croatia and higher runtime in Ireland.
- In Germany, we successfully completed testing operations for our first deep gas exploration well drilled earlier this year. The well flow tested at a restricted rate of 17 mmcf/d(15) of natural gas with a wellhead pressure of 4,625 psi, which supports our expectation that deliverability would have been higher without testing equipment limitations. Tie-in operations are progressing to bring the well on production in the first half of 2025.
- We commenced drilling on our second deep gas exploration well (0.3 net) in August 2024 and successfully completed drilling operations at the end of October 2024. We are pleased to report that we discovered gas within the reservoir and are now proceeding with completion and testing operations. Subsequent to the quarter, we commenced drilling on our third German deep gas exploration well (1.0 net) in October 2024. We anticipate results from the second well test and third well drilling operations in the first half of 2025.
- In Croatia, we successfully increased production on the SA-10 block after commissioning the gas plant in late June 2024. Production in Q3 2024 averaged 1,855 boe/d (100% European natural gas) and currently exceeds 2,000 boe/d. On the SA-7 block, we completed testing on the third well of our four-well program, at a reservoir depth of 885 metres, which flow tested at 5.6 mmcf/d(16) of natural gas.
- During Q3 2024 we achieved a major safety milestone in Ireland, where we celebrated two years and one million man-hours without a lost time incident, a testament to Vermilion's high standard for safety in our operations.
- In Canada, we completed and brought on production five (5.0 net) Montney liquids-rich shale gas wells during the third quarter. These wells have produced at an average IP90 rate of over 1,000 boe/d(17) per well (43% liquids)(17), which is in line with expectations. The total drill, complete, equip and tie-in ("DCET") cost for the 9-21 pad was approximately $9.6 million per well as we continue to make progress towards our normalized targeted cost range of $9.0 to $9.5 million per well. The new battery and water infrastructure have achieved 99% run time since starting up and are contributing to these cost savings.
- In conjunction with our Q3 2024 release, we announced a quarterly cash dividend of $0.12 per common share, payable on January 15, 2025 to shareholders of record on December 31, 2024.
- We have tightened our 2024 production guidance range to 84,000 to 85,000 boe/d to reflect increased certainty on annual production levels, and our capital budget of $600 to $625 million remains unchanged. We are in the process of finalizing our 2025 budget which will target modest production growth on a similar capital spending level as 2024, while maintaining our return of capital payout target at 50% of EFCF.

($M except as indicated)	Q3 2024	Q2 2024	Q3 2023	YTD 2024	YTD 2023
Financial					
Petroleum and natural gas sales	**490,095**	478,925	475,532	**1,477,055**	1,499,586
Cash flows from operating activities	**134,547**	266,322	118,436	**755,164**	680,697
Fund flows from operations [1]	**275,024**	236,703	270,218	**943,085**	770,494
Fund flows from operations ($/basic share) [2]	**1.76**	1.48	1.65	**5.93**	4.70
Fund flows from operations ($/diluted share) [2]	**1.75**	1.47	1.62	**5.87**	4.61
Net earnings (loss)	**51,697**	(82,425)	57,309	**(28,423)**	565,549
Net earnings (loss) ($/basic share)	**0.33**	(0.52)	0.35	**(0.18)**	3.45
Cash flows used in investing activities	**145,828**	153,025	170,404	**480,196**	443,503
Capital expenditures [3]	**121,269**	110,610	125,639	**422,321**	447,304
Acquisitions [9]	**1,642**	5,450	5,238	**16,844**	247,294
Dispositions	**—**	—	—	**—**	182,152
Asset retirement obligations settled	**15,332**	11,745	13,582	**32,052**	28,029
Repurchase of shares	**40,106**	46,555	11,645	**123,070**	66,102
Cash dividends ($/share)	**0.12**	0.12	0.10	**0.36**	0.30
Dividends declared	**18,642**	18,981	16,367	**56,806**	49,023
% of fund flows from operations [10]	**7 %**	8 %	6 %	**6 %**	6 %
Payout [12]	**155,243**	141,336	155,588	**511,179**	524,356
% of fund flows from operations [11]	**56 %**	60 %	58 %	**54 %**	68 %
Free cash flow [4]	**153,755**	126,093	144,579	**520,764**	323,190
Long-term debt	**903,354**	915,364	966,505	**903,354**	966,505
Net debt [6]	**833,331**	906,715	1,242,522	**833,331**	1,242,522
Net debt to four quarter trailing fund flows from operations [7]	**0.6**	0.7	1.2	**0.6**	1.2
Operational					
Production [8]					
Crude oil and condensate (bbls/d)	**29,837**	32,879	31,417	**31,797**	31,407
NGLs (bbls/d)	**7,547**	7,196	7,344	**7,264**	7,261
Natural gas (mmcf/d)	**280.73**	269.39	263.80	**274.93**	265.09
Total (boe/d)	**84,173**	84,974	82,727	**84,881**	82,849
Average realized prices					
Crude oil and condensate ($/bbl)	**103.55**	108.93	106.94	**105.54**	100.64
NGLs ($/bbl)	**27.49**	31.61	27.77	**30.99**	30.89
Natural gas ($/mcf)	**6.57**	5.69	6.32	**6.13**	8.08
Production mix (% of production)					
% priced with reference to WTI	**32 %**	32 %	34 %	**32 %**	35 %
% priced with reference to Dated Brent	**13 %**	15 %	13 %	**14 %**	12 %
% priced with reference to AECO	**33 %**	33 %	34 %	**33 %**	34 %
% priced with reference to TTF and NBP	**22 %**	20 %	19 %	**21 %**	19 %
Netbacks ($/boe)					
Operating netback [12]	**41.89**	40.32	49.30	**48.23**	46.42
Fund flows from operations ($/boe) [13]	**34.78**	30.87	35.76	**39.99**	34.19
Average reference prices					
WTI (US $/bbl)	**75.10**	80.57	82.26	**77.54**	77.40
Dated Brent (US $/bbl)	**80.18**	84.94	86.76	**82.79**	82.14
AECO ($/mcf)	**0.69**	1.18	2.61	**1.45**	2.76
TTF ($/mcf)	**15.52**	13.62	14.11	**13.62**	17.39
Share information ('000s)					
Shares outstanding - basic	**155,348**	158,174	163,666	**155,348**	163,666
Shares outstanding - diluted [14]	**158,912**	161,672	167,904	**158,912**	167,904
Weighted average shares outstanding - basic	**156,624**	159,525	163,946	**159,114**	163,848
Weighted average shares outstanding - diluted [14]	**157,502**	161,069	166,392	**160,743**	167,167

(1) Fund flows from operations (FFO) is a total of segments measure comparable to net earnings (loss) that is comprised of sales less royalties, transportation, operating, G&A, corporate income tax, PRRT, windfall taxes, 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 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. FFO does not have a standardized meaning under IFRS and therefore may not be comparable to similar measures provided by other issuers. More information and a reconciliation to primary financial statement measures can be found in the "Non-GAAP and Other Specified Financial Measures" section of this document.

(2) Fund flows from operations per share (basic and diluted) are supplementary financial measures and are not standardized financial measures under IFRS, and therefore may not be comparable to similar measures disclosed by other issuers. They are calculated using FFO (a total of segments measure) and basic/ diluted shares outstanding. The measure is used to assess the contribution per share of each business unit. More information and a reconciliation to primary financial statement measures can be found in the "Non-GAAP and Other Specified Financial Measures" section of this document.

(3) Capital expenditures is a non-GAAP financial measure that is the sum of drilling and development costs and exploration and evaluation costs from the Consolidated Statements of Cash Flows. More information and a reconciliation to primary financial statement measures can be found in the "Non-GAAP and Other Specified Financial Measures" section of this document.

(4) Free cash flow (FCF) and excess free cash flow (EFCF) are non-GAAP financial measures comparable to cash flows from operating activities. FCF is comprised of FFO less drilling and development and exploration and evaluation expenditures and EFCF is FCF less payments on lease obligations and asset retirement obligations settled. More information and a reconciliation to primary financial statement measures can be found in the "Non-GAAP and Other Specified Financial Measures" section of this document.

(5) Free cash flow per basic share is a non-GAAP supplementary financial measure and is not a standardized financial measure under IFRS and may not be comparable to similar measures disclosed by other issuers. It is calculated using FCF and basic shares outstanding.

(6) Net debt is a capital management measure most directly comparable to long-term debt and 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). More information and a reconciliation to primary financial statement measures can be found in the "Non-GAAP and Other Specified Financial Measures" section of this document.

(7) Net debt to four quarter trailing fund flows from operations is a supplementary financial measure and is not a standardized financial measure under IFRS. It may not be comparable to similar measures disclosed by other issuers and is calculated using net debt (capital management measure) and FFO (total of segment measure). The measure is used to assess the ability to repay debt. Information in this document is included by reference; refer to the "Non-GAAP and Other Specified Financial Measures" section of this document.

(8) Please refer to Supplemental Table 4 "Production" of the accompanying Management's Discussion and Analysis for disclosure by product type.

(9) Acquisitions is a non-GAAP financial measure that 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. More information and a reconciliation to primary financial statement measures can be found in the "Non-GAAP and Other Specified Financial Measures" section of this document.

(10) Dividends % of FFO is a supplementary financial measure that is not standardized under IFRS and may not be comparable to similar measures disclosed by other issuers. Dividends % of FFO is calculated as dividends declared divided by FFO. The ratio is used by management as a metric to assess the cash distributed to shareholders.

(11) Payout and payout % of FFO are a non-GAAP financial measure and a non-GAAP ratio, respectively, that are not standardized under IFRS and may not be comparable to similar measures disclosed by other issuers. Payout is comparable to dividends declared and is comprised of dividends declared plus drilling and development costs, exploration and evaluation costs, and asset retirement obligations settled, while the ratio is calculated as payout divided by FFO. More information and a reconciliation to primary financial statement measures can be found in the "Non-GAAP and Other Specified Financial Measures" section of this document.

(12) Operating netback is a non-GAAP financial measure comparable to net earnings and is comprised of sales less royalties, operating expense, transportation costs, PRRT, and realized hedging gains and losses. More information and a reconciliation to primary financial statement measures can be found in the "Non-GAAP and Other Specified Financial Measures" section of this document.

(13) Fund flows from operations per boe is a supplementary financial measure that is not standardized under IFRS and may not be comparable to similar measures disclosed by other issuers, calculated as FFO by boe production. Fund flows from operations per boe is used by management to assess the profitability of our business units and Vermilion as a whole. More information and a reconciliation to primary financial statement measures can be found in the "Non-GAAP and Other Specified Financial Measures" section of this document.

(14) Diluted shares outstanding represent 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.

(15) Osterheide Z2-2 well (100% working interest) tested at a rate of 17.3 mmcf/d during an eight-hour flow period with flowing wellhead pressure of 4,625 psi during initial well cleanup on an adjustable choke. The completion fluid was recovered during the clean-up flow period. A final shut-in wellhead pressure of 5,757 psi and bottom hole pressure of 7,235 psi were recorded following the well test. The tested zone is the Rotliegend Wustrow formation which was encountered at 5,757m measured depth ("MD") and a 42.0 m gas column was logged with 13.8 m of net reservoir and average effective porosity of 8.3%. Test results are not necessarily indicative of long-term performance or ultimate recovery.

(16) Gojlo-1 Jug well (60% working interest) tested at rate of 5.6 mmcf/d and flowing wellhead pressure of 692 psi during a well cleanup on a 0.5938" diameter choke. The well was shut-in and then flow tested for 24 hours on 3 choke sizes (0.25", 0.3125", 0.375") to obtain necessary reservoir data and to minimize flaring. Gojlo-1Jug well tested 8.5 hours at an average rate of 2.9 mmcf/d with a flowing wellhead pressure of 861 psi on a 0.375" diameter choke. Load fluid was recovered, and no formation water was produced during the test. A final shut-in wellhead pressure of 1,009 psi and bottom hole pressure of 1,070 psi were recorded following the well test. The tested zone was the Mramor Brdo formation which was encountered at 885m MD and a 17.6m gas column was logged in

the well to the base of the reservoir with 15.6m of net reservoir and an average porosity of 31%. Test results are not necessarily indicative of long-term performance or ultimate recovery.

(17) Initial 90-day production ("IP90") for the Company's most recent five (5.0 net) wells drilled on our British Columbia lands averaged 1,000 boe/d per well. IP90 consisted of 34% tight oil, 9% NGLs, and 57% shale gas, using a conversion of six mcf of gas to one barrel of oil, based on field level estimates for the first 90 full days of production following the tie-in of the well. Production rates presented are for a limited timeframe only and may not be indicative of future performance or the ultimate recovery for a given well or pad.

Message to Shareholders

The third quarter of 2024 highlighted the strength of our diversified portfolio and the compounding impact of our share buyback program. Production during the third quarter averaged 84,173 boe/d[1] including the impact from a planned turnaround in Australia and the partial shut-in of some Canadian gas production due to weak AECO pricing. Our Q3 2024 production represents an increase of 2% year-over-year, or 7% on a per share basis reflecting the positive impact from our share repurchase program. We generated $275 million of fund flows from operations ("FFO") during the third quarter, representing a 16% increase over the prior quarter, primarily due to stronger European gas prices. Benchmark TTF Day Ahead pricing increased 14% over the prior quarter, averaging $15.52/mmbtu in Q3 2024, and European gas was the only commodity in our portfolio that increased quarter-over-quarter and year-over-year. European natural gas comprises 40% of our natural gas production and 22% of our total corporate production. The forward price for European natural gas benchmarks, TTF and NBP, remain strong, with 2025 forward pricing over $17/mmcf, or approximately eight times higher than AECO. This pricing dynamic supports strong cash flow and netbacks across our European business units, with 2024 operating netbacks of approximately $60/boe[4] from our European natural gas operations.

We invested $121 million of E&D capital during the third quarter, resulting in free cash flow ("FCF") of $154 million, of which $59 million was returned to shareholders, including $19 million in dividends and $40 million of share buybacks. Year-to-date, we have returned $180 million ($1.13/basic share) to shareholders through dividends and share buybacks, representing 38% of EFCF, including the repurchase and cancellation of 8.0 million shares, which has reduced our outstanding common shares to 155.3 million as at September 30, 2024. The balance of our free cash flow was used primarily for debt reduction, resulting in net debt decreasing by $73 million to $833 million at the end of Q3 2024 and representing a net debt to trailing FFO ratio of 0.6 times, the lowest in 15 years.

Our primary operational focus during the third quarter was on completing and testing the remaining European exploration wells drilled earlier in the year, ramping up production from the new gas plant on the SA-10 block in Croatia and ramping up production on the new battery at our Mica Montney asset in British Columbia, Canada. Subsequent to the quarter, we successfully completed drilling operations on the second deep gas exploration well in Germany and are pleased to report that we discovered gas in the reservoir and we are now proceeding with completion and testing operations. In total, we have drilled six exploration wells in Europe so far this year, all of which were successful, and we are currently in the process of drilling a third deep gas exploration well in Germany to finish out our 2024 European drilling campaign. This year was the largest exploration drilling campaign we have ever executed in Europe and the results to date help validate our geological model while providing valuable information for assessing future drilling prospects. Our team has identified numerous exploration and development prospects across our 1.7 million net acre undeveloped land base in Europe, representing well over a decade of drilling inventory with the potential to provide meaningful organic growth opportunities.

As previously disclosed, the first deep gas exploration well in Germany (100% WI) was completed in the Rotliegend zone at a depth of approximately 5,000 metres and flow tested at a restricted rate of 17 mmcf/d[2] of natural gas with a wellhead pressure of 4,625 psi. We also tested the third well on the SA-7 block in Croatia, at a reservoir depth of 885 metres which flow tested at 5.6 mmcf/d[3] of natural gas. We are very encouraged with the exploration results in Croatia, which have proven up multiple producing zones and de-risked future development and exploration targets across four discrete areas. Europe continues to be our most profitable operating region and is an area where we expect to grow organically in the years ahead as we tie in these successful wells and continue with future exploration and development drilling. Our European gas production has increased by over 40% in the last two years and we are excited about the potential for future organic growth in Germany, Croatia, and the Netherlands.

Following the start-up of the Montney battery and the Croatia SA-10 gas plant late in the second quarter, both facilities contributed to results during the third quarter. Production from both facilities increased to capacity levels by the end of the quarter, and we continue to see strong performance from these assets. This production growth was partially offset by planned maintenance at our Wandoo facility in Australia. The turnaround activity in Australia was executed as planned and production resumed late in the third quarter. Our internationally diversified asset base continues to provide strategic advantages to Vermilion by providing exposure to premium global commodity prices along with capital and operational flexibility, as evidenced by our ability to adjust the timing of the Australia turnaround to offset a delay in a third-party turnaround in Canada.

We remain on track to achieve our 2024 production and capital guidance and are in the process of finalizing our 2025 budget which will target modest production growth on a similar level of capital budget as 2024, while maintaining our return of capital payout target. We are on track to return 50% of EFCF to shareholders in 2024 through our fixed dividend and variable share buybacks, representing approximately 10% of our market capitalization, and expect to continue providing ratable dividend increases and repurchasing shares in future periods. We believe Vermilion is well positioned to execute on this plan given our robust asset base and strong balance sheet, which is at the lowest leverage in well over a decade. We plan to release our 2025 budget later in the year and look forward to providing further details on our capital investment and shareholder return plans for 2025.

Q3 2024 Operations Review

North America

Production from our North American operations averaged 53,936 boe/d[1] in Q3 2024, a decrease of 2% from the previous quarter due to declines in our Deep Basin and United States assets and some Canadian gas production shut-in due to weak AECO pricing, partially offset by new production from our recent BC Mica Montney wells.

At Mica, we completed and brought on production five (5.0 net) BC Montney liquids-rich shale gas wells. In the Deep Basin, we drilled three (2.3 net), completed three (2.3 net), and brought on production one (1.0 net) Mannville liquids-rich conventional natural gas wells. In Saskatchewan, we drilled, completed, and brought on production five (5.0 net) light and medium crude oil wells, while in the United States, five (0.2 net) non-operated light and medium crude oil wells were brought on production.

In Canada, the five (5.0 net) Montney wells from the 9-21 pad that were brought on production during the third quarter have produced at an average IP90 rate of over 1,000 boe/d[5] per well (43% liquids)[5], which is in line with expectations. These 9-21 wells were flowed preferentially through our new 8-33 BC Montney battery to maximize liquids recovery during a period of low natural gas prices. The gas stream from our BC Montney wells was also partially restricted due to capacity constraints on the sales gas line from the 8-33 BC Montney battery. We plan to increase takeaway capacity by de-bottlenecking as part of our infrastructure expansion scheduled for 2025. The total drill, complete, equip and tie-in ("DCET") cost for the 9-21 pad was approximately $9.6 million per well as we continue to make progress towards our normalized targeted cost range of $9.0 to $9.5 million per well. The new battery and water infrastructure have achieved 99% run time since starting up and are contributing to these cost savings.

International

Production from our International operations averaged 30,237 boe/d[1] in Q3 2024, an increase of 1% from the previous quarter primarily due to new production from our SA-10 block in Croatia and higher runtime in Germany and Ireland, partially offset by planned maintenance downtime in Australia.

In Germany, we successfully completed testing operations for our first deep gas exploration well drilled earlier this year. The well flow tested at a restricted rate of 17 mmcf/d[2] of natural gas with a wellhead pressure of 4,625 psi, which supports our expectation that deliverability would have been higher without testing equipment limitations. Tie-in operations are progressing to bring the well on production in the first half of 2025. We commenced drilling on our second deep gas exploration well (0.3 net) in August 2024 and successfully completed drilling operations at the end of October 2024. We are pleased to report that we discovered gas within the reservoir and are now proceeding with completion and testing operations. Subsequent to the quarter, we commenced drilling on our third deep gas exploration well (1.0 net) in October 2024. We anticipate results from the second well test and third well drilling operations in the first half of 2025.

In Croatia, we successfully increased production on the SA-10 block after commissioning the gas plant in late June 2024. Production in Q3 2024 averaged 1,855 boe/d (100% European natural gas) and currently exceeds 2,000 boe/d. On the SA-7 block, we completed testing on the third well of our four-well program, which flow tested at 5.6 mmcf/d[3] of natural gas.

During Q3 2024 we achieved a major safety milestone in Ireland, where we celebrated two years and one million man-hours without a lost time incident. We have successfully completed many complex projects over the past two years, including the refrigeration project and major turnarounds, while upholding our high standard for safety. The Corrib facility has maintained steady-state operations with an exceptional plant uptime record, and continues to be a major contributor to our operational and financial success.

In Australia, planned maintenance at our Wandoo facility was executed during Q3 2024. Production resumed late in the quarter and continues to perform well.

Outlook and Guidance Update

We have tightened our 2024 production guidance range to 84,000 to 85,000 boe/d to reflect increased certainty on annual production levels. Our Q4 2024 production will be impacted by planned third-party turnaround activity in Alberta and partial shut-in of some Canadian gas production in response to weak AECO prices, totaling approximately 2,000 boe/d combined. Our 2024 capital budget of $600 to $625 million remains unchanged, with Q4 2024 representing an active capital program in the Deep Basin, Saskatchewan, and the Montney in Canada, along with participating in several non-operated wells in the United States and continuing with drilling operations on the two deep gas exploration wells in Germany.

Commodity Hedging

Vermilion hedges to manage commodity price exposures and increase the stability of our cash flows. In aggregate, as of November 6, 2024, we have 38% of our expected net-of-royalty production hedged for the remainder of 2024. With respect to individual commodity products, we have hedged 53% of our European natural gas production, 41% of our crude oil production, and 23% of our North American natural gas volumes, respectively. Please refer to the Hedging section of our website under Invest With Us for further details using the following link: https://www.vermilionenergy.com/invest-with-us/hedging.

Board of Directors

Mr. Robert Michaleski has stepped down as Chair of the Board of the Directors of the Company effective November 1, 2024 and has advised of his intention to retire from Vermilion's Board of Directors, effective at the Company's next Annual General Meeting, currently scheduled for May 7, 2025. Mr. Michaleski joined Vermilion's Board of Directors in 2016 as an Independent Director and assumed the role of Chair of the Board on September 1, 2022. We want to thank Mr. Michaleski for his efforts and invaluable contributions to the Company, including providing leadership and guidance during his tenure as Chair and serving on the Audit Committee and Governance and Human Resources Committee.

As part of our planned board succession, Vermilion is pleased to announce that Mr. Myron Stadnyk has been chosen and has assumed the role of Chair of the Board effective November 1, 2024. Mr. Stadnyk was appointed to Vermilion's Board of Directors in 2022 and has been a valuable contributor to the Company as a member of the Health, Safety and Environment Committee and Technical Committee. He has also provided insightful guidance and vision in helping to shape Vermilion's strategy, along with sharing his in-depth technical knowledge as Vermilion advanced several new growth projects. Mr. Stadnyk has over 39 years of business and industry knowledge, with extensive experience in executive leadership, operational excellence, governance, health, safety, and environment. He most recently served as the President and Chief Executive Officer of ARC Resources Ltd. where he led ARC's transformation to a top-tier Montney producer, demonstrating outstanding strategic leadership. For Mr. Stadnyk's full biography as well as further information on the Board, please visit https:// www.vermilionenergy.com/about-us/our-directors/.

(Signed "Dion Hatcher")

Dion Hatcher
President & Chief Executive Officer
November 6, 2024

(1) Please refer to Supplemental Table 4 "Production" of the accompanying Management's Discussion and Analysis for disclosure by product type.

(2) Osterheide Z2-2 well (100% working interest) tested at a rate of 17.3 mmcf/d during an eight-hour flow period with flowing wellhead pressure of 4,625 psi during initial well cleanup on an adjustable choke. The completion fluid was recovered during the clean-up flow period. A final shut-in wellhead pressure of 5,757 psi and bottom hole pressure of 7,235 psi were recorded following the well test. The tested zone is the Rotliegend Wustrow formation which was encountered at 5,757m measured depth ("MD") and a 42.0 m gas column was logged with 13.8 m of net reservoir and average effective porosity of 8.3%. Test results are not necessarily indicative of long-term performance or ultimate recovery.

(3) Gojlo-1 Jug well (60% working interest) tested at rate of 5.6 mmcf/d and flowing wellhead pressure of 692 psi during a well cleanup on a 0.5938" diameter choke. The well was shut-in and then flow tested for 24 hours on 3 choke sizes (0.25", 0.3125", 0.375") to obtain necessary reservoir data and to minimize flaring. Gojlo-1Jug well tested 8.5 hours at an average rate of 2.9 mmcf/d with a flowing wellhead pressure of 861 psi on a 0.375" diameter choke. Load fluid was recovered, and no formation water was produced during the test. A final shut-in wellhead pressure of 1,009 psi and bottom hole pressure of 1,070 psi were recorded following the well test. The tested zone was the Mramor Brdo formation which was encountered at 885m MD and a 17.6m gas column was logged in the well to the base of the reservoir with 15.6m of net reservoir and an average porosity of 31%. Test results are not necessarily indicative of long-term performance or ultimate recovery.

(4) 2024 operating netback based on Company estimates using November 1, 2024, strip pricing: Brent US$80.72/bbl; WTI US$75.79/bbl; LSB = WTI less US$5.97/bbl; TTF $14.61/mmbtu; NBP $14.15/mmbtu; AECO $1.43/mcf; CAD/USD 1.37; CAD/EUR 1.49 and CAD/AUD 0.91. Operating netback is a non-GAAP financial measure most directly comparable to net earnings and is comprised of sales less royalties, operating expense, transportation costs, PRRT, and realized hedging gains and losses presented on a per unit basis. Management assesses operating netback as a measure of the profitability and efficiency of our field operations. Operating netback per boe is not a standardized financial measure under IFRS and, therefore may not be comparable with the calculation of similar financial measures disclosed by other entities.

(5) Initial 90-day production ("IP90") for the Company's most recent five (5.0 net) wells drilled on our British Columbia lands averaged 1,000 boe/d per well. IP90 consisted of 34% tight oil, 9% NGLs, and 57% shale gas, using a conversion of six mcf of gas to one barrel of oil, based on field level estimates for the first 90 full days of production following the tie-in of the well. Production rates presented are for a limited timeframe only and may not be indicative of future performance or the ultimate recovery for a given well or pad.

Non-GAAP and Other Specified Financial Measures

This report and other materials released by Vermilion includes financial measures that are not standardized, specified, defined, or determined under IFRS and are therefore considered non-GAAP or other specified financial measures and may not be comparable to similar measures presented by other issuers. These financial measures include:

Total of Segments Measures

Fund flows from operations (FFO): Most directly comparable to net earnings (loss), FFO is a total of segments measure comprised of sales less royalties, transportation, operating, G&A, corporate income tax, PRRT, windfall taxes, 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 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 primary financial statement measures can be found below.

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Sales	**490,095**	**61.97**	475,532	62.92	**1,477,055**	**62.63**	1,499,586	66.57
Royalties	**(42,738)**	**(5.40)**	(32,209)	(4.26)	**(137,901)**	**(5.85)**	(146,546)	(6.51)
Transportation	**(26,693)**	**(3.38)**	(21,460)	(2.84)	**(74,972)**	**(3.18)**	(66,415)	(2.95)
Operating	**(138,806)**	**(17.55)**	(122,870)	(16.26)	**(428,347)**	**(18.16)**	(396,444)	(17.60)
General and administration	**(21,803)**	**(2.76)**	(20,959)	(2.77)	**(72,043)**	**(3.05)**	(60,906)	(2.70)
Corporate income tax expense	**(12,707)**	**(1.61)**	(31,368)	(4.15)	**(50,445)**	**(2.14)**	(72,558)	(3.22)
Windfall taxes	**—**	**—**	(21,953)	(2.90)	**—**	**—**	(78,177)	(3.47)
PRRT	**(507)**	**(0.06)**	—	—	**(14,928)**	**(0.63)**	—	—
Interest expense	**(21,187)**	**(2.68)**	(20,218)	(2.68)	**(60,641)**	**(2.57)**	(62,303)	(2.77)
Equity based compensation	**—**	**—**	—	—	**(14,361)**	**(0.61)**	—	—
Realized gain on derivatives	**49,891**	**6.31**	73,625	9.74	**316,523**	**13.42**	155,628	6.91
Realized foreign exchange gain	**1,155**	**0.15**	2,089	0.28	**5,293**	**0.22**	997	0.04
Realized other income	**(1,676)**	**(0.21)**	(9,991)	(1.32)	**(2,148)**	**(0.09)**	(2,368)	(0.11)
Fund flows from operations	**275,024**	**34.78**	270,218	35.76	**943,085**	**39.99**	770,494	34.19
Equity based compensation	**(6,412)**		(6,362)		**(8,070)**		(34,885)	
Unrealized (loss) gain on derivative instruments (1)	**(1,052)**		(65,294)		**(315,585)**		38,581	
Unrealized foreign exchange gain (loss) (1)	**(11,382)**		(12,042)		**(29,954)**		7,604	
Accretion	**(19,126)**		(20,068)		**(55,269)**		(58,718)	
Depletion and depreciation	**(180,164)**		(151,087)		**(519,782)**		(453,607)	
Deferred tax (expense) recovery	**(4,713)**		42,489		**(42,025)**		79,435	
Gain on business combination	**—**		—		**—**		445,094	
Loss on disposition	**—**		—		**—**		(226,828)	
Unrealized other expense	**(478)**		(545)		**(823)**		(1,621)	
Net earnings (loss)	**51,697**		57,309		**(28,423)**		565,549	

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

Non-GAAP Financial Measures and Non-GAAP Ratios

Free cash flow (FCF) and excess free cash flow (EFCF): Most directly comparable to cash flows from operating activities, FCF is a non-GAAP measure calculated as fund flows from operations less drilling and development costs and exploration and evaluation costs and EFCF is comprised of FCF less payments on lease obligations and asset retirement obligations settled. 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. EFCF is used by management to determine the funding available to return to shareholders after costs attributable to normal business operations. Reconciliation to the primary financial statement measures can be found in the following table.

($M)	Q3 2024	Q3 2023	2024	2023
Cash flows from operating activities	**134,547**	118,436	**755,164**	680,697
Changes in non-cash operating working capital	**125,145**	138,200	**155,869**	61,768
Asset retirement obligations settled	**15,332**	13,582	**32,052**	28,029
Fund flows from operations	**275,024**	270,218	**943,085**	770,494
Drilling and development	**(118,809)**	(119,404)	**(410,457)**	(436,802)
Exploration and evaluation	**(2,460)**	(6,235)	**(11,864)**	(10,502)
Free cash flow	**153,755**	144,579	**520,764**	323,190
Payments on lease obligations	**(7,547)**	(4,053)	**(19,479)**	(13,117)
Asset retirement obligations settled	**(15,332)**	(13,582)	**(32,052)**	(28,029)
Excess free cash flow	**130,876**	126,944	**469,233**	282,044

Capital expenditures: Most directly comparable to cash flows used in investing activities, capital expenditures is a non-GAAP 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)	Q3 2024	Q3 2023	2024	2023
Drilling and development	**118,809**	119,404	**410,457**	436,802
Exploration and evaluation	**2,460**	6,235	**11,864**	10,502
Capital expenditures	**121,269**	125,639	**422,321**	447,304

Payout and payout % of FFO: Payout and payout % of FFO are, respectively, a non-GAAP financial measure and non-GAAP ratio, 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 (total of segments measure). 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)	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Dividends declared	**18,642**	16,367	**56,806**	49,023
Drilling and development	**118,809**	119,404	**410,457**	436,802
Exploration and evaluation	**2,460**	6,235	**11,864**	10,502
Asset retirement obligations settled	**15,332**	13,582	**32,052**	28,029
Payout	**155,243**	155,588	**511,179**	524,356
% of fund flows from operations	**56 %**	58 %	**54 %**	68 %

Return on capital employed (ROCE): A non-GAAP ratio, ROCE is a measure that we use 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 (loss) 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)	Sep 30, 2024	Sep 30, 2023
Net (loss) earnings	**(831,559)**	960,957
Taxes	**(4,597)**	537,895
Interest expense	**83,550**	84,809
EBIT	**(752,606)**	1,583,661
Average capital employed	**5,995,108**	6,024,614
Return on capital employed	**(13)%**	26 %

Adjusted working capital: Defined 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.

($M)	As at Sep 30, 2024	Dec 31, 2023
Current assets	**651,197**	823,514
Current derivative asset	**(92,537)**	(313,792)
Current liabilities	**(521,669)**	(696,074)
Current lease liability	**23,545**	21,068
Current derivative liability	**9,487**	732
Adjusted working capital	**70,023**	(164,552)

Acquisitions: 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. We believe 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)	Q3 2024	Q3 2023	Q3 2024	Q3 2023
Acquisitions, net of cash acquired	**1,642**	3,191	**7,471**	139,612
Acquisition of securities	**—**	2,047	**9,373**	4,155
Acquired working capital	**—**	—	**—**	103,527
Acquisitions	**1,642**	5,238	**16,844**	247,294

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.

($M)	As at Sep 30, 2024	Dec 31, 2023
Long-term debt	**903,354**	914,015
Adjusted working capital	**(70,023)**	164,552
Net debt	**833,331**	1,078,567
Ratio of net debt to four quarter trailing fund flows from operations	**0.6**	0.9

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)	Q3 2024	Q3 2023
Shares outstanding	**155,348**	163,666
Potential shares issuable pursuant to the LTIP	**3,564**	4,238
Diluted shares outstanding	**158,912**	167,904

Fund flows from operations per basic and diluted share: Management assesses fund flows from operations on a per share basis as we believe this provides a measure of our operating performance after taking into account the issuance and potential future issuance of Vermilion common shares. Fund flows from operations per basic share is calculated by dividing fund flows from operations (total of segments measure) by the basic weighted average shares outstanding as defined under IFRS. Fund flows from operations per diluted share is calculated by dividing fund flows from operations by the sum of basic weighted average shares outstanding and incremental shares issuable under the equity based compensation plans as determined using the treasury stock method.

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

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.

Net debt to four quarter trailing fund flows from operations: Management uses net debt 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 calculated as net debt (capital management measure) divided by fund flows from operations (total of segments measure) from the preceding four quarters.

Management's Discussion and Analysis

The following is Management's Discussion and Analysis ("MD&A"), dated November 6, 2024, of Vermilion Energy Inc.'s ("Vermilion", "we", "our", "us" or the "Company") operating and financial results as at and for the three and nine months ended September 30, 2024 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 and nine months ended September 30, 2024 and the audited consolidated financial statements for the years ended December 31, 2023 and 2022, 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 and nine months ended September 30, 2024 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 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 12, 2023, we released our 2024 capital budget and associated production guidance, which assumed a mid-year startup of the new BC Montney battery and Croatia gas plant. On May 1, 2024, we increased 2024 guidance for royalty rate and cash taxes to reflect the impact of higher forward pricing for crude oil on these items. On July 31, 2024, we increased 2024 production guidance to reflect consistently strong operational performance across our asset base over the first half of 2024. On November 6, 2024, we tightened our 2024 production guidance range to reflect increased certainty on annual production levels. The Company's guidance for 2024 is as follows:

Category	Prior (1)	Current (1)
Production (boe/d)	83,000 - 86,000	84,000 - 85,000
E&D capital expenditures ($MM)	$600 - 625	$600 - 625
Royalty rate (% of sales)	9 - 11%	9 - 11%
Operating ($/boe)	$17.00 - 18.00	$17.00 - 18.00
Transportation ($/boe)	$3.00 - 3.50	$3.00 - 3.50
General and administration ($/boe)	$2.50 - 3.00	$2.50 - 3.00
Cash taxes (% of pre-tax FFO)	7 - 9%	7 - 9%
Asset retirement obligations settled ($MM)	$60	$60
Payments on lease obligations ($MM) (2)	$30 - 60	$30 - 60

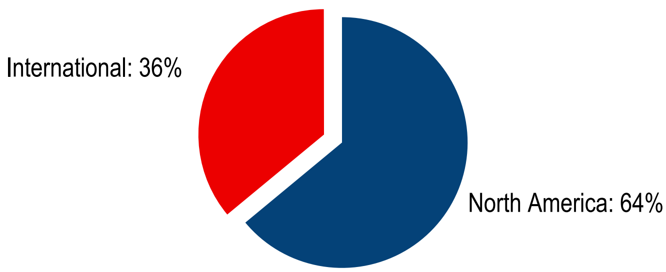
(1) Current 2024 guidance reflects foreign exchange assumptions of CAD/USD 1.37, CAD/EUR 1.49, and CAD/AUD 0.91. Prior 2024 guidance reflects foreign exchange assumptions of CAD/USD 1.36, CAD/EUR 1.48, and CAD/AUD 0.91.

(2) Payments on lease obligations includes contractual amounts owing on leases, as well as up to $30 million to account for accelerated principal payments that may be made in 2024.

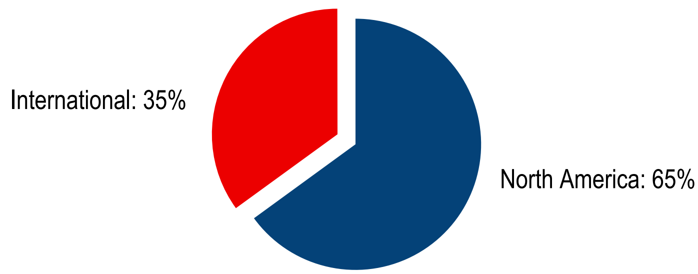
Vermilion's Business

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.

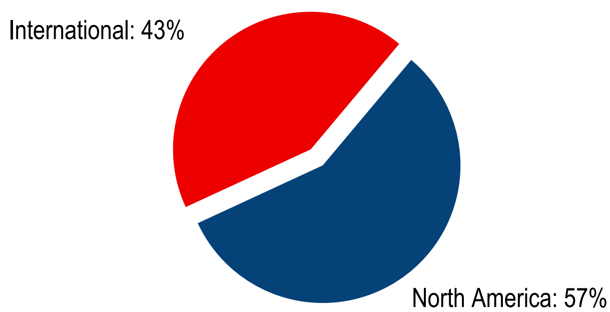
YTD 2024 production of 84,881 boe/d



YTD 2024 capital expenditures of $422.3MM



YTD 2024 fund flows from operations of $943.1MM



Consolidated Results Overview

	Q3 2024	Q3 2023	Q3/24 vs. Q3/23	YTD 2024	YTD 2023	2024 vs. 2023
Production [1]						
Crude oil and condensate (bbls/d)	**29,837**	31,417	(5)%	**31,797**	31,407	1%
NGLs (bbls/d)	**7,547**	7,344	3%	**7,264**	7,261	—%
Natural gas (mmcf/d)	**280.73**	263.80	6%	**274.93**	265.09	4%
Total (boe/d)	**84,173**	82,727	2%	**84,881**	82,849	3%
(Draw) build in inventory (mbbls)	**(164)**	52		**(324)**	73	
Financial metrics						
Fund flows from operations ($M) [2]	**275,024**	270,218	2%	**943,085**	770,494	22%
Per share ($/basic share)	**1.76**	1.65	7%	**5.93**	4.70	26%
Net earnings (loss) ($M)	**51,697**	57,309	(10)%	**(28,423)**	565,549	N/A
Per share ($/basic share)	**0.33**	0.35	(6)%	**(0.18)**	3.45	N/A
Cash flows from operating activities ($M)	**134,547**	118,436	14%	**755,164**	680,697	11%
Free cash flow ($M) [3]	**153,755**	144,579	6%	**520,764**	323,190	61%
Long-term debt ($M)	**903,354**	966,505	(7)%	**903,354**	966,505	(7)%
Net debt ($M) [4]	**833,331**	1,242,522	(33)%	**833,331**	1,242,522	(33)%
Activity						
Capital expenditures ($M) [5]	**121,269**	125,639	(4)%	**422,321**	447,304	(6)%
Acquisitions ($M) [6]	**1,642**	5,238	(69)%	**16,844**	247,294	(93)%
Dispositions ($M)	**—**	—		**—**	182,152	

(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 (loss) and net earnings (loss) per share, respectively. The measures do not have a standardized meaning under IFRS 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, windfall taxes, 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 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.

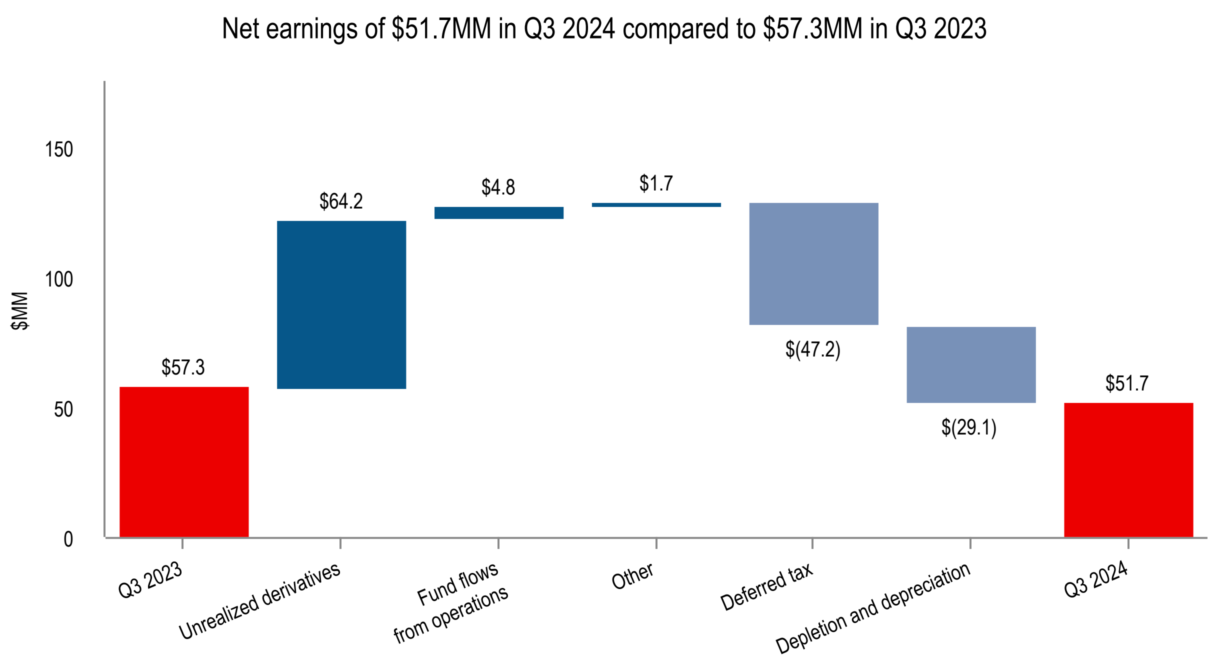
(4) Net debt is a capital management measure in accordance with IAS 1 "Presentation of Financial Statements" and is most directly comparable to long-term debt. Net debt is comprised of long-term debt (excluding unrealized foreign exchange on swapped USD borrowings) plus adjusted working capital (defined 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 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 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.

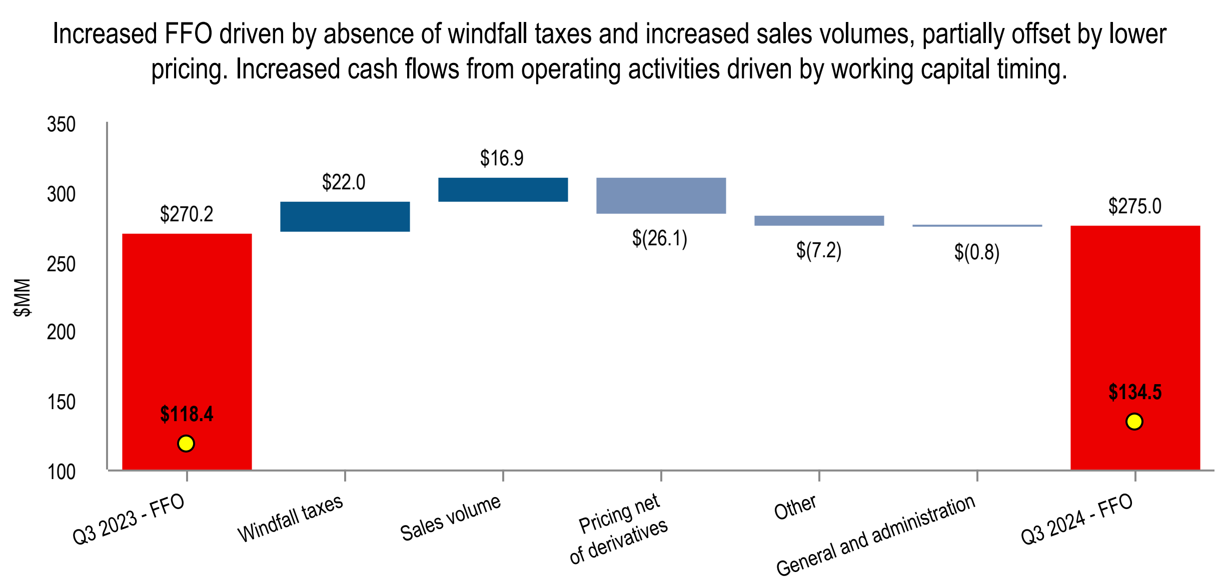
Financial performance review

Q3 2024 vs. Q3 2023



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

- We recorded net earnings of $51.7 million ($0.33/basic share) for Q3 2024 compared to net earnings of $57.3 million ($0.35/basic share) in Q3 2023. The decrease in net earnings was primarily due to increases in deferred tax and depletion and depreciation, partially offset by decreases in unrealized derivative losses of $64.2 million due to changes in our mark-to-market position.

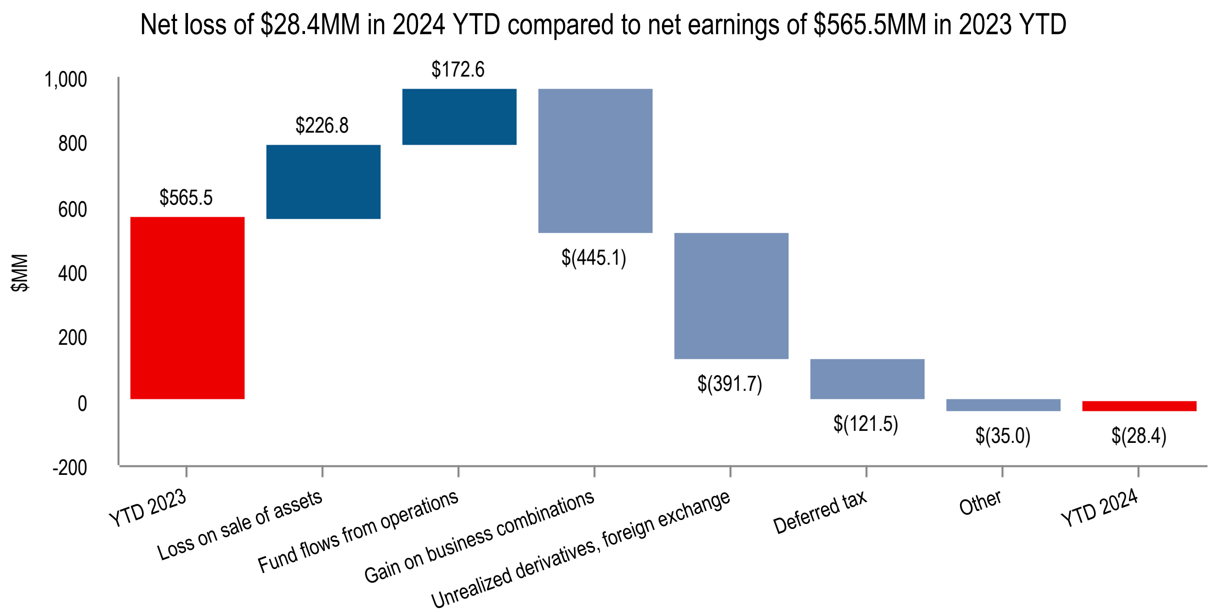


"Pricing net of derivatives" contains pricing variance on sales volumes (WTI, AECO, Dated Brent & TTF and NBP) and realized derivatives. "Sales volume" is the sum of sales volume variance in all regions. "Other" contains royalties, transportation, operating expense, interest, taxes, realized foreign exchange, and other realized income.

Cash flows from operating activities

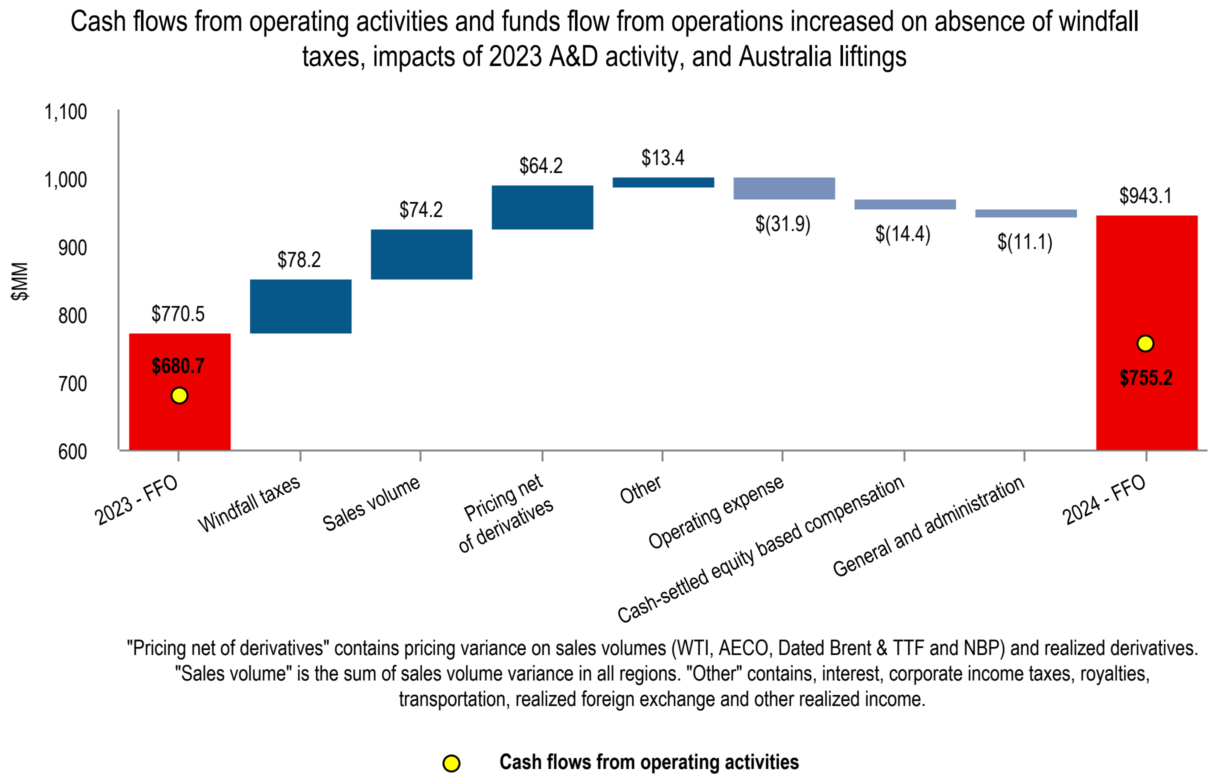
- We generated cash flows from operating activities of $134.5 million in Q3 2024 compared to $118.4 million in Q3 2023 and fund flows from operations of $275.0 million in Q3 2024 compared to $270.2 million in Q3 2023. The increase in fund flows from operations was primarily driven by the absence of windfall taxes and increased sales volumes in Australia, Ireland and Croatia, partially offset by lower realized gains on Euro gas derivative contracts. The variance between cash flows from operating activities and fund flows from operations is primarily due to working capital timing related to payments made on windfall taxes payable.

2024 vs. 2023



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

- For the nine months ended September 30, 2024, we recorded a net loss of $28.4 million compared to net earnings of $565.5 million for the comparable period in 2023. The decrease in net earnings (loss) was primarily attributable to the net gain recognized on acquisition and disposition activity in 2023 and changes in our mark-to-market position, partially offset by higher FFO driven by higher realized gains on commodity contracts.



- For the nine months ended September 30, 2024 as compared to 2023, cash flows from operating activities increased by $74.5 million to $755.2 million and fund flows from operations increased by $172.6 million to $943.1 million. The increase in fund flows from operations was primarily driven by the absence of windfall taxes, organic growth and acquisitions and increased sales volumes in Australia, Ireland and Croatia, and realized gains on derivative contracts. This was partially offset by cash-settled equity compensation in 2024, and other costs and taxes. Variances between cash flows from operating activities and funds flow from operations are primarily driven by working capital timing differences related to payments made on windfall taxes payable.

Production review

Q3 2024 vs. Q3 2023

- Consolidated average production of 84,173 boe/d in Q3 2024 increased compared to Q3 2023 production of 82,727 boe/d. Production increased primarily due to production starting on the SA-10 block in Croatia, timing of annual turnarounds in Ireland, and production in Australia after downtime in 2023, partially offset by lower production in North America as Montney growth was more than offset by natural declines in Alberta, Saskatchewan and Wyoming and some Canadian gas production shut-in due to weak AECO pricing.

2024 vs. 2023

- Consolidated average production of 84,881 boe/d in the nine months ended September 30, 2024 increased compared to the prior year comparative period production of 82,849 boe/d. Production increased primarily due to unplanned downtime in Australia in 2023 and increased production in Ireland due to the acquisition of an additional 36.5% interest in the Corrib Natural Gas Project at the end of Q1 2023. This was partially offset by disposition activities in 2023.

Activity review

For the three months ended September 30, 2024, capital expenditures were $121.3 million.

- In our North America core region we invested capital expenditures of $78.2 million, primarily comprised of $76.8 million of capital expenditure in Canada:
  - At Mica, we completed and brought on production five (5.0 net) BC Montney liquids-rich shale gas wells;
  - In the Deep Basin, we drilled three (2.3 net), completed three (2.3 net), and brought on production one (1.0 net) Mannville liquids-rich conventional natural gas wells;
  - In Saskatchewan, we drilled, completed, and brought on production five (5.0 net) light and medium crude oil wells;
  - In the United States, we invested $1.4 million as five (0.2 net) non-operated light and medium crude oil wells were brought on production.

- In our International core region, capital expenditures of $43.1 million were invested during Q3 2024:
  - In Germany, we invested $15.5 million as we began drilling our second deep gas exploration well and made progress on tie-in operations of our successful first deep gas exploration well, which is planned to come on production first half 2025;
  - In France, we invested $11.4 million primarily on subsurface maintenance, workover, and facilities activities;
  - In Australia, $8.7 million was invested as we performed routine facilities maintenance;
  - In the Netherlands, we invested $5.2 million, primarily on facilities and tie-in activities;
  - In Central and Eastern Europe, $2.0 million was invested as we successfully increased production of the SA-10 block and completed testing on the third well of our four-well program on the SA-7 block;
  - In Ireland, $0.3 million was invested on facilities.

Financial sustainability review

Free cash flow

- Free cash flow of $520.8 million increased by $197.6 million for the nine months ended September 30, 2024 compared to the prior year period primarily driven by increased fund flows from operations primarily driven by non-recurring windfall taxes incurred in 2023, increased sales volumes, higher pricing net of derivatives, and timing of capital expenditures.

Long-term debt and net debt

- Long-term debt decreased to $903.4 million as at September 30, 2024 (December 31, 2023 - $914.0 million) due to repurchases made on the 2025 senior notes partially offset by the strengthening of the US dollar. The revolving credit facility remained undrawn.
- As at September 30, 2024, net debt decreased to $833.3 million (December 31, 2023 - $1,078.6 million) as a result of strong free cash flow generation.
- The ratio of net debt to four quarter trailing fund flows from operations[(1)] decreased to 0.6 as at September 30, 2024 (December 31, 2023 - 0.9) primarily due to lower net debt and higher four quarter trailing fund flows from operations on settlement of derivative contracts and lower windfall taxes.

(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 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.

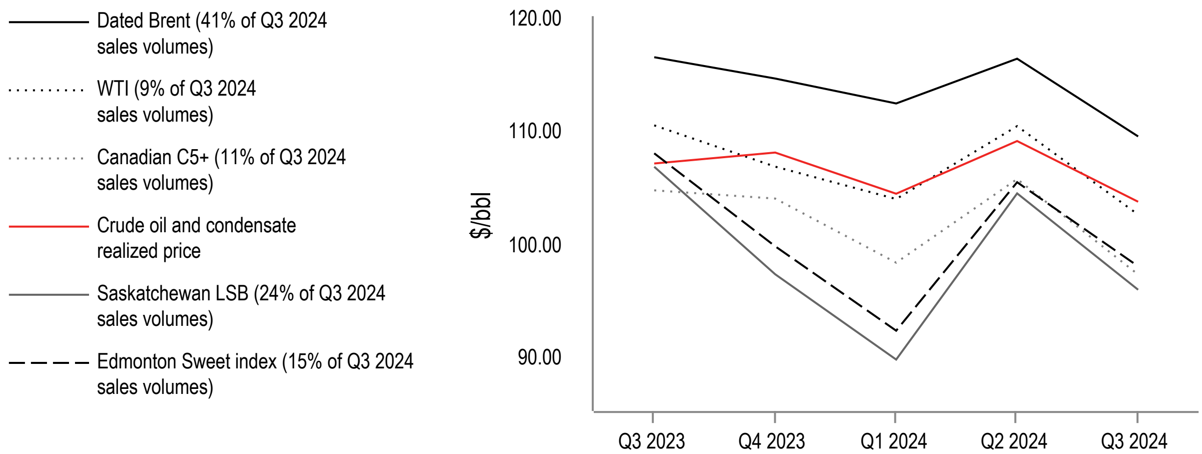
Benchmark Commodity Prices

	Q3 2024	Q3 2023	Q3/24 vs. Q3/23	YTD 2024	YTD 2023	2024 vs. 2023
Crude oil						
WTI ($/bbl)	**102.41**	110.33	(7)%	**105.49**	104.15	1%
WTI (US $/bbl)	**75.10**	82.26	(9)%	**77.54**	77.40	—%
Edmonton Sweet index ($/bbl)	**97.83**	107.84	(9)%	**98.40**	100.62	(2)%
Edmonton Sweet index (US $/bbl)	**71.74**	80.41	(11)%	**72.33**	74.77	(3)%
Saskatchewan LSB index ($/bbl)	**95.75**	106.65	(10)%	**96.51**	98.25	(2)%
Saskatchewan LSB index (US $/bbl)	**70.21**	79.52	(12)%	**70.94**	73.02	(3)%
Canadian C5+ Condensate index ($/bbl)	**97.10**	104.56	(7)%	**100.28**	103.23	(3)%
Canadian C5+ Condensate index (US $/bbl)	**71.20**	77.96	(9)%	**73.71**	76.72	(4)%
Dated Brent ($/bbl)	**109.34**	116.35	(6)%	**112.63**	110.53	2%
Dated Brent (US $/bbl)	**80.18**	86.76	(8)%	**82.79**	82.14	1%
Natural gas						
North America						
AECO 5A ($/mcf)	**0.69**	2.61	(74)%	**1.45**	2.76	(47)%
AECO 7A ($/mcf)	**0.81**	2.38	(66)%	**1.43**	3.03	(53)%
Henry Hub ($/mcf)	**2.94**	3.42	(14)%	**2.85**	3.62	(21)%
Henry Hub (US $/mcf)	**2.16**	2.55	(15)%	**2.10**	2.69	(22)%
Europe[1]						
NBP Day Ahead ($/mmbtu)	**14.51**	13.88	5%	**13.14**	16.61	(21)%
NBP Month Ahead ($/mmbtu)	**14.78**	13.54	9%	**13.41**	20.36	(34)%
NBP Day Ahead (€/mmbtu)	**9.68**	9.51	2%	**8.89**	11.40	(22)%
NBP Month Ahead (€/mmbtu)	**9.86**	9.28	6%	**9.07**	13.97	(35)%
TTF Day Ahead ($/mmbtu)	**15.52**	14.11	10%	**13.62**	17.39	(22)%
TTF Month Ahead ($/mmbtu)	**15.42**	13.74	12%	**13.70**	21.19	(35)%
TTF Day Ahead (€/mmbtu)	**10.35**	9.67	7%	**9.21**	11.93	(23)%
TTF Month Ahead (€/mmbtu)	**10.29**	9.42	9%	**9.26**	14.54	(36)%
Average exchange rates						
CDN $/US $	**1.36**	1.34	1%	**1.36**	1.35	1%
CDN $/Euro	**1.50**	1.46	3%	**1.48**	1.46	1%
Realized prices						
Crude oil and condensate ($/bbl)	**103.55**	106.94	(3)%	**105.54**	100.64	5%
NGLs ($/bbl)	**27.49**	27.77	(1)%	**30.99**	30.89	—%
Natural gas ($/mcf)	**6.57**	6.32	4%	**6.13**	8.08	(24)%
Total ($/boe)	**61.97**	62.92	(2)%	**62.63**	66.57	(6)%

(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.

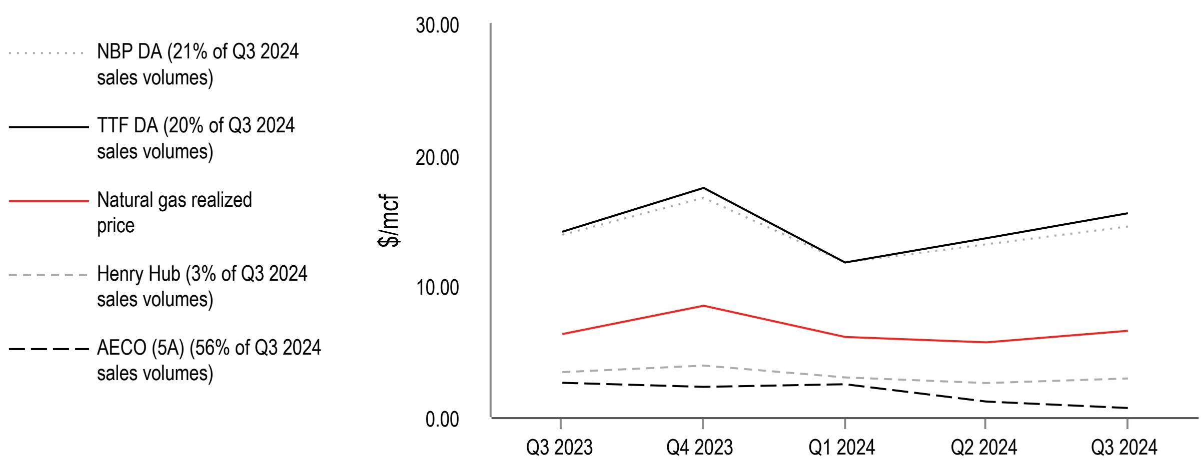
As an internationally diversified producer, we are exposed to a range of commodity prices. In our North America core region, our crude oil is sold at benchmarks linked to WTI (including the Edmonton Sweet index, the Saskatchewan LSB index, and the Canadian C5+ index) and our natural gas is sold at benchmarks 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.

Q3 2024 realized crude oil and condensate price was a $5.72/bbl premium to Edmonton Sweet Index



- Crude oil prices decreased in Q3 2024 relative to Q3 2023 on weaker supply-demand fundamentals and macroeconomic uncertainty. Canadian dollar WTI decreased by 7% and Brent decreased by 6% in Q3 2024 relative to Q3 2023.
- In Canadian dollar terms, year-over-year, the Edmonton Sweet differential widened by $2.09/bbl to a discount of $4.58/bbl against WTI, and the Saskatchewan LSB differential widened by $2.98/bbl to a discount of $6.66/bbl against WTI.
- Approximately 41% of Vermilion's Q3 2024 crude oil and condensate production was priced at the Dated Brent index, which averaged a premium to WTI of US$5.08/bbl, while the remainder of our crude oil and condensate production was priced at the Saskatchewan LSB, Canadian C5+, Edmonton Sweet, and WTI indices.

Q3 2024 realized natural gas price was a $5.88/mcf premium to AECO 5A



- In Canadian dollar terms, year-over-year, prices for European natural gas at NBP and TTF increased by 5% and 10% respectively on a day-ahead basis. On a month ahead basis, NBP and TTF increased by 9% and 12% respectively. Prices increased in response to greater competition in the global LNG market and the risk of losing Russian gas flows transiting Ukraine.
- Year-over-year natural gas prices in Canadian dollar terms at NYMEX HH decreased by 15%, and AECO 7A decreased by 66%. 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 Q3 2024, average European natural gas prices represented an $14.37/mcf premium to AECO. Approximately 41% of our natural gas production in Q3 2024 benefited from this premium European pricing.

North America

	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Production [1]				
Crude oil and condensate (bbls/d)	**19,045**	20,883	**19,483**	21,619
NGLs (bbls/d)	**7,547**	7,344	**7,264**	7,261
Natural gas (mmcf/d)	**164.07**	171.19	**163.31**	168.42
Total production volume (boe/d)	**53,936**	56,758	**53,961**	56,951

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

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Sales	**201,804**	**40.67**	257,248	49.26	**647,110**	**43.77**	775,580	49.88
Royalties	**(30,492)**	**(6.14)**	(40,489)	(7.75)	**(99,025)**	**(6.70)**	(108,812)	(7.00)
Transportation	**(15,474)**	**(3.12)**	(10,878)	(2.08)	**(40,931)**	**(2.77)**	(31,763)	(2.04)
Operating	**(58,937)**	**(11.88)**	(63,138)	(12.09)	**(197,095)**	**(13.33)**	(199,473)	(12.83)
General and administration [1]	**(5,432)**	**(1.09)**	(3,748)	(0.72)	**(26,323)**	**(1.78)**	(8,605)	(0.55)
Corporate income tax expense [1]	**(1,676)**	**(0.34)**	(35)	(0.01)	**(729)**	**(0.05)**	(1,184)	(0.08)
Fund flows from operations	**89,793**	**18.10**	138,960	26.61	**283,007**	**19.14**	425,743	27.38
Drilling and development	**(78,171)**		(69,703)		**(276,200)**		(321,496)	
Free cash flow	**11,622**		69,257		**6,807**		104,247	

(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 our North American operations averaged 53,936 boe/d in Q3 2024, a decrease of 2% from Q2 2024 due to declines in our Deep Basin and United States assets and some Canadian gas production shut-in due to weak AECO pricing, partially offset by new production from our recent BC Mica Montney wells.

At Mica, we completed and brought on production five (5.0 net) BC Montney liquids-rich shale gas wells. In the Deep Basin, we drilled three (2.3 net), completed three (2.3 net), and brought on production one (1.0 net) Mannville liquids-rich conventional natural gas wells. In Saskatchewan, we drilled, completed, and brought on production five (5.0 net) light and medium crude oil wells, while in the United States, five (0.2 net) non-operated light and medium crude oil wells were brought on production.

Sales

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Canada	**170,780**	**38.06**	209,403	45.52	**535,460**	**40.51**	661,289	47.36
United States	**31,024**	**65.30**	47,845	77.03	**111,650**	**71.23**	114,291	72.07
North America	**201,804**	**40.67**	257,248	49.26	**647,110**	**43.77**	775,580	49.88

Sales in North America decreased for the three and nine months ended September 30, 2024 compared to the prior year primarily due to lower realized pricing combined with lower production volumes following the sale of non-core southeast Saskatchewan assets and sale of Wyoming assets in 2023.

Royalties

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Canada	**(22,214)**	**(4.95)**	(26,856)	(5.84)	**(66,935)**	**(5.06)**	(77,752)	(5.57)
United States	**(8,278)**	**(17.42)**	(13,633)	(21.95)	**(32,090)**	**(20.47)**	(31,060)	(19.59)
North America	**(30,492)**	**(6.14)**	(40,489)	(7.75)	**(99,025)**	**(6.70)**	(108,812)	(7.00)
Royalty rate (% of sales)	**15.1 %**		15.7 %		**15.3 %**		14.0 %	

Royalties in North America decreased on a dollar and per unit basis for the three months ended September 30, 2024 compared to the prior year primarily due to lower realized pricing. Royalties decreased on a dollar basis and per unit basis for the nine months ended September 30, 2024 compared to the prior year primarily due to reduced pricing and partially offset by new wells drilled in Mica and the United States with higher royalty rates.

Transportation

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Canada	**(15,079)**	**(3.36)**	(10,709)	(2.33)	**(39,606)**	**(3.00)**	(31,462)	(2.25)
United States	**(395)**	**(0.83)**	(169)	(0.27)	**(1,325)**	**(0.85)**	(301)	(0.19)
North America	**(15,474)**	**(3.12)**	(10,878)	(2.08)	**(40,931)**	**(2.77)**	(31,763)	(2.04)

Transportation expense in North America increased on a dollar and per boe basis for the three and nine months ended September 30, 2024 compared to the prior year comparable periods primarily due to increased trucking expenses related to new activity on our Mica assets and higher pipeline fees.

Operating expense

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Canada	**(52,837)**	**(11.78)**	(59,191)	(12.87)	**(176,435)**	**(13.35)**	(182,288)	(13.06)
United States	**(6,100)**	**(12.84)**	(3,947)	(6.35)	**(20,660)**	**(13.18)**	(17,185)	(10.84)
North America	**(58,937)**	**(11.88)**	(63,138)	(12.09)	**(197,095)**	**(13.33)**	(199,473)	(12.83)

Operating expense in North America decreased on a dollar and per boe basis for the three months ended September 30, 2024 compared to the prior year comparable period primarily due to timing of maintenance activities. For the nine months ended September 30, 2024, operating expense increased on a per boe basis primarily due to gas processing fees in the Mica region, and decreased on a dollar basis on lower production due to the disposition of properties in southeast Saskatchewan and Wyoming in 2023.

International

	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Production [1]				
Crude oil and condensate (bbls/d)	**10,792**	10,534	**12,314**	9,787
Natural gas (mmcf/d)	**116.66**	92.61	**111.62**	96.67
Total production volume (boe/d)	**30,237**	25,969	**30,920**	25,899
Total sales volume (boe/d)	**32,024**	25,386	**32,106**	25,565

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

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Sales	**288,291**	**97.85**	218,284	93.46	**829,945**	**94.34**	724,006	103.74
Royalties	**(12,246)**	**(4.16)**	8,280	3.55	**(38,876)**	**(4.42)**	(37,734)	(5.41)
Transportation	**(11,219)**	**(3.81)**	(10,582)	(4.53)	**(34,041)**	**(3.87)**	(34,652)	(4.96)
Operating	**(79,869)**	**(27.11)**	(59,732)	(25.58)	**(231,252)**	**(26.29)**	(196,971)	(28.22)
General and administration	**(16,371)**	**(5.56)**	(17,211)	(7.37)	**(45,720)**	**(5.20)**	(52,301)	(7.49)
Corporate income tax expense	**(11,031)**	**(3.74)**	(31,333)	(13.42)	**(49,716)**	**(5.65)**	(71,374)	(10.23)
PRRT	**(507)**	**(0.17)**	—	—	**(14,928)**	**(1.70)**	—	—
Fund flows from operations	**157,048**	**53.30**	107,706	46.11	**415,412**	**47.21**	330,974	47.43
Drilling and development	**(40,638)**		(49,701)		**(134,257)**		(115,306)	
Exploration and evaluation	**(2,460)**		(6,235)		**(11,864)**		(10,502)	
Free cash flow	**113,950**		51,770		**269,291**		205,166	

Production from our International operations averaged 30,237 boe/d in Q3 2024, an increase of 1% from Q2 2024 primarily due to new production from our SA-10 block in Croatia and higher runtime in Germany and Ireland, partially offset by planned maintenance downtime in Australia.

In Germany, we successfully completed testing operations for our first deep gas exploration well drilled earlier this year. The well flow tested at a restricted rate of 17 mmcf/d of natural gas with a wellhead pressure of 4,625 psi, which supports our expectation that deliverability would have been higher without testing equipment limitations. Tie-in operations are progressing to bring the well on production in the first half of 2025.

In Croatia, we successfully increased production on the SA-10 block after commissioning the gas plant in late June 2024. Production in Q3 2024 averaged 1,855 boe/d (100% European natural gas) and currently exceeds 2,000 boe/d. On the SA-7 block, we completed testing on the third well of our four-well program, which flow tested at 5.6 mmcf/d of natural gas.

In Australia, planned maintenance at our Wandoo facility was executed during Q3 2024. Production resumed late in the quarter and continues to perform well.

Sales

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Australia	**47,661**	**128.84**	—	—	**155,274**	**130.39**	—	—
France	**67,888**	**108.26**	88,970	115.36	**240,540**	**111.43**	233,154	107.18
Netherlands	**34,204**	**88.18**	27,856	74.00	**99,711**	**77.59**	135,193	109.30
Germany	**43,063**	**88.79**	37,606	83.24	**103,404**	**80.74**	151,331	106.29
Ireland	**79,333**	**87.60**	63,798	86.76	**213,590**	**79.23**	201,974	94.92
Central and Eastern Europe	**16,142**	**94.59**	54	73.37	**17,426**	**93.67**	2,354	156.78
International	**288,291**	**97.85**	218,284	93.46	**829,945**	**94.34**	724,006	103.74

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

Crude oil sales volumes (bbls/d)	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Australia	**4,021**	—	**4,346**	—
France	**6,816**	8,383	**7,878**	7,968
Germany	**1,704**	1,528	**1,191**	1,429
International	**12,541**	9,911	**13,415**	9,397

Sales increased on a dollar basis for the three months ended September 30, 2024 compared to the prior year primarily due to production in Australia coming back online after downtime in 2023 and production starting on the SA-10 block in Croatia. On a per boe basis, sales increased due to the impact of realized prices on our Australian and Croatian production partially offset by lower realized commodity prices.

Sales increased on a dollar basis for the nine months ended September 30, 2024 compared to the prior year primarily due to production starting on the SA-10 block in Croatia, downtime in Australia in 2023, incremental volumes related to the Corrib acquisition in Ireland, and timing of transportation in France. On a per boe basis, sales decreased due to lower realized gas prices, partially offset by the impact of realized prices on our Australian production.

Royalties

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
France	**(8,538)**	**(13.62)**	(12,351)	(16.01)	**(31,873)**	**(14.77)**	(30,275)	(13.92)
Netherlands	**—**	**—**	20,607	54.75	**(217)**	**(0.17)**	(875)	(0.71)
Germany	**(1,348)**	**(2.78)**	142	0.32	**(4,138)**	**(3.23)**	(5,257)	(3.69)
Central and Eastern Europe	**(2,360)**	**(13.83)**	(118)	(160.33)	**(2,648)**	**(14.23)**	(1,327)	(88.38)
International	**(12,246)**	**(4.16)**	8,280	3.55	**(38,876)**	**(4.42)**	(37,734)	(5.41)
Royalty rate (% of sales)	**4.2 %**		(3.8)%		**4.7 %**		5.2 %	

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 increased on a dollar and per unit basis for the three months ended September 30, 2024 compared to the three months ended September 30, 2023 primarily due to adjustments for prior period royalties in Netherlands and Germany recorded in 2023. Royalties decreased on a per unit basis for the nine months ended September 30, 2024 primarily due to higher production volumes in Croatia, which is subject to lower royalties.

Transportation

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
France	**(5,712)**	**(9.11)**	(4,351)	(5.64)	**(17,476)**	**(8.10)**	(18,766)	(8.63)
Germany	**(3,210)**	**(6.62)**	(3,674)	(8.13)	**(8,788)**	**(6.86)**	(9,847)	(6.92)
Ireland	**(2,297)**	**(2.54)**	(2,557)	(3.48)	**(7,777)**	**(2.88)**	(6,039)	(2.84)
International	**(11,219)**	**(3.81)**	(10,582)	(4.53)	**(34,041)**	**(3.87)**	(34,652)	(4.96)

Transportation expense decreased on a per boe basis for the three and nine months ended September 30, 2024 compared to the prior year primarily due to prior period tariff adjustments in Germany recorded in 2023 and the impact of vessel cost and sales volume timing in France.

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

Operating expense

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Australia	**(28,521)**	**(77.10)**	(9,937)	—	**(69,481)**	**(58.35)**	(41,683)	—
France	**(14,733)**	**(23.49)**	(21,810)	(28.28)	**(50,779)**	**(23.52)**	(63,113)	(29.01)
Netherlands	**(7,887)**	**(20.33)**	(3,411)	(9.06)	**(29,206)**	**(22.73)**	(30,014)	(24.26)
Germany	**(14,394)**	**(29.68)**	(14,008)	(31.01)	**(39,585)**	**(30.91)**	(35,624)	(25.02)
Ireland	**(13,632)**	**(15.05)**	(10,372)	(14.10)	**(40,689)**	**(15.09)**	(25,516)	(11.99)
Central and Eastern Europe	**(702)**	**(4.11)**	(194)	(263.59)	**(1,512)**	**(8.13)**	(1,021)	(68.00)
International	**(79,869)**	**(27.11)**	(59,732)	(25.58)	**(231,252)**	**(26.29)**	(196,971)	(28.22)

Operating expenses increased on a dollar and per boe basis for the three months ended September 30, 2024 primarily due to the resumption of production in Australia and associated liftings, partially offset by decreased fuel and electricity costs in France in the current year combined with higher sales volumes in the prior year.

For the nine months ended September 30, 2024, operating expenses increased on a dollar basis primarily due to the resumption of production in Australia and associated liftings, combined with an increased working interest acquired in Ireland at Q1 2023, and higher facility maintenance and turnaround costs for planned downtime in Q2 2024. This increase was partially offset by decreased power costs in France in the current year combined with higher sales volumes in the prior year.

Operating expenses decreased on a per boe basis for the nine months ended September 30, 2024 compared to the prior year primarily attributable to lower power costs in France and Netherlands, partially offset by planned downtime in Germany and Ireland resulting in lower volumes.

Consolidated Financial Performance Review

Financial performance

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Sales	**490,095**	**61.97**	475,532	62.92	**1,477,055**	**62.63**	1,499,586	66.57
Royalties	**(42,738)**	**(5.40)**	(32,209)	(4.26)	**(137,901)**	**(5.85)**	(146,546)	(6.51)
Transportation	**(26,693)**	**(3.38)**	(21,460)	(2.84)	**(74,972)**	**(3.18)**	(66,415)	(2.95)
Operating	**(138,806)**	**(17.55)**	(122,870)	(16.26)	**(428,347)**	**(18.16)**	(396,444)	(17.60)
General and administration	**(21,803)**	**(2.76)**	(20,959)	(2.77)	**(72,043)**	**(3.05)**	(60,906)	(2.70)
Corporate income tax expense	**(12,707)**	**(1.61)**	(31,368)	(4.15)	**(50,445)**	**(2.14)**	(72,558)	(3.22)
Windfall taxes	**—**	**—**	(21,953)	(2.90)	**—**	**—**	(78,177)	(3.47)
PRRT	**(507)**	**(0.06)**	—	—	**(14,928)**	**(0.63)**	—	—
Interest expense	**(21,187)**	**(2.68)**	(20,218)	(2.68)	**(60,641)**	**(2.57)**	(62,303)	(2.77)
Equity based compensation	**—**	**—**	—	—	**(14,361)**	**(0.61)**	—	—
Realized gain on derivatives	**49,891**	**6.31**	73,625	9.74	**316,523**	**13.42**	155,628	6.91
Realized foreign exchange gain	**1,155**	**0.15**	2,089	0.28	**5,293**	**0.22**	997	0.04
Realized other (expense) income	**(1,676)**	**(0.21)**	(9,991)	(1.32)	**(2,148)**	**(0.09)**	(2,368)	(0.11)
Fund flows from operations	**275,024**	**34.78**	270,218	35.76	**943,085**	**39.99**	770,494	34.19
Equity based compensation	**(6,412)**		(6,362)		**(8,070)**		(34,885)	
Unrealized (loss) gain on derivative instruments [(1)]	**(1,052)**		(65,294)		**(315,585)**		38,581	
Unrealized foreign exchange gain (loss) [(1)]	**(11,382)**		(12,042)		**(29,954)**		7,604	
Accretion	**(19,126)**		(20,068)		**(55,269)**		(58,718)	
Depletion and depreciation	**(180,164)**		(151,087)		**(519,782)**		(453,607)	
Deferred tax (expense) recovery	**(4,713)**		42,489		**(42,025)**		79,435	
Gain on business combination	**—**		—		**—**		445,094	
Loss on disposition	**—**		—		**—**		(226,828)	
Unrealized other expense [(1)]	**(478)**		(545)		**(823)**		(1,621)	
Net earnings (loss)	**51,697**		57,309		**(28,423)**		565,549	

(1) Unrealized (loss) gain on derivative instruments, Unrealized foreign exchange (loss) gain, 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 remained relatively flat for the three months ended September 30, 2024 compared to the prior year.
- General and administration expense increased for the nine months ended September 30, 2024 compared to the prior year primarily due to accounting for the cash settlement of previously issued equity based settled compensation (previously accounted for as a share-based settled expense) and headcount costs.

Equity based compensation

- Equity based compensation included within funds flow from operations for the three and nine months ended September 30, 2024 is a result of settling withholding taxes via cash which were previously settled through the issuance and sale of shares from treasury.

PRRT and corporate income taxes

- PRRT for the three and nine months ended September 30, 2024 increased compared to the prior year due to downtime in Australia that resulted in no taxable income for the nine months ended September 30, 2023.
- Corporate income taxes for the three and nine months ended September 30, 2024 decreased compared to the same periods in the prior year due to combined lower taxable income mainly as a result of decreased commodity prices.

Windfall taxes

- Windfall taxes are the temporary taxes levied pursuant to the European Union's temporary solidarity contribution. The contribution set out minimum amounts to be calculated on taxable profits starting in 2022 and/or 2023, which are above a 20% increase of the average yearly taxable profits for 2018 to 2021. For the two-year period of the European Union's temporary solidarity contribution, Vermilion incurred $301 million of incremental taxes. Windfall taxes are not applicable to 2024 and future periods.

Interest expense

- Interest expense for the three months ended September 30, 2024 increased compared to the same period in the prior year primarily due to interest incurred on the processing facility lease in Canada, partially offset by interest income earned on our cash position and reduced debt on the 2025 senior notes due to buybacks. Interest expense for the nine months ended September 30, 2024 decreased compared to the same period 2023 due to the credit facility remaining undrawn throughout the period, reduced debt on the senior notes due to buybacks and higher interest income earned on our cash position, partially offset by interest incurred on the processing facility lease.

Realized gain or loss on derivatives

- For the three and nine months ended September 30, 2024, 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 September 30, 2024 is included in "Supplemental Table 2" of this MD&A.

Realized other income or expense

- Realized other income for the three and nine months ended September 30, 2024 decreased compared to the same periods in the prior year primarily due to decreased amounts for funding under the Saskatchewan Accelerated Site Closure program and proceeds received from insurance claims in 2023.

Net earnings (loss)

Fluctuations in net earnings (loss) 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 September 30, 2024 remained relatively flat compared to the same period in the prior year. Equity based compensation expense for the nine months ended September 30, 2024 decreased compared to the same period in the prior year primarily due to the cash settlement of previously share-based settled expenses and the lower value of LTIP awards settled in the current 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 September 30, 2024, we recognized a net unrealized loss on derivative instruments of $1.1 million. This consists of unrealized losses of $21.9 million on our European natural gas commodity derivative instruments and $7.0 million on our equity swaps, partially offset by unrealized gains of $22.4 million on our crude oil commodity derivative instruments, $4.5 million on our North American gas commodity derivative instruments and $0.9 million on our USD-to-CAD foreign exchange swaps.

For the nine months ended September 30, 2024, we recognized a net unrealized loss on derivative instruments of $315.6 million. This consists of unrealized losses of $294.4 million on our European natural gas commodity derivative instruments, $10.3 million on our equity swaps, $9.7 million on our crude oil commodity derivative instruments and $3.6 million on our USD-to-CAD foreign exchange swaps, partially offset by a $2.4 million gain on our North American gas commodity derivative instruments.

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 2024, unrealized foreign exchange gains and losses primarily resulted from:

- The translation of Euro and US dollar denominated intercompany loans 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, 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 (loss) reflects only the parent company's side of the translation.
- The translation of our USD denominated 2025 senior unsecured notes and USD denominated 2030 senior unsecured notes.

For the three months ended September 30, 2024, we recognized a net unrealized foreign exchange loss of $11.4 million, primarily driven by the effects of the Euro strengthening 2.8% on our Euro denominated loans and the US dollar weakening 1.4% on our US dollar denominated loans. This loss was partially offset by the US dollar weakening 1.4% against the Canadian dollar on our USD senior notes. For the nine months ended September 30, 2024, we recognized an unrealized foreign exchange loss of $30.0 million, primarily driven by the effects of the US dollar strengthening 2.1% against the Canadian dollar on our USD senior notes combined with losses on our Euro denominated intercompany loans, partially offset by gains on our USD denominated intercompany loans.

Accretion

Accretion expense is recognized to update the present value of the asset retirement obligation balance. For the three months ended September 30, 2024, compared to the three months ended September 30, 2023, accretion remained relatively flat. For the nine months ended September 30, 2024, accretion expense decreased versus the prior year primarily due to lower North American asset retirement balance related to dispositions completed in 2023 and changes in discount rates, partially offset by the Corrib acquisition completed in 2023.

Depletion and depreciation

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

Fluctuations in depletion and depreciation expense are primarily the result of changes in produced crude oil and natural gas volumes, and changes in depletion and depreciation per unit. Fluctuations in depletion and depreciation per unit are the result of changes in reserves, depletable base (net book value of capital assets and future development costs), and relative production mix.

Depletion and depreciation on a per boe basis for the three and nine months ended September 30, 2024 of $22.78 and $22.04 increased from $19.99 and $20.14 in the same periods of the prior year, respectively, primarily due to higher future development costs increasing the depletable base, decreased reserve estimates, and the weakening of the Canadian dollar on European assets. The increase was partially offset by decreases to the depletable base from the impairments and dispositions recorded in 2023.

Deferred tax

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

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

For the three and nine months ended September 30, 2024, the Company recorded deferred tax expense of $4.7 million and $42.0 million, respectively, compared to a deferred tax recovery of $42.5 million and $79.4 million, respectively, in the comparative periods in the prior year. The expense recorded in the current year is primarily attributable to the derecognition of deferred tax assets in Ireland driven by the decrease in European gas prices. In 2023, the deferred tax recovery was driven primarily by the disposition of assets in southeast Saskatchewan.

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 September 30, 2024, we have a ratio of net debt to four quarter trailing fund flows from operations of 0.6. We will continue to monitor for changes in forecasted fund flows from operations and, as appropriate, will adjust our exploration, development capital plans (and associated production targets), and return of capital plans to target optimal debt levels.

Net debt

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

	As at	
($M)	Sep 30, 2024	Dec 31, 2023
Long-term debt	**903,354**	914,015
Adjusted working capital [1]	**(70,023)**	164,552
Net debt	**833,331**	1,078,567
Ratio of net debt to four quarter trailing fund flows from operations	**0.6**	0.9

(1) Adjusted working capital is a non-GAAP financial measure that is not standardized under IFRS 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.

As at September 30, 2024, net debt decreased to $833.3 million (December 31, 2023 - $1.1 billion) primarily due to repurchases of senior notes and strong free cash flow generation. The ratio of net debt to four quarter trailing fund flows from operations as at September 30, 2024 decreased to 0.6 (December 31, 2023 - 0.9) due to lower net debt and higher four quarter trailing fund flows from operations.

Long-term debt

The balances recognized on our balance sheet are as follows:

	As at	
	Sep 30, 2024	Dec 31, 2023
2025 senior unsecured notes	**373,469**	395,839
2030 senior unsecured notes	**529,885**	518,176
Long-term debt	**903,354**	914,015

Revolving Credit Facility

As at September 30, 2024, Vermilion had in place a bank revolving credit facility maturing May 26, 2028 with terms and outstanding positions as follows:

	As at	
($M)	Sep 30, 2024	Dec 31, 2023
Total facility amount	**1,350,000**	1,600,000
Letters of credit outstanding	**(21,886)**	(18,116)
Unutilized capacity	**1,328,114**	1,581,884

On May 17, 2024, the maturity date of the facility was extended to May 26, 2028 (previously May 28, 2027) and the total facility amount of $1.6 billion was reduced to $1.35 billion, with an accordion feature to increase the aggregate amount available under the facility to $1.6 billion. As at September 30, 2024, the revolving credit facility was undrawn.

As at September 30, 2024, the revolving credit facility was subject to the following financial covenants:

		As at	
Financial covenant	Limit	Sep 30, 2024	Dec 31, 2023
Consolidated total debt to consolidated EBITDA	Less than 4.0	**0.68**	0.65
Consolidated total senior debt to consolidated EBITDA	Less than 3.5	**0.05**	—
Consolidated EBITDA to consolidated interest expense	Greater than 2.5	**17.81**	17.33

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

- Consolidated total debt: Includes all amounts classified as “Long-term debt”, “Current portion of long-term debt”, and “Lease obligations” (including the current portion included within "Accounts payable and accrued liabilities" but excluding operating leases as defined under IAS 17) on our consolidated balance sheet.
- Consolidated total senior debt: Consolidated total debt excluding unsecured and subordinated debt.
- Consolidated EBITDA: Consolidated net earnings (loss) before interest, income taxes, depreciation, accretion and certain other non-cash items, adjusted for the impact of the acquisition of a material subsidiary.
- Total interest expense: Includes all amounts classified as "Interest expense", but excludes interest on operating leases as defined under IAS 17.

In addition, our revolving credit facility has provisions relating to our liability management ratings in Alberta and Saskatchewan whereby if our security adjusted liability management ratings fall below specified limits in a province, a portion of the asset retirement obligations are included in the definitions of consolidated total debt and consolidated total senior debt. An event of default occurs if our security adjusted liability management ratings breach additional lower limits for a period greater than 90 days. As of September 30, 2024, Vermilion's liability management ratings were higher than the specified levels, and as such, no amounts relating to asset retirement obligations were included in the calculation of consolidated total debt and consolidated total senior debt.

As at September 30, 2024 and December 31, 2023, Vermilion was in compliance with the above covenants.

2025 senior unsecured notes

On March 13, 2017, Vermilion issued US $300.0 million of senior unsecured notes at par. The notes bear interest at a rate of 5.625% per annum, paid semi-annually on March 15 and September 15, and mature on March 15, 2025. As direct senior unsecured obligations of Vermilion, the notes rank equally in right of payment with existing and future senior indebtedness of the Company.

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

Subsequent to March 15, 2023, Vermilion may redeem some or all of the senior unsecured notes at a 100.00% redemption price plus any accrued and unpaid interest.

During the nine months ended September 30, 2024, Vermilion purchased $31.6 million of senior unsecured notes on the open market which were subsequently cancelled.

The Company has the right to roll over the senior unsecured notes under the existing revolving credit facility which matures May 26, 2028 and thus has continued to classify the senior unsecured notes as non-current.

2030 senior unsecured notes

On April 26, 2022, Vermilion closed a private offering of US $400.0 million 8-year senior unsecured notes. The notes were priced at 99.241% of par, mature on May 1, 2030, and bear interest at a rate of 6.875% per annum. Interest is paid semi-annually on May 1 and November 1, commencing on November 1, 2022. The notes are senior unsecured obligations of Vermilion and rank equally with existing and future senior unsecured indebtedness.

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 %
2028 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

The following table reconciles the change in shareholders’ capital:

Shareholders’ Capital	Shares ('000s)	Amount ($M)
Balance at January 1	**162,271**	**4,142,566**
Vesting of equity based awards	**996**	**9,998**
Share-settled dividends on vested equity based awards	**78**	**1,257**
Repurchase of shares	**(7,997)**	**(206,154)**
Balance at September 30	**155,348**	**3,947,667**

As at September 30, 2024, there were approximately 4.5 million equity based compensation awards outstanding. As at November 6, 2024, there were approximately 155.1 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 third quarter of 2024, Vermilion purchased 2.8 million common shares under the NCIB for total consideration of $40.1 million. Year-to-date, Vermilion purchased 8.0 million common shares under the NCIB for total consideration of 123.1 million. The common shares purchased under the NCIB were cancelled.

Subsequent to September 30, 2024, Vermilion purchased and cancelled 0.4 million shares under the NCIB for total consideration of $5.9 million.

Contractual Obligations and Commitments

Further information regarding the Company's contractual obligations and commitments can be found in the annual MD&A for the year ended December 31, 2023, available on SEDAR+ at www.sedarplus.ca or on Vermilion's website at www.vermilionenergy.com.

Asset Retirement Obligations

As at September 30, 2024, asset retirement obligations were $1,221.3 million compared to $1,159.1 million as at December 31, 2023. The increase in asset retirement obligations is primarily attributable to accretion expense recognized and unfavourable foreign exchange impacts. The credit spread decreased to 3.3% at September 30, 2024 compared to 3.6% at December 31, 2023 primarily due to a lower 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:

	Sep 30, 2024	Dec 31, 2023	Change
Credit spread added to below noted risk-free rates	**3.3 %**	3.6 %	(0.3)%
Country specific risk-free rate			
Canada	**3.1 %**	3.0 %	0.1 %
United States	**4.1 %**	4.2 %	(0.1)%
France	**3.5 %**	3.0 %	0.5 %
Netherlands	**2.6 %**	2.1 %	0.5 %
Germany	**2.5 %**	2.3 %	0.2 %
Ireland	**2.7 %**	2.7 %	— %
Australia	**4.2 %**	4.0 %	0.2 %
Central and Eastern Europe	**4.5 %**	4.4 %	0.1 %

Current cost estimates are inflated to the estimated time of abandonment using inflation rates of between 1.3% and 5.5% (as at December 31, 2023 - between 1.3% and 5.5%).

Risks and Uncertainties

Vermilion is exposed to various market and operational risks. For a discussion of these risks, please see Vermilion's MD&A and Annual Information Form, each for the year ended December 31, 2023 available on SEDAR+ at www.sedarplus.ca or on Vermilion’s website at www.vermilionenergy.com.

Critical Accounting Estimates

The preparation of financial statements in accordance with IFRS requires management to make estimates, judgments and assumptions that affect reported assets, liabilities, revenues and expenses, gains and losses, and disclosures of any possible contingencies. These estimates and assumptions are developed based on the best available information which management believed to be reasonable at the time such estimates and assumptions were made. As such, these assumptions are uncertain at the time estimates are made and could change, resulting in a material impact on Vermilion’s consolidated financial statements. Estimates are reviewed by management on an ongoing basis and as a result may change from period to period due to the availability of new information or changes in circumstances. Additionally, as a result of the unique circumstances of each jurisdiction that Vermilion operates in, the critical accounting estimates may affect one or more jurisdictions. There have been no material changes to our critical accounting estimates used in applying accounting policies for the nine months ended September 30, 2024. 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, 2023, 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.

Recently Adopted Accounting Pronouncements

Vermilion did not adopt any new accounting pronouncements as at September 30, 2024 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 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 September 30, 2024, 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: Netbacks

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

	Q3 2024			Q2 2024			YTD 2024			Q3 2023	YTD 2023
	Liquids	Natural Gas	Total	Liquids	Natural Gas	Total	Liquids	Natural Gas	Total	Total	Total
	$/bbl	$/mcf	$/boe	$/bbl	$/mcf	$/boe	$/bbl	$/mcf	$/boe	$/boe	$/boe
Canada											
Sales	75.97	0.88	**38.06**	83.40	1.29	42.58	77.79	1.42	**40.51**	45.52	47.36
Royalties	(10.58)	(0.01)	**(4.95)**	(11.07)	0.04	(4.98)	(10.63)	(0.05)	**(5.06)**	(5.84)	(5.57)
Transportation	(4.95)	(0.33)	**(3.36)**	(4.45)	(0.31)	(3.05)	(4.65)	(0.26)	**(3.00)**	(2.33)	(2.25)
Operating	(23.53)	(0.27)	**(11.78)**	(27.97)	(0.40)	(14.18)	(25.63)	(0.47)	**(13.35)**	(12.87)	(13.06)
Operating netback	36.91	0.27	**17.97**	39.91	0.62	20.37	36.88	0.64	**19.10**	24.48	26.48
General and administration			**(0.27)**			(1.22)			**(1.49)**	(5.56)	(5.09)
Fund flows from operations ($/boe)			**17.70**			19.15			**17.61**	18.92	21.39
United States											
Sales	82.44	1.24	**65.30**	94.63	1.22	77.12	88.29	1.74	**71.23**	77.03	72.07
Royalties	(21.88)	(0.40)	**(17.42)**	(27.93)	(0.31)	(22.70)	(25.28)	(0.56)	**(20.47)**	(21.95)	(19.59)
Transportation	(1.08)	—	**(0.83)**	(1.25)	—	(1.00)	(1.08)	—	**(0.85)**	(0.27)	(0.19)
Operating	(16.14)	(0.28)	**(12.84)**	(14.37)	(0.04)	(11.54)	(16.37)	(0.30)	**(13.18)**	(6.35)	(10.84)
Operating netback	43.34	0.56	**34.21**	51.08	0.87	41.88	45.56	0.88	**36.73**	48.46	41.45
General and administration			**(6.61)**			(5.95)			**(6.17)**	(5.21)	(4.43)
Fund flows from operations ($/boe)			**27.60**			35.93			**30.56**	43.25	37.02
France											
Sales	108.26	—	**108.26**	112.22	—	112.22	111.43	—	**111.43**	115.36	107.18
Royalties	(13.62)	—	**(13.62)**	(13.79)	—	(13.79)	(14.77)	—	**(14.77)**	(16.01)	(13.92)
Transportation	(9.11)	—	**(9.11)**	(8.59)	—	(8.59)	(8.10)	—	**(8.10)**	(5.64)	(8.63)
Operating	(23.49)	—	**(23.49)**	(19.59)	—	(19.59)	(23.52)	—	**(23.52)**	(28.28)	(29.01)
Operating netback	62.04	—	**62.04**	70.25	—	70.25	65.04	—	**65.04**	65.43	55.62
General and administration			**(7.29)**			(5.11)			**(6.29)**	(2.22)	(6.62)
Current income taxes			**(3.69)**			(7.99)			**(6.53)**	(7.01)	(3.87)
Fund flows from operations ($/boe)			**51.06**			57.15			**52.22**	56.20	45.13
Netherlands											
Sales	106.74	14.67	**88.18**	103.64	12.31	74.19	91.80	12.89	**77.59**	74.00	109.30
Royalties	—	—	**—**	—	—	—	—	(0.03)	**(0.17)**	54.75	(0.71)
Transportation	—	—	**—**	—	—	—	—	—	**—**	—	—
Operating	15.61	(3.45)	**(20.33)**	(46.54)	(4.30)	(26.01)	(25.08)	(3.78)	**(22.73)**	(9.06)	(24.26)
Operating netback	122.35	11.22	**67.85**	57.10	8.01	48.18	66.72	9.08	**54.69**	119.69	84.33
General and administration			**(5.24)**			(4.31)			**(4.47)**	(17.60)	(6.26)
Current income taxes			**(12.88)**			(19.09)			**(18.57)**	(45.38)	(23.92)
Fund flows from operations ($/boe)			**49.73**			24.78			**31.65**	56.71	54.15
Germany											
Sales	103.32	13.64	**88.79**	109.38	11.46	78.76	106.12	12.01	**80.74**	83.24	106.29
Royalties	(4.55)	(0.32)	**(2.78)**	0.31	(0.87)	(3.88)	(2.68)	(0.57)	**(3.23)**	0.32	(3.69)
Transportation	(15.19)	(0.42)	**(6.62)**	(17.74)	(0.46)	(6.45)	(18.66)	(0.47)	**(6.86)**	(8.13)	(6.92)
Operating	(33.51)	(4.64)	**(29.68)**	(53.89)	(5.69)	(38.98)	(40.03)	(4.63)	**(30.91)**	(31.01)	(25.02)
Operating netback	50.07	8.26	**49.71**	38.06	4.44	29.45	44.75	6.34	**39.74**	44.42	70.66
General and administration			**(6.23)**			(8.27)			**(6.76)**	(3.81)	(6.40)
Current income taxes			**(4.96)**			(4.60)			**(6.62)**	(18.34)	(21.81)
Fund flows from operations ($/boe)			**38.52**			16.58			**26.36**	22.27	42.45

	Q3 2024			Q2 2024			YTD 2024			Q3 2023	YTD 2023
	Liquids	Natural Gas	Total	Liquids	Natural Gas	Total	Liquids	Natural Gas	Total	Total	Total
	$/bbl	$/mcf	$/boe	$/bbl	$/mcf	$/boe	$/bbl	$/mcf	$/boe	$/boe	$/boe
Ireland											
Sales	—	14.60	**87.60**	—	13.29	79.76	—	13.21	**79.23**	86.76	94.92
Transportation	—	(0.42)	**(2.54)**	—	(0.46)	(2.75)	—	(0.48)	**(2.88)**	(3.48)	(2.84)
Operating	—	(2.51)	**(15.05)**	—	(3.13)	(18.80)	—	(2.52)	**(15.09)**	(14.10)	(11.99)
Operating netback	—	11.67	**70.01**	—	9.70	58.21	—	10.21	**61.26**	69.18	80.09
General and administration			**(2.99)**			(1.67)			**(2.35)**	(5.34)	(4.69)
Current income taxes			**(0.19)**			(0.36)			**(0.35)**	(0.22)	(0.18)
Fund flows from operations ($/boe)			**66.83**			56.18			**58.56**	63.62	75.22
Australia											
Sales	128.84	—	**128.84**	131.06	—	131.06	130.39	—	**130.39**	—	—
Operating	(77.10)	—	**(77.10)**	(56.66)	—	(56.66)	(58.35)	—	**(58.35)**	—	—
PRRT [(1)]	(1.37)	—	**(1.37)**	(14.54)	—	(14.54)	(12.54)	—	**(12.54)**	—	—
Operating netback	50.37	—	**50.37**	59.86	—	59.86	59.50	—	**59.50**	—	—
General and administration			**(5.59)**			(8.01)			**(4.88)**	—	—
Current income taxes			**(3.08)**			(1.40)			**(1.96)**	—	—
Fund flows from operations ($/boe)			**41.70**			50.45			**52.66**	—	—
Central and Eastern Europe											
Sales	—	15.76	**94.59**	62.27	14.44	84.76	62.04	15.63	**93.67**	73.37	156.78
Royalties	—	(2.30)	**(13.83)**	(5.49)	(3.81)	(21.53)	(5.47)	(2.38)	**(14.23)**	(160.33)	(88.38)
Operating	—	(0.69)	**(4.11)**	(38.46)	(5.92)	(33.51)	(5.47)	(1.36)	**(8.13)**	(263.59)	(68.00)
Operating netback	—	12.77	**76.65**	18.32	4.71	29.72	51.10	11.89	**71.31**	(350.55)	0.40
General and administration			**(11.57)**			(156.46)			**(30.13)**	(2,533.97)	(360.77)
Current income taxes			**—**			—			**—**	(1.36)	0.07
Fund flows from operations ($/boe)			**65.08**			(126.74)			**41.18**	(2,885.88)	(360.30)
Total Company											
Sales	88.90	6.57	**61.97**	94.79	5.69	62.46	92.09	6.13	**62.63**	62.92	66.57
Realized hedging gain (loss)	2.23	1.62	**6.31**	(0.16)	1.90	6.00	1.10	4.04	**13.42**	9.74	6.91
Royalties	(8.57)	(0.46)	**(5.40)**	(11.80)	(0.18)	(6.08)	(11.66)	(0.12)	**(5.85)**	(4.26)	(6.51)
Transportation	(5.27)	(0.30)	**(3.38)**	(5.07)	(0.29)	(3.30)	(4.94)	(0.27)	**(3.18)**	(2.84)	(2.95)
Operating	(25.77)	(1.78)	**(17.55)**	(27.41)	(1.72)	(18.29)	(26.80)	(1.76)	**(18.16)**	(16.26)	(17.60)
PRRT [(2)]	(0.14)	—	**(0.06)**	(1.02)	—	(0.47)	(1.35)	—	**(0.63)**	—	—
Operating netback	51.38	5.65	**41.89**	49.33	5.40	40.32	48.44	8.02	**48.23**	49.30	46.42
General and administration			**(2.76)**			(3.46)			**(3.05)**	(2.77)	(2.70)
Interest expense			**(2.68)**			(2.75)			**(2.57)**	(2.68)	(2.77)
Equity based compensation			**—**			(1.87)			**(0.61)**	—	—
Realized foreign exchange gain			**0.15**			0.30			**0.22**	0.28	0.04
Other income			**(0.21)**			(0.09)			**(0.09)**	(1.32)	(0.11)
Corporate income taxes			**(1.61)**			(1.58)			**(2.14)**	(4.15)	(3.22)
Windfall taxes			**—**			—			**—**	(2.90)	(3.47)
Fund flows from operations ($/boe)			**34.78**			30.87			**39.99**	35.76	34.19

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

Supplemental Table 2: Hedges

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

The following tables outline Vermilion's outstanding risk management positions as at September 30, 2024:

	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
WTI												
Q4 2024	bbl	USD	—	—	—	—	—	—	11,000	79.27	—	—
Q1 2025	bbl	USD	—	—	—	—	—	—	3,500	77.14	—	—
AECO												
Q4 2024	mcf	CAD	4,739	3.17	4,739	4.22	—	—	9,849	3.31	—	—
Q1 2025	mcf	CAD	4,739	3.17	4,739	4.22	—	—	23,695	3.89	—	—
Q2 2025	mcf	CAD	4,739	3.17	4,739	4.22	—	—	23,695	3.89	—	—
Q3 2025	mcf	CAD	4,739	3.17	4,739	4.22	—	—	23,695	3.89	—	—
Q4 2025	mcf	CAD	4,739	3.17	4,739	4.22	—	—	23,695	3.89	—	—
Q1 2026	mcf	CAD	4,739	3.17	4,739	4.22	—	—	23,695	3.89	—	—
Q2 2026	mcf	CAD	4,739	3.17	4,739	4.22	—	—	23,695	3.89	—	—
Q3 2026	mcf	CAD	4,739	3.17	4,739	4.22	—	—	23,695	3.89	—	—
Q4 2026	mcf	CAD	4,739	3.17	4,739	4.22	—	—	23,695	3.89	—	—
AECO Basis (AECO less NYMEX Henry Hub)												
Q1 2025	mcf	USD	—	—	—	—	—	—	10,000	(1.15)	—	—
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												
Q4 2024	mcf	USD	20,000	3.50	20,000	4.45	—	—	4,000	3.51	—	—
Q1 2025	mcf	USD	24,000	3.50	24,000	4.49	—	—	—	—	—	—
Q2 2025	mcf	USD	24,000	3.50	24,000	4.49	—	—	—	—	—	—
Q3 2025	mcf	USD	24,000	3.50	24,000	4.49	—	—	—	—	—	—
Q4 2025	mcf	USD	24,000	3.50	24,000	4.49	—	—	—	—	—	—
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	—	—	—	—	—	—
TTF												
Q4 2024	mcf	EUR	17,197	10.06	17,197	14.88	6,142	3.28	39,308	14.52	—	—
Q1 2025	mcf	EUR	18,426	10.07	18,426	14.89	13,512	4.69	39,308	14.52	—	—
Q2 2025	mcf	EUR	22,111	8.31	22,111	12.86	22,111	4.01	24,567	12.99	—	—
Q3 2025	mcf	EUR	22,111	8.31	22,111	12.86	22,111	4.01	24,567	12.99	—	—
Q4 2025	mcf	EUR	31,938	8.05	31,938	12.49	31,938	3.67	20,882	11.87	—	—
Q1 2026	mcf	EUR	24,567	7.39	24,567	11.66	24,567	3.02	20,882	11.87	—	—
Q2 2026	mcf	EUR	24,567	7.39	24,567	11.66	24,567	3.02	18,426	9.60	—	—
Q3 2026	mcf	EUR	24,567	7.39	24,567	11.66	24,567	3.02	18,426	9.60	—	—
Q4 2026	mcf	EUR	28,253	7.43	28,253	11.66	28,253	2.93	4,913	8.54	—	—
Q1 2027	mcf	EUR	28,253	7.43	28,253	11.66	28,253	2.93	4,913	8.54	—	—
THE												
Q4 2024	mcf	EUR	—	—	—	—	—	—	2,457	14.95	—	—
Q1 2025	mcf	EUR	—	—	—	—	—	—	2,457	14.95	—	—
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 2025	20.9788	CAD	2,250,000
Swap	Jan 2020 - Jul 2025	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
Forward	Sell USD, Buy CAD	Oct 2024 - Dec 2024	—		—	—		—	16,000,000	USD	1.3549
Collar	Sell USD, Buy CAD	Oct 2024 - Dec 2024	4,000,000	USD	1.3600	4,000,000	USD	1.3963	—		—
Collar	Sell USD, Buy CAD	Jan 2025 - Dec 2025	1,000,000	USD	1.3600	1,000,000	USD	1.4000	—		—

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											
Jan 2025 - Dec 2025	bbl	USD	31-Dec-2024	—	—	—	—	—	—	2,000	80.00
NYMEX											
Jan 2025 - Dec 2025	mcf	USD	23-Dec-2024	—	—	—	—	—	—	10,000	3.65

Supplemental Table 3: Capital Expenditures and Acquisitions

By classification ($M)	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Drilling and development	**118,809**	119,404	**410,457**	436,802
Exploration and evaluation	**2,460**	6,235	**11,864**	10,502
Capital expenditures	**121,269**	125,639	**422,321**	447,304
Acquisitions, net of cash acquired	**1,642**	3,191	**7,471**	139,612
Acquisition of securities	**—**	2,047	**9,373**	4,155
Acquired working capital	**—**	—	**—**	103,527
Acquisitions	**1,642**	5,238	**16,844**	247,294

Dispositions ($M)	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Canada	**—**	—	**—**	182,152
Total dispositions	**—**	—	**—**	182,152

By category ($M)	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Drilling, completion, new well equip and tie-in, workovers and recompletions	**80,676**	59,989	**258,173**	305,020
Production equipment and facilities	**39,121**	56,979	**150,250**	121,394
Seismic, studies, land and other	**1,472**	8,671	**13,898**	20,890
Capital expenditures	**121,269**	125,639	**422,321**	447,304
Acquisitions	**1,642**	5,238	**16,844**	247,294
Total capital expenditures and acquisitions	**122,911**	130,877	**439,165**	694,598

Capital expenditures by country ($M)	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Canada	**76,799**	59,111	**260,288**	234,432
United States	**1,372**	10,592	**15,912**	87,064
France	**11,366**	14,069	**33,770**	37,080
Netherlands	**5,237**	17,162	**13,868**	33,360
Germany	**15,472**	10,648	**61,397**	26,665
Ireland	**345**	6,994	**3,794**	8,433
Australia	**8,661**	6,072	**23,641**	16,674
Central and Eastern Europe	**2,017**	991	**9,651**	3,596
Total capital expenditures	**121,269**	125,639	**422,321**	447,304

Acquisitions by country ($M)	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Canada	**1,642**	5,238	**16,844**	51,068
United States	**—**	—	**—**	3,808
Ireland	**—**	—	**—**	192,418
Acquisitions	**1,642**	5,238	**16,844**	247,294

Supplemental Table 4: Production

	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23	Q1/23	Q4/22	Q3/22	Q2/22	Q1/22	Q4/21
Canada												
Light and medium crude oil (bbls/d)	**12,526**	12,468	11,649	11,614	12,054	12,901	16,674	17,448	16,835	17,042	15,980	16,388
Condensate [1] (bbls/d)	**3,598**	3,853	4,075	4,034	4,410	3,506	4,719	4,525	4,204	4,873	4,892	4,785
Other NGLs [1] (bbls/d)	**6,483**	6,208	5,968	6,281	6,219	5,513	6,875	6,279	6,870	7,155	7,286	7,073
NGLs (bbls/d)	**10,081**	10,061	10,043	10,315	10,629	9,019	11,594	10,804	11,074	12,028	12,178	11,858
Conventional natural gas (mmcf/d)	**156.99**	158.48	151.84	160.16	163.94	159.26	160.34	146.81	145.04	143.94	140.55	128.85
Total (boe/d)	**48,772**	48,943	46,997	48,623	50,007	48,464	54,991	52,720	52,080	53,060	51,584	49,720
United States												
Light and medium crude oil (bbls/d)	**2,909**	3,817	3,483	3,187	4,404	3,349	2,824	3,282	2,824	2,846	2,675	2,647
Condensate [1] (bbls/d)	**12**	27	29	27	15	22	20	36	35	40	24	26
Other NGLs [1] (bbls/d)	**1,064**	988	1,078	1,131	1,124	1,025	1,020	1,218	1,031	958	1,056	1,388
NGLs (bbls/d)	**1,076**	1,015	1,107	1,158	1,139	1,047	1,040	1,254	1,066	998	1,080	1,414
Conventional natural gas (mmcf/d)	**7.08**	7.27	8.23	7.49	7.25	7.23	7.14	7.45	7.03	6.74	7.56	9.09
Total (boe/d)	**5,164**	6,044	5,962	5,593	6,751	5,601	5,055	5,779	5,062	4,967	5,014	5,575
France												
Light and medium crude oil (bbls/d)	**7,115**	7,246	7,308	7,395	7,578	7,788	7,578	7,247	6,818	8,126	8,389	8,453
Total (boe/d)	**7,115**	7,246	7,308	7,395	7,578	7,788	7,578	7,247	6,818	8,126	8,389	8,453
Netherlands												
Light and medium crude oil (bbls/d)	**—**	—	—	—	—	—	—	—	—	1	1	—
Condensate [1] (bbls/d)	**39**	51	165	119	39	61	66	49	74	60	83	97
NGLs (bbls/d)	**39**	51	165	119	39	61	66	49	74	60	83	97
Conventional natural gas (mmcf/d)	**25.06**	26.84	31.02	32.06	24.32	27.28	29.07	27.41	29.15	35.22	39.03	51.98
Total (boe/d)	**4,216**	4,524	5,336	5,462	4,091	4,607	4,910	4,617	4,933	5,930	6,589	8,761
Germany												
Light and medium crude oil (bbls/d)	**1,598**	1,698	1,722	1,775	1,713	1,715	1,410	1,481	1,764	1,331	1,158	1,127
Conventional natural gas (mmcf/d)	**21.41**	18.41	22.87	19.62	20.29	22.05	25.85	25.86	26.54	25.36	26.95	18.00
Total (boe/d)	**5,167**	4,766	5,533	5,046	5,095	5,391	5,717	5,791	6,187	5,558	5,650	4,127
Ireland												
Conventional natural gas (mmcf/d)	**59.06**	57.70	60.34	64.04	47.96	67.51	24.58	26.04	25.74	27.93	30.26	30.12
Total (boe/d)	**9,844**	9,616	10,057	10,673	7,993	11,251	4,096	4,340	4,290	4,655	5,043	5,020
Australia												
Light and medium crude oil (bbls/d)	**2,040**	3,713	4,264	4,715	1,204	—	—	4,847	4,763	2,465	3,888	2,742
Total (boe/d)	**2,040**	3,713	4,264	4,715	1,204	—	—	4,847	4,763	2,465	3,888	2,742
Central and Eastern Europe												
Conventional natural gas (mmcf/d)	**11.13**	0.69	0.29	0.54	0.05	0.30	0.64	0.67	0.63	0.64	0.34	0.12
Total (boe/d)	**1,855**	122	48	90	8	50	107	111	104	106	57	20
Consolidated												
Light and medium crude oil (bbls/d)	**26,188**	28,948	28,426	28,685	26,952	25,753	28,485	34,305	33,003	31,811	32,091	31,356
Condensate [1] (bbls/d)	**3,649**	3,931	4,269	4,180	4,463	3,589	4,805	4,610	4,312	4,973	4,999	4,908
Other NGLs [1] (bbls/d)	**7,547**	7,196	7,046	7,412	7,344	6,538	7,896	7,497	7,901	8,113	8,342	8,461
NGLs (bbls/d)	**11,196**	11,127	11,315	11,592	11,807	10,127	12,701	12,107	12,213	13,086	13,341	13,369
Conventional natural gas (mmcf/d)	**280.73**	269.39	274.59	283.91	263.80	283.63	247.61	234.23	234.12	239.83	244.69	238.16
Total (boe/d)	**84,173**	84,974	85,505	87,597	82,727	83,152	82,455	85,450	84,237	84,868	86,213	84,417

	YTD 2024	2023	2022	2021	2020	2019
Canada						
Light and medium crude oil (bbls/d)	**12,218**	13,293	16,830	16,954	21,106	23,971
Condensate [(1)] (bbls/d)	**3,841**	4,166	4,621	4,831	4,886	4,295
Other NGLs [(1)] (bbls/d)	**6,221**	6,220	6,895	7,179	7,719	6,988
NGLs (bbls/d)	**10,062**	10,386	11,516	12,010	12,605	11,283
Conventional natural gas (mmcf/d)	**155.79**	160.94	144.10	138.03	151.38	148.35
Total (boe/d)	**48,240**	50,503	52,364	51,968	58,942	59,979
United States						
Light and medium crude oil (bbls/d)	**3,401**	3,445	2,908	2,597	3,046	2,514
Condensate [(1)] (bbls/d)	**23**	21	34	8	5	18
Other NGLs [(1)] (bbls/d)	**1,043**	1,076	1,066	1,146	1,218	996
NGLs (bbls/d)	**1,066**	1,097	1,100	1,154	1,223	1,014
Conventional natural gas (mmcf/d)	**7.52**	7.28	7.20	6.84	7.47	6.89
Total (boe/d)	**5,721**	5,754	5,207	4,890	5,514	4,675
France						
Light and medium crude oil (bbls/d)	**7,223**	7,584	7,639	8,799	8,903	10,435
Conventional natural gas (mmcf/d)	**—**	—	—	—	—	0.19
Total (boe/d)	**7,223**	7,584	7,639	8,799	8,903	10,467
Netherlands						
Light and medium crude oil (bbls/d)	**—**	—	—	3	1	3
Condensate [(1)] (bbls/d)	**85**	71	66	97	88	88
NGLs (bbls/d)	**85**	71	66	97	88	88
Conventional natural gas (mmcf/d)	**27.63**	28.18	32.66	43.40	46.16	49.10
Total (boe/d)	**4,690**	4,768	5,510	7,334	7,782	8,274
Germany						
Light and medium crude oil (bbls/d)	**1,672**	1,654	1,435	1,044	968	917
Conventional natural gas (mmcf/d)	**20.90**	21.93	26.18	15.81	12.65	15.31
Total (boe/d)	**5,155**	5,310	5,798	3,679	3,076	3,468
Ireland						
Conventional natural gas (mmcf/d)	**59.03**	51.12	27.48	29.25	37.44	46.57
Total (boe/d)	**9,839**	8,520	4,579	4,875	6,240	7,762
Australia						
Light and medium crude oil (bbls/d)	**3,334**	1,492	3,995	3,810	4,416	5,662
Total (boe/d)	**3,334**	1,492	3,995	3,810	4,416	5,662
Central and Eastern Europe						
Conventional natural gas (mmcf/d)	**4.06**	0.38	0.57	0.31	1.90	0.42
Total (boe/d)	**679**	63	95	51	317	70
Consolidated						
Light and medium crude oil (bbls/d)	**27,848**	27,469	32,809	33,208	38,441	43,502
Condensate [(1)] (bbls/d)	**3,949**	4,258	4,721	4,936	4,980	4,400
Other NGLs [(1)] (bbls/d)	**7,264**	7,296	7,961	8,325	8,937	7,984
NGLs (bbls/d)	**11,213**	11,554	12,682	13,261	13,917	12,384
Conventional natural gas (mmcf/d)	**274.93**	269.84	238.18	233.64	256.99	266.82
Total (boe/d)	**84,881**	83,994	85,187	85,408	95,190	100,357

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

Supplemental Table 5: Operational and Financial Data by Core Region

Production volumes [1]

	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23	Q1/23	Q4/22	Q3/22	Q2/22	Q1/22	Q4/21
North America												
Crude oil and condensate (bbls/d)	**19,045**	20,165	19,236	18,862	20,883	19,778	24,237	25,291	23,898	24,801	23,571	23,846
NGLs (bbls/d)	**7,547**	7,196	7,046	7,412	7,344	6,538	7,895	7,497	7,901	8,113	8,342	8,461
Natural gas (mmcf/d)	**164.07**	165.75	160.07	167.65	171.19	166.49	167.48	154.26	152.07	150.68	148.11	137.93
Total (boe/d)	**53,936**	54,987	52,959	54,216	56,758	54,065	60,046	58,499	57,142	58,027	56,598	55,295
International												
Crude oil and condensate (bbls/d)	**10,792**	12,714	13,459	14,004	10,534	9,564	9,054	13,624	13,419	11,983	13,519	12,419
Natural gas (mmcf/d)	**116.66**	103.64	114.52	116.27	92.61	117.14	80.13	79.97	82.05	89.15	96.58	100.22
Total (boe/d)	**30,237**	29,987	32,546	33,381	25,969	29,087	22,408	26,953	27,095	26,840	29,616	29,123
Consolidated												
Crude oil and condensate (bbls/d)	**29,837**	32,879	32,695	32,866	31,416	29,341	33,290	38,915	37,315	36,784	37,090	36,264
NGLs (bbls/d)	**7,547**	7,196	7,046	7,412	7,344	6,538	7,896	7,497	7,901	8,113	8,342	8,461
Natural gas (mmcf/d)	**280.73**	269.39	274.59	283.92	263.80	283.63	247.61	234.23	234.12	239.83	244.69	238.16
Total (boe/d)	**84,173**	84,974	85,505	87,597	82,727	83,152	82,455	85,450	84,237	84,868	86,213	84,417

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

Sales volumes

	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23	Q1/23	Q4/22	Q3/22	Q2/22	Q1/22	Q4/21
North America												
Crude oil and condensate (bbls/d)	**19,044**	20,166	19,235	18,862	20,883	19,778	24,237	25,291	23,897	24,801	23,571	23,845
NGLs (bbls/d)	**7,547**	7,196	7,045	7,412	7,344	6,538	7,895	7,497	7,901	8,113	8,342	8,461
Natural gas (mmcf/d)	**164.07**	165.75	160.07	167.65	171.19	166.49	167.48	154.26	152.07	150.68	148.11	137.93
Total (boe/d)	**53,936**	54,987	52,960	54,216	56,758	54,065	60,046	58,499	57,142	58,027	56,598	55,295
International												
Crude oil and condensate (bbls/d)	**12,580**	11,998	15,938	9,221	9,950	10,302	8,087	16,257	11,493	11,720	12,615	13,985
Natural gas (mmcf/d)	**116.66**	103.64	114.52	116.27	92.61	117.14	80.13	79.97	82.05	89.15	96.58	100.22
Total (boe/d)	**32,024**	29,271	35,026	28,598	25,386	29,824	21,442	29,585	25,169	26,578	28,712	30,689
Consolidated												
Crude oil and condensate (bbls/d)	**31,624**	32,163	35,174	28,083	30,833	30,080	32,324	41,547	35,391	36,522	36,186	37,830
NGLs (bbls/d)	**7,547**	7,196	7,046	7,412	7,344	6,538	7,896	7,497	7,901	8,113	8,342	8,461
Natural gas (mmcf/d)	**280.73**	269.39	274.59	283.92	263.80	283.63	247.61	234.23	234.12	239.83	244.69	238.16
Total (boe/d)	**85,960**	84,258	87,985	82,814	82,144	83,889	81,489	88,083	82,312	84,607	85,310	85,984

Financial results

	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23	Q1/23	Q4/22	Q3/22	Q2/22	Q1/22	Q4/21
North America												
Crude oil and condensate sales ($/bbl)	**96.54**	104.57	91.50	100.16	103.46	94.78	95.63	106.66	114.82	134.72	111.42	92.99
NGL sales ($/bbl)	**27.49**	31.61	34.16	33.38	27.77	28.11	36.24	39.93	44.64	51.86	46.94	47.26
Natural gas sales ($/mcf)	**0.90**	1.29	2.14	2.62	2.52	2.29	4.11	5.96	6.41	7.13	4.80	5.07
Sales ($/boe)	**40.67**	46.37	44.25	47.51	49.26	45.12	54.84	66.95	71.24	83.34	65.88	59.97
Royalties ($/boe)	**(6.14)**	(6.93)	(7.03)	(7.25)	(7.75)	(5.45)	(7.68)	(9.47)	(12.58)	(12.51)	(11.24)	(9.26)
Transportation ($/boe)	**(3.12)**	(2.82)	(2.35)	(2.44)	(2.08)	(1.57)	(2.44)	(2.42)	(2.16)	(2.15)	(1.91)	(1.86)
Operating ($/boe)	**(11.88)**	(13.89)	(14.25)	(11.50)	(12.09)	(12.22)	(14.10)	(13.51)	(14.00)	(11.58)	(11.95)	(11.68)
General and administration ($/boe)	**(1.09)**	(2.54)	(1.70)	0.87	(0.72)	0.10	(0.99)	0.10	(1.27)	(1.52)	(1.26)	(2.01)
Corporate income taxes ($/boe)	**(0.34)**	0.82	(0.65)	0.23	(0.01)	(0.10)	(0.12)	(0.13)	(0.03)	—	(0.02)	0.42
Fund flows from operations ($/boe)	**18.10**	21.01	18.27	27.42	26.61	25.88	29.51	41.52	41.20	55.58	39.50	35.58
Fund flows from operations	**89,793**	105,187	88,027	136,766	138,960	127,346	159,435	223,443	216,579	293,470	201,193	180,979
Drilling and development	**(78,171)**	(61,520)	(136,509)	(58,704)	(69,703)	(135,723)	(116,070)	(113,892)	(112,238)	(54,913)	(57,513)	(89,643)
Free cash flow	**11,622**	43,667	(48,482)	78,062	69,257	(8,377)	43,365	109,551	104,341	238,557	143,680	91,336
International												
Crude oil and condensate sales ($/bbl)	**114.16**	116.24	119.68	123.77	114.26	100.23	107.57	128.02	140.09	146.67	136.69	103.53
Natural gas sales ($/mcf)	**14.55**	12.72	11.63	16.92	13.34	14.58	24.69	39.54	58.55	32.33	36.75	35.54
Sales ($/boe)	**97.85**	92.68	92.48	108.70	93.46	91.89	132.84	177.23	254.86	173.14	183.66	163.23
Royalties ($/boe)	**(4.16)**	(4.49)	(4.60)	(3.41)	3.55	(7.43)	(13.39)	(6.38)	(7.21)	(7.23)	(5.43)	(4.13)
Transportation ($/boe)	**(3.81)**	(4.20)	(3.65)	(3.91)	(4.53)	(5.23)	(5.11)	(3.29)	(3.51)	(3.64)	(2.91)	(3.40)
Operating ($/boe)	**(27.11)**	(26.56)	(25.30)	(22.64)	(25.58)	(28.24)	(31.41)	(23.35)	(22.63)	(22.11)	(19.86)	(18.86)
General and administration ($/boe)	**(5.56)**	(5.20)	(4.86)	(9.18)	(7.37)	(7.58)	(7.52)	(5.09)	(3.34)	(3.16)	(3.02)	(2.53)
Corporate income taxes ($/boe)	**(3.74)**	(6.08)	(7.06)	(7.81)	(13.42)	(6.79)	(11.20)	(15.15)	(21.97)	(28.73)	(17.63)	(12.17)
PRRT ($/boe)	**(0.17)**	(1.37)	(3.38)	7.93	—	—	—	(1.85)	(1.96)	(0.83)	(2.60)	(1.96)
Fund flows from operations ($/boe)	**53.30**	44.78	43.63	69.68	46.11	36.62	64.21	122.12	194.24	107.44	132.21	120.18
Fund flows from operations	**157,048**	119,310	139,054	183,353	107,706	99,377	123,893	332,377	449,771	259,840	341,626	339,286
Drilling and development	**(40,638)**	(47,830)	(45,789)	(73,604)	(49,701)	(28,347)	(37,258)	(43,957)	(65,640)	(54,575)	(25,328)	(29,359)
Exploration and evaluation	**(2,460)**	(1,260)	(8,144)	(10,579)	(6,235)	(2,775)	(1,492)	(11,456)	(6,137)	(3,665)	(2,503)	(26,805)
Free cash flow	**113,950**	70,220	85,121	99,170	51,770	68,255	85,143	276,964	377,994	201,600	313,795	283,122

	Q3/24	Q2/24	Q1/24	Q4/23	Q3/23	Q2/23	Q1/23	Q4/22	Q3/22	Q2/22	Q1/22	Q4/21
Consolidated												
Crude oil and condensate sales ($/bbl)	**103.55**	108.93	104.26	107.91	106.94	96.64	98.62	115.02	123.02	138.55	120.23	96.88
NGL sales ($/bbl)	**27.49**	31.61	34.16	33.38	27.77	28.11	36.23	39.93	44.64	51.86	46.94	47.26
Natural gas sales ($/mcf)	**6.57**	5.69	6.10	8.48	6.32	7.37	10.77	17.43	24.68	16.50	17.41	17.89
Sales ($/boe)	**61.97**	62.46	63.45	68.64	62.92	61.74	75.36	103.99	127.39	111.55	105.52	96.82
Royalties ($/boe)	**(5.40)**	(6.08)	(6.06)	(5.93)	(4.26)	(6.16)	(9.18)	(8.43)	(10.94)	(10.85)	(9.29)	(7.43)
Transportation ($/boe)	**(3.38)**	(3.30)	(2.87)	(2.95)	(2.84)	(2.87)	(3.14)	(2.71)	(2.57)	(2.62)	(2.25)	(2.41)
Operating ($/boe)	**(17.55)**	(18.29)	(18.65)	(15.35)	(16.26)	(17.91)	(18.66)	(16.81)	(16.64)	(14.89)	(14.61)	(14.24)
General and administration ($/boe)	**(2.76)**	(3.46)	(2.96)	(2.60)	(2.77)	(2.63)	(2.71)	(1.65)	(1.90)	(2.04)	(1.85)	(2.20)
Corporate income taxes ($/boe)	**(1.61)**	(1.58)	(3.20)	(2.54)	(4.15)	(2.48)	(3.04)	(5.18)	(6.74)	(9.03)	(5.95)	(4.07)
Windfall taxes ($/boe)	**—**	—	—	(0.03)	(2.90)	(4.56)	(2.92)	(27.50)	—	—	—	—
PRRT ($/boe)	**(0.06)**	(0.47)	(1.35)	2.74	—	—	—	(0.62)	(0.60)	(0.26)	(0.87)	(0.70)
Interest ($/boe)	**(2.68)**	(2.75)	(2.30)	(3.01)	(2.68)	(2.65)	(2.98)	(2.78)	(3.23)	(2.74)	(1.93)	(2.06)
Equity based compensation ($/boe)	**—**	(1.87)	—	—	—	—	—	—	—	—	—	—
Realized derivatives ($/boe)	**6.31**	6.00	27.55	10.33	9.74	8.86	1.95	(5.42)	(18.22)	(10.36)	(18.78)	(23.97)
Realized foreign exchange ($/boe)	**0.15**	0.30	0.23	(0.73)	0.28	0.48	(0.65)	2.33	(0.28)	(0.30)	0.10	(0.30)
Realized other ($/boe)	**(0.21)**	(0.09)	0.02	0.26	(1.32)	0.53	0.49	(0.14)	0.80	0.36	0.70	1.29
Fund flows from operations ($/boe)	**34.78**	30.87	53.86	48.83	35.76	32.35	34.52	35.08	67.07	58.82	50.79	40.73
Fund flows from operations	**275,024**	236,703	431,358	372,117	270,218	247,109	253,167	284,220	507,876	452,901	389,868	322,173
Drilling and development	**(118,809)**	(109,350)	(182,298)	(132,308)	(119,404)	(164,070)	(153,328)	(157,849)	(177,878)	(109,488)	(82,841)	(119,002)
Exploration and evaluation	**(2,460)**	(1,260)	(8,144)	(10,579)	(6,235)	(2,775)	(1,492)	(11,456)	(6,137)	(3,665)	(2,503)	(26,805)
Free cash flow	**153,755**	126,093	240,916	229,230	144,579	80,264	98,347	114,915	323,861	339,748	304,524	176,366

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 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 (loss), FFO is a total of segments measure comprised of sales less royalties, transportation, operating, G&A, corporate income tax, PRRT, windfall taxes, 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 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 primary financial statement measures can be found below.

	Q3 2024		Q3 2023		YTD 2024		YTD 2023	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Sales	**490,095**	**61.97**	475,532	62.92	**1,477,055**	**62.63**	1,499,586	66.57
Royalties	**(42,738)**	**(5.40)**	(32,209)	(4.26)	**(137,901)**	**(5.85)**	(146,546)	(6.51)
Transportation	**(26,693)**	**(3.38)**	(21,460)	(2.84)	**(74,972)**	**(3.18)**	(66,415)	(2.95)
Operating	**(138,806)**	**(17.55)**	(122,870)	(16.26)	**(428,347)**	**(18.16)**	(396,444)	(17.60)
General and administration	**(21,803)**	**(2.76)**	(20,959)	(2.77)	**(72,043)**	**(3.05)**	(60,906)	(2.70)
Corporate income tax expense	**(12,707)**	**(1.61)**	(31,368)	(4.15)	**(50,445)**	**(2.14)**	(72,558)	(3.22)
Windfall taxes	**—**	**—**	(21,953)	(2.90)	**—**	**—**	(78,177)	(3.47)
PRRT	**(507)**	**(0.06)**	—	—	**(14,928)**	**(0.63)**	—	—
Interest expense	**(21,187)**	**(2.68)**	(20,218)	(2.68)	**(60,641)**	**(2.57)**	(62,303)	(2.77)
Equity based compensation	**—**	**—**	—	—	**(14,361)**	**(0.61)**	—	—
Realized gain on derivatives	**49,891**	**6.31**	73,625	9.74	**316,523**	**13.42**	155,628	6.91
Realized foreign exchange gain	**1,155**	**0.15**	2,089	0.28	**5,293**	**0.22**	997	0.04
Realized other income	**(1,676)**	**(0.21)**	(9,991)	(1.32)	**(2,148)**	**(0.09)**	(2,368)	(0.11)
Fund flows from operations	**275,024**	**34.78**	270,218	35.76	**943,085**	**39.99**	770,494	34.19
Equity based compensation	**(6,412)**		(6,362)		**(8,070)**		(34,885)	
Unrealized (loss) gain on derivative instruments [(1)]	**(1,052)**		(65,294)		**(315,585)**		38,581	
Unrealized foreign exchange gain (loss) [(1)]	**(11,382)**		(12,042)		**(29,954)**		7,604	
Accretion	**(19,126)**		(20,068)		**(55,269)**		(58,718)	
Depletion and depreciation	**(180,164)**		(151,087)		**(519,782)**		(453,607)	
Deferred tax (expense) recovery	**(4,713)**		42,489		**(42,025)**		79,435	
Gain on business combination	**—**		—		**—**		445,094	
Loss on disposition	**—**		—		**—**		(226,828)	
Unrealized other expense [(1)]	**(478)**		(545)		**(823)**		(1,621)	
Net earnings (loss)	**51,697**		57,309		**(28,423)**		565,549	

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

Non-GAAP Financial Measures and Non-GAAP Ratios

Free cash flow (FCF): Most directly comparable to cash flows from operating activities, FCF is a non-GAAP 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)	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Cash flows from operating activities	**134,547**	118,436	**755,164**	680,697
Changes in non-cash operating working capital	**125,145**	138,200	**155,869**	61,768
Asset retirement obligations settled	**15,332**	13,582	**32,052**	28,029
Fund flows from operations	**275,024**	270,218	**943,085**	770,494
Drilling and development	**(118,809)**	(119,404)	**(410,457)**	(436,802)
Exploration and evaluation	**(2,460)**	(6,235)	**(11,864)**	(10,502)
Free cash flow	**153,755**	144,579	**520,764**	323,190

Capital expenditures: Most directly comparable to cash flows used in investing activities, capital expenditures is a non-GAAP 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)	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Drilling and development	**118,809**	119,404	**410,457**	436,802
Exploration and evaluation	**2,460**	6,235	**11,864**	10,502
Capital expenditures	**121,269**	125,639	**422,321**	447,304

Payout and payout % of FFO: Payout and payout % of FFO are, respectively, a non-GAAP financial measure and non-GAAP ratio, 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 (total of segments measure). 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)	Q3 2024	Q3 2023	YTD 2024	YTD 2023
Dividends declared	**18,642**	16,367	**56,806**	49,023
Drilling and development	**118,809**	119,404	**410,457**	436,802
Exploration and evaluation	**2,460**	6,235	**11,864**	10,502
Asset retirement obligations settled	**15,332**	13,582	**32,052**	28,029
Payout	**155,243**	155,588	**511,179**	524,356
% of fund flows from operations	**56 %**	58 %	**54 %**	68 %

Return on capital employed (ROCE): A non-GAAP ratio, ROCE is a measure that we use 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 (loss) before interest and taxes ("EBIT") by average capital employed over the preceding twelve months. Capital employed is calculated as total assets less current liabilities while average capital employed is calculated using the balance sheets at the beginning and end of the twelve-month period.

($M)	Twelve Months Ended Sep 30, 2024	Sep 30, 2023
Net (loss) earnings	**(831,559)**	960,957
Taxes	**(4,597)**	537,895
Interest expense	**83,550**	84,809
EBIT	**(752,606)**	1,583,661
Average capital employed	**5,995,108**	6,024,614
Return on capital employed	**(13)%**	26 %

Adjusted working capital: Defined 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.

($M)	As at Sep 30, 2024	Dec 31, 2023
Current assets	**651,197**	823,514
Current derivative asset	**(92,537)**	(313,792)
Current liabilities	**(521,669)**	(696,074)
Current lease liability	**23,545**	21,068
Current derivative liability	**9,487**	732
Adjusted working capital	**70,023**	(164,552)

Acquisitions: 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. We believe 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)	Q3 2024	Q3 2023	Q3 2024	Q3 2023
Acquisitions, net of cash acquired	**1,642**	3,191	**7,471**	139,612
Acquisition of securities	**—**	2,047	**9,373**	4,155
Acquired working capital	**—**	—	**—**	103,527
Acquisitions	**1,642**	5,238	**16,844**	247,294

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.

($M)	As at Sep 30, 2024	Dec 31, 2023
Long-term debt	**903,354**	914,015
Adjusted working capital	**(70,023)**	164,552
Net debt	**833,331**	1,078,567
Ratio of net debt to four quarter trailing fund flows from operations	**0.6**	0.9

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)	Q3 2024	Q3 2023
Shares outstanding	**155,348**	163,666
Potential shares issuable pursuant to the LTIP	**3,564**	4,238
Diluted shares outstanding	**158,912**	167,904

Fund flows from operations per basic and diluted share: Management assesses fund flows from operations on a per share basis as we believe this provides a measure of our operating performance after taking into account the issuance and potential future issuance of Vermilion common shares. Fund flows from operations per basic share is calculated by dividing fund flows from operations (total of segments measure) by the basic weighted average shares outstanding as defined under IFRS. Fund flows from operations per diluted share is calculated by dividing fund flows from operations by the sum of basic weighted average shares outstanding and incremental shares issuable under the equity based compensation plans as determined using the treasury stock method.

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

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.

Net debt to four quarter trailing fund flows from operations: Management uses net debt 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 calculated as net debt (capital management measure) divided by fund flows from operations (total of segments measure) from the preceding four quarters.

Consolidated Interim Financial Statements

Consolidated Balance Sheet

thousands of Canadian dollars, unaudited

	Note	September 30, 2024	December 31, 2023
Assets			
Current			
Cash and cash equivalents	11	**190,946**	141,456
Accounts receivable		**274,317**	242,926
Crude oil inventory		**29,146**	57,333
Derivative instruments		**92,537**	313,792
Prepaid expenses		**64,251**	68,007
Total current assets		**651,197**	823,514
Derivative instruments		**27,200**	76,107
Investments	3	**79,327**	73,261
Deferred taxes		**127,603**	182,051
Exploration and evaluation assets	5	**215,569**	198,379
Capital assets	4	**4,983,258**	4,882,509
Total assets		**6,084,154**	6,235,821
Liabilities			
Current			
Accounts payable and accrued liabilities		**344,516**	380,370
Dividends payable	9	**18,642**	16,227
Derivative instruments		**9,487**	732
Income taxes payable		**149,024**	298,745
Total current liabilities		**521,669**	696,074
Derivative instruments		**57,718**	21,050
Long-term debt	8	**903,354**	914,015
Lease obligations		**121,807**	33,001
Asset retirement obligations	6	**1,221,312**	1,159,063
Deferred taxes		**379,688**	380,970
Total liabilities		**3,205,548**	3,204,173
Shareholders' Equity			
Shareholders' capital	9	**3,947,667**	4,142,566
Contributed surplus		**41,420**	43,348
Accumulated other comprehensive income		**156,489**	109,302
Deficit		**(1,266,970)**	(1,263,568)
Total shareholders' equity		**2,878,606**	3,031,648
Total liabilities and shareholders' equity		**6,084,154**	6,235,821

Approved by the Board

(Signed "Manjit Sharma") *(Signed "Dion Hatcher")*

Manjit Sharma, Director Dion Hatcher, Director

Consolidated Statements of Net Earnings (Loss) and Comprehensive Income

thousands of Canadian dollars, except share and per share amounts, unaudited

		Three Months Ended		Nine Months Ended	
	Note	Sep 30, 2024	Sep 30, 2023	Sep 30, 2024	Sep 30, 2023
Revenue					
Petroleum and natural gas sales		**490,095**	475,532	**1,477,055**	1,499,586
Royalties		**(42,738)**	(32,209)	**(137,901)**	(146,546)
Sales of purchased commodities		**14,458**	51,252	**81,479**	138,542
Petroleum and natural gas revenue		**461,815**	494,575	**1,420,633**	1,491,582
Expenses					
Purchased commodities		**14,458**	51,252	**81,479**	138,542
Operating		**138,806**	122,870	**428,347**	396,444
Transportation		**26,693**	21,460	**74,972**	66,415
Equity based compensation		**6,412**	6,362	**22,431**	34,885
Gain on derivative instruments		**(48,839)**	(8,331)	**(938)**	(194,209)
Interest expense		**21,187**	20,218	**60,641**	62,303
General and administration		**21,803**	20,959	**72,043**	60,906
Foreign exchange loss (gain)		**10,227**	9,953	**24,661**	(8,601)
Other expense		**2,154**	10,536	**2,971**	3,989
Accretion	6	**19,126**	20,068	**55,269**	58,718
Depletion and depreciation	4, 5	**180,164**	151,087	**519,782**	453,607
Gain on business combination		**—**	—	**—**	(445,094)
Loss on disposition		**—**	—	**—**	226,828
		392,191	426,434	**1,341,658**	854,733
Earnings before income taxes		**69,624**	68,141	**78,975**	636,849
Income tax expense (recovery)					
Deferred		**4,713**	(42,489)	**42,025**	(79,435)
Current		**13,214**	31,368	**65,373**	72,558
Windfall taxes		**—**	21,953	**—**	78,177
		17,927	10,832	**107,398**	71,300
Net earnings (loss)		**51,697**	57,309	**(28,423)**	565,549
Other comprehensive income					
Currency translation adjustments		**46,985**	(15,584)	**44,494**	(47,196)
Hedge accounting reserve, net of tax		**1,633**	1,631	**4,896**	5,420
Fair value adjustment on investment in securities, net of tax	3	**—**	7,614	**(2,203)**	7,765
Comprehensive income		**100,315**	50,970	**18,764**	531,538
Net earnings (loss) per share					
Basic		**0.33**	0.35	**(0.18)**	3.45
Diluted		**0.33**	0.34	**(0.18)**	3.38
Weighted average shares outstanding ('000s)					
Basic		**156,624**	163,946	**159,114**	163,848
Diluted		**157,502**	166,392	**160,743**	167,167

Consolidated Statements of Cash Flows

thousands of Canadian dollars, unaudited

	Note	Three Months Ended		Nine Months Ended	
		Sep 30, 2024	Sep 30, 2023	Sep 30, 2024	Sep 30, 2023
Operating					
Net earnings (loss)		**51,697**	57,309	**(28,423)**	565,549
Adjustments:					
Accretion	6	**19,126**	20,068	**55,269**	58,718
Depletion and depreciation	4, 5	**180,164**	151,087	**519,782**	453,607
Gain on business combination		**—**	—	**—**	(445,094)
Loss on disposition		**—**	—	**—**	226,828
Unrealized loss (gain) on derivative instruments		**1,052**	65,294	**315,585**	(38,581)
Equity based compensation		**6,412**	6,362	**8,070**	34,885
Unrealized foreign exchange loss (gain)		**11,382**	12,042	**29,954**	(7,604)
Unrealized other expense		**478**	545	**823**	1,621
Deferred tax expense (recovery)		**4,713**	(42,489)	**42,025**	(79,435)
Asset retirement obligations settled	6	**(15,332)**	(13,582)	**(32,052)**	(28,029)
Changes in non-cash operating working capital		**(125,145)**	(138,200)	**(155,869)**	(61,768)
Cash flows from operating activities		**134,547**	118,436	**755,164**	680,697
Investing					
Drilling and development	4	**(118,809)**	(119,404)	**(410,457)**	(436,802)
Exploration and evaluation	5	**(2,460)**	(6,235)	**(11,864)**	(10,502)
Acquisitions, net of cash acquired	4	**(1,642)**	(3,191)	**(7,471)**	(139,612)
Acquisition of securities	3	**—**	(2,047)	**(9,373)**	(4,155)
Dispositions	4	**—**	—	**—**	182,152
Changes in non-cash investing working capital		**(22,917)**	(39,527)	**(41,031)**	(34,584)
Cash flows used in investing activities		**(145,828)**	(170,404)	**(480,196)**	(443,503)
Financing					
Net repayments (borrowings) on the revolving credit facility	8	**—**	32,858	**—**	(113,733)
Repurchases of senior unsecured notes	8	**—**	—	**(31,561)**	—
Payments on lease obligations		**(7,547)**	(4,053)	**(19,479)**	(13,117)
Repurchase of shares	9	**(40,106)**	(11,645)	**(123,070)**	(66,102)
Cash dividends	9	**(18,981)**	(16,429)	**(54,391)**	(45,713)
Changes in non-cash financing working capital		**785**	—	**2,412**	—
Cash flows (used in) from financing activities		**(65,849)**	731	**(226,089)**	(238,665)
Foreign exchange gain (loss) on cash held in foreign currencies		**404**	537	**611**	(12,365)
Net change in cash and cash equivalents		**(76,726)**	(50,700)	**49,490**	(13,836)
Cash and cash equivalents, beginning of period		**267,672**	50,700	**141,456**	13,836
Cash and cash equivalents, end of period		**190,946**	—	**190,946**	—
Supplementary information for cash flows from operating activities					
Interest paid		**14,600**	13,742	**56,582**	56,387
Income taxes paid		**147,261**	149,721	**215,088**	302,497

Consolidated Statements of Changes in Shareholders' Equity

thousands of Canadian dollars, unaudited

		Nine Months Ended	
	Note	September 30, 2024	September 30, 2023
Shareholders' capital	9		
Balance, beginning of period		**4,142,566**	4,243,794
Vesting of equity based awards		**9,998**	21,175
Equity based compensation		**—**	10,280
Share-settled dividends on vested equity based awards		**1,257**	1,051
Repurchase of shares		**(206,154)**	(94,190)
Balance, end of period		**3,947,667**	4,182,110
Contributed surplus	9		
Balance, beginning of period		**43,348**	35,409
Equity based compensation		**8,070**	24,605
Vesting of equity based awards		**(9,998)**	(21,175)
Balance, end of period		**41,420**	38,839
Accumulated other comprehensive income			
Balance, beginning of period		**109,302**	123,505
Currency translation adjustments		**44,494**	(47,196)
Hedge accounting reserve		**4,896**	5,420
Fair value adjustment on investment in securities, net of tax	3	**(2,203)**	7,765
Balance, end of period		**156,489**	89,494
Deficit			
Balance, beginning of period		**(1,263,568)**	(1,001,650)
Net (loss) earnings		**(28,423)**	565,549
Dividends declared		**(56,806)**	(49,023)
Share-settled dividends on vested equity based awards		**(1,257)**	(1,051)
Repurchase of shares	9	**83,084**	28,088
Balance, end of period		**(1,266,970)**	(458,087)
Total shareholders' equity		**2,878,606**	3,852,356

Description of equity reserves

Shareholders' capital

Represents the recognized amount for common shares issued (net of equity issuance costs and deferred taxes) less the weighted-average carrying value of shares repurchased. The price paid to repurchase common shares is compared to the carrying value of the shares and the difference is recorded against deficit.

Contributed surplus

Represents the recognized value of unvested equity based awards that will be settled in shares. Once vested, the value of the awards are transferred to shareholders' capital.

Accumulated other comprehensive income

Represents currency translation adjustments, hedge accounting reserve and fair value adjustments on investments.

Currency translation adjustments result from translating the balance sheets of subsidiaries with a foreign functional currency to Canadian dollars at period-end rates. These amounts may be reclassified to net earnings (loss) if there is a disposal or partial disposal of a subsidiary.

The hedge accounting reserve represents the effective portion of the change in fair value related to cash flow and net investment hedges recognized in other comprehensive income, net of tax and reclassified to the consolidated statement of net earnings (loss) in the same period in which the transaction associated with the hedged item occurs.

Fair value adjustment on investment in securities, net of tax, are a result of changes in the fair value of investments that have been elected to be subsequently measured at fair value through other comprehensive income.

Deficit

Represents the cumulative net earnings (loss) less distributed earnings and surplus of the price paid to repurchase common shares of Vermilion Energy Inc. over the weighted-average carrying value of the shares repurchased.

Notes to the Condensed Consolidated Interim Financial Statements for the three and nine months ended September 30, 2024 and 2023

tabular amounts in thousands of Canadian dollars, except share and per share amounts, unaudited

1. Basis of presentation

Vermilion Energy Inc. (the "Company" or "Vermilion") is a corporation governed by the laws of the Province of Alberta and is actively engaged in the business of crude oil and natural gas exploration, development, acquisition, and production.

These condensed consolidated interim financial statements are in compliance with International Accounting Standard ("IAS") 34, "Interim Financial Reporting". These condensed consolidated interim financial statements have been prepared using the same accounting policies and methods of computation as Vermilion's consolidated financial statements for the year ended December 31, 2023.

These condensed consolidated interim financial statements should be read in conjunction with Vermilion's consolidated financial statements for the year ended December 31, 2023, which are contained within Vermilion's Annual Report for the year ended December 31, 2023 and are available on SEDAR+ at www.sedarplus.ca or on Vermilion's website at www.vermilionenergy.com.

These condensed consolidated interim financial statements were approved and authorized for issuance by the Board of Directors of Vermilion on November 6, 2024.

2. Segmented information

	Three Months Ended September 30, 2024									
	Canada	USA	France	Netherlands	Germany	Ireland	Australia	CEE	Corporate	Total
Drilling and development	76,799	1,372	11,366	5,237	14,162	345	8,661	867	—	118,809
Exploration and evaluation	—	—	—	—	1,310	—	—	1,150	—	2,460
Crude oil and condensate sales	142,448	26,699	67,888	383	16,198	—	47,661	—	—	301,277
NGL sales	15,565	3,519	—	—	—	—	—	—	—	19,084
Natural gas sales	12,767	806	—	33,821	26,865	79,333	—	16,142	—	169,734
Sales of purchased commodities	—	—	—	—	—	—	—	—	14,458	14,458
Royalties	(22,214)	(8,278)	(8,538)	—	(1,348)	—	—	(2,360)	—	(42,738)
Revenue from external customers	148,566	22,746	59,350	34,204	41,715	79,333	47,661	13,782	14,458	461,815
Purchased commodities	—	—	—	—	—	—	—	—	(14,458)	(14,458)
Transportation	(15,079)	(395)	(5,712)	—	(3,210)	(2,297)	—	—	—	(26,693)
Operating	(52,837)	(6,100)	(14,733)	(7,887)	(14,394)	(13,632)	(28,521)	(702)	—	(138,806)
General and administration	(1,233)	(3,138)	(4,573)	(2,033)	(3,020)	(2,704)	(2,067)	(1,974)	(1,061)	(21,803)
PRRT	—	—	—	—	—	—	(507)	—	—	(507)
Corporate income taxes	(2)	—	(2,314)	(4,997)	(2,407)	(174)	(1,139)	—	(1,674)	(12,707)
Interest expense	—	—	—	—	—	—	—	—	(21,187)	(21,187)
Realized gain on derivative instruments	—	—	—	—	—	—	—	—	49,891	49,891
Realized foreign exchange gain	—	—	—	—	—	—	—	—	1,155	1,155
Realized other expense	—	—	—	—	—	—	—	—	(1,676)	(1,676)
Fund flows from operations	**79,415**	**13,113**	**32,018**	**19,287**	**18,684**	**60,526**	**15,427**	**11,106**	**25,448**	**275,024**

	Three Months Ended September 30, 2023									
	Canada	USA	France	Netherlands	Germany	Ireland	Australia	CEE	Corporate	Total
Drilling and development	59,111	10,592	14,069	17,162	5,509	6,994	6,072	(105)	—	119,404
Exploration and evaluation	—	—	—	—	5,139	—	—	1,096	—	6,235
Crude oil and condensate sales	155,251	43,510	88,970	351	15,275	—	—	—	—	303,357
NGL sales	15,711	3,048	—	—	—	—	—	—	—	18,759
Natural gas sales	38,441	1,287	—	27,505	22,331	63,798	—	54	—	153,416
Sales of purchased commodities	—	—	—	—	—	—	—	—	51,252	51,252
Royalties	(26,856)	(13,633)	(12,351)	20,607	142	—	—	(118)	—	(32,209)
Revenue from external customers	182,547	34,212	76,619	48,463	37,748	63,798	—	(64)	51,252	494,575
Purchased commodities	—	—	—	—	—	—	—	—	(51,252)	(51,252)
Transportation	(10,709)	(169)	(4,351)	—	(3,674)	(2,557)	—	—	—	(21,460)
Operating	(59,191)	(3,947)	(21,810)	(3,411)	(14,008)	(10,372)	(9,937)	(194)	—	(122,870)
General and administration	(25,575)	(3,239)	(1,716)	(6,624)	(1,721)	(3,929)	(1,356)	(1,865)	25,066	(20,959)
Corporate income taxes	—	—	(5,410)	(17,079)	(8,284)	(163)	(397)	—	(35)	(31,368)
Windfall tax	—	—	—	—	—	—	—	—	(21,953)	(21,953)
Interest expense	—	—	—	—	—	—	—	—	(20,218)	(20,218)
Realized gain on derivative instruments	—	—	—	—	—	—	—	—	73,625	73,625
Realized foreign exchange gain	—	—	—	—	—	—	—	—	2,089	2,089
Realized other expense	—	—	—	—	—	—	—	—	(9,991)	(9,991)
Fund flows from operations	**87,072**	**26,857**	**43,332**	**21,349**	**10,061**	**46,777**	**(11,690)**	**(2,123)**	**48,583**	**270,218**

	Canada	USA	France	Netherlands	Germany	Ireland	Australia	CEE	Corporate	Total
					Nine Months Ended September 30, 2024					
Total assets	2,772,473	243,898	609,100	212,531	490,405	933,883	271,271	95,829	454,764	6,084,154
Drilling and development	260,288	15,912	33,770	13,868	55,209	3,794	23,641	3,975	—	410,457
Exploration and evaluation	—	—	—	—	6,188	—	—	5,676	—	11,864
Crude oil and condensate sales	425,497	95,704	240,540	2,138	34,629	—	155,274	34	—	953,816
NGL sales	49,329	12,358	—	—	—	—	—	—	—	61,687
Natural gas sales	60,634	3,588	—	97,573	68,775	213,590	—	17,392	—	461,552
Sales of purchased commodities	—	—	—	—	—	—	—	—	81,479	81,479
Royalties	(66,935)	(32,090)	(31,873)	(217)	(4,138)	—	—	(2,648)	—	(137,901)
Revenue from external customers	468,525	79,560	208,667	99,494	99,266	213,590	155,274	14,778	81,479	1,420,633
Purchased commodities	—	—	—	—	—	—	—	—	(81,479)	(81,479)
Transportation	(39,606)	(1,325)	(17,476)	—	(8,788)	(7,777)	—	—	—	(74,972)
Operating	(176,435)	(20,660)	(50,779)	(29,206)	(39,585)	(40,689)	(69,481)	(1,512)	—	(428,347)
General and administration	(19,681)	(9,678)	(13,569)	(5,746)	(8,654)	(6,336)	(5,810)	(5,605)	3,036	(72,043)
PRRT	—	—	—	—	—	—	(14,928)	—	—	(14,928)
Corporate income taxes	(4)	—	(14,095)	(23,866)	(8,483)	(943)	(2,329)	—	(725)	(50,445)
Interest expense	—	—	—	—	—	—	—	—	(60,641)	(60,641)
Equity based compensation	—	—	—	—	—	—	—	—	(14,361)	(14,361)
Realized gain on derivative instruments	—	—	—	—	—	—	—	—	316,523	316,523
Realized foreign exchange gain	—	—	—	—	—	—	—	—	5,293	5,293
Realized other expense	—	—	—	—	—	—	—	—	(2,148)	(2,148)
Fund flows from operations	**232,799**	**47,897**	**112,748**	**40,676**	**33,756**	**157,845**	**62,726**	**7,661**	**246,977**	**943,085**

	Canada	USA	France	Netherlands	Germany	Ireland	Australia	CEE	Corporate	Total
					Nine Months Ended September 30, 2023					
Total assets	3,127,777	689,903	850,651	216,308	391,394	1,163,499	279,216	71,048	371,365	7,161,161
Drilling and development	234,432	87,064	37,080	33,359	18,445	8,433	16,674	1,315	—	436,802
Exploration and evaluation	—	—	—	1	8,220	—	—	2,281	—	10,502
Crude oil and condensate sales	479,061	98,883	233,154	1,233	42,436	32	—	—	—	854,799
NGL sales	50,557	10,673	—	—	—	—	—	—	—	61,230
Natural gas sales	131,671	4,735	—	133,960	108,895	201,942	—	2,354	—	583,557
Sales of purchased commodities	—	—	—	—	—	—	—	—	138,542	138,542
Royalties	(77,752)	(31,060)	(30,275)	(875)	(5,257)	—	—	(1,327)	—	(146,546)
Revenue from external customers	583,537	83,231	202,879	134,318	146,074	201,974	—	1,027	138,542	1,491,582
Purchased commodities	—	—	—	—	—	—	—	—	(138,542)	(138,542)
Transportation	(31,462)	(301)	(18,766)	—	(9,847)	(6,039)	—	—	—	(66,415)
Operating	(182,288)	(17,185)	(63,113)	(30,014)	(35,624)	(25,516)	(41,683)	(1,021)	—	(396,444)
General and administration	(71,037)	(7,028)	(14,397)	(7,739)	(9,105)	(9,969)	(5,674)	(5,417)	69,460	(60,906)
Corporate income taxes	—	—	(8,425)	(29,591)	(31,056)	(390)	(1,912)	—	(1,184)	(72,558)
Windfall tax	—	—	—	—	—	—	—	—	(78,177)	(78,177)
Interest expense	—	—	—	—	—	—	—	—	(62,303)	(62,303)
Realized gain on derivative instruments	—	—	—	—	—	—	—	—	155,628	155,628
Realized foreign exchange gain	—	—	—	—	—	—	—	—	997	997
Realized other expense	—	—	—	—	—	—	—	—	(2,368)	(2,368)
Fund flows from operations	**298,750**	**58,717**	**98,178**	**66,974**	**60,442**	**160,060**	**(49,269)**	**(5,411)**	**82,053**	**770,494**

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

	Three Months Ended		Nine Months Ended	
	Sep 30, 2024	Sep 30, 2023	Sep 30, 2024	Sep 30, 2023
Fund flows from operations	**275,024**	270,218	**943,085**	770,494
Equity based compensation	**(6,412)**	(6,362)	**(8,070)**	(34,885)
Unrealized (loss) gain on derivative instruments	**(1,052)**	(65,294)	**(315,585)**	38,581
Unrealized foreign exchange (loss) gain	**(11,382)**	(12,042)	**(29,954)**	7,604
Accretion	**(19,126)**	(20,068)	**(55,269)**	(58,718)
Depletion and depreciation	**(180,164)**	(151,087)	**(519,782)**	(453,607)
Deferred tax (expense) recovery	**(4,713)**	42,489	**(42,025)**	79,435
Gain on business combination	**—**	—	**—**	445,094
Loss on disposition	**—**	—	**—**	(226,828)
Unrealized other expense	**(478)**	(545)	**(823)**	(1,621)
Net earnings (loss)	**51,697**	57,309	**(28,423)**	565,549

3. Investments

Adoption of accounting policy - Investment in associate

Associates are entities for which the company has significant influence, but not control or joint control over the financial and operational decisions. Investments in associates are accounted for using the equity method of accounting and are initially recognized at cost and adjusted thereafter for the change in the company's share of the associate's net income and comprehensive income less distributions received until the date that significant influence ceases, within other income on the consolidated statements of net earnings and comprehensive income.

Subsequent to February 29, 2024, Vermilion owns approximately 21% of the issued and outstanding common shares of Coelacanth Energy Inc. ("CEI"), an oil and natural gas company, actively engaged in the acquisition, development, exploration, and production of oil and natural gas reserves in northeastern British Columbia, Canada. As such, Vermilion has concluded that it has significant influence over the entity and should be accounted for using the equity method of accounting. Prior to February 29, 2024, this investment was accounted for under IFRS 9 as an investment in securities using the fair value method of accounting. The transaction was treated as a disposal of the original investment at fair value and an acquisition of an investment in associate, with no resulting gain or loss recognized in the consolidated statement of net earnings.

The following table reconciles the change in Vermilion's investments:

	2024
Balance at January 1	**73,261**
Acquisition of securities	**9,373**
Fair value adjustment [1]	**(2,203)**
Investment in securities prior to reclassification to Investment in associate	**80,431**
Investment loss [2]	**(1,104)**
Balance at September 30	**79,327**

(1) The investment was classified as a level 1 instrument on the fair value hierarchy and used observable inputs when making fair value adjustments and was recorded until the date of significant influence, on February 29, 2024.

(2) Investment losses are recognized within other income on the consolidated statements of net earnings and comprehensive income.

The following tables summarize financial information of CEI and Vermilion's share based on their most recently available publicly available documents as at and for the six months ended June 30, 2024:

Current assets	**60,515**
Non-current assets	**123,375**
Current liabilities	**(5,098)**
Non-current liabilities	**(7,360)**
Net assets	**171,432**
Vermilion's share of net assets	**35,630**

	Seven Months Ended September 30, 2024
Total Revenue	**7,229**
Net loss	**(5,313)**
Vermilion's share of net loss	**(1,104)**

At September 30, 2024, the fair value of Vermilion's investment in CEI is $84.8 million or $0.77/share (December 31, 2023 - $73.3 million or $0.75/share).

4. Capital assets

The following table reconciles the change in Vermilion's capital assets:

	2024
Balance at January 1	**4,882,509**
Acquisitions	**7,471**
Additions	**410,457**
Increase in right-of-use assets	**109,606**
Depletion and depreciation	**(508,636)**
Changes in asset retirement obligations	**8,578**
Foreign exchange	**73,273**
Balance at September 30	**4,983,258**

Right-of-use assets

The following table discloses the carrying balance and depreciation charge relating to right-of-use assets by class of underlying asset as at and for the nine months ended September 30, 2024:

	As at Sep 30, 2024		As at Dec 31, 2023	
($M)	Depreciation	Balance	Depreciation	Balance
Office space	**6,160**	**55,230**	8,115	25,893
Processing facilities	**12,540**	**76,025**	7,691	6,326
Oil storage facilities	**1,966**	**4,629**	2,667	7,037
Vehicles and equipment	**1,239**	**4,929**	5,433	9,760
Total	**21,905**	**140,813**	23,906	49,016

In May 2024, Vermilion recognized a seven-year lease for a processing facility in the Canadian Business Unit adding $76.4 million of right-of-use assets offset with lease liabilities ($4.3 million current; $72.1 million non-current). The rate implicit in the lease is 11.7%.

In July 2024, Vermilion signed an extension of our existing head office lease from 2027 to 2035. The lease increased right-of-use assets by $30.9 million offset with changes to lease liabilities (current reduced by $3.4 million; non-current increased by $34.4 million). Vermilion's incremental borrowing rate at the time of signing the lease was 7.0%.

5. Exploration and evaluation assets

The following table reconciles the change in Vermilion's exploration and evaluation assets:

	2024
Balance at January 1	**198,379**
Additions	**11,864**
Depreciation	**(230)**
Foreign exchange	**5,556**
Balance at September 30	**215,569**

6. Asset retirement obligations

The following table reconciles the change in Vermilion's asset retirement obligations:

	2024
Balance at January 1	**1,159,063**
Additional obligations recognized	**658**
Obligations settled	**(32,052)**
Accretion	**55,269**
Changes in rates	**7,920**
Foreign exchange	**30,454**
Balance at September 30	**1,221,312**

Vermilion calculated the present value of the obligations using a credit-adjusted risk-free rate, calculated using a credit spread of 3.3% as at September 30, 2024 (December 31, 2023 - 3.6%) 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 country-specific risk-free rates used as inputs to discount the obligations were as follows:

	Sep 30, 2024	Dec 31, 2023
Canada	**3.1 %**	3.0 %
United States	**4.1 %**	4.2 %
France	**3.5 %**	3.0 %
Netherlands	**2.6 %**	2.1 %
Germany	**2.5 %**	2.3 %
Ireland	**2.7 %**	2.7 %
Australia	**4.2 %**	4.0 %
Central and Eastern Europe	**4.5 %**	4.4 %

7. Capital disclosures

Vermilion defines capital as net debt and shareholders' capital. Net debt consists 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). In managing capital, Vermilion reviews whether fund flows from operations is sufficient to fund capital expenditures, dividends, share buybacks, and asset retirement obligations.

The following table calculates Vermilion's ratio of net debt to four quarter trailing fund flows from operations:

	Sep 30, 2024	Dec 31, 2023
Long-term debt	**903,354**	914,015
Adjusted working capital [(1)]	**(70,023)**	164,552
Net debt	**833,331**	1,078,567
Ratio of net debt to four quarter trailing fund flows from operations	**0.6**	0.9

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

8. Long-term debt

The following table summarizes Vermilion's outstanding long-term debt:

	As at	
	Sep 30, 2024	**Dec 31, 2023**
2025 senior unsecured notes	**373,469**	395,839
2030 senior unsecured notes	**529,885**	518,176
Long-term debt	**903,354**	914,015

The fair value of the revolving credit facility is equal to its carrying value due to the use of short-term borrowing instruments at market rates of interest. The fair value of the 2025 senior unsecured notes as at September 30, 2024 was $373.4 million (December 31, 2023 - $392.7 million). The fair value of the 2030 senior unsecured notes as at September 30, 2024 was $540.5 million (December 31, 2023 - $511.7 million).

The following table reconciles the change in Vermilion's long-term debt:

	2024
Balance at January 1	**914,015**
Repurchases of senior unsecured notes	**(31,561)**
Amortization of transaction costs	**1,688**
Foreign exchange	**19,212**
Balance at September 30	**903,354**

Revolving credit facility

As at September 30, 2024, Vermilion had in place a bank revolving credit facility maturing May 26, 2028 with the following terms:

	As at	
	Sep 30, 2024	**Dec 31, 2023**
Total facility amount	**1,350,000**	1,600,000
Letters of credit outstanding	**(21,886)**	(18,116)
Unutilized capacity	**1,328,114**	1,581,884

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.

On May 17, 2024, the maturity date of the facility was extended to May 26, 2028 (previously May 28, 2027) and the total facility amount of $1.6 billion was reduced to $1.35 billion, with an accordion feature to increase the aggregate amount available under the facility to $1.6 billion. As at September 30, 2024, the revolving credit facility was undrawn.

The facility bears interest at a rate applicable to demand loans plus applicable margins.

As at September 30, 2024, the revolving credit facility was subject to the following financial covenants:

		As at	
Financial covenant	**Limit**	**Sep 30, 2024**	**Dec 31, 2023**
Consolidated total debt to consolidated EBITDA	Less than 4.0	**0.68**	0.65
Consolidated total senior debt to consolidated EBITDA	Less than 3.5	**0.05**	—
Consolidated EBITDA to consolidated interest expense	Greater than 2.5	**17.81**	17.33

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

- Consolidated total debt: Includes all amounts classified as "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 the consolidated balance sheet.
- Consolidated total senior debt: Consolidated total debt excluding unsecured and subordinated debt.

- Consolidated EBITDA: Consolidated net earnings (loss) before interest, income taxes, depreciation, accretion and certain other non-cash items, adjusted for the impact of the acquisition of a material subsidiary.
- Consolidated total interest expense: Includes all amounts classified as "Interest expense", but excludes interest on operating leases as defined under IAS 17.

In addition, our revolving credit facility has provisions relating to our liability management ratings in Alberta and Saskatchewan whereby if our security adjusted liability management ratings fall below specified limits in a province, a portion of the asset retirement obligations are included in the definitions of consolidated total debt and consolidated total senior debt. An event of default occurs if our security adjusted liability management ratings breach additional lower limits for a period greater than 90 days. As of September 30, 2024, Vermilion's liability management ratings were higher than the specified levels, and as such, no amounts relating to asset retirement obligations were included in the calculation of consolidated total debt and consolidated total senior debt.

As at September 30, 2024 and December 31, 2023, Vermilion was in compliance with the above covenants.

2025 senior unsecured notes

On March 13, 2017, Vermilion issued US $300.0 million of senior unsecured notes at par. The notes bear interest at a rate of 5.625% per annum, to be paid semi-annually on March 15 and September 15. The notes mature on March 15, 2025. 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.

Subsequent to March 15, 2023, Vermilion may redeem some or all of the senior unsecured notes at a 100.00% redemption price plus any accrued and unpaid interest.

During the nine months ended September 30, 2024, Vermilion purchased $31.6 million of senior unsecured notes on the open market which were subsequently cancelled.

The Company has the right to roll over the senior unsecured notes under the existing revolving credit facility which matures May 26, 2028 thus has continued to classify the senior unsecured notes as non-current.

2030 senior unsecured notes

On April 26, 2022, Vermilion closed a private offering of US $400.0 million 8-year senior unsecured notes. The notes were priced at 99.241% of par, mature on May 1, 2030, and bear interest at a rate of 6.875% per annum. Interest is paid semi-annually on May 1 and November 1, commencing on November 1, 2022. The notes are senior unsecured obligations of Vermilion and rank equally with existing and future senior unsecured indebtedness.

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 %
2028 and thereafter	100.000 %

9. Shareholders' capital

The following table reconciles the change in Vermilion's shareholders' capital:

Shareholders' Capital	2024 Shares ('000s)	Amount
Balance at January 1	**162,271**	**4,142,566**
Vesting of equity based awards	**996**	**9,998**
Share-settled dividends on vested equity based awards	**78**	**1,257**
Repurchase of shares	**(7,997)**	**(206,154)**
Balance at September 30	**155,348**	**3,947,667**

Dividends are approved by the Board of Directors and are paid quarterly. Dividends declared to shareholders for the nine months ended September 30, 2024 were $56.8 million or $0.36 per common share (2023 - $49.0 million or $0.30 per common share).

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 third quarter of 2024, Vermilion purchased 2.8 million common shares under the NCIB for total consideration of $40.1 million. Year-to-date, Vermilion purchased 8.0 million common shares under the NCIB for total consideration of $123.1 million. The common shares purchased under the NCIB were cancelled.

Subsequent to September 30, 2024, Vermilion purchased and cancelled 0.4 million shares under the NCIB for total consideration of $5.9 million.

10. Financial instruments

The following table summarizes the increase (positive values) or decrease (negative values) to net earnings (loss) before tax due to a change in the value of Vermilion's financial instruments as a result of a change in the relevant market risk variable. This analysis does not attempt to reflect any interdependencies between the relevant risk variables.

	Sep 30, 2024
Currency risk - Euro to Canadian dollar	
$0.01 increase in strength of the Canadian dollar against the Euro	**5,050**
$0.01 decrease in strength of the Canadian dollar against the Euro	**(5,050)**
Currency risk - US dollar to Canadian dollar	
$0.01 increase in strength of the Canadian dollar against the US $	**4,225**
$0.01 decrease in strength of the Canadian dollar against the US $	**(4,225)**
Commodity price risk - Crude oil	
US $5.00/bbl increase in crude oil price used to determine the fair value of derivatives	**(8,949)**
US $5.00/bbl decrease in crude oil price used to determine the fair value of derivatives	**8,949**
Commodity price risk - European natural gas	
€5.0/GJ increase in European natural gas price used to determine the fair value of derivatives	**(256,888)**
€5.0/GJ decrease in European natural gas price used to determine the fair value of derivatives	**286,247**

11. Cash and cash equivalents

The following table summarizes Vermilion's cash and cash equivalents:

	As at	
	Sep 30, 2024	**Dec 31, 2023**
Cash on deposit with financial institutions	**190,946**	140,795
Guaranteed investment certificates	**—**	661
Cash and cash equivalents	**190,946**	141,456

DIRECTORS

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Edwards, Colorado

Carin Knickel [4,7,11]
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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

Dion Hatcher *
President & Chief Executive Officer

Lars Glemser *
Vice President & Chief Financial Officer

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

AUDITORS

Deloitte LLP
Calgary, Alberta

BANKERS

The Toronto-Dominion Bank

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

JPMorgan Chase Bank, N.A., Toronto Branch

Goldman Sachs Lending Partners LLC

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TRANSFER AGENT

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