

Q2 2021

# SECOND QUARTER REPORT

EXCELLENCE. TRUST. RESPECT. RESPONSIBILITY.



INTERNATIONALLY DIVERSIFIED | FREE CASH FLOW FOCUSED

VERMILION  
E N E R G Y



# Disclaimer

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

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

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

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

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

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

## Abbreviations

\$M	thousand dollars
\$MM	million dollars
AECO	the daily average benchmark price for natural gas at the AECO 'C' hub in Alberta
bbl(s)	barrel(s)
bbls/d	barrels per day
boe	barrel of oil equivalent, including: crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe for six mcf of natural gas)
boe/d	barrel of oil equivalent per day
GJ	gigajoules
LSB	light sour blend crude oil reference price
mbbls	thousand barrels
mcf	thousand cubic feet
mmcf/d	million cubic feet per day
NBP	the reference price paid for natural gas in the United Kingdom at the National Balancing Point Virtual Trading Point.
NGLs	natural gas liquids, which includes butane, propane, and ethane
PRRT	Petroleum Resource Rent Tax, a profit based tax levied on petroleum projects in Australia
tCO <sub>2</sub> e	tonnes of carbon dioxide equivalent
TTF	the price for natural gas in the Netherlands, quoted in megawatt hours of natural gas, at the Title Transfer Facility Virtual Trading Point
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma

# Highlights

- Fund flows from operations ("FFO")<sup>(1)</sup> was \$173 million in Q2 2021, an increase of 7% from the prior quarter. The increase was primarily due to higher commodity prices.
- We generated \$94 million of free cash flow ("FCF")<sup>(1)</sup> in Q2 2021 after investing \$79 million in exploration and development ("E&D") capital expenditures, resulting in a payout ratio of 48% including reclamation and abandonment expenditures. During the first half of 2021, we have generated \$173 million of FCF compared to negative \$24 million in the first half of 2020. With the continued strength in commodity prices, as reflected under current strip pricing, we expect to generate significantly higher FFO during the second half of 2021 and now forecast annual FCF in excess of \$400 million, or over \$2.50 per share, for 2021.
- Net debt at the end of Q2 2021 was \$2.0 billion, representing a 5% decrease compared to year-end 2020. We have reduced the amount outstanding under our revolving credit facility by over \$327 million or 19% since Q2 2020. With the excess FCF we expect to generate over the balance of the year, we will continue to reduce net debt, with our ultimate goal of having leverage reduced to 1.5 times debt to cash flow or less.
- Production in Q2 2021 averaged 86,335 boe/d<sup>(2)</sup>, relatively consistent with first quarter production of 86,276 boe/d as new production adds in Canada from our Q1 2021 drilling program offset declines in other operating regions.
- Production from our North American assets averaged 58,354 in Q2 2021, an increase of 3% from the prior quarter primarily as a result of new production added from our Q1 2021 Canadian drilling program.
- Production from our International assets averaged 27,981 in Q2 2021, a decrease of 5% from the prior quarter primarily due to natural declines and downtime in Australia and Ireland.
- In Canada, during the second quarter we drilled one (0.2 net) well and brought on two (1.7 net) condensate-rich Mannville natural gas wells and initiated our drilling campaign in south-east Saskatchewan, where we drilled eight (6.9 net) wells and completed six (5.4 net) wells. Five (4.4 net) of these wells were brought on production during the quarter with the remaining wells to be brought on production in Q3 2021.
- In the United States we commenced our four (4.0 net) well drilling program centered on Turner horizontal wells in the Powder River basin. Two of the wells were completed and brought on production in the quarter, and are performing as expected. The remaining two wells are expected to be completed and brought on production in Q3 2021. Drilling costs on this program were reduced by 20% compared to budget.
- In the Netherlands, we successfully drilled one (1.0 net) natural gas well which encountered a 16 meter gas column in the Rotliegend Slochteren formation and multiple thin sands with reservoir potential in the Rotliegend Ten Boer formation. The well was completed at the end of June and we expect to bring it on production in Q3 2021. Subsequent to Q2 2021, we began inline testing of the Rotliegend formation on the Blesdijke natural gas well (0.5 net) drilled in Q1 2021 and achieved initial rates up to 7.0 mmcf/d. We plan on conducting further testing in Q3 2021 and expect to bring the well onstream later in the year.
- Furthering our focus on the energy transition, we established a third geothermal application from our produced water in France. Our Vic Bilh facility will provide geothermal heat to a nearby Fleur de Vie facility that produces high quality spirulina, a microalgae with a wide variety of uses. The facility is expected to be completed in autumn 2021.
- We published our 2021 Sustainability Report, Value Matters, which includes 2020 ESG-related data updates.

<sup>(1)</sup> Non-GAAP Financial Measure. Please see the "Non-GAAP Financial Measures" section of the accompanying Management's Discussion and Analysis.

<sup>(2)</sup> Please refer to Supplemental Table 4 "Production" of the accompanying Management's Discussion and Analysis for disclosure by product type.

(\$M except as indicated)	Q2 2021	Q1 2021	Q2 2020	YTD 2021	YTD 2020
<b>Financial</b>					
Petroleum and natural gas sales	407,179	368,137	193,013	775,316	521,327
Fund flows from operations	172,942	162,051	81,852	334,993	252,077
Fund flows from operations (\$/basic share) <sup>(1)</sup>	1.07	1.02	0.52	2.09	1.60
Fund flows from operations (\$/diluted share) <sup>(1)</sup>	1.05	1.00	0.52	2.06	1.60
Net earnings (loss)	451,274	499,964	(71,290)	951,238	(1,389,794)
Net (loss) earnings (\$/basic share)	2.79	3.15	(0.45)	5.94	(8.83)
Capital expenditures	79,176	83,363	42,274	162,539	275,978
Acquisitions	11,859	393	2,932	12,252	14,269
Asset retirement obligations settled	3,321	7,023	970	10,344	4,702
Cash dividends (\$/share)	—	—	—	—	0.575
Dividends declared	—	—	—	—	90,067
% of fund flows from operations	— %	— %	— %	— %	36 %
Payout <sup>(1)</sup>	82,497	90,386	42,612	172,883	362,470
% of fund flows from operations	48 %	56 %	52 %	52 %	144 %
Free Cash Flow <sup>(1)</sup>	93,766	78,688	39,578	172,454	(23,901)
Net debt	2,005,272	1,996,675	2,161,442	2,005,272	2,161,442
Net debt to four quarter trailing fund flows from operations	3.43	4.04	3.16	3.43	3.16
<b>Operational</b>					
Production <sup>(2)</sup>					
Crude oil and condensate (bbls/d)	38,354	39,204	45,041	38,777	44,961
NGLs (bbls/d)	8,695	8,074	9,588	8,386	8,805
Natural gas (mmcf/d)	235.72	233.98	274.42	234.86	269.96
Total (boe/d)	86,335	86,276	100,366	86,306	98,760
Average realized prices					
Crude oil and condensate (\$/bbl)	79.06	71.09	34.90	75.21	47.20
NGLs (\$/bbl)	25.43	29.39	8.94	27.32	8.94
Natural gas (\$/mcf)	5.24	5.51	1.85	5.37	2.39
Production mix (% of production)					
% priced with reference to WTI	38 %	38 %	41 %	38 %	40 %
% priced with reference to Dated Brent	17 %	18 %	14 %	17 %	16 %
% priced with reference to AECO	30 %	28 %	29 %	29 %	28 %
% priced with reference to TTF and NBP	15 %	16 %	16 %	16 %	16 %
Netbacks (\$/boe)					
Operating netback <sup>(1)</sup>	25.90	25.58	12.49	25.74	17.25
Fund flows from operations netback	22.04	21.66	9.08	21.85	13.96
Operating expenses	12.72	12.86	11.00	12.79	12.21
General and administration expenses	1.46	1.57	1.88	1.51	1.67
Average reference prices and foreign exchange rates					
WTI (US \$/bbl)	66.07	57.84	27.85	61.96	37.01
Edmonton Sweet index (US \$/bbl)	62.96	52.60	21.71	57.78	30.15
Saskatchewan LSB index (US \$/bbl)	62.71	52.82	21.60	57.77	30.01
Dated Brent (US \$/bbl)	68.83	60.90	29.20	64.86	39.73
AECO (\$/mcf)	3.09	3.15	1.99	3.12	2.01
NBP (\$/mcf)	10.92	8.70	2.26	9.83	3.31
TTF (\$/mcf)	10.76	8.27	2.39	9.54	3.32
CDN \$/US \$	1.23	1.27	1.39	1.25	1.37
CDN \$/Euro	1.48	1.53	1.53	1.50	1.50
<b>Share information ('000s)</b>					
Shares outstanding - basic	161,893	159,349	158,307	161,893	158,307
Shares outstanding - diluted <sup>(1)</sup>	168,903	166,018	164,090	168,903	164,090
Weighted average shares outstanding - basic	161,546	158,892	158,189	160,226	157,375
Weighted average shares outstanding - diluted <sup>(1)</sup>	165,034	161,397	158,189	162,553	157,375

<sup>(1)</sup> The above table includes non-GAAP financial measures which may not be comparable to other companies. Please see the "Non-GAAP Financial Measures" section of the accompanying Management's Discussion and Analysis.

<sup>(2)</sup> Please refer to Supplemental Table 4 "Production" of the accompanying Management's Discussion and Analysis for disclosure by product type.



# Message to Shareholders

Commodity prices continued to strengthen through the second quarter as economies around the world began to reopen following the year-long COVID-related lockdowns. Benchmark oil prices increased approximately 14% in Q2 2021 compared to the previous quarter and European natural gas prices increased approximately 30% from the previous quarter, driving an 11% increase in our quarterly revenue on production of 86,335 boe/d which was up slightly from the previous quarter.

We generated \$173 million of FFO in Q2 2021, representing an increase of 7% over the previous quarter. E&D capital expenditures were \$79 million in the quarter, resulting in \$94 million of FCF<sup>(1)</sup> and a payout ratio of 48% including reclamation and abandonment expenditures. During the first half of 2021, we generated \$172 million of FCF compared to negative \$24 million in the first half of 2020.

With the continued strength in commodity prices, as reflected under current strip pricing, we expect to generate significantly higher FFO during the second half of 2021 and now forecast annual FCF in excess of \$400 million, or over \$2.50 per share, for 2021. This significant improvement in FCF is not only due to higher commodity prices but is also the result of a more level-loaded capital program compared to last year. We continue to believe a level-loaded capital program delivers more efficient operations and a more manageable production base. Some of the benefits from a level-loaded capital program were evidenced during the second quarter as we realized a 20% reduction in our US drilling costs which is the result of a number of initiatives including executing the program in the spring (versus winter) and using an experienced drilling crew that worked on our Canadian winter drilling campaign in Q1 2021.

The majority of FCF generated in the quarter was used to reduce our revolving credit facility. Over the past year we have reduced the amount outstanding under our revolving credit facility by \$326 million or 19%. Net debt at the end of Q2 2021 was relatively unchanged from the previous quarter at \$2 billion mainly due to an increase in derivative liabilities associated with higher commodity prices; however, our net debt to four-quarter-trailing FFO ratio improved to 3.4x from 4.0x in the previous quarter. While this is still well above our comfort level, it is a step in the right direction and moves us closer to our ultimate leverage target of 1.5x or lower.

We have made solid progress during the first half of 2021, with our production and FCF results exceeding budget expectations. As we move through the second half of 2021, we will remain disciplined in our strategy with a continued focus on improving operational efficiencies and reducing debt. Production levels averaged in excess 86,300 boe/d in 1H 2021 but are expected to moderate in 2H 2021 due to planned maintenance across several of our operating jurisdictions, including extended turnarounds in Ireland and Australia. Our 2021 production guidance of 83,000 to 85,000 boe/d remains intact and our E&D capital budget remains unchanged at \$300 million; however, we may still consider adding up to \$50 million of incremental capital in Q4 2021 if commodity prices remain supportive. We have several projects lined up and ready to execute should we decide to invest incremental capital in Q4 2021; however, any new production associated with these projects would not contribute to 2021 volumes.

As we look to 2022 and start working through our budgeting process over the coming months, it is our intent to remain financially disciplined and manage towards a similar production range as 2021 with a continued focus on striking the right balance between allocating FCF to the balance sheet and asset base. We aim to achieve this through a combination of organic capital development and strategic acquisitions if and when the right opportunities become available. As we have stated previously, our long-term goal is to return to a dividend paying capital markets model and we believe this balanced approach is the most appropriate way to achieve this. We will continue to focus on debt reduction in the near-term, and once we are comfortable with our leverage ratio, we will consider returning capital to our shareholders through the re-instatement of a dividend as we believe the FCF capability of our asset base is supportive of the dividend capital markets model.

## Q2 2021 Operations Review

---

### *North America*

Production from our North American assets averaged 58,354 in Q2 2021, an increase of 3% from the prior quarter primarily as a result of new production added from Q1 2021 Canadian drilling program. During the second quarter, we drilled one (0.2 net) well and brought two (1.7 net) condensate-rich Mannville natural gas wells on production in west-central Alberta and initiated our drilling campaign in south-east Saskatchewan, where we drilled eight (6.9 net) wells and completed six (5.4 net) wells. Five (4.4 net) of these wells were brought on production during the quarter with the remaining wells to be brought on production in Q3 2021.

In the United States, we moved one of our experienced drilling crews from our Canadian operations to Wyoming and commenced our four (4.0 net) well drilling program in April, centered on Turner horizontal wells in the Powder River basin. Two of the wells were completed and brought on production in the quarter, and are performing as expected. The remaining two wells are expected to be completed and brought on production in Q3 2021. Drilling costs on this program were reduced by 20% compared to budget.

## *International*

Production from our International assets averaged 27,981 in Q2 2021, a decrease of 5% from the prior quarter primarily due to natural declines and downtime in Ireland and Australia. In Europe, we drilled one (1.0 net) natural gas well in the Netherlands and continued our workover programs in France, Netherlands and Germany.

In the Netherlands, we successfully drilled the Nijega well (1.0 net), which encountered a 16 meter gas column in the Rotliegend Slochteren formation and multiple thin sands with reservoir potential in the Rotliegend Ten Boer formation. The well was completed at the end of June 2021 and we expect to bring it on production in Q3 2021. Subsequent to Q2 2021, we began inline testing of the Rotliegend formation on the Blesdijke natural gas well (0.5 net) drilled in Q1 2021 and achieved initial rates up to 7.0 mmcf/d. We plan on conducting further testing in Q3 2021 and expect to bring the well onstream later in the year.

In Germany, we had strong operational performance and runtime across our operated and non-operated assets and we continued to prepare for the start-up of the Burgmoor Z5 well (46% working interest) in Q3 2021.

In France, our trucking operations in the Paris Basin continue to run smoothly following the transition of our Paris Basin oil production from pipeline delivery to trucking after the Total Grandpuits refinery ceased crude oil refining in Q1 2021. The majority of the Paris Basin production is being delivered to the Total Le Havre refinery in northwest France and to our Parentis facility which delivers crude to various refineries in Europe through the Ambes terminal in southwest France. Additionally, we started trucking some volumes to a refinery in Germany and will continue to evaluate other shipping options to further optimize operations and reduce costs.

In Central and Eastern Europe ("CEE"), we successfully completed our 3-D seismic program in the SA-10 block in Croatia, with an additional seismic program planned for the SA-07 block later this year, which will further enhance our knowledge of the region prior to our next drilling program planned for 2022. Work is continuing to progress on the Croatian gas plant on the SA-10 block in preparation for the tie-in of the two successful gas wells drilled previously.

In Ireland, one of the 6 producing sub-sea wells was offline for approximately 40 days during Q2 2021 due to a stuck choke valve. The valve has been replaced and the well was brought back on production at the end of June 2021. We continued to make preparations for the 21-day turnaround at Corrib scheduled in Q3 2021.

In Australia, we had a 4-day shutdown in Q2 2021 due to a vessel cleanout, and we continue to plan for a 20-day scheduled turnaround in the second half of 2021.

## *Commodity Hedging*

Vermilion hedges to manage commodity price exposures and increase the stability of our cash flows. In aggregate, as of August 13, 2021, we have 29% of our expected net-of-royalty production hedged for the second half of 2021. With respect to individual commodity products, we have hedged 69% of our European natural gas production, 5% of our oil production, and 49% of our North American natural gas volumes for the second half of 2021, 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.cfm>.

## *Sustainability*

In August 2021, we published our 2021 Sustainability Report, Value Matters, which includes 2020 data updates. This eighth annual report demonstrates our continued commitment to environmental, social and governance ("ESG") matters and the energy transition, including the release of our renewed sustainability strategy. Created using input from staff across the Company and from external stakeholders, including investors, our strategy focuses on the key areas of carbon, conservation and community. The report is available on our Sustainability micro-site at the following link: <https://sustainability.vermilionenergy.com/>, and includes a climate-related Energy Transition section that can be read as a standalone report. PDF versions of both reports are available at the "download report" link on the micro-site, along with our 2021 CDP Climate Change and CDP Water Security submissions. In addition, MSCI confirmed our "AA" ESG rating for 2021.<sup>(3)</sup>

As part of our progression towards achieving our recently announced carbon emission reduction targets, we completed the installation of nine solar powered chemical injection pumps at various well sites in Alberta. This project is expected to reduce Vermilion's Scope 1 emissions by 9,000 tCO<sub>2</sub>e/year. Furthering our focus on energy transition, we also established a third geothermal application from our produced water in France. Our Vic Bilh facility will provide geothermal heat to a nearby Fleur de Vie facility that produces high quality spirulina, a microalgae with a wide variety of uses. The facility is expected to be completed in autumn 2021.

## Board of Directors

Vermilion recently announced the appointments of Ms. Manjit Sharma and Ms. Judy Steele to our Board of Directors.

Ms. Sharma brings over 25 years' experience in a wide range of operational matters in a variety of industries, most recently as Chief Financial Officer of WSP Canada, and previously with GE Canada for over 20 years, serving in various senior management roles. Ms. Sharma serves as a member of the Board of Directors for Export Development Canada, and is a member of the GE Canada Pension Trust Committee. She holds a Bachelor of Commerce (Honours) from the University of Toronto and the Chartered Professional Accountant designation. She is an alumnus of the Rotman School of Management's Judy Project for Executive Women in Leadership and was recognized as one of Canada's Top 100 Most Powerful Women in 2019.

Since October 2012, Ms. Steele has been the President & Chief Operating Officer of Emera Energy Inc., where she is responsible for commercial performance, operations, business growth and development, risk management, and team leadership and development. She has been involved in overseeing various energy businesses including hydro, wind, biomass and natural gas fired electrical generating facilities. Prior to her current role, Ms. Steele held a variety of executive and senior management positions within Emera Inc. She is currently a Board member of Canadian Blood Services and a Governor of St. Francis Xavier University. Ms. Steele holds the designation Fellow Chartered Accountant, and a Bachelor of Public Relations from Mount Saint Vincent University. She is a recipient of the Chartered Accountant of the Year Award, from the Institute of Chartered Accountants of Nova Scotia, for outstanding community leadership.

Ms. Cathy Williams is retiring from Vermilion's Board of Directors. Ms. Williams has been a Director of Vermilion since 2015 and was a member of Vermilion's Audit Committee and Governance and Human Resources Committee. We wish to thank Cathy for her valuable contribution to Vermilion as a Board member and wish her all the best in her retirement.

*(Signed "Lorenzo Donadeo")*

Lorenzo Donadeo  
Executive Chairman  
August 13, 2021

*(Signed "Curtis Hicks")*

Curtis Hicks  
President  
August 13, 2021

<sup>(1)</sup> Non-GAAP Financial Measure. Please see the "Non-GAAP Financial Measures" section of the accompanying Management's Discussion and Analysis.

<sup>(2)</sup> Please refer to Supplemental Table 4 "Production" of the accompanying Management's Discussion and Analysis for disclosure by product type.

<sup>(3)</sup> \* The use by Vermilion Energy Inc of any MSCI ESG Research LLC or its affiliates ("MSCI") data, and the use of MSCI logos, trademarks, service marks or index names herein, do not constitute a sponsorship, endorsement, recommendation, or promotion of Vermilion by MSCI. MSCI services and data are the property of MSCI or its information providers, and are provided 'as-is' and without warranty. MSCI names and logos are trademarks or service marks of MSCI.



# Management's Discussion and Analysis

The following is Management's Discussion and Analysis ("MD&A"), dated August 13, 2021, of Vermilion Energy Inc.'s ("Vermilion", "we", "our", "us" or the "Company") operating and financial results as at and for the three and six months ended June 30, 2021 compared with the corresponding periods in the prior year.

This discussion should be read in conjunction with the unaudited condensed consolidated interim financial statements for the three and six months ended June 30, 2021 and the audited consolidated financial statements for the years ended December 31, 2020 and 2019, together with the accompanying notes. Additional information relating to Vermilion, including its Annual Information Form, is available on SEDAR at [www.sedar.com](http://www.sedar.com) or on Vermilion's website at [www.vermilionenergy.com](http://www.vermilionenergy.com).

The unaudited condensed consolidated interim financial statements for the three and six months ended June 30, 2021 and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with IAS 34, "Interim Financial Reporting", as issued by the International Accounting Standards Board ("IASB").

This MD&A includes references to certain financial and performance measures which do not have standardized meanings prescribed by International Financial Reporting Standards ("IFRS"). These measures include:

- **Fund flows from operations:** Fund flows from operations is a measure of profit or loss in accordance with IFRS 8 "Operating Segments". Please see "Segmented Information" in the "Notes to the Condensed Consolidated Interim Financial Statements" for a reconciliation of fund flows from operations to net earnings. We analyze fund flows from operations both on a consolidated basis and on a business unit basis in order to assess the contribution of each business unit to our ability to generate income necessary to pay dividends, repay debt, fund asset retirement obligations and make capital investments.
- **Free cash flow:** Represents fund flows from operations in excess of capital expenditures. We use free cash flow to determine the funding available for investing and financing activities, including payment of dividends, repayment of long-term debt, reallocation to existing business units, and deployment into new ventures. We also assess free cash flow as a percentage of fund flows from operations, which is a measure of the percentage of fund flows from operations that is retained for incremental investing and financing activities.
- **Net debt:** Net debt is a capital management measure in accordance with IAS 1 "Presentation of Financial Statements". Net debt is comprised of long-term debt plus current liabilities less current assets and represents Vermilion's net financing obligations after adjusting for the timing of working capital fluctuations. Net debt excludes non-current lease obligations which are secured by a corresponding right-of-use asset. Please see "Capital disclosures" in the "Notes to the Condensed Consolidated Interim Financial Statements" for additional information.
- **Netbacks:** Netbacks are per boe and per mcf performance measures used in the analysis of operational activities. We assess netbacks both on a consolidated basis and on a business unit basis in order to compare and assess the operational and financial performance of each business unit versus other business units and also versus third party crude oil and natural gas producers.

In addition, this MD&A includes references to certain financial measures which are not specified, defined, or determined under IFRS and are therefore considered non-GAAP financial measures. These non-GAAP financial measures are unlikely to be comparable to similar financial measures presented by other issuers. For a full description of these non-GAAP financial measures and a reconciliation of these measures to their most directly comparable GAAP measures, please refer to "Non-GAAP Financial Measures".

## Product Type Disclosure

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

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

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

## Guidance

On January 18, 2021, we released our 2021 capital budget and associated production guidance.

The following table summarizes our guidance:

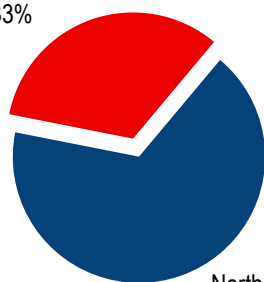
	Date	Capital Expenditures (\$MM)	Production (boe/d)
<b>2021 Guidance</b>			
2021 Guidance	January 18, 2021	300	83,000 to 85,000

## Vermilion's Business

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

2021 YTD production of 86,306 boe/d

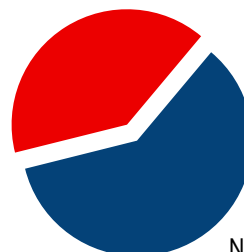
International: 33%



North America: 67%

2021 YTD capital expenditures of \$162.5MM

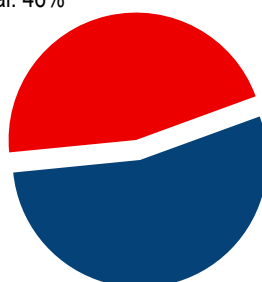
International: 40%



North America: 60%

2021 YTD fund flows from operations of \$335.0MM

International: 46%



North America: 54%

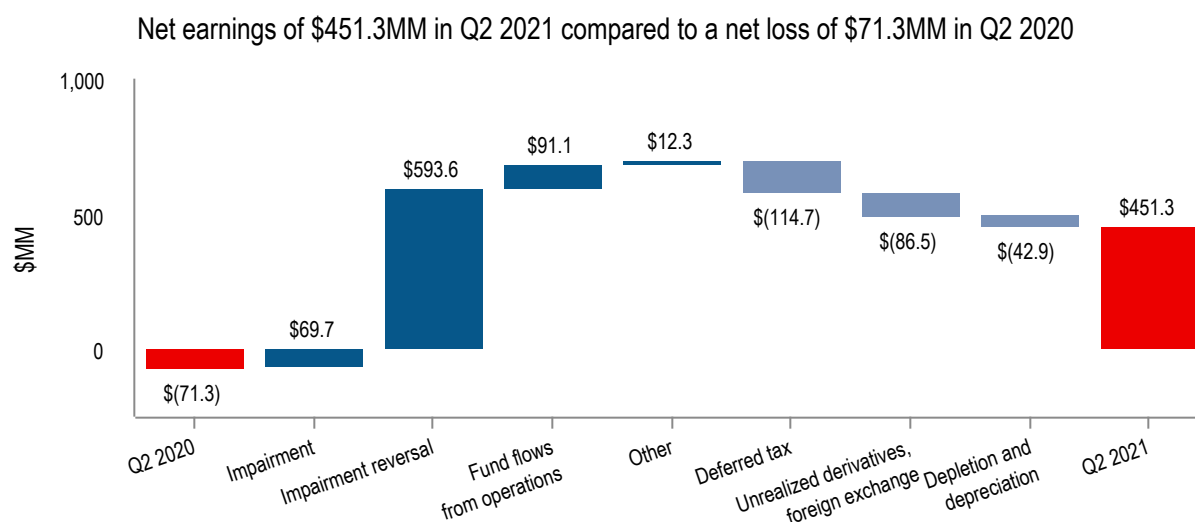
## Consolidated Results Overview

	Q2 2021	Q2 2020	Q2/21 vs. Q2/20	YTD 2021	YTD 2020	2021 vs. 2020
<b>Production <sup>(1)</sup></b>						
Crude oil and condensate (bbls/d)	38,354	45,041	(15)%	38,777	44,961	(14)%
NGLs (bbls/d)	8,695	9,588	(9)%	8,386	8,805	(5)%
Natural gas (mmcf/d)	235.72	274.42	(14)%	234.86	269.96	(13)%
Total (boe/d)	86,335	100,366	(14)%	86,306	98,760	(13)%
Build (draw) in inventory (mbbls)	15	115		299	(76)	
<b>Financial metrics</b>						
Fund flows from operations (\$M)	172,942	81,852	111%	334,993	252,077	33%
Per share (\$/basic share)	1.07	0.52	106%	2.09	1.60	31%
Net earnings (loss) (\$M)	451,274	(71,290)	N/A	951,238	(1,389,794)	N/A
Per share (\$/basic share)	2.79	(0.45)	N/A	5.94	(8.83)	N/A
Free cash flow	93,766	39,578	137%	172,454	(23,901)	N/A
Net debt (\$M)	2,005,272	2,161,442	(7)%	2,005,272	2,161,442	(7)%
<b>Activity</b>						
Capital expenditures (\$M)	79,176	42,274	87%	162,539	275,978	(41)%
Acquisitions (\$M)	11,859	2,932		12,252	14,269	

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

## Financial performance review

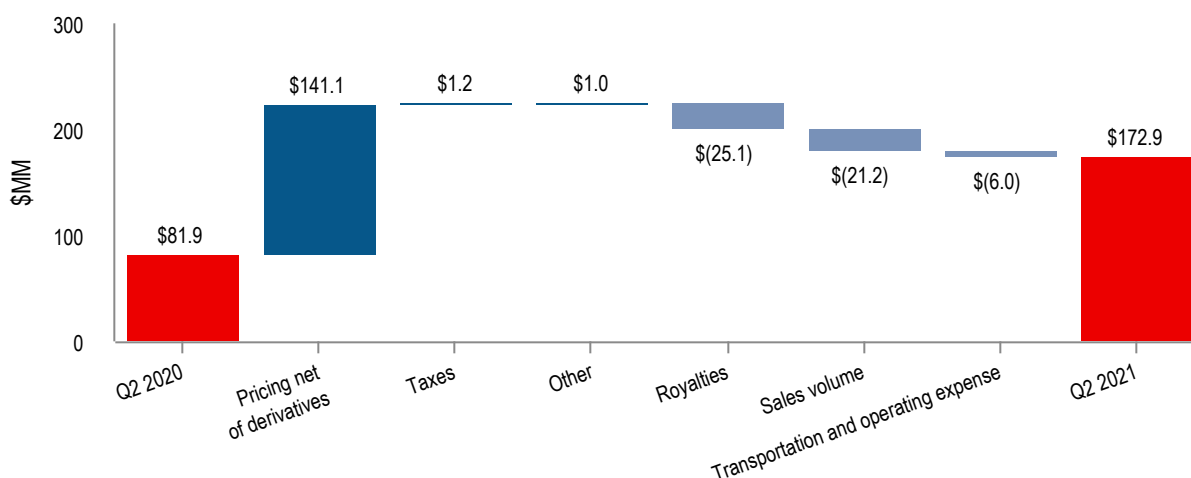
### Q2 2021 vs. Q2 2020



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

- We recorded net earnings of \$451.3 million (\$2.79/basic share) for Q2 2021 compared to a net loss of \$71.3 million (\$0.45/basic share) in Q2 2020. The increase was primarily driven by impairment reversals of \$593.6 million in Q2 2021 and an increase in FFO primarily driven by an increase in realized pricing. This was partially offset by an increase in deferred taxes driven by impairment reversals in Q2 2021 and unrealized losses on derivatives due to increased commodity prices.

### Fund flows from operations of \$172.9MM in Q2 2021 compared to \$81.9MM in Q2 2020

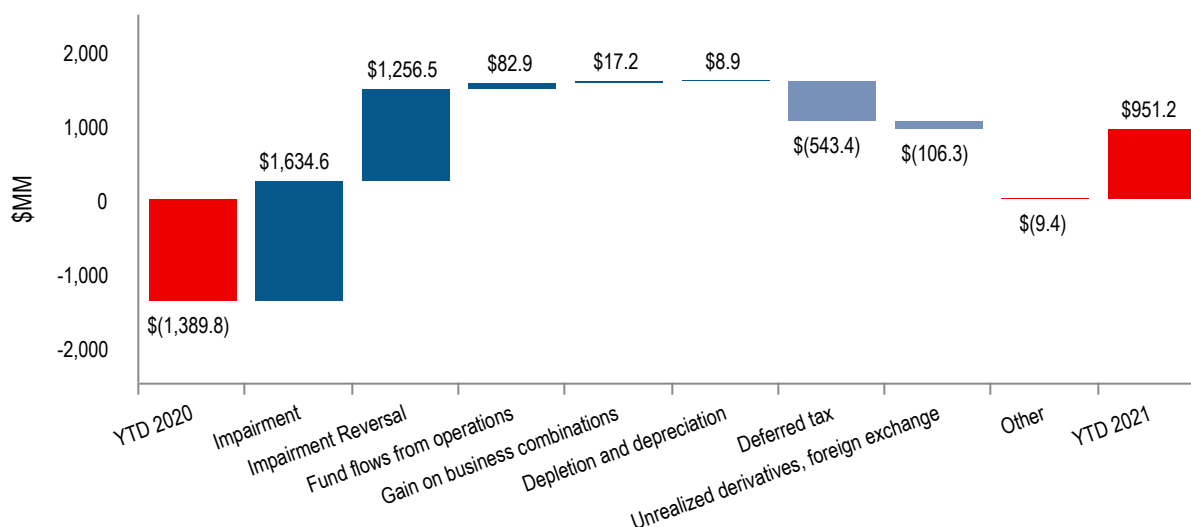


"Other" contains general and administration, interest, and realized foreign exchange

- We generated fund flows from operations of \$172.9 million in Q2 2021, an increase from \$81.9 million in Q2 2020 primarily as a result of higher commodity prices which is reflected in our consolidated realized price per boe increasing from \$21.40/boe in Q2 2020 to \$51.93/boe in Q2 2021. This was partially offset by increased royalties driven by increased pricing and a decrease in sales volumes primarily driven by natural decline.

### YTD 2021 vs. YTD 2020

### Net earnings of \$951.2MM in 2021 compared to net loss of \$1,389.8MM in 2020

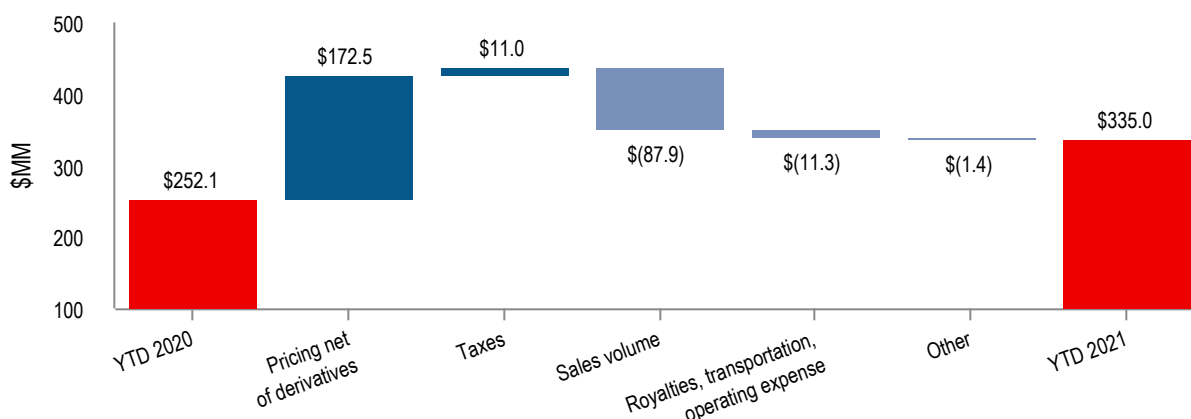


"Other" contains equity based compensation, accretion and unrealized other

- For the six months ended June 30, 2021, we achieved net earnings of \$951.2 million compared to a net loss of \$1,389.8 million for the comparable period in 2020. The increase in net earnings was primarily due to impairment charges we recorded of \$1,236.7 million in 2020 (net of \$397.9 million income tax recovery), impairment reversal charges we recorded of \$952.6 million in 2021 (net of \$303.9 million income tax expense) and higher fund flows from operations driven by increased consolidated realized pricing. These increases were partially offset by higher unrealized derivative losses driven by increased commodity prices.



### Fund flows from operations of \$335.0MM in 2021 compared to \$252.1MM in 2020



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

- Fund flows from operations increased by 33% for the six months ended June 30, 2021 versus the same period in 2020 primarily driven by a 75% increase in our consolidated realized price from \$28.88/boe to \$50.60/boe resulting from higher commodity prices. Sales volumes decreased year-over-year primarily due to natural decline in North America, Ireland, and Netherlands, as well as timing of liftings in Australia.

## Production review

### Q2 2021 vs. Q2 2020

- Consolidated average production of 86,335 boe/d in Q2 2021 represented a decrease of 14% from Q2 2020 production of 100,366 boe/d. Production decreases were mainly in Canada of 8,569 boe/d and in the United States of 2,972 boe/d due to natural decline and reduced capital activity as we are focused on maximizing free cash flow and reducing debt in 2021.

### YTD 2021 vs. YTD 2020

- Consolidated average production of 86,306 boe/d for the six months ended June 30, 2021 represented a decrease of 13% from the prior year comparable period of 98,760 boe/d. Production decreases were mainly in Canada of 7,843 boe/d and in the United States of 1,644 boe/d due to natural decline and reduced capital activity.

## Activity review

- For the three months ended June 30, 2021, capital expenditures of \$79.2 million were incurred.
- In our North America core region, capital expenditures of \$38.8 million were incurred during Q2 2021. In Canada, \$20.2 million was incurred primarily related to drilling and completions activity. In south-east Saskatchewan we drilled eight (6.9 net) wells and completed six (5.4 net) wells. Five (4.4 net) wells were brought on production during the quarter. In addition, we drilled one (0.2 net) and brought two (1.7 net) Mannville natural gas wells on production. In the United States, we completed and brought on production two (2.0 net) wells in the quarter.
- In our International core region, capital expenditures of \$40.3 million were incurred during Q2 2021. Our activities included \$13.1 million incurred in Australia primarily for riser replacement work, \$8.9 million in France mainly due to increased activity on subsurface maintenance and facilities, \$7.7 million in the Netherlands mainly related to the drilling of one (1.0 net) wells, and \$6.8 million in Central and Eastern Europe mainly related to land and seismic expenditures in Croatia.

## Financial sustainability review

---

### *Free cash flow*

- Free cash flow increased by \$196.4 million for the six months ended June 20, 2021 compared to the prior year period. This was primarily the result of a 75% increase in consolidated realized prices, as well as lower capital spending due to a focus on generating free cash flow and reducing debt in 2021.

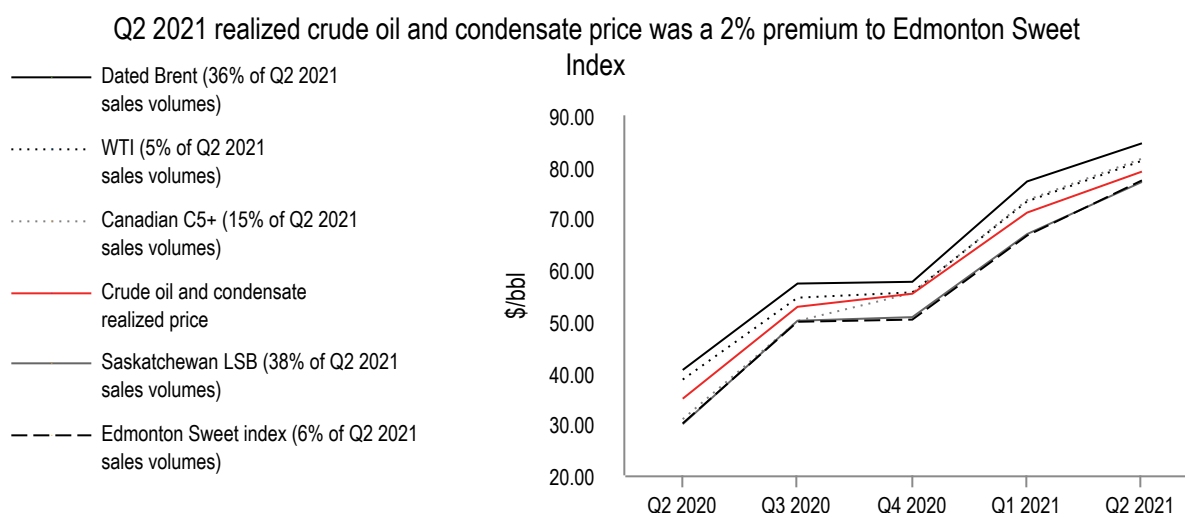
### *Long-term debt and net debt*

- Long-term debt decreased to \$1.8 billion as at June 30, 2021 from \$1.9 billion as at December 31, 2020.
- Net debt decreased to \$2.0 billion as at June 30, 2021 from \$2.1 billion as at December 31, 2020, mainly due to a decrease in long-term debt of \$164 million as a result of debt repayments.
- The ratio of net debt to four quarter trailing fund flows from operations decreased to 3.43 as at June 30, 2021 (December 31, 2020 - 4.19) mainly due to lower net debt combined with higher four quarter trailing fund flows from operations.

## Benchmark Commodity Prices

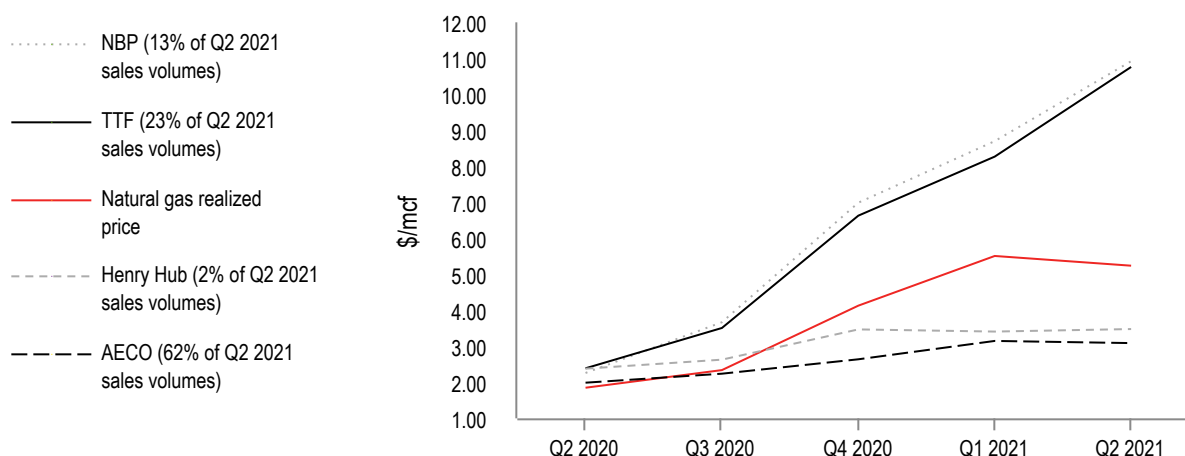
	Q2 2021	Q2 2020	Q2/21 vs. Q2/20	YTD 2021	YTD 2020	2021 vs. 2020
<b>Crude oil</b>						
WTI (\$/bbl)	81.17	38.62	110%	77.31	50.54	53%
WTI (US \$/bbl)	66.07	27.85	137%	61.96	37.01	67%
Edmonton Sweet index (\$/bbl)	77.35	30.11	157%	72.09	41.17	75%
Edmonton Sweet index (US \$/bbl)	62.96	21.71	190%	57.78	30.15	92%
Saskatchewan LSB index (\$/bbl)	77.05	29.95	157%	72.08	40.98	76%
Saskatchewan LSB index (US \$/bbl)	62.71	21.60	190%	57.77	30.01	93%
Canadian C5+ Condensate index (\$/bbl)	81.58	30.92	164%	77.63	46.82	66%
Canadian C5+ Condensate index (US \$/bbl)	66.40	22.30	198%	62.22	34.29	82%
Dated Brent (\$/bbl)	84.56	40.49	109%	80.93	54.25	49%
Dated Brent (US \$/bbl)	68.83	29.20	136%	64.86	39.73	63%
<b>Natural gas</b>						
AECO (\$/mcf)	3.09	1.99	55%	3.12	2.01	55%
NBP (\$/mcf)	10.92	2.26	383%	9.83	3.31	197%
NBP (€/mcf)	7.37	1.48	398%	6.53	2.20	197%
TTF (\$/mcf)	10.76	2.39	350%	9.54	3.32	187%
TTF (€/mcf)	7.27	1.56	366%	6.34	2.21	187%
Henry Hub (\$/mcf)	3.48	2.38	46%	3.45	2.50	38%
Henry Hub (US \$/mcf)	2.83	1.72	65%	2.76	1.83	51%
<b>Average exchange rates</b>						
CDN \$/US \$	1.23	1.39	(12)%	1.25	1.37	(9)%
CDN \$/Euro	1.48	1.53	(3)%	1.50	1.50	—%
<b>Realized prices</b>						
Crude oil and condensate (\$/bbl)	79.06	34.90	127%	75.21	47.20	59%
NGLs (\$/bbl)	25.43	8.94	185%	27.32	8.94	206%
Natural gas (\$/mcf)	5.24	1.85	183%	5.37	2.39	125%
Total (\$/boe)	51.93	21.40	143%	50.60	28.88	75%

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



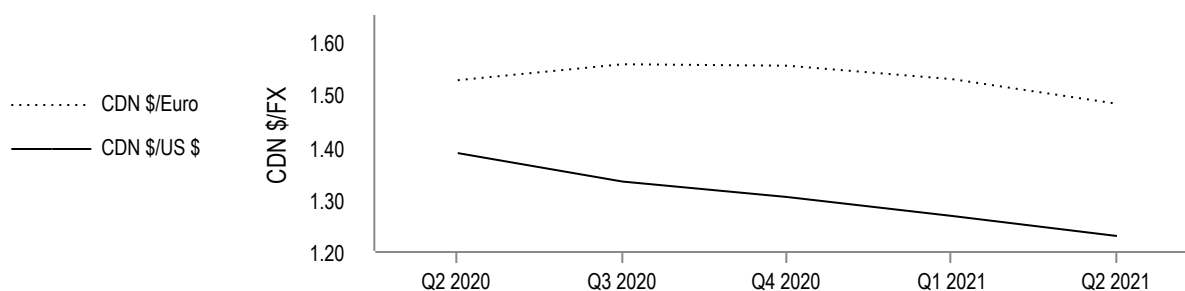
- Crude oil prices increased in Q2 2021 relative to Q2 2020 due to continued global demand recovery, a coordinated supply cut from the OPEC+ group, and lower US shale production. Year-over-year, Canadian dollar WTI and Brent prices rose 110% and 109% respectively.
- In Canadian dollar terms, year-over-year, the Edmonton Sweet differential improved by \$4.69/bbl to a discount of \$3.82/bbl against WTI, and the Saskatchewan LSB differential improved by \$4.55/bbl to a discount of \$4.12/bbl against WTI.
- Approximately 36% of Vermilion's Q2 2021 crude oil and condensate production was priced at the Dated Brent index (which averaged a premium to WTI of US\$2.76/bbl), while the remainder of our crude oil and condensate production was priced at the Saskatchewan LSB, Canadian C5+, Edmonton Sweet, and WTI indices.

#### Q2 2021 realized natural gas price was a \$2.15/mcf premium to AECO



- In Canadian dollar terms, prices for European natural gas (NBP and TTF) rose by 383% and 350%, respectively, in Q2 2021 compared to Q2 2020. A rebalancing of the European gas market has been driven by a demand recovery, lower supply from both pipeline flows and LNG imports, and higher European carbon prices.
- Natural gas prices at AECO in Q2 2021 increased by 55% compared to Q2 2020, with seasonal demand and supportive storage balances improving prices.
- For Q2 2021, average European natural gas prices represented a \$7.75/mcf premium to AECO. Approximately 36% of our natural gas production in Q2 2021 benefited from this premium European pricing.

#### Quarter-over-quarter, the Canadian dollar strengthened versus the Euro and US Dollar



- For the three months ended June 30, 2021, the Canadian dollar strengthened 3% against the Euro quarter-over-quarter.
- For the three months ended June 30, 2021, the Canadian dollar strengthened 3% against the US dollar quarter-over-quarter.

## North America

	Q2 2021	Q2 2020	YTD 2021	YTD 2020
<b>Production <sup>(1)</sup></b>				
Crude oil and condensate (bbls/d)	24,316	31,569	24,480	30,728
NGLs (bbls/d)	8,695	9,588	8,386	8,805
Natural gas (mmcf/d)	152.06	172.43	148.23	165.16
Total production volume (boe/d)	58,354	69,895	57,572	67,059

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

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Sales	224,609	42.30	116,009	18.24	444,743	42.68	286,800	23.50
Royalties	(31,755)	(5.98)	(10,613)	(1.67)	(59,835)	(5.74)	(31,314)	(2.57)
Transportation	(10,084)	(1.90)	(10,934)	(1.72)	(20,568)	(1.97)	(22,072)	(1.81)
Operating	(57,830)	(10.89)	(61,046)	(9.60)	(115,111)	(11.05)	(130,780)	(10.72)
General and administration <sup>(1)</sup>	(4,825)	(0.91)	(9,674)	(1.52)	(11,673)	(1.12)	(14,612)	(1.20)
Corporate income tax (expense) <sup>(1)</sup>	(199)	(0.04)	(103)	(0.02)	(413)	(0.04)	(335)	(0.03)
Fund flows from operations	119,916	22.58	23,639	3.72	237,143	22.76	87,687	7.18
Capital expenditures	(38,847)		(23,979)		(97,960)		(221,905)	
Free cash flow	81,069		(340)		139,183		(134,218)	

<sup>(1)</sup> Includes amounts from Corporate segment.

In North America, production averaged 58,354 in Q2 2021, a decrease of 17% year-over-year primarily due to natural decline and reduced capital activity as we focused on maximizing free cash flow and reducing debt.

In Q2 2021, we drilled one (0.2 net) well and brought two (1.7 net) condensate-rich Mannville natural gas wells on production in west-central Alberta from our Q1 2021 drilling campaign. In south-east Saskatchewan we initiated our drilling campaign where we drilled eight (6.9 net) wells and completed six (5.4 net) wells, of which five (4.4 net) wells were brought on production during the quarter. The remaining wells will be brought on production in Q3 2021.

In the United States business unit, we moved one of our experienced drilling crews from our Canadian program to Wyoming and commenced our four (4.0 net) well drilling program, centered on Turner horizontal wells in the Powder River basin. Two of the wells were completed and brought on production in the quarter. The remaining two wells are expected to be completed and brought on production in Q3 2021.

## Sales

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Canada	206,848	41.62	100,135	17.41	402,656	41.57	255,098	22.84
United States	17,761	52.24	15,874	26.00	42,087	57.38	31,702	30.58
<b>North America</b>	<b>224,609</b>	<b>42.30</b>	<b>116,009</b>	<b>18.24</b>	<b>444,743</b>	<b>42.68</b>	<b>286,800</b>	<b>23.50</b>

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

## Royalties

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Canada	(27,001)	(5.43)	(6,777)	(1.18)	(48,775)	(5.04)	(23,462)	(2.10)
United States	(4,754)	(13.98)	(3,836)	(6.28)	(11,060)	(15.08)	(7,852)	(7.57)
<b>North America</b>	<b>(31,755)</b>	<b>(5.98)</b>	<b>(10,613)</b>	<b>(1.67)</b>	<b>(59,835)</b>	<b>(5.74)</b>	<b>(31,314)</b>	<b>(2.57)</b>



Royalties in North America increased on a dollar and per unit basis for the three and six months ended June 30, 2021 versus the comparable prior periods primarily due to higher benchmark prices. Royalties as a percentage of sales for the three and six months ended June 30, 2021 of 14.1% and 13.5% increased versus comparable periods in the prior year primarily due to the effect of higher commodity prices on sliding scale royalties.

## Transportation

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Canada	(9,868)	(1.99)	(10,465)	(1.82)	(20,104)	(2.08)	(21,603)	(1.93)
United States	(216)	(0.64)	(469)	(0.77)	(464)	(0.63)	(469)	(0.45)
<b>North America</b>	<b>(10,084)</b>	<b>(1.90)</b>	<b>(10,934)</b>	<b>(1.72)</b>	<b>(20,568)</b>	<b>(1.97)</b>	<b>(22,072)</b>	<b>(1.81)</b>

Transportation expense in North America decreased versus the comparable prior periods primarily due to lower volumes shipped through pipelines, partially offset by increased pipeline tariffs. For the six months ended June 30, 2021, transportation expense in the United States increased on a per unit basis primarily due more volume being shipped via pipeline.

## Operating expense

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Canada	(54,441)	(10.95)	(57,281)	(9.96)	(107,607)	(11.11)	(121,466)	(10.88)
United States	(3,389)	(9.97)	(3,765)	(6.17)	(7,504)	(10.23)	(9,314)	(8.98)
<b>North America</b>	<b>(57,830)</b>	<b>(10.89)</b>	<b>(61,046)</b>	<b>(9.60)</b>	<b>(115,111)</b>	<b>(11.05)</b>	<b>(130,780)</b>	<b>(10.72)</b>

Operating expenses in North America decreased on a dollar basis for the three and six months ended June 30, 2021 primarily due to cost reduction initiatives combined with lower production volumes. On a per unit basis, operating expenses increased for the three months ended June 30, 2021 primarily due to lower production volumes and the resulting impact of fixed costs.

## International

	Q2 2021	Q2 2020	YTD 2021	YTD 2020
<b>Production <sup>(1)</sup></b>				
Crude oil and condensate (bbls/d)	14,037	13,471	14,298	14,232
Natural gas (mmcf/d)	83.66	101.99	86.62	104.81
Total production volume (boe/d)	27,981	30,472	28,734	31,701
Total sales volume (boe/d)	27,802	29,201	27,084	32,114

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

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Sales	182,570	72.16	77,004	28.98	330,573	67.43	234,527	40.13
Royalties	(9,701)	(3.83)	(5,739)	(2.16)	(18,067)	(3.69)	(16,163)	(2.77)
Transportation	(11,750)	(4.64)	(5,431)	(2.04)	(18,287)	(3.73)	(11,623)	(1.99)
Operating	(41,907)	(16.56)	(38,129)	(14.35)	(80,867)	(16.50)	(89,533)	(15.32)
General and administration	(6,607)	(2.61)	(7,238)	(2.72)	(11,489)	(2.34)	(15,617)	(2.67)
Corporate income tax recovery (expense)	(492)	(0.19)	(55)	(0.02)	1,067	0.22	(397)	(0.07)
PRRT	(1,459)	(0.58)	(3,219)	(1.21)	(2,873)	(0.59)	(12,475)	(2.13)
Fund flows from operations	110,654	43.74	17,193	6.47	200,057	40.81	88,719	15.18
Capital expenditures	(40,329)		(18,295)		(64,579)		(54,073)	
Free cash flow	70,325		(1,102)		135,478		34,646	

Production from our International assets averaged 27,981 boe/d in Q2 2021, representing a decrease of 8% year-over-year primarily due to natural decline and reduced capital activity.

In Europe, during the second quarter, we drilled one (1.0 net) natural gas well in the Netherlands from the Rotliegend Slochteren formation. The well was completed in June 2021 and we expect to bring production on in Q3 2021. Subsequent to Q2 2021, we began inline testing of the Rotliegend formation on the Blesdijke natural gas well (0.5 net) drilled in Q1 2021 and achieved initial rates up to 7.0 mmcf/d. We plan on conducting further testing in Q3 2021 and expect to bring the well onstream later in the year.

## Sales

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Australia	31,256	97.49	28,772	61.91	58,638	96.07	80,767	80.55
France	68,108	81.80	23,329	43.94	119,637	79.75	80,118	54.85
Netherlands	32,555	56.23	10,654	14.69	61,106	50.52	30,257	20.63
Germany	20,274	60.36	6,553	21.33	33,369	55.73	17,022	27.95
Ireland	30,188	65.93	7,268	12.43	57,256	59.03	24,856	20.50
Central and Eastern Europe	189	45.15	428	9.74	567	41.77	1,507	16.11
<b>International</b>	<b>182,570</b>	<b>72.16</b>	<b>77,004</b>	<b>49.42</b>	<b>330,573</b>	<b>67.43</b>	<b>234,527</b>	<b>40.13</b>

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

Crude oil sales volumes (bbls/d)	Q2 2021	Q2 2020	YTD 2021	YTD 2020
Australia	3,523	5,107	3,372	5,509
France	9,149	5,835	8,288	8,026
Germany	1,091	1,172	890	1,023
<b>International</b>	<b>13,763</b>	<b>12,114</b>	<b>12,550</b>	<b>14,558</b>

Sales increased on a dollar and per boe basis for the three and six months ended June 30, 2021 versus the prior year comparable periods primarily due to higher realized prices across most business units driven by higher commodity prices over the same periods. This higher pricing was partially offset by lower sales volumes in the Netherlands, Ireland and Central Eastern Europe driven by natural decline and downtime in Australia due to a shutdown, and the timing of liftings in France and Australia.

## Royalties

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
France	(9,167)	(11.01)	(4,711)	(8.87)	(16,403)	(10.93)	(13,751)	(9.41)
Netherlands	(128)	(0.22)	(55)	(0.08)	(225)	(0.19)	(198)	(0.14)
Germany	(367)	(1.09)	(795)	(2.59)	(1,322)	(2.21)	(1,737)	(2.85)
Central and Eastern Europe	(39)	(9.32)	(178)	(4.05)	(117)	(8.62)	(477)	(5.10)
<b>International</b>	<b>(9,701)</b>	<b>(3.83)</b>	<b>(5,739)</b>	<b>(3.27)</b>	<b>(18,067)</b>	<b>(3.69)</b>	<b>(16,163)</b>	<b>(2.77)</b>

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

Royalties increased in our International core region for the three and six months ended June 30, 2021 versus the prior year comparable periods mainly due to higher production and sales in France. Royalties as a percentage of sales for the three and six months ended June 30, 2021 of 5.3% and 5.5% decreased versus the prior year comparable periods of 7.5% and 6.9%. This is primarily due to the impact of RCDM royalties in France, which are levied on units of production and not subject to changes in commodity prices.

## Transportation

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
France	(9,118)	(10.95)	(2,747)	(5.17)	(13,523)	(9.01)	(6,472)	(4.43)
Germany	(1,554)	(4.63)	(1,505)	(4.90)	(2,575)	(4.30)	(2,827)	(4.64)
Ireland	(1,078)	(2.35)	(1,179)	(2.02)	(2,189)	(2.26)	(2,324)	(1.92)
<b>International</b>	<b>(11,750)</b>	<b>(4.64)</b>	<b>(5,431)</b>	<b>(1.94)</b>	<b>(18,287)</b>	<b>(3.73)</b>	<b>(11,623)</b>	<b>(1.99)</b>

Transportation expense increased for the three and six months ended June 30, 2021 versus the comparable prior year periods. This increase was primarily in France relating to higher volumes in 2021 and the use of incremental trucking in the Paris Basin following the conversion of the Grandpuits refinery.

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

## Operating expense

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Australia	(10,408)	(32.46)	(10,659)	(22.93)	(20,146)	(33.01)	(28,032)	(27.96)
France	(12,591)	(15.12)	(10,016)	(18.86)	(24,382)	(16.25)	(25,915)	(17.74)
Netherlands	(7,895)	(13.64)	(7,526)	(10.37)	(15,306)	(12.66)	(16,441)	(11.21)
Germany	(6,807)	(20.27)	(5,912)	(19.24)	(13,109)	(21.89)	(10,827)	(17.78)
Ireland	(4,157)	(9.08)	(3,852)	(6.59)	(7,814)	(8.06)	(8,064)	(6.65)
Central and Eastern Europe	(49)	(11.71)	(164)	(3.73)	(110)	(8.10)	(254)	(2.72)
<b>International</b>	<b>(41,907)</b>	<b>(16.56)</b>	<b>(38,129)</b>	<b>(14.35)</b>	<b>(80,867)</b>	<b>(16.50)</b>	<b>(89,533)</b>	<b>(15.32)</b>

Operating expenses on a dollar and per boe basis increased for Q2 2021 versus Q2 2020. This increase primarily resulted from higher inventory draws in France where operating expenses are deferred on the balance sheet until crude oil is sold at which point the related expenses are recognized into income.

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

# Consolidated Financial Performance Review

## Fund flows from operations

	Q2 2021		Q2 2020		YTD 2021		YTD 2020	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Sales	407,179	51.93	193,013	21.40	775,316	50.60	521,327	28.88
Royalties	(41,456)	(5.29)	(16,352)	(1.81)	(77,902)	(5.08)	(47,477)	(2.63)
Transportation	(21,834)	(2.78)	(16,365)	(1.81)	(38,855)	(2.54)	(33,695)	(1.87)
Operating	(99,737)	(12.72)	(99,175)	(11.00)	(195,978)	(12.79)	(220,313)	(12.21)
General and administration	(11,432)	(1.46)	(16,912)	(1.88)	(23,162)	(1.51)	(30,229)	(1.67)
Corporate income tax recovery (expense)	(691)	(0.09)	(158)	(0.02)	654	0.04	(732)	(0.04)
PRRT	(1,459)	(0.19)	(3,219)	(0.36)	(2,873)	(0.19)	(12,475)	(0.69)
Interest expense	(18,862)	(2.41)	(17,887)	(1.98)	(38,097)	(2.49)	(37,869)	(2.10)
Realized (loss) gain on derivatives	(39,574)	(5.05)	54,704	6.07	(65,207)	(4.26)	104,123	5.77
Realized foreign exchange (loss) gain	(1,958)	(0.25)	3,972	0.44	(7,139)	(0.47)	12,495	0.69
Realized other income (expense)	2,766	0.35	231	0.03	8,236	0.54	(3,078)	(0.17)
<b>Fund flows from operations</b>	<b>172,942</b>	<b>22.04</b>	<b>81,852</b>	<b>9.08</b>	<b>334,993</b>	<b>21.85</b>	<b>252,077</b>	<b>13.96</b>

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 decreased for the three and six months ended June 30, 2021 versus the comparable prior year periods primarily due to work-force reductions made in 2020.

### PRRT and corporate income taxes

- PRRT decreased for the three months ended June 30, 2021 versus the prior year comparable periods due to higher sales in Australia which were offset by increased capital expenditures, and the six months ended June 30, 2021 versus the prior year comparable periods due to lower sales in Australia.
- Corporate income taxes for the three and six months ended June 30, 2021 versus the prior year comparable periods remained relatively consistent.

### Interest expense

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

### Realized gain or loss on derivatives

- Realized gains on derivatives in 2020 relate to receipts for European natural gas and crude oil hedges. For the three and six months ended June 30, 2021, we recorded realized losses on our crude oil and natural gas prices due to higher commodity pricing compared to the strike prices on our hedges.
- A listing of derivative positions as at June 30, 2021 is included in "Supplemental Table 2" of this MD&A.

### Realized other income

- Realized other income for the three and six months ended June 30, 2021 primarily relates to amounts for funding under the Saskatchewan Accelerated Site Closure program to complete abandonment and reclamation on inactive oil and gas wells and facilities. Realized other expense for the prior year comparable period relates primarily to amounts uncertain to be received pursuant to a negotiated settlement of a legal matter.



## Net earnings

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

(\$M)	Q2 2021	Q2 2020	YTD 2021	YTD 2020
Fund flows from operations	172,942	81,852	334,993	252,077
Equity based compensation	(10,536)	(9,164)	(27,076)	(22,161)
Unrealized (loss) gain on derivative instruments	(79,408)	(3,771)	(73,966)	5,545
Unrealized foreign exchange loss	(18,298)	(7,410)	(44,208)	(17,392)
Accretion	(10,863)	(7,288)	(21,370)	(17,026)
Depletion and depreciation	(149,651)	(106,707)	(255,664)	(264,514)
Deferred tax (expense) recovery	(63,526)	51,126	(234,754)	308,668
Gain on business combinations	17,198	—	17,198	—
Impairment reversal (expense)	593,606	(69,713)	1,256,472	(1,634,567)
Unrealized other expense	(190)	(215)	(387)	(424)
<b>Net earnings (loss)</b>	<b>451,274</b>	<b>(71,290)</b>	<b>951,238</b>	<b>(1,389,794)</b>

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

### *Equity based compensation*

Equity based compensation expense relates primarily to non-cash compensation expense attributable to long-term incentives granted to directors, officers, and employees under security-based arrangements. Equity based compensation expense increased for the three and six months ended June 30, 2021 versus the prior year comparable periods due to the higher value of VIP awards outstanding in the current periods.

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

Unrealized gain or loss on derivative instruments arise as a result of changes in forecasts for future prices and rates. As Vermilion uses derivative instruments to manage the commodity price exposure of our future crude oil and natural gas production, we will normally recognize unrealized gains on derivative instruments when future commodity price forecasts decline and vice-versa. As derivative instruments are settled, the unrealized gain or loss previously recognized is reversed, and the settlement results in a realized gain or loss on derivative instruments.

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

For the three months ended June 30, 2021, we recognized a net unrealized loss on derivative instruments of \$79.4 million. This consists of unrealized losses of \$111.8 million on our European natural gas commodity derivative instruments and \$6.4 million on our North American natural gas commodity derivative instruments. These unrealized losses are partially offset by unrealized gains of \$22.8 million on our USD-to-CAD foreign exchange swaps, \$9.5 million on our crude oil commodity derivative instruments and \$6.5 million on our equity swaps.

For the six months ended June 30, 2021, we recognized a net unrealized loss on derivative instruments of \$74.0 million. This consists of unrealized losses of \$124.9 million on our European natural gas commodity derivative instruments, \$10.3 million on our North American natural gas commodity derivative instruments and \$1.0 million on our crude oil commodity derivative instruments. These unrealized losses are partially offset by unrealized gains of \$42.8 million on our USD-to-CAD foreign exchange swaps and \$19.4 million on our equity swaps.

### *Unrealized foreign exchange gains or losses*

As a result of Vermilion's international operations, Vermilion has monetary assets and liabilities denominated in currencies other than the Canadian dollar. These monetary assets and liabilities include cash, receivables, payables, long-term debt, derivative instruments and intercompany loans. Unrealized foreign exchange gains and losses result from translating these monetary assets and liabilities from their underlying currency to the Canadian dollar.

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

- The translation of Euro denominated intercompany loans from Vermilion Energy Inc. to our international subsidiaries. An appreciation in the Euro against the Canadian dollar will result in an unrealized foreign exchange gain (and vice-versa). Under IFRS, the offsetting foreign exchange loss or gain is recorded as a currency translation adjustment within other comprehensive income. As a result, consolidated

comprehensive income reflects the offsetting of these translation adjustments while net earnings reflects only the parent company's side of the translation.

- The translation of USD borrowings on our revolving credit facility. The unrealized foreign exchange gains or losses on these borrowings are offset by unrealized derivative gains or losses on associated USD-to-CAD cross currency interest rate swaps (discussed further below).
- The translation of our USD denominated senior unsecured notes prior to June 12, 2019 and from May 5, 2020 onward. During the period between June 12, 2019 and May 5, 2020 the USD senior notes were hedged by a USD-to-CAD cross currency interest rate swap. Subsequent to the termination of these instruments, amounts previously recognized in the hedge accounting reserve will be recognized into earnings through unrealized foreign exchange loss over the period of the hedged cash flows.

For the three months ended June 30, 2021, we recognized a net unrealized foreign exchange loss of \$18.3 million due to unrealized losses of \$16.8 million on intercompany loans due to the Euro weakening 1.0% against the Canadian dollar in Q2 2021 and \$10.0 million on our USD borrowings from our revolving credit facility. These were partially offset by the impact of the US dollar weakening 2.3% against the Canadian dollar in Q2 2021 resulting in an unrealized gain of \$8.5 million on our senior unsecured notes.

For the six months ended June 30, 2021, we recognized a net unrealized foreign exchange loss of \$44.2 million. This was due to unrealized losses of \$33.0 million on our USD borrowings from our revolving credit facility and \$24.3 million on intercompany loans due to the Euro weakening 5.9% against the Canadian dollar. These were partially offset by the impact of the US dollar weakening 3.4% against the Canadian dollar resulting in an unrealized gain of \$13.1 million on our senior unsecured notes.

As at June 30, 2021, a \$0.01 appreciation of the Euro against the Canadian dollar would result in a \$0.7 million increase to net earnings as a result of an unrealized gain on foreign exchange. In contrast, a \$0.01 appreciation of the US dollar against the Canadian dollar would result in a \$3.0 million decrease to net earnings as a result of an unrealized loss on foreign exchange.

### *Accretion*

Accretion expense is recognized to update the present value of the asset retirement obligation balance. For the three and six months ended June 30, 2021 versus the comparable prior year periods accretion expense increased primarily due to additional obligations recognized at the end of 2020 partially offset by the weakening of the Euro against the Canadian dollar.

### *Depletion and depreciation*

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

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

Depletion and depreciation on a per boe basis for the three and six months ended June 30, 2021 of \$19.09 and \$16.69 increased from \$11.83 and \$14.65 in the prior year comparable periods primarily due to impairment reversals recorded in Q1 2021.

### *Deferred tax*

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

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

For the three and six months ended June 30, 2021, deferred tax expense was recognized of \$63.5 million and \$234.8 million respectively compared to a deferred tax recovery of \$51.1 million and \$308.7 million for the prior year comparable periods primarily due to impairment reversals in 2021, partially offset by the recognition of a portion of non-expiring tax loss pools in Ireland that are expected to be utilized due to an increase in forecast commodity prices.

### *Impairment*

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

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

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

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

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

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

### *Gain on business combinations*

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

# Financial Position Review

## Balance sheet strategy

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

As at June 30, 2021, we have a ratio of net debt to fund flows from operations of 3.43. We will continue to monitor for changes in forecasted fund flows from operations and, as appropriate, will adjust our exploration and development capital plans (and associated growth targets) to minimize any further increase to debt. As commodity prices improve, we intend to strengthen our balance sheet through the reduction of debt.

## Net debt

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

(\$M)	As at	
	Jun 30, 2021	Dec 31, 2020
Long-term debt	1,769,866	1,933,848
Current liabilities	528,180	433,128
Current assets	(292,774)	(260,993)
<b>Net debt</b>	<b>2,005,272</b>	<b>2,105,983</b>
<b>Ratio of net debt to four quarter trailing fund flows from operations</b>	<b>3.43</b>	<b>4.19</b>

As at June 30, 2021, net debt decreased to \$2.0 billion (December 31, 2020 - \$2.1 billion) primarily as a result of free cash flow generated for the six months ended June 30, 2021 of \$172.5 million, partially offset by timing of payments and increased current derivative liabilities due to increased commodity prices. We will draw on unutilized capacity of the revolving credit facility to fund working capital deficiencies. The ratio of net debt to four quarter trailing fund flows from operations decreased to 3.43 (December 31, 2020 - 4.19) mainly due to the decrease in net debt combined with higher four quarter trailing fund flows from operations.

## Long-term debt

The balances recognized on our balance sheet are as follows:

(\$M)	As at	
	Jun 30, 2021	Dec 31, 2020
Revolving credit facility	1,403,877	1,555,215
Senior unsecured notes	365,989	378,633
<b>Long-term debt</b>	<b>1,769,866</b>	<b>1,933,848</b>

## Revolving Credit Facility

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

(\$M)	As at	
	Jun 30, 2021	Dec 31, 2020
Total facility amount	2,100,000	2,100,000
Amount drawn	(1,403,877)	(1,555,215)
Letters of credit outstanding	(15,489)	(23,210)
<b>Unutilized capacity</b>	<b>680,634</b>	<b>521,575</b>

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

Financial covenant	Limit	As at	
		Jun 30, 2021	Dec 31, 2020
Consolidated total debt to consolidated EBITDA	Less than 4.0	2.76	3.48
Consolidated total senior debt to consolidated EBITDA	Less than 3.5	2.19	2.82
Consolidated EBITDA to consolidated interest expense	Greater than 2.5	9.09	8.12

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

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

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

### *Senior Unsecured Notes*

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

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

Vermilion may redeem some or all of the senior unsecured notes at the redemption prices set forth in the following table plus any accrued and unpaid interest, if redeemed during the twelve-month period beginning on March 15 of each of the years indicated below:

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



## Shareholders' capital

The following table outlines our dividend payment history:

Date	Monthly dividend per unit or share
January 2003 to December 2007	\$0.170
January 2008 to December 2012	\$0.190
January 2013 to December 2013	\$0.200
January 2014 to March 2018	\$0.215
April 2018 to February 2020	\$0.230
March 2020	\$0.115

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

The following table reconciles the change in shareholders' capital:

Shareholders' Capital	Number of Shares ('000s)	Amount (\$M)
<b>Balance at December 31, 2020</b>	<b>158,724</b>	<b>4,181,160</b>
Vesting of equity based awards	2,113	44,852
Equity based compensation	838	7,693
Share-settled dividends on vested equity based awards	218	1,920
<b>Balance at June 30, 2021</b>	<b>161,893</b>	<b>4,235,625</b>

As at June 30, 2021, there were approximately 7.1 million equity based compensation awards outstanding. As at August 13, 2021, there were approximately 162.0 million common shares issued and outstanding.

## Asset Retirement Obligations

As at June 30, 2021, asset retirement obligations were \$809.2 million compared to \$467.7 million as at December 31, 2020. The increase in asset retirement obligations is primarily attributable to a decrease in the credit-adjusted risk-free rate from December 31, 2020 to June 30, 2021. This increase was partially offset by the Euro weakening against the Canadian dollar and obligations settled.

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

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

	Jun 30, 2021	Dec 31, 2020	Change
Credit spread added to below noted risk-free rates	4.7 %	9.5 %	(4.8)%
Country specific risk-free rate			
Canada	1.9 %	1.2 %	0.7 %
United States	2.1 %	1.6 %	0.5 %
France	0.8 %	0.3 %	0.5 %
Netherlands	(0.3)%	(0.6)%	0.3 %
Germany	0.3 %	(0.2)%	0.5 %
Ireland	0.5 %	(0.1)%	0.6 %
Australia	1.8 %	1.3 %	0.5 %

## 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, 2020 available on SEDAR at [www.sedar.com](http://www.sedar.com) or on Vermilion's website at [www.vermilionenergy.com](http://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 six months ended June 30, 2021. Further information, including a discussion of critical accounting estimates, can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2020, available on SEDAR at [www.sedar.com](http://www.sedar.com) or on Vermilion's website at [www.vermilionenergy.com](http://www.vermilionenergy.com).

## Off Balance Sheet Arrangements

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

## Internal Control Over Financial Reporting

Other than Vermilion's response to COVID-19, there has been no change in Vermilion's internal control over financial reporting ("ICFR") during the period covered by this MD&A that materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

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

## Recently Adopted Accounting Pronouncements

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

## Disclosure Controls and Procedures

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

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

## Supplemental Table 1: Netbacks

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

	Q2 2021			YTD 2021			Q2 2020	YTD 2020
	Liquids \$/bbl	Natural Gas \$/mcf	Total \$/boe	Liquids \$/bbl	Natural Gas \$/mcf	Total \$/boe	Total \$/boe	Total \$/boe
<b>Canada</b>								
Sales	62.13	2.71	41.62	59.63	3.15	41.57	17.41	22.84
Royalties	(9.17)	(0.14)	(5.43)	(8.27)	(0.16)	(5.04)	(1.18)	(2.10)
Transportation	(2.61)	(0.20)	(1.99)	(2.73)	(0.21)	(2.08)	(1.82)	(1.93)
Operating	(13.28)	(1.35)	(10.95)	(13.58)	(1.34)	(11.11)	(9.96)	(10.88)
Operating netback	37.07	1.02	23.25	35.05	1.44	23.34	4.45	7.93
General and administration			(1.20)			(1.07)	(1.51)	(1.03)
Fund flows from operations netback			22.05			22.27	2.94	6.90
<b>United States</b>								
Sales	63.65	2.87	52.24	60.95	7.63	57.38	26.00	30.58
Royalties	(16.55)	(1.02)	(13.98)	(15.72)	(2.16)	(15.08)	(6.28)	(7.57)
Transportation	(0.84)	—	(0.64)	(0.83)	—	(0.63)	(0.77)	(0.45)
Operating	(10.02)	(1.64)	(9.97)	(10.31)	(1.66)	(10.23)	(6.17)	(8.98)
Operating netback	36.24	0.21	27.65	34.09	3.81	31.44	12.78	13.58
General and administration			(2.13)			(2.21)	(2.94)	(3.63)
Fund flows from operations netback			25.52			29.23	9.84	9.95
<b>France</b>								
Sales	81.80	—	81.80	79.75	—	79.75	43.94	54.85
Royalties	(11.01)	—	(11.01)	(10.93)	—	(10.93)	(8.87)	(9.41)
Transportation	(10.95)	—	(10.95)	(9.01)	—	(9.01)	(5.17)	(4.43)
Operating	(15.12)	—	(15.12)	(16.25)	—	(16.25)	(18.86)	(17.74)
Operating netback	44.72	—	44.72	43.56	—	43.56	11.04	23.27
General and administration			(3.86)			(3.75)	(6.59)	(4.76)
Current income taxes			—			—	—	—
Fund flows from operations netback			40.86			39.81	4.45	18.51
<b>Netherlands</b>								
Sales	67.76	9.34	56.23	52.53	8.42	50.52	14.69	20.63
Royalties	—	(0.04)	(0.22)	—	(0.03)	(0.19)	(0.08)	(0.14)
Operating	—	(2.31)	(13.64)	—	(2.14)	(12.66)	(10.37)	(11.21)
Operating netback	67.76	6.99	42.37	52.53	6.25	37.67	4.24	9.28
General and administration			(0.19)			(0.31)	(0.29)	(0.52)
Current income taxes			(4.08)			(1.95)	0.35	0.18
Fund flows from operations netback			38.10			35.41	4.30	8.94
<b>Germany</b>								
Sales	78.00	8.83	60.36	75.58	8.07	55.73	21.33	27.95
Royalties	(1.24)	(0.17)	(1.09)	(0.95)	(0.45)	(2.21)	(2.59)	(2.85)
Transportation	(10.82)	(0.34)	(4.63)	(9.68)	(0.39)	(4.30)	(4.90)	(4.64)
Operating	(23.71)	(3.14)	(20.27)	(23.60)	(3.54)	(21.89)	(19.24)	(17.78)
Operating netback	42.23	5.18	34.37	41.35	3.69	27.33	(5.40)	2.68
General and administration			(4.34)			(4.31)	(4.28)	(5.02)
Fund flows from operations netback			30.03			23.02	(9.68)	(2.34)
<b>Ireland</b>								
Sales	—	10.98	65.93	—	9.83	59.03	12.43	20.50
Transportation	—	(0.39)	(2.35)	—	(0.38)	(2.26)	(2.02)	(1.92)
Operating	—	(1.51)	(9.08)	—	(1.34)	(8.06)	(6.59)	(6.65)
Operating netback	—	9.08	54.50	—	8.11	48.71	3.82	11.93
General and administration			(0.05)			0.71	0.18	(0.23)
Fund flows from operations netback			54.45			49.42	4.00	11.70

	Liquids \$/bbl	Q2 2021 Natural Gas \$/mcf	Total \$/boe	Liquids \$/bbl	YTD 2021 Natural Gas \$/mcf	Total \$/boe	Q2 2020 Total \$/boe	YTD 2020 Total \$/boe
<b>Australia</b>								
Sales	97.49	—	97.49	96.07	—	96.07	61.91	80.55
Operating	(32.46)	—	(32.46)	(33.01)	—	(33.01)	(22.93)	(27.96)
PRRT <sup>(1)</sup>	(4.55)	—	(4.55)	(4.71)	—	(4.71)	(6.93)	(12.44)
Operating netback	60.48	—	60.48	58.35	—	58.35	32.05	40.15
General and administration			(2.35)			(2.42)	(1.91)	(1.76)
Current income taxes			5.84			5.62	(0.67)	(0.65)
Fund flows from operations netback			63.97			61.55	29.47	37.74

<b>Total Company</b>								
Sales	69.11	5.24	51.93	66.38	5.37	50.60	21.40	28.88
Realized hedging (loss) gain	(4.67)	(0.92)	(5.05)	(4.67)	(0.63)	(4.26)	6.07	5.77
Royalties	(9.08)	(0.13)	(5.29)	(8.49)	(0.19)	(5.08)	(1.81)	(2.63)
Transportation	(4.12)	(0.20)	(2.78)	(3.67)	(0.20)	(2.54)	(1.81)	(1.87)
Operating	(15.10)	(1.65)	(12.72)	(15.45)	(1.62)	(12.79)	(11.00)	(12.21)
PRRT <sup>(1)</sup>	(0.34)	—	(0.19)	(0.35)	—	(0.19)	(0.36)	(0.69)
Operating netback	35.80	2.34	25.90	33.75	2.73	25.74	12.49	17.25
General and administration			(1.46)			(1.51)	(1.88)	(1.67)
Interest expense			(2.41)			(2.49)	(1.98)	(2.10)
Realized foreign exchange loss			(0.25)			(0.47)	0.44	0.69
Other income			0.35			0.54	0.03	(0.17)
Corporate income taxes			(0.09)			0.04	(0.02)	(0.04)
Fund flows from operations netback			22.04			21.85	9.08	13.96

<sup>(1)</sup> 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 June 30, 2021:

	Unit	Currency	Daily Bought Put Volume	Weighted Average Bought Put Price	Daily Sold Call Volume	Weighted Average Sold Call Price	Daily Sold Put Volume	Weighted Average Sold Put Price	Daily Sold Swap Volume	Weighted Average Sold Swap Price	Daily Bought Swap Volume	Weighted Average Bought Swap Price
<b>Dated Brent</b>												
Q3 2021	bbl	USD	500	55.00	500	63.25	500	47.50	500	52.00	—	—
Q4 2021	bbl	USD	—	—	—	—	—	—	500	52.00	—	—
Q1 2022	bbl	USD	—	—	—	—	—	—	500	52.00	—	—
<b>WTI</b>												
Q3 2021	bbl	USD	1,500	57.50	1,500	73.67	1,500	48.33	—	—	—	—
Q4 2021	bbl	USD	1,000	60.00	1,000	80.50	1,000	50.00	—	—	—	—
Q1 2022	bbl	USD	500	60.00	500	70.00	500	45.00	—	—	—	—
Q2 2022	bbl	USD	500	60.00	500	70.00	500	45.00	—	—	—	—
<b>AECO</b>												
Q3 2021	mcf	CAD	—	—	—	—	—	—	9,478	2.12	—	—
Q4 2021	mcf	CAD	—	—	—	—	—	—	3,194	2.12	—	—
<b>AECO Basis (AECO less NYMEX Henry Hub)</b>												
Q3 2021	mcf	USD	—	—	—	—	—	—	45,000	(1.08)	—	—
Q4 2021	mcf	USD	—	—	—	—	—	—	35,054	(1.09)	—	—
Q1 2022	mcf	USD	—	—	—	—	—	—	30,000	(1.10)	—	—
Q2 2022	mcf	USD	—	—	—	—	—	—	35,000	(1.09)	—	—
Q3 2022	mcf	USD	—	—	—	—	—	—	35,000	(1.09)	—	—
Q4 2022	mcf	USD	—	—	—	—	—	—	11,793	(1.09)	—	—
<b>NYMEX Henry Hub</b>												
Q3 2021	mcf	USD	35,000	2.72	35,000	3.12	—	—	28,500	2.83	—	—
Q4 2021	mcf	USD	31,685	2.72	31,685	3.12	—	—	21,870	2.78	—	—
<b>Ventura Basis (Ventura less NYMEX Henry Hub)</b>												
Q3 2021	mcf	USD	—	—	—	—	—	—	—	—	10,000	0.05
Q4 2021	mcf	USD	—	—	—	—	—	—	—	—	3,370	0.05
<b>Conway Propane</b>												
Q3 2021	bbl	USD	—	—	—	—	—	—	500	50% WTI	—	—
Q4 2021	bbl	USD	—	—	—	—	—	—	168	50% WTI	—	—

	Unit	Currency	Daily Bought Put Volume	Weighted Average Bought Put Price	Daily Sold Call Volume	Weighted Average Sold Call Price	Daily Sold Put Volume	Weighted Average Sold Put Price	Daily Sold Swap Volume	Weighted Average Sold Swap Price	Daily Bought Swap Volume	Weighted Average Bought Swap Price
<b>NBP</b>												
Q3 2021	mcf	EUR	49,135	5.37	49,135	5.62	49,135	3.87	2,457	4.69	—	—
Q4 2021	mcf	EUR	58,962	5.37	58,962	5.56	58,962	3.88	2,457	4.69	—	—
Q1 2022	mcf	EUR	34,394	5.18	34,394	5.95	34,394	3.63	4,913	4.91	—	—
Q2 2022	mcf	EUR	27,024	5.07	27,024	5.73	27,024	3.50	4,913	4.91	—	—
Q3 2022	mcf	EUR	17,197	5.00	17,197	5.79	17,197	3.56	4,913	4.91	—	—
Q4 2022	mcf	EUR	17,197	5.00	17,197	5.78	17,197	3.56	4,913	4.91	—	—
Q1 2023	mcf	EUR	9,827	5.02	9,827	5.72	9,827	3.59	—	—	—	—
Q2 2023	mcf	EUR	2,457	5.86	2,457	7.62	2,457	4.40	—	—	—	—
<b>TTF</b>												
Q3 2021	mcf	EUR	2,457	4.25	2,457	4.07	2,457	2.93	—	—	—	—
Q1 2022	mcf	EUR	2,457	4.84	2,457	5.64	2,457	3.52	—	—	—	—
Q2 2022	mcf	EUR	2,457	4.84	2,457	5.64	2,457	3.52	—	—	—	—
Q3 2022	mcf	EUR	2,457	4.84	2,457	5.64	2,457	3.52	—	—	—	—
Q4 2022	mcf	EUR	2,457	4.84	2,457	5.64	2,457	3.52	—	—	—	—
Q1 2023	mcf	EUR	2,457	4.84	2,457	5.64	2,457	3.52	—	—	—	—

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

<b>Foreign Currency Swaps</b>			<b>Notional Amount</b>		<b>Notional Amount</b>		<b>Average Rate</b>
Swap	July 2021		1,131,404,500	USD	1,400,000,000	CAD	1.2374

## Supplemental Table 3: Capital Expenditures and Acquisitions

By classification (\$M)	Q2 2021	Q2 2020	YTD 2021	YTD 2020
Drilling and development	77,703	42,383	157,215	269,816
Exploration and evaluation	1,473	(109)	5,324	6,162
<b>Capital expenditures</b>	<b>79,176</b>	<b>42,274</b>	<b>162,539</b>	<b>275,978</b>
Acquisitions	12,196	2,932	12,589	14,269
Contingent consideration	330	—	330	—
Long-term debt net of working capital assumed	(7)	—	(7)	—
<b>Acquisitions</b>	<b>11,859</b>	<b>2,932</b>	<b>12,252</b>	<b>14,269</b>

By category (\$M)	Q2 2021	Q2 2020	YTD 2021	YTD 2020
Drilling, completion, new well equip and tie-in, workovers and recompletions	47,453	21,954	116,235	230,118
Production equipment and facilities	24,859	15,190	36,890	32,817
Seismic, studies, land and other	6,864	5,130	9,414	13,043
Capital expenditures	79,176	42,274	162,539	275,978
Acquisitions	11,859	2,932	12,252	14,269
<b>Total capital expenditures and acquisitions</b>	<b>91,035</b>	<b>45,206</b>	<b>174,791</b>	<b>290,247</b>

Capital expenditures by country (\$M)	Q2 2021	Q2 2020	YTD 2021	YTD 2020
Canada	20,210	9,785	74,531	162,362
United States	18,637	14,194	23,429	59,543
France	8,913	5,603	15,792	16,860
Netherlands	7,683	2,638	11,816	5,135
Germany	3,607	3,345	6,106	11,134
Ireland	172	704	238	684
Australia	13,118	4,200	19,957	16,202
Central and Eastern Europe	6,836	1,805	10,670	4,058
<b>Total capital expenditures</b>	<b>79,176</b>	<b>42,274</b>	<b>162,539</b>	<b>275,978</b>

Acquisitions by country (\$M)	Q2 2021	Q2 2020	YTD 2021	YTD 2020
Canada	308	260	358	5,699
United States	—	749	—	6,607
France	—	—	—	—
Netherlands	—	—	—	—
Germany	11,551	564	11,894	583
Ireland	—	—	—	—
Australia	—	—	—	—
Central and Eastern Europe	—	1,359	—	1,380
<b>Total acquisitions</b>	<b>11,859</b>	<b>2,932</b>	<b>12,252</b>	<b>14,269</b>



## Supplemental Table 4: Production

	Q2/21	Q1/21	Q4/20	Q3/20	Q2/20	Q1/20	Q4/19	Q3/19	Q2/19	Q1/19	Q4/18	Q3/18
<b>Canada</b>												
Light and medium crude oil (bbls/d)	16,868	17,767	19,301	19,847	22,545	22,767	23,259	23,610	23,973	25,067	25,640	24,602
Condensate <sup>(1)</sup> (bbls/d)	5,558	4,556	4,662	5,200	5,047	4,634	4,140	4,072	4,872	4,096	3,918	3,875
Other NGLs <sup>(1)</sup> (bbls/d)	7,767	7,016	7,334	8,350	8,248	6,943	7,005	6,632	7,352	6,968	6,816	6,126
NGLs (bbls/d)	13,325	11,572	11,996	13,550	13,295	11,577	11,145	10,704	12,224	11,064	10,734	10,001
Conventional natural gas (mmcf/d)	146.55	138.41	135.27	155.15	164.08	151.16	145.14	145.14	151.87	151.37	146.65	136.77
Total (boe/d)	54,618	52,407	53,840	59,256	63,187	59,537	58,593	58,504	61,507	61,360	60,814	57,397
<b>United States</b>												
Light and medium crude oil (bbls/d)	1,888	2,322	2,495	3,243	3,971	2,481	3,149	2,717	2,421	1,750	1,582	1,455
Condensate <sup>(1)</sup> (bbls/d)	2	—	1	6	6	6	12	4	63	(8)	23	6
Other NGLs <sup>(1)</sup> (bbls/d)	928	1,058	1,294	1,158	1,340	1,079	1,156	1,140	754	929	998	714
NGLs (bbls/d)	930	1,058	1,295	1,164	1,346	1,085	1,168	1,144	817	921	1,021	720
Conventional natural gas (mmcf/d)	5.51	5.95	6.87	7.94	8.35	6.72	8.20	6.38	7.06	5.89	5.65	4.82
Total (boe/d)	3,736	4,373	4,934	5,730	6,708	4,685	5,683	4,925	4,414	3,653	3,545	2,979
<b>France</b>												
Light and medium crude oil (bbls/d)	9,013	9,062	9,255	9,347	7,046	9,957	10,264	10,347	9,800	11,342	11,317	11,407
Conventional natural gas (mmcf/d)	—	—	—	—	—	—	—	—	—	0.77	0.82	—
Total (boe/d)	9,013	9,062	9,255	9,347	7,046	9,957	10,264	10,347	9,800	11,470	11,454	11,407
<b>Netherlands</b>												
Light and medium crude oil (bbls/d)	1	6	1	—	1	3	4	1	9	—	—	—
Condensate <sup>(1)</sup> (bbls/d)	95	92	99	83	86	84	86	81	91	93	112	84
NGLs (bbls/d)	95	92	99	83	86	84	86	81	91	93	112	84
Conventional natural gas (mmcf/d)	37.59	41.45	42.95	46.09	47.31	48.33	47.99	44.08	52.90	51.51	51.82	44.37
Total (boe/d)	6,362	7,006	7,257	7,764	7,972	8,143	8,088	7,429	8,917	8,677	8,749	7,479
<b>Germany</b>												
Light and medium crude oil (bbls/d)	1,093	911	960	964	1,039	909	800	845	1,047	978	913	1,019
Conventional natural gas (mmcf/d)	15.60	13.40	11.50	11.25	13.23	14.64	15.44	14.54	14.56	16.71	16.94	14.88
Total (boe/d)	3,694	3,144	2,876	2,839	3,244	3,349	3,373	3,269	3,474	3,763	3,736	3,498
<b>Ireland</b>												
Conventional natural gas (mmcf/d)	30.19	34.14	34.76	35.12	38.57	41.38	42.30	43.21	49.21	51.71	52.03	51.38
Total (boe/d)	5,031	5,690	5,793	5,853	6,428	6,896	7,049	7,202	8,201	8,619	8,672	8,563
<b>Australia</b>												
Light and medium crude oil (bbls/d)	3,835	4,489	3,781	4,549	5,299	4,041	4,548	5,564	6,689	5,862	4,174	4,704
Total (boe/d)	3,835	4,489	3,781	4,549	5,299	4,041	4,548	5,564	6,689	5,862	4,174	4,704
<b>Central and Eastern Europe</b>												
Conventional natural gas (mmcf/d)	0.28	0.63	0.67	0.80	2.89	3.27	1.66	—	—	—	2.86	1.17
Total (boe/d)	46	104	111	132	483	546	276	—	—	—	477	195
<b>Consolidated</b>												
Light and medium crude oil (bbls/d)	32,698	34,556	35,793	37,951	39,899	40,157	42,024	43,084	43,938	45,001	43,625	43,186
Condensate <sup>(1)</sup> (bbls/d)	5,656	4,648	4,762	5,289	5,142	4,724	4,237	4,158	5,026	4,181	4,053	3,965
Other NGLs <sup>(1)</sup> (bbls/d)	8,695	8,074	8,627	9,509	9,588	8,022	8,160	7,772	8,107	7,897	7,815	6,839
NGLs (bbls/d)	14,351	12,722	13,389	14,798	14,730	12,746	12,397	11,930	13,133	12,078	11,868	10,804
Conventional natural gas (mmcf/d)	235.72	233.98	232.00	256.34	274.42	265.51	260.72	253.36	275.60	277.96	276.77	253.38
Total (boe/d)	86,335	86,276	87,848	95,471	100,366	97,154	97,875	97,239	103,003	103,404	101,621	96,222

	YTD 2021	2020	2019	2018	2017	2016
<b>Canada</b>						
Light and medium crude oil (bbls/d)	17,315	21,106	23,971	17,400	6,015	6,657
Condensate <sup>(1)</sup> (bbls/d)	5,060	4,886	4,295	3,754	3,036	2,514
Other NGLs <sup>(1)</sup> (bbls/d)	7,393	7,719	6,988	5,914	4,144	2,552
NGLs (bbls/d)	12,453	12,605	11,283	9,668	7,180	5,066
Conventional natural gas (mmcf/d)	142.50	151.38	148.35	129.37	97.89	84.29
Total (boe/d)	53,519	58,942	59,979	48,630	29,510	25,771
<b>United States</b>						
Light and medium crude oil (bbls/d)	2,104	3,046	2,514	1,069	662	393
Condensate <sup>(1)</sup> (bbls/d)	1	5	18	8	4	—
Other NGLs <sup>(1)</sup> (bbls/d)	993	1,218	996	452	50	29
NGLs (bbls/d)	994	1,223	1,014	460	54	29
Conventional natural gas (mmcf/d)	5.73	7.47	6.89	2.78	0.39	0.21
Total (boe/d)	4,053	5,514	4,675	1,992	781	457
<b>France</b>						
Light and medium crude oil (bbls/d)	9,038	8,903	10,435	11,362	11,084	11,896
Conventional natural gas (mmcf/d)	—	—	0.19	0.21	—	0.44
Total (boe/d)	9,038	8,903	10,467	11,396	11,085	11,970
<b>Netherlands</b>						
Light and medium crude oil (bbls/d)	3	1	3	—	—	—
Condensate <sup>(1)</sup> (bbls/d)	94	88	88	90	90	88
NGLs (bbls/d)	94	88	88	90	90	88
Conventional natural gas (mmcf/d)	39.51	46.16	49.10	46.13	40.54	47.82
Total (boe/d)	6,682	7,782	8,274	7,779	6,847	8,058
<b>Germany</b>						
Light and medium crude oil (bbls/d)	1,003	968	917	1,004	1,060	—
Conventional natural gas (mmcf/d)	14.51	12.65	15.31	15.66	19.39	14.90
Total (boe/d)	3,420	3,076	3,468	3,614	4,291	2,483
<b>Ireland</b>						
Conventional natural gas (mmcf/d)	32.15	37.44	46.57	55.17	58.43	50.89
Total (boe/d)	5,359	6,240	7,762	9,195	9,737	8,482
<b>Australia</b>						
Light and medium crude oil (bbls/d)	4,160	4,416	5,662	4,494	5,770	6,304
Total (boe/d)	4,160	4,416	5,662	4,494	5,770	6,304
<b>Central and Eastern Europe</b>						
Conventional natural gas (mmcf/d)	0.45	1.90	0.42	1.02	—	—
Total (boe/d)	75	317	70	169	—	—
<b>Consolidated</b>						
Light and medium crude oil (bbls/d)	33,622	38,441	43,502	35,329	24,591	25,250
Condensate <sup>(1)</sup> (bbls/d)	5,155	4,980	4,400	3,853	3,130	2,602
Other NGLs <sup>(1)</sup> (bbls/d)	8,386	8,937	7,984	6,366	4,194	2,582
NGLs (bbls/d)	13,541	13,917	12,384	10,219	7,324	5,184
Conventional natural gas (mmcf/d)	234.86	256.99	266.82	250.33	216.64	198.55
Total (boe/d)	86,306	95,190	100,357	87,270	68,021	63,526

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

## Supplemental Table 5: Operational and Financial Data by Core Region

### Production volumes <sup>(1)</sup>

	Q2/21	Q1/21	Q4/20	Q3/20	Q2/20	Q1/20	Q4/19	Q3/19	Q2/19	Q1/19	Q4/18	Q3/18
<b>North America</b>												
Crude oil and condensate (bbls/d)	24,316	24,645	26,459	28,296	31,569	29,888	30,560	30,403	31,329	30,905	31,163	29,938
NGLs (bbls/d)	8,695	8,074	8,628	9,508	9,588	8,022	8,161	7,772	8,106	7,897	7,814	6,840
Natural gas (mmcf/d)	152.06	144.36	142.13	163.09	172.43	157.88	153.34	151.52	158.93	157.26	152.30	141.59
<b>Total (boe/d)</b>	<b>58,354</b>	<b>56,780</b>	<b>58,774</b>	<b>64,986</b>	<b>69,895</b>	<b>64,222</b>	<b>64,276</b>	<b>63,429</b>	<b>65,921</b>	<b>65,013</b>	<b>64,359</b>	<b>60,376</b>
<b>International</b>												
Crude oil and condensate (bbls/d)	14,037	14,560	14,096	14,943	13,471	14,994	15,702	16,838	17,636	18,275	16,516	17,214
Natural gas (mmcf/d)	83.66	89.62	89.86	93.25	101.99	107.63	107.38	101.83	116.67	120.70	124.48	111.79
<b>Total (boe/d)</b>	<b>27,981</b>	<b>29,495</b>	<b>29,073</b>	<b>30,484</b>	<b>30,472</b>	<b>32,932</b>	<b>33,598</b>	<b>33,811</b>	<b>37,081</b>	<b>38,391</b>	<b>37,262</b>	<b>35,846</b>
<b>Consolidated</b>												
Crude oil and condensate (bbls/d)	38,354	39,204	40,555	43,240	45,041	44,881	46,261	47,242	48,964	49,182	47,678	47,151
NGLs (bbls/d)	8,695	8,074	8,627	9,509	9,588	8,022	8,160	7,772	8,107	7,897	7,815	6,839
Natural gas (mmcf/d)	235.72	233.98	232.00	256.34	274.42	265.51	260.72	253.36	275.60	277.96	276.77	253.38
<b>Total (boe/d)</b>	<b>86,335</b>	<b>86,276</b>	<b>87,848</b>	<b>95,471</b>	<b>100,366</b>	<b>97,154</b>	<b>97,875</b>	<b>97,239</b>	<b>103,003</b>	<b>103,404</b>	<b>101,621</b>	<b>96,222</b>

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

### Sales volumes

	Q2/21	Q1/21	Q4/20	Q3/20	Q2/20	Q1/20	Q4/19	Q3/19	Q2/19	Q1/19	Q4/18	Q3/18
<b>North America</b>												
Crude oil and condensate (bbls/d)	24,316	24,645	26,459	28,297	31,569	29,888	30,560	30,404	31,327	30,906	31,162	29,938
NGLs (bbls/d)	8,695	8,074	8,628	9,508	9,588	8,022	8,161	7,772	8,106	7,897	7,814	6,840
Natural gas (mmcf/d)	152.06	144.36	142.13	163.09	172.43	157.88	153.34	151.52	158.93	157.26	152.30	141.59
<b>Total (boe/d)</b>	<b>58,354</b>	<b>56,780</b>	<b>58,774</b>	<b>64,986</b>	<b>69,895</b>	<b>64,222</b>	<b>64,276</b>	<b>63,429</b>	<b>65,921</b>	<b>65,013</b>	<b>64,359</b>	<b>60,376</b>
<b>International</b>												
Crude oil and condensate (bbls/d)	13,859	11,421	15,359	15,689	12,202	17,090	13,864	18,575	16,009	20,163	16,458	16,559
Natural gas (mmcf/d)	83.66	89.62	89.86	93.25	101.99	107.63	107.38	101.83	116.67	120.70	124.48	111.02
<b>Total (boe/d)</b>	<b>27,802</b>	<b>26,357</b>	<b>30,336</b>	<b>31,229</b>	<b>29,201</b>	<b>35,028</b>	<b>31,760</b>	<b>35,547</b>	<b>35,454</b>	<b>40,279</b>	<b>37,204</b>	<b>35,062</b>
<b>Consolidated</b>												
Crude oil and condensate (bbls/d)	38,174	36,066	41,818	43,985	43,771	46,977	44,423	48,979	47,337	51,068	47,620	46,368
NGLs (bbls/d)	8,695	8,074	8,627	9,509	9,588	8,022	8,160	7,772	8,107	7,897	7,815	6,839
Natural gas (mmcf/d)	235.72	233.98	232.00	256.34	274.42	265.51	260.72	253.36	275.60	277.96	276.77	253.38
<b>Total (boe/d)</b>	<b>86,156</b>	<b>83,138</b>	<b>89,111</b>	<b>96,217</b>	<b>99,096</b>	<b>99,250</b>	<b>96,037</b>	<b>98,976</b>	<b>101,377</b>	<b>105,291</b>	<b>101,563</b>	<b>95,437</b>

## Financial results

	Q2/21	Q1/21	Q4/20	Q3/20	Q2/20	Q1/20	Q4/19	Q3/19	Q2/19	Q1/19	Q4/18	Q3/18
<b>North America</b>												
Crude oil and condensate sales (\$/bbl)	75.43	66.31	51.06	49.79	28.94	50.25	66.31	66.67	72.40	65.95	54.90	80.22
NGL sales (\$/bbl)	25.43	29.39	19.20	15.04	8.94	8.92	14.63	6.14	11.25	22.49	25.70	27.97
Natural gas sales (\$/mcf)	2.72	3.98	2.77	2.02	1.60	1.92	2.29	1.18	1.15	2.52	1.79	1.46
Sales (\$/boe)	42.30	43.08	32.51	28.94	18.24	29.22	38.86	35.52	38.56	40.17	33.94	46.37
Royalties (\$/boe)	(5.98)	(5.49)	(3.64)	(3.58)	(1.67)	(3.54)	(4.98)	(4.93)	(4.22)	(5.00)	(5.01)	(6.71)
Transportation (\$/boe)	(1.90)	(2.05)	(1.92)	(1.74)	(1.72)	(1.91)	(1.76)	(1.78)	(1.63)	(1.83)	(1.88)	(1.63)
Operating (\$/boe)	(10.89)	(11.21)	(10.94)	(7.82)	(9.60)	(11.93)	(11.15)	(10.67)	(10.66)	(11.46)	(10.96)	(10.48)
General and administration (\$/boe)	(0.91)	(1.34)	(1.94)	(0.78)	(1.52)	(0.84)	(0.97)	(0.60)	(1.04)	(0.83)	(0.28)	(0.36)
Corporate income taxes (\$/boe)	(0.04)	(0.04)	0.04	(0.02)	(0.02)	(0.04)	(0.11)	0.09	(0.02)	(0.03)	0.10	(0.16)
PRRT (\$/boe)	—	—	—	—	—	—	—	—	—	—	—	—
<b>Fund flows netback (\$/boe)</b>	<b>22.58</b>	<b>22.94</b>	<b>14.12</b>	<b>14.99</b>	<b>3.72</b>	<b>10.96</b>	<b>19.89</b>	<b>17.63</b>	<b>20.99</b>	<b>21.03</b>	<b>15.91</b>	<b>27.04</b>
Fund flows from operations	119,916	117,227	76,375	89,635	23,639	64,048	117,623	102,867	125,893	123,071	94,200	150,202
Capital expenditures	(38,847)	(59,113)	(33,781)	(9,575)	(23,979)	(197,926)	(69,775)	(91,027)	(42,047)	(148,091)	(93,092)	(101,223)
<b>Free cash flow</b>	<b>81,069</b>	<b>58,114</b>	<b>42,594</b>	<b>80,060</b>	<b>(340)</b>	<b>(133,878)</b>	<b>47,848</b>	<b>11,840</b>	<b>83,846</b>	<b>(25,020)</b>	<b>1,108</b>	<b>48,979</b>
<b>International</b>												
Crude oil and condensate sales (\$/bbl)	85.41	81.40	62.65	58.19	50.27	73.35	82.14	84.55	93.28	84.95	87.56	95.32
Natural gas sales (\$/mcf)	9.83	7.98	6.27	2.91	2.28	4.44	5.49	4.29	5.73	8.46	10.78	10.34
Sales (\$/boe)	72.16	62.39	50.30	37.94	28.98	49.42	54.42	56.46	60.98	67.87	74.80	77.76
Royalties (\$/boe)	(3.83)	(3.53)	(3.02)	(3.32)	(2.16)	(3.27)	(3.85)	(3.89)	(3.97)	(3.89)	(4.16)	(5.13)
Transportation (\$/boe)	(4.64)	(2.76)	(2.40)	(2.28)	(2.04)	(1.94)	(1.77)	(2.76)	(3.40)	(1.66)	(1.70)	(1.45)
Operating (\$/boe)	(16.56)	(16.42)	(16.99)	(15.18)	(14.35)	(16.13)	(15.28)	(13.13)	(11.76)	(15.28)	(13.89)	(12.26)
General and administration (\$/boe)	(2.61)	(2.06)	(2.92)	(2.53)	(2.72)	(2.63)	(3.70)	(3.10)	(2.93)	(2.27)	(3.27)	(3.49)
Corporate income taxes (\$/boe)	(0.19)	0.66	2.25	0.04	(0.02)	(0.11)	2.22	(1.55)	(3.63)	(4.30)	(2.49)	(2.65)
PRRT (\$/boe)	(0.58)	(0.60)	(1.45)	(1.27)	(1.21)	(2.90)	(0.50)	(1.78)	(2.56)	(2.87)	0.71	0.08
<b>Fund flows netback (\$/boe)</b>	<b>43.74</b>	<b>37.69</b>	<b>25.77</b>	<b>13.40</b>	<b>6.47</b>	<b>22.44</b>	<b>31.54</b>	<b>30.26</b>	<b>32.73</b>	<b>37.60</b>	<b>49.99</b>	<b>52.88</b>
Fund flows from operations	110,654	89,403	71,934	38,498	17,193	71,526	92,160	98,955	105,600	136,298	171,119	170,563
Capital expenditures	(40,329)	(24,250)	(26,113)	(21,755)	(18,295)	(35,778)	(30,850)	(36,852)	(50,560)	(53,962)	(70,488)	(44,962)
<b>Free cash flow</b>	<b>70,325</b>	<b>65,153</b>	<b>45,821</b>	<b>16,743</b>	<b>(1,102)</b>	<b>35,748</b>	<b>61,310</b>	<b>62,103</b>	<b>55,040</b>	<b>82,336</b>	<b>100,631</b>	<b>125,601</b>
	Q2/21	Q1/21	Q4/20	Q3/20	Q2/20	Q1/20	Q4/19	Q3/19	Q2/19	Q1/19	Q4/18	Q3/18
<b>Consolidated</b>												
Crude oil and condensate sales (\$/bbl)	79.06	71.09	55.31	52.79	34.89	58.66	71.25	73.45	79.46	73.45	66.19	85.84
NGL sales (\$/bbl)	25.43	29.39	19.20	15.04	8.94	8.92	14.63	6.14	11.25	22.49	25.69	27.97
Natural gas sales (\$/mcf)	5.24	5.51	4.13	2.34	1.85	2.94	3.61	2.43	3.09	5.10	5.83	5.35
Sales (\$/boe)	51.93	49.20	38.57	31.86	21.40	36.35	44.01	43.04	46.40	50.77	48.90	57.90
Royalties (\$/boe)	(5.29)	(4.87)	(3.43)	(3.50)	(1.81)	(3.45)	(4.60)	(4.56)	(4.13)	(4.58)	(4.70)	(6.13)
Transportation (\$/boe)	(2.78)	(2.27)	(2.08)	(1.92)	(1.81)	(1.92)	(1.76)	(2.13)	(2.25)	(1.76)	(1.81)	(1.56)
Operating (\$/boe)	(12.72)	(12.86)	(13.00)	(10.21)	(11.00)	(13.41)	(12.52)	(11.55)	(11.04)	(12.92)	(12.04)	(11.13)
General and administration (\$/boe)	(1.46)	(1.57)	(2.27)	(1.35)	(1.88)	(1.47)	(1.88)	(1.50)	(1.70)	(1.38)	(1.37)	(1.51)
Corporate income taxes (\$/boe)	(0.09)	0.18	0.80	—	(0.02)	(0.06)	0.66	(0.50)	(1.28)	(1.66)	(0.85)	(1.07)
PRRT (\$/boe)	(0.19)	(0.19)	(0.49)	(0.41)	(0.36)	(1.02)	(0.16)	(0.64)	(0.90)	(1.10)	0.26	0.03
Interest (\$/boe)	(2.41)	(2.57)	(2.42)	(1.97)	(1.98)	(2.21)	(2.17)	(2.16)	(2.34)	(2.21)	(2.23)	(2.25)
Realized derivatives (\$/boe)	(5.05)	(3.43)	0.10	0.47	6.07	5.47	2.57	4.06	1.54	1.09	(3.03)	(4.26)
Realized foreign exchange (\$/boe)	(0.25)	(0.69)	0.16	(0.31)	0.44	0.94	0.23	(0.37)	(0.17)	(0.22)	0.63	(0.35)
Realized other (\$/boe)	0.35	0.73	0.56	0.29	0.03	(0.37)	0.03	0.04	0.02	0.73	0.03	0.02
<b>Fund flows netback (\$/boe)</b>	<b>22.06</b>	<b>21.66</b>	<b>16.49</b>	<b>12.97</b>	<b>9.08</b>	<b>18.85</b>	<b>24.40</b>	<b>23.74</b>	<b>24.14</b>	<b>26.76</b>	<b>23.80</b>	<b>29.69</b>
Fund flows from operations	172,942	162,051	135,212	114,776	81,852	170,225	215,592	216,153	222,738	253,572	222,342	260,705
Capital expenditures	(79,176)	(83,363)	(59,894)	(31,330)	(42,274)	(233,704)	(100,625)	(127,879)	(92,607)	(202,053)	(163,580)	(146,185)
<b>Free cash flow</b>	<b>93,766</b>	<b>78,688</b>	<b>75,318</b>	<b>83,446</b>	<b>39,578</b>	<b>(63,479)</b>	<b>114,967</b>	<b>88,274</b>	<b>130,131</b>	<b>51,519</b>	<b>58,762</b>	<b>114,520</b>

## Non-GAAP Financial Measures

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

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

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

**Capital expenditures:** The sum of drilling and development and exploration and evaluation from the Consolidated Statements of Cash Flows. We consider capital expenditures to be a useful measure of our investment in our existing asset base. Capital expenditures are also referred to as E&D capital.

**Cash dividends per share:** Represents cash dividends declared per share and is a useful measure of the dividends a common shareholder was entitled to during the period.

**Covenants:** The financial covenants on our revolving credit facility contain non-GAAP measures. The definitions for these financial covenants are included in Financial Position Review.

**Diluted shares outstanding:** The sum of shares outstanding at the period end plus outstanding awards under the VIP, based on current estimates of future performance factors and forfeiture rates.

**Free cash flow:** Represents fund flows from operations in excess of capital expenditures. We use free cash flow to determine the funding available for investing and financing activities, including payment of dividends, repayment of long-term debt, reallocation to existing business units, and deployment into new ventures. We also assess free cash flow as a percentage of fund flows from operations, which is a measure of the percentage of fund flows from operations that is retained for incremental investing and financing activities.

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

**Net dividends:** We define net dividends as dividends declared less proceeds received for the issuance of shares pursuant to the Dividend Reinvestment Plan. Management monitors net dividends and net dividends as a percentage of fund flows from operations to assess our ability to pay dividends.

**Operating netback:** Sales less royalties, operating expense, transportation costs, PRRT, and realized hedging gains and losses presented on a per unit basis. Management assesses operating netback as a measure of the profitability and efficiency of our field operations. In contrast, fund flows from operations netback also includes general and administration expense, corporate income taxes, and interest. Fund flows from operations netback is used by management to assess the profitability of our business units and Vermilion as a whole.

**Payout:** We define payout as net dividends plus drilling and development costs, exploration and evaluation costs, and asset retirement obligations settled. Management uses payout and payout as a percentage of fund flows from operations (also referred to as the **payout or sustainability ratio**) to assess the amount of cash distributed back to shareholders and re-invested in the business for maintaining production and organic growth.

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

The following tables reconcile net dividends, payout, and diluted shares outstanding from their most directly comparable GAAP measures as presented in our financial statements:

(\$M)	Q2 2021	Q2 2020	YTD 2021	YTD 2020
Dividends declared	—	—	—	90,067
Shares issued for the Dividend Reinvestment Plan	—	(632)	—	(8,277)
Net dividends	—	—	—	81,790
Drilling and development	77,703	42,383	157,215	269,816
Exploration and evaluation	1,473	(109)	5,324	6,162
Asset retirement obligations settled	3,321	970	10,344	4,702
Payout	82,497	42,612	172,883	362,470
% of fund flows from operations	48 %	52 %	52 %	144 %

('000s of shares)	Q2 2021	Q2 2020
Shares outstanding	161,893	158,307
Potential shares issuable pursuant to the VIP	7,010	5,783
Diluted shares outstanding	168,903	164,090

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

(\$M)	Twelve Months Ended	
	Jun 30, 2021	Jun 30, 2020
Net earnings (loss)	823,605	(1,398,546)
Taxes	172,462	(273,324)
Interest expense	75,305	76,699
EBIT	1,071,372	(1,595,171)
Average capital employed	4,436,484	4,826,230
Return on capital employed	24 %	(33)%

# Consolidated Interim Financial Statements

## Consolidated Balance Sheet

thousands of Canadian dollars, unaudited

	Note	June 30, 2021	December 31, 2020
<b>Assets</b>			
<b>Current</b>			
Cash and cash equivalents		—	6,904
Accounts receivable		205,937	196,077
Crude oil inventory		28,549	13,402
Derivative instruments		36,834	16,924
Prepaid expenses		21,454	27,686
Total current assets		292,774	260,993
Derivative instruments		—	2,451
Deferred taxes		298,405	484,497
Exploration and evaluation assets		237,576	254,094
Capital assets	3	4,578,718	3,107,104
Total assets		5,407,473	4,109,139
<b>Liabilities</b>			
<b>Current</b>			
Accounts payable and accrued liabilities		346,501	297,670
Derivative instruments		168,187	130,919
Income taxes payable		13,492	4,539
Total current liabilities		528,180	433,128
Derivative instruments		62,384	8,228
Long-term debt	6	1,769,866	1,933,848
Lease obligations		71,636	76,524
Asset retirement obligations	4	809,240	467,737
Deferred taxes		304,367	264,272
Total liabilities		3,545,673	3,183,737
<b>Shareholders' Equity</b>			
Shareholders' capital	7	4,235,625	4,181,160
Contributed surplus		40,781	66,250
Accumulated other comprehensive income		36,070	77,986
Deficit		(2,450,676)	(3,399,994)
Total shareholders' equity		1,861,800	925,402
Total liabilities and shareholders' equity		5,407,473	4,109,139

### Approved by the Board

(Signed "Robert Michaleski")

Robert Michaleski, Director

(Signed "Lorenzo Donadeo")

Lorenzo Donadeo, Director



## Consolidated Statements of Net Earnings (Loss) and Comprehensive Income (Loss)

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

	Note	Three Months Ended		Six Months Ended	
		Jun 30, 2021	Jun 30, 2020	Jun 30, 2021	Jun 30, 2020
<b>Revenue</b>					
Petroleum and natural gas sales		407,179	193,013	775,316	521,327
Royalties		(41,456)	(16,352)	(77,902)	(47,477)
Sales of purchased commodities		29,851	16,118	73,615	72,226
<b>Petroleum and natural gas revenue</b>		<b>395,574</b>	<b>192,779</b>	<b>771,029</b>	<b>546,076</b>
<b>Expenses</b>					
Purchased commodities		29,851	16,118	73,615	72,226
Operating		99,737	99,175	195,978	220,313
Transportation		21,834	16,365	38,855	33,695
Equity based compensation		10,536	9,164	27,076	22,161
Loss (gain) on derivative instruments		118,982	(50,933)	139,173	(109,668)
Interest expense		18,862	17,887	38,097	37,869
General and administration		11,432	16,912	23,162	30,229
Foreign exchange loss		20,256	3,438	51,347	4,897
Other (income) expense		(2,576)	(16)	(7,849)	3,502
Accretion	4	10,863	7,288	21,370	17,026
Depletion and depreciation	3	149,651	106,707	255,664	264,514
Impairment (reversal) expense	3	(593,606)	69,713	(1,256,472)	1,634,567
Gain on business combination	3	(17,198)	—	(17,198)	—
		(121,376)	311,818	(417,182)	2,231,331
<b>Earnings (loss) before income taxes</b>		<b>516,950</b>	<b>(119,039)</b>	<b>1,188,211</b>	<b>(1,685,255)</b>
<b>Income tax expense (recovery)</b>					
Deferred	3	63,526	(51,126)	234,754	(308,668)
Current		2,150	3,377	2,219	13,207
		65,676	(47,749)	236,973	(295,461)
<b>Net earnings (loss)</b>		<b>451,274</b>	<b>(71,290)</b>	<b>951,238</b>	<b>(1,389,794)</b>
<b>Other comprehensive income (loss)</b>					
Currency translation adjustments		(12,244)	(22,989)	(45,180)	66,422
Unrealized gain (loss) on hedges		1,631	(37,178)	3,264	(39,621)
<b>Comprehensive income (loss)</b>		<b>440,661</b>	<b>(131,457)</b>	<b>909,322</b>	<b>(1,362,993)</b>
<b>Net earnings (loss) per share</b>					
Basic		2.79	(0.45)	5.94	(8.83)
Diluted		2.73	(0.45)	5.85	(8.83)
<b>Weighted average shares outstanding ('000s)</b>					
Basic		161,546	158,189	160,226	157,375
Diluted		165,034	158,189	162,553	157,375

# Consolidated Statements of Cash Flows

thousands of Canadian dollars, unaudited

	Note	Three Months Ended		Six Months Ended	
		Jun 30, 2021	Jun 30, 2020	Jun 30, 2021	Jun 30, 2020
<b>Operating</b>					
Net earnings (loss)		451,274	(71,290)	951,238	(1,389,794)
Adjustments:					
Accretion	4	10,863	7,288	21,370	17,026
Depletion and depreciation	3	149,651	106,707	255,664	264,514
Impairment (reversal) expense	3	(593,606)	69,713	(1,256,472)	1,634,567
Gain on business combinations	3	(17,198)	—	(17,198)	—
Unrealized loss (gain) on derivative instruments		79,408	3,771	73,966	(5,545)
Equity based compensation		10,536	9,164	27,076	22,161
Unrealized foreign exchange loss		18,298	7,410	44,208	17,392
Unrealized other expense		190	215	387	424
Deferred taxes		63,526	(51,126)	234,754	(308,668)
Asset retirement obligations settled	4	(3,321)	(970)	(10,344)	(4,702)
Changes in non-cash operating working capital		83,785	(88,050)	47,904	23,896
Cash flows from (used in) operating activities		253,406	(7,168)	372,553	271,271
<b>Investing</b>					
Drilling and development	3	(77,703)	(42,383)	(157,215)	(269,816)
Exploration and evaluation		(1,473)	109	(5,324)	(6,162)
Acquisitions	3	(12,196)	(2,932)	(12,589)	(14,269)
Changes in non-cash investing working capital		(5,866)	(76,782)	3,231	(18,744)
Cash flows used in investing activities		(97,238)	(121,988)	(171,897)	(308,991)
<b>Financing</b>					
(Repayments) borrowings on the revolving credit facility	6	(154,037)	141,842	(195,491)	144,955
Payments on lease obligations		(5,815)	(6,224)	(11,567)	(13,450)
Cash dividends		—	(17,425)	—	(117,737)
Cash flows (used in) from financing activities		(159,852)	118,193	(207,058)	13,768
Foreign exchange gain (loss) on cash held in foreign currencies		81	(886)	(502)	(290)
Net change in cash and cash equivalents		(3,603)	(11,849)	(6,904)	(24,242)
Cash and cash equivalents, beginning of period		3,603	16,635	6,904	29,028
Cash and cash equivalents, end of period		—	4,786	—	4,786
<b>Supplementary information for cash flows from operating activities</b>					
Interest paid		12,989	18,475	36,926	38,155
Income taxes refunded		(4,397)	(15,075)	(6,734)	(5,128)

## Consolidated Statements of Changes in Shareholders' Equity

thousands of Canadian dollars, unaudited

	Note	Six Months Ended Jun 30, 2021	Jun 30, 2020
<b>Shareholders' capital</b>	7		
Balance, beginning of period		4,181,160	4,119,031
Shares issued for the Dividend Reinvestment Plan		—	8,277
Vesting of equity based awards		44,852	43,474
Equity based compensation		7,693	2,118
Share-settled dividends on vested equity based awards		1,920	1,360
Balance, end of period		4,235,625	4,174,260
<b>Contributed surplus</b>	7		
Balance, beginning of period		66,250	75,735
Equity based compensation		19,383	20,043
Vesting of equity based awards		(44,852)	(43,474)
Balance, end of period		40,781	52,304
<b>Accumulated other comprehensive income</b>			
Balance, beginning of period		77,986	49,578
Currency translation adjustments		(45,180)	53,984
Hedge accounting reserve		3,264	(27,183)
Balance, end of period		36,070	76,379
<b>Deficit</b>			
Balance, beginning of period		(3,399,994)	(1,791,039)
Net earnings (loss)		951,238	(1,389,794)
Dividends declared		—	(90,067)
Share-settled dividends on vested equity based awards		(1,920)	(1,360)
Balance, end of period		(2,450,676)	(3,272,260)
<b>Total shareholders' equity</b>		<b>1,861,800</b>	<b>1,030,683</b>

### Description of equity reserves

#### *Shareholders' capital*

Represents the recognized amount for common shares when issued, net of equity issuance costs and deferred taxes.

#### *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 and hedge accounting reserve.

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 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 in the same period in which the transaction associated with the hedged item occurs. For the six months ended June 30, 2021, accumulated losses of \$2.5 million and \$0.8 million were recognized in the consolidated statement of net earnings on the cash flow hedges and net investment hedges, respectively, and will be recognized in net earnings through 2025 when the senior unsecured notes mature.

#### *Deficit*

Represents the cumulative net earnings less distributed earnings of Vermilion Energy Inc.

# Notes to the Condensed Consolidated Interim Financial Statements for the three and six months ended June 30, 2021 and 2020

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, 2020.

These condensed consolidated interim financial statements should be read in conjunction with Vermilion’s consolidated financial statements for the year ended December 31, 2020, which are contained within Vermilion’s Annual Report for the year ended December 31, 2020 and are available on SEDAR at [www.sedar.com](http://www.sedar.com) or on Vermilion’s website at [www.vermilionenergy.com](http://www.vermilionenergy.com).

These condensed consolidated interim financial statements were approved and authorized for issuance by the Board of Directors of Vermilion on August 13, 2021.

## 2. Segmented information

	Three Months Ended June 30, 2021								Total
	Canada	USA	France	Netherlands	Germany	Ireland	Australia	Corporate	
Drilling and development	20,210	18,637	8,896	7,739	3,121	172	13,118	5,810	77,703
Exploration and evaluation	—	—	17	(56)	486	—	—	1,026	1,473
Crude oil and condensate sales	153,331	13,582	68,108	592	7,741	23	31,256	—	274,633
NGL sales	17,380	2,740	—	—	—	—	—	—	20,120
Natural gas sales	36,137	1,439	—	31,963	12,533	30,165	—	189	112,426
Sales of purchased commodities	—	—	—	—	—	—	—	29,851	29,851
Royalties	(27,001)	(4,754)	(9,167)	(128)	(367)	—	—	(39)	(41,456)
Revenue from external customers	179,847	13,007	58,941	32,427	19,907	30,188	31,256	30,001	395,574
Purchased commodities	—	—	—	—	—	—	—	(29,851)	(29,851)
Transportation	(9,868)	(216)	(9,118)	—	(1,554)	(1,078)	—	—	(21,834)
Operating	(54,441)	(3,389)	(12,591)	(7,895)	(6,807)	(4,157)	(10,408)	(49)	(99,737)
General and administration	(5,953)	(725)	(3,216)	(110)	(1,459)	(25)	(754)	810	(11,432)
PRRT	—	—	—	—	—	—	(1,459)	—	(1,459)
Corporate income taxes	—	—	(1)	(2,362)	—	—	1,871	(199)	(691)
Interest expense	—	—	—	—	—	—	—	(18,862)	(18,862)
Realized loss on derivative instruments	—	—	—	—	—	—	—	(39,574)	(39,574)
Realized foreign exchange loss	—	—	—	—	—	—	—	(1,958)	(1,958)
Realized other income	—	—	—	—	—	—	—	2,766	2,766
<b>Fund flows from operations</b>	<b>109,585</b>	<b>8,677</b>	<b>34,015</b>	<b>22,060</b>	<b>10,087</b>	<b>24,928</b>	<b>20,506</b>	<b>(56,916)</b>	<b>172,942</b>

	Three Months Ended June 30, 2020								Total
	Canada	USA	France	Netherlands	Germany	Ireland	Australia	Corporate	
Drilling and development	9,785	14,194	5,563	6,417	1,402	704	4,200	118	42,383
Exploration and evaluation	—	—	40	(3,779)	1,943	—	—	1,687	(109)
Crude oil and condensate sales	68,587	14,550	23,329	113	3,659	(16)	28,772	(48)	138,953
NGL sales	7,222	582	—	—	—	—	—	—	7,804
Natural gas sales	24,326	742	—	10,541	2,894	7,284	—	469	46,256
Sales of purchased commodities	—	—	—	—	—	—	—	16,118	16,118
Royalties	(6,777)	(3,836)	(4,711)	(55)	(795)	—	—	(178)	(16,352)
Revenue from external customers	93,358	12,038	18,618	10,599	5,758	7,268	28,772	16,368	192,779
Purchased commodities	—	—	—	—	—	—	—	(16,118)	(16,118)
Transportation	(10,465)	(469)	(2,747)	—	(1,505)	(1,179)	—	—	(16,365)
Operating	(57,281)	(3,765)	(10,016)	(7,526)	(5,912)	(3,852)	(10,659)	(164)	(99,175)
General and administration	(8,705)	(1,796)	(3,499)	(212)	(1,314)	106	(888)	(604)	(16,912)
PRRT	—	—	—	—	—	—	(3,219)	—	(3,219)
Corporate income taxes	—	—	—	257	—	—	(313)	(102)	(158)
Interest expense	—	—	—	—	—	—	—	(17,887)	(17,887)
Realized gain on derivative instruments	—	—	—	—	—	—	—	54,704	54,704
Realized foreign exchange gain	—	—	—	—	—	—	—	3,972	3,972
Realized other income	—	—	—	—	—	—	—	231	231
<b>Fund flows from operations</b>	<b>16,907</b>	<b>6,008</b>	<b>2,356</b>	<b>3,118</b>	<b>(2,973)</b>	<b>2,343</b>	<b>13,693</b>	<b>40,400</b>	<b>81,852</b>

Six Months Ended June 30, 2021									
	Canada	USA	France	Netherlands	Germany	Ireland	Australia	Corporate	Total
Drilling and development	74,531	23,429	15,770	11,872	5,421	238	19,957	5,997	157,215
Exploration and evaluation	—	—	22	(56)	685	—	—	4,673	5,324
Crude oil and condensate sales	285,833	28,156	119,637	920	12,176	23	58,638	—	505,383
NGL sales	35,456	6,018	—	—	—	—	—	—	41,474
Natural gas sales	81,367	7,913	—	60,186	21,193	57,233	—	567	228,459
Sales of purchased commodities	—	—	—	—	—	—	—	73,615	73,615
Royalties	(48,775)	(11,060)	(16,403)	(225)	(1,322)	—	—	(117)	(77,902)
Revenue from external customers	353,881	31,027	103,234	60,881	32,047	57,256	58,638	74,066	771,029
Purchased commodities	—	—	—	—	—	—	—	(73,615)	(73,615)
Transportation	(20,104)	(464)	(13,523)	—	(2,575)	(2,189)	—	—	(38,855)
Operating	(107,607)	(7,504)	(24,382)	(15,306)	(13,109)	(7,814)	(20,146)	(110)	(195,978)
General and administration	(10,412)	(1,623)	(5,630)	(377)	(2,581)	687	(1,479)	(1,747)	(23,162)
PRRT	—	—	—	—	—	—	(2,873)	—	(2,873)
Corporate income taxes	—	—	(1)	(2,362)	—	—	3,430	(413)	654
Interest expense	—	—	—	—	—	—	—	(38,097)	(38,097)
Realized loss on derivative instruments	—	—	—	—	—	—	—	(65,207)	(65,207)
Realized foreign exchange loss	—	—	—	—	—	—	—	(7,139)	(7,139)
Realized other income	—	—	—	—	—	—	—	8,236	8,236
<b>Fund flows from operations</b>	<b>215,758</b>	<b>21,436</b>	<b>59,698</b>	<b>42,836</b>	<b>13,782</b>	<b>47,940</b>	<b>37,570</b>	<b>(104,027)</b>	<b>334,993</b>

Six Months Ended June 30, 2020									
	Canada	USA	France	Netherlands	Germany	Ireland	Australia	Corporate	Total
Drilling and development	162,362	59,543	16,795	5,381	8,692	684	16,202	157	269,816
Exploration and evaluation	—	—	65	(246)	2,442	—	—	3,901	6,162
Crude oil and condensate sales	193,056	26,750	80,118	624	8,414	12	80,767	(41)	389,700
NGL sales	11,630	2,689	—	—	—	—	—	—	14,319
Natural gas sales	50,412	2,263	—	29,633	8,608	24,844	—	1,548	117,308
Sales of purchased commodities	—	—	—	—	—	—	—	72,226	72,226
Royalties	(23,462)	(7,852)	(13,751)	(198)	(1,737)	—	—	(477)	(47,477)
Revenue from external customers	231,636	23,850	66,367	30,059	15,285	24,856	80,767	73,256	546,076
Purchased commodities	—	—	—	—	—	—	—	(72,226)	(72,226)
Transportation	(21,603)	(469)	(6,472)	—	(2,827)	(2,324)	—	—	(33,695)
Operating	(121,466)	(9,314)	(25,915)	(16,441)	(10,827)	(8,064)	(28,032)	(254)	(220,313)
General and administration	(11,548)	(3,766)	(6,947)	(767)	(3,055)	(284)	(1,763)	(2,099)	(30,229)
PRRT	—	—	—	—	—	—	(12,475)	—	(12,475)
Corporate income taxes	—	—	—	257	—	—	(654)	(335)	(732)
Interest expense	—	—	—	—	—	—	—	(37,869)	(37,869)
Realized gain on derivative instruments	—	—	—	—	—	—	—	104,123	104,123
Realized foreign exchange gain	—	—	—	—	—	—	—	12,495	12,495
Realized other expense	—	—	—	—	—	—	—	(3,078)	(3,078)
<b>Fund flows from operations</b>	<b>77,019</b>	<b>10,301</b>	<b>27,033</b>	<b>13,108</b>	<b>(1,424)</b>	<b>14,184</b>	<b>37,843</b>	<b>74,013</b>	<b>252,077</b>

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

	Three Months Ended		Six Months Ended	
	Jun 30, 2021	Jun 30, 2020	Jun 30, 2021	Jun 30, 2020
Fund flows from operations	172,942	81,852	334,993	252,077
Equity based compensation	(10,536)	(9,164)	(27,076)	(22,161)
Unrealized (loss) gain on derivative instruments	(79,408)	(3,771)	(73,966)	5,545
Unrealized foreign exchange loss	(18,298)	(7,410)	(44,208)	(17,392)
Accretion	(10,863)	(7,288)	(21,370)	(17,026)
Depletion and depreciation	(149,651)	(106,707)	(255,664)	(264,514)
Deferred tax (expense) recovery	(63,526)	51,126	(234,754)	308,668
Gain on business combinations	17,198	—	17,198	—
Impairment reversal (expense)	593,606	(69,713)	1,256,472	(1,634,567)
Unrealized other expense	(190)	(215)	(387)	(424)
<b>Net earnings (loss)</b>	<b>451,274</b>	<b>(71,290)</b>	<b>951,238</b>	<b>(1,389,794)</b>

### 3. Capital assets

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

	2021
<b>Balance at January 1</b>	<b>3,107,104</b>
Acquisitions	50,447
Additions	157,215
Increase in right-of-use assets	2,814
Impairment reversal	1,256,472
Depletion and depreciation	(246,092)
Changes in asset retirement obligations	340,029
Foreign exchange	(89,271)
<b>Balance at June 30</b>	<b>4,578,718</b>

In the second quarter of 2021, indicators of impairment reversal were present in our Alberta, Saskatchewan, Germany, Ireland and United States cash generating units ("CGU") due to an increase and stabilization in forecast oil and gas prices. As a result of the indicators of impairment reversal, the Company performed impairment reversal calculations on the identified CGUs and the recoverable amounts were determined using fair value less costs to sell, which considered future after-tax cash flows from proved plus probable reserves and an after-tax discount rate of 12.0%. Based on the results of the impairment reversal calculations completed, recoverable amounts were determined to be greater than the carrying values of the CGUs tested and \$460.4 million (net of \$133.2 million deferred income tax expense) of impairment reversal was recorded. Inputs used in the measurement of capital assets are not based on observable market data and fall within level 3 of the fair value hierarchy.

The following benchmark price forecasts were used to calculate the recoverable amounts:

	2H2021	2022	2023	2024	2025	2026	2027	2028	2029	2030 <sup>(2)</sup>
Brent Crude (\$ US/bbl) <sup>(1)</sup>	73.25	69.55	66.42	67.75	69.11	70.49	71.90	73.34	74.80	76.30
WTI Crude (\$ US/bbl) <sup>(1)</sup>	71.00	66.30	62.42	63.67	64.95	66.25	67.57	68.92	70.30	71.71
NBP (€/mmbtu) <sup>(1)</sup>	9.17	7.19	5.53	5.65	5.75	5.87	5.99	6.11	6.23	6.35
Exchange rate (CAD/USD)	0.81	0.81	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80

(1) The forecast benchmark prices listed are adjusted for quality differentials, heat content, transportation and marketing costs and other factors specific to the Company's operations when determining recoverable amounts.

(2) In 2031 and beyond, commodity price forecasts are inflated at a rate of 2.0% per annum. In 2031 and beyond there is no escalation of exchange rates.

The following are the results of tests completed, recoverable amounts, and sensitivity impacts which would decrease impairment reversals taken:



Operating Segment	CGU	Impairment Reversal <sup>(1)</sup>	Recoverable Amount	1% increase in discount rate	5% decrease in pricing
Canada	Alberta	88,708	988,447	—	29,716
Canada	Saskatchewan	270,897	1,500,139	80,724	156,875
Ireland	Ireland	133,005	339,315	9,136	23,975
Germany	Germany - Gas	43,735	168,290	—	—
United States	United States	57,261	429,322	26,903	44,317
<b>Total</b>		<b>593,606</b>	<b>3,425,513</b>	<b>116,763</b>	<b>254,883</b>

(1) Impairment reversals are subject to the lower of the recoverable amount and the carrying value, which includes depletion and depreciation of the CGU had no impairment charges been previously taken.

In the first quarter of 2021, indicators of impairment reversal were present in our Australia, Alberta, Saskatchewan, and United States CGUs due to an increase and stabilization in forecast oil prices. As a result of the indicators of impairment reversal, the Company performed impairment reversal calculations on the identified CGUs and the recoverable amounts were determined using fair value less costs to sell, which considered future after-tax cash flows from proved plus probable reserves and an after-tax discount rate of 12.0%. Based on the results of the impairment reversal calculations completed, recoverable amounts were determined to be greater than the carrying values of the CGUs tested and \$492.2 million (net of \$170.7 million deferred income tax expense) of impairment reversal was recorded. Inputs used in the measurement of capital assets are not based on observable market data and fall within level 3 of the fair value hierarchy.

The following benchmark price forecasts were used to calculate the recoverable amounts:

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030 <sup>(2)</sup>
Brent Crude (\$ US/bbl) <sup>(1)</sup>	64.50	62.08	61.69	62.84	64.02	65.22	66.45	67.70	68.97	70.35
WTI Crude (\$ US/bbl) <sup>(1)</sup>	62.00	58.58	57.69	58.84	60.02	61.22	62.45	63.70	64.97	66.27
Exchange rate (CAD/USD)	0.80	0.79	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78

(1) The forecast benchmark prices listed are adjusted for quality differentials, heat content, transportation and marketing costs and other factors specific to the Company's operations when determining recoverable amounts.

(2) In 2031 and beyond, commodity price forecasts are inflated at a rate of 2.0% per annum. In 2031 and beyond there is no escalation of exchange rates.

The following are the results of tests completed, recoverable amounts, and sensitivity impacts which would decrease impairment reversals taken:

Operating Segment	CGU	Impairment Reversal <sup>(1)</sup>	Recoverable Amount	1% increase in discount rate	5% decrease in pricing
Australia	Australia	82,016	189,749	6,921	19,756
Canada	Alberta	232,724	859,706	46,223	81,212
Canada	Saskatchewan	290,241	1,206,343	69,104	143,281
United States	United States	57,885	364,242	24,180	41,345
<b>Total</b>		<b>662,866</b>	<b>2,620,040</b>	<b>146,428</b>	<b>285,594</b>

(1) Impairment reversals are subject to the lower of the recoverable amount and the carrying value, which includes depletion and depreciation of the CGU had no impairment charges been previously taken.

### Minor Acquisition

In the second quarter of 2021, Vermilion completed a minor acquisition within its Germany Gas CGU for total consideration of \$11.6 million, in which \$49.2 million in capital assets, \$12.4 million in asset retirement obligations, and \$7.9 million in deferred tax liabilities were recognized. The acquisition resulted in a gain on acquisition of \$17.2 million which was due to increases in commodity prices from the effective date to close.

## 4. Asset retirement obligations

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

	2021
<b>Balance at January 1</b>	<b>467,737</b>
Additional obligations recognized	12,822
Changes in estimated abandonment timing and costs	726
Obligations settled	(10,344)
Accretion	21,370
Changes in discount rates	338,924
Foreign exchange	(21,995)
<b>Balance at June 30</b>	<b>809,240</b>

Vermilion calculated the present value of the obligations using a credit-adjusted risk-free rate, calculated using a credit spread of 4.7% as at June 30, 2021 (December 31, 2020 - 9.5%) added to risk-free rates based on long-term, risk-free government bonds. Vermilion's credit spread is determined as the yield to maturity on its senior unsecured notes as at the reporting period.

The country specific risk-free rates used as inputs to discount the obligations were as follows:

	Jun 30, 2021	Dec 31, 2020
Canada	1.9 %	1.2 %
United States	2.1 %	1.6 %
France	0.8 %	0.3 %
Netherlands	(0.3)%	(0.6)%
Germany	0.3 %	(0.2)%
Ireland	0.5 %	(0.1)%
Australia	1.8 %	1.3 %

## 5. Capital disclosures

Vermilion defines capital as net debt (long-term debt plus net working capital) and shareholders' capital. In managing capital, Vermilion reviews whether fund flows from operations is sufficient to fund capital expenditures, dividends, and asset retirement obligations.

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

	Jun 30, 2021	Dec 31, 2020
Long-term debt	1,769,866	1,933,848
Current liabilities	528,180	433,128
Current assets	(292,774)	(260,993)
<b>Net debt</b>	<b>2,005,272</b>	<b>2,105,983</b>
<b>Ratio of net debt to four quarter trailing fund flows from operations</b>	<b>3.43</b>	<b>4.19</b>

## 6. Long-term debt

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

	As at Jun 30, 2021	Dec 31, 2020
Revolving credit facility	1,403,877	1,555,215
Senior unsecured notes	365,989	378,633
<b>Long-term debt</b>	<b>1,769,866</b>	<b>1,933,848</b>

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 senior unsecured notes as at June 30, 2021 was \$375.2 million.

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

	2021
<b>Balance at January 1</b>	<b>1,933,848</b>
(Repayments) borrowings on the revolving credit facility	(195,491)
Amortization of transaction costs	387
Foreign exchange	31,122
<b>Balance at June 30</b>	<b>1,769,866</b>

### *Revolving credit facility*

In Q1 2020, we negotiated an extension to our \$2.1 billion revolving credit facility to extend the maturity to May 31, 2024.

As at June 30, 2021, Vermilion had in place a bank revolving credit facility maturing May 31, 2024 with the following terms:

	As at	
	Jun 30, 2021	Dec 31, 2020
Total facility amount	2,100,000	2,100,000
Amount drawn	(1,403,877)	(1,555,215)
Letters of credit outstanding	(15,489)	(23,210)
<b>Unutilized capacity</b>	<b>680,634</b>	<b>521,575</b>

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.

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

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

Financial covenant	Limit	As at	
		Jun 30, 2021	Dec 31, 2020
Consolidated total debt to consolidated EBITDA	Less than 4.0	2.76	3.48
Consolidated total senior debt to consolidated EBITDA	Less than 3.5	2.19	2.82
Consolidated EBITDA to consolidated interest expense	Greater than 2.5	9.09	8.12

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 balance sheet.
- Consolidated total senior debt: Defined as consolidated total debt excluding unsecured and subordinated debt.
- Consolidated EBITDA: Defined as consolidated net earnings before interest, income taxes, depreciation, accretion and certain other non-cash items, adjusted for the impact of the acquisition of a material subsidiary.
- 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 June 30, 2021, Vermilion's liability management ratings were higher than the specified levels, and as such, no amounts relating to asset retirement obligations were included in the calculation of consolidated total debt and consolidated total senior debt.

As at June 30, 2021 and December 31, 2020, Vermilion was in compliance with the above covenants.

### *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.

Vermilion may redeem some or all of the senior unsecured notes at the redemption prices set forth in the following table plus any accrued and unpaid interest, if redeemed during the twelve-month period beginning on March 15 of each of the years indicated below:

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

## 7. Shareholders' capital

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

Shareholders' Capital	2021	
	Shares ('000s)	Amount
<b>Balance at January 1</b>	<b>158,724</b>	<b>4,181,160</b>
Vesting of equity based awards	2,113	44,852
Shares issued for equity based compensation	838	7,693
Share-settled dividends on vested equity based awards	218	1,920
<b>Balance at June 30</b>	<b>161,893</b>	<b>4,235,625</b>

## 8. Financial instruments

The following table summarizes the increase (positive values) or decrease (negative values) to net earnings 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.

	Jun 30, 2021
<b>Currency risk - Euro to Canadian dollar</b>	
\$0.01 increase in strength of the Canadian dollar against the Euro	(712)
\$0.01 decrease in strength of the Canadian dollar against the Euro	712
<b>Currency risk - US dollar to Canadian dollar</b>	
\$0.01 increase in strength of the Canadian dollar against the US \$	2,976
\$0.01 decrease in strength of the Canadian dollar against the US \$	(2,976)
<b>Commodity price risk - Crude oil</b>	
US \$5.00/bbl increase in crude oil price used to determine the fair value of derivatives	(2,276)
US \$5.00/bbl decrease in crude oil price used to determine the fair value of derivatives	1,233
<b>Commodity price risk - European natural gas</b>	
€0.5/GJ increase in European natural gas price used to determine the fair value of derivatives	(18,145)
€0.5/GJ decrease in European natural gas price used to determine the fair value of derivatives	17,772
<b>Share price risk - Equity swaps</b>	
\$1.00 increase from initial share price of the equity swap	3,750
\$1.00 decrease from initial share price of the equity swap	(3,750)

## DIRECTORS

Lorenzo Donadeo <sup>1</sup>  
Calgary, Alberta

Larry J. Macdonald <sup>2, 4, 8, 10</sup>  
Calgary, Alberta

Carin Knickel <sup>5, 8, 12</sup>  
Golden, Colorado

Stephen P. Larke <sup>4, 6, 12</sup>  
Calgary, Alberta

Timothy R. Marchant <sup>7, 10, 11</sup>  
Calgary, Alberta

Robert Michaleski <sup>3, 6</sup>  
Calgary, Alberta

William Roby <sup>8, 9, 12</sup>  
Katy, Texas

Manjit Sharma <sup>4, 8</sup>  
Toronto, Ontario

Judy Steele <sup>6, 12</sup>  
Halifax, Nova Scotia

Catherine L. Williams <sup>4, 6</sup>  
Calgary, Alberta

<sup>1</sup> Executive Chairman

<sup>2</sup> Lead Director (Independent)

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

<sup>4</sup> Audit Committee Member

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

<sup>6</sup> Governance and Human Resources Committee Member

<sup>7</sup> Health, Safety and Environment Committee Chair (Independent)

<sup>8</sup> Health, Safety and Environment Committee Member

<sup>9</sup> Independent Reserves Committee Chair (Independent)

<sup>10</sup> Independent Reserves Committee Member

<sup>11</sup> Sustainability Committee Chair (Independent)

<sup>12</sup> Sustainability Committee Member

## OFFICERS / CORPORATE SECRETARY

Lorenzo Donadeo \*  
Executive Chairman

Curtis Hicks \*  
President

Lars Glemser \*  
Vice President & Chief Financial Officer

Dion Hatcher \*  
Vice President North America

Terry Hergott  
Vice President Marketing

Yvonne Jeffery  
Vice President Sustainability

Darcy Kerwin \*  
Vice President International & HSE

Kyle Preston  
Vice President Investor Relations

Jenson Tan \*  
Vice President Business Development

Gerard Schut \*  
Vice President European Operations

Robert (Bob) J. Engbloom  
Corporate Secretary

\* Executive Committee

## AUDITORS

Deloitte LLP  
Calgary, Alberta

## BANKERS

The Toronto-Dominion Bank

Bank of Montreal

Canadian Imperial Bank of Commerce

Export Development Canada

National Bank of Canada

Royal Bank of Canada

The Bank of Nova Scotia

Wells Fargo Bank N.A., Canadian Branch

Bank of America N.A., Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

JPMorgan Chase Bank, N.A., Toronto Branch

La Caisse Centrale Desjardins du Québec

Alberta Treasury Branches

Canadian Western Bank

Goldman Sachs Lending Partners LLC

## EVALUATION ENGINEERS

GLJ Petroleum Consultants Ltd.  
Calgary, Alberta

## LEGAL COUNSEL

Norton Rose Fulbright Canada LLP  
Calgary, Alberta

## TRANSFER AGENT

Odyssey Trust Company

## STOCK EXCHANGE LISTINGS

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

## INVESTOR RELATIONS

Kyle Preston  
Vice President Investor Relations  
403-476-8431 TEL  
403-476-8100 FAX  
1-866-895-8101 IR TOLL FREE  
[investor\\_relations@vermillionenergy.com](mailto:investor_relations@vermillionenergy.com)

## EXCELLENCE

We aim for exceptional results in everything we do.

## TRUST

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

## RESPECT

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

## RESPONSIBILITY

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

**VERMILION**  
**E N E R G Y**



Vermilion Energy Inc.  
3500, 520 3rd Avenue SW  
Calgary, Alberta T2P 0R3

Telephone: 1.403.269.4884  
Facsimile: 1.403.476.8100  
IR Toll Free: 1.866.895.8101  
[investor\\_relations@vermillionenergy.com](mailto:investor_relations@vermillionenergy.com)  
[vermillionenergy.com](http://vermillionenergy.com)