

# FIRST QUARTER REPORT

EXCELLENCE. TRUST. RESPECT. RESPONSIBILITY.

DEFINED PRODUCTION GROWTH | RELIABLE & GROWING DIVIDENDS

VERMILION  
ENERGY



Vermilion Energy Inc. ("Vermilion", "We", "Our", "Us" or the "Company") (TSX, NYSE: VET) is pleased to report operating and unaudited financial results for the three months ended March 31, 2016.

## HIGHLIGHTS

- Achieved average production of 65,389 boe/d during the first quarter of 2016, an increase of 7% as compared to 61,058 boe/d in the prior quarter, with significant increases recorded in our Irish and Canadian operations. Production increased 30% from 50,386 boe/d in the first quarter of 2015, with higher volumes from our Irish, French, Netherlands, Australian, Canadian and U.S. business units.
- Fund flows from operations ("FFO") for Q1 2016 of \$93.7 million (\$0.83/basic share<sup>(1)</sup>) represented a decrease of 31% quarter-over-quarter and 22% year-over-year. The quarter-over-quarter decrease in FFO was attributable to lower commodity prices and an inventory build in Australia (due to the timing of crude liftings), partially offset by lower operating expenses from our ongoing focus on cost reduction.
- During Q1, we announced a reduction in our 2016 E&D capital budget from \$285 million to \$235 million. Despite the \$50 million reduction in capital investment, we still anticipate delivering nearly 10% per share production growth on a year-over-year basis. Our production guidance for 2016 remains 62,500 to 63,500 boe/d.
- Since the initiation of first gas on December 30, 2015, Corrib has produced strongly, with robust well deliverability and minimal downtime. Net production for Q1 2016 averaged approximately 34 mmcf/d (5,650 boe/d). Five of the six wells are capable of production with the remaining well to be brought online in the third quarter of 2016 following conclusion of our offshore work program. Production remains subject to limitations on maximum pipeline operating pressures while previously-planned certification activities are conducted on the Irish distribution pipeline network. Upon completion of the recertification process, production levels at Corrib are expected to rise to an estimated peak rate of 58 mmcf/d (9,700 boe/d), net to Vermilion.
- We continue to prioritize the strength of our balance sheet and the long-term profitability of our business through our Profitability Enhancement Program ("PEP") initiative. PEP cost savings related to capital spending, operating expenses and G&A expenditures reached nearly \$90 million for full-year 2015. For 2016, we expect to deliver a further \$30 to \$40 million of cost reductions.
- We redeemed the senior unsecured notes that were due February 10, 2016 by using funds from our revolving credit facility. Our revolving credit facility limit of \$2.0 billion remains unchanged and we have approximately \$520 million of borrowing capacity available. We were in compliance with all covenants as of March 31, 2016 and expect to remain in compliance based on commodity strip pricing.
- Vermilion was recognized by the Great Place to Work® Institute as a Best Workplace in Canada, France, the Netherlands and Germany in 2016. Vermilion was the only energy company to rank on the Best Workplaces lists in Canada and France. The Great Place to Work awards recognize Vermilion's strong corporate culture, a key driver of Vermilion's leading long-term corporate performance.
- Vermilion was recently ranked 9<sup>th</sup> by Corporate Knights on the Future 40 Responsible Corporate Leaders in Canada list, an improvement over last year's ranking of 15<sup>th</sup>. We are the highest rated oil and gas company on the list of top sustainability performers. This recognition reflects Vermilion's focus on financial results combined with exemplary environmental, social and governance performance. Please refer to our Sustainability Report at <http://sustainability.vermilionenergy.com/> for more information about our environmental and social stewardship.

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

## HIGHLIGHTS

(\$M except as indicated) Financial	Three Months Ended		
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015
Petroleum and natural gas sales	177,385	234,319	195,885
Fund flows from operations	93,667	136,441	120,795
Fund flows from operations (\$/basic share) <sup>(1)</sup>	0.83	1.22	1.12
Fund flows from operations (\$/diluted share) <sup>(1)</sup>	0.82	1.21	1.11
Net (loss) earnings	(85,848)	(142,080)	1,275
Net (loss) earnings (\$/basic share)	(0.76)	(1.28)	0.01
Capital expenditures	62,773	128,996	174,311
Acquisitions	870	6,227	35
Asset retirement obligations settled	2,024	4,921	3,107
Cash dividends (\$/share)	0.645	0.645	0.645
Dividends declared	72,847	71,965	69,390
% of fund flows from operations	78%	53%	57%
Net dividends <sup>(1)</sup>	24,857	25,201	48,012
% of fund flows from operations	27%	18%	40%
Payout <sup>(1)</sup>	89,654	159,118	225,430
% of fund flows from operations	96%	117%	187%
% of fund flows from operations (excluding the Corrib project) <sup>(1)</sup>	N/A	106%	173%
Net debt	1,367,063	1,381,951	1,388,603
Ratio of net debt to annualized fund flows from operations	3.6	2.5	2.9
<b>Operational</b>			
Production			
Crude oil and condensate (bbls/d)	29,199	31,304	29,514
NGLs (bbls/d)	2,672	2,739	1,706
Natural gas (mmcf/d)	201.11	162.09	115.00
Total (boe/d)	65,389	61,058	50,386
Average realized prices			
Crude oil, condensate and NGLs (\$/bbl)	39.35	51.64	58.25
Natural gas (\$/mmbtu)	3.76	4.55	5.26
Production mix (% of production)			
% priced with reference to WTI	20%	21%	28%
% priced with reference to AECO	25%	24%	20%
% priced with reference to TTF and NBP	26%	20%	18%
% priced with reference to Dated Brent	29%	35%	34%
Netbacks (\$/boe)			
Operating netback	21.63	28.44	31.30
Fund flows from operations netback	16.12	23.91	29.07
Operating expenses	9.58	11.50	10.56
Average reference prices			
WTI (US \$/bbl)	33.45	42.18	48.63
Edmonton Sweet index (US \$/bbl)	29.76	39.72	41.83
Dated Brent (US \$/bbl)	33.89	43.69	53.97
AECO (\$/mmbtu)	1.83	2.46	2.75
TTF (\$/mmbtu)	5.70	7.28	8.70
Average foreign currency exchange rates			
CDN \$/US \$	1.37	1.34	1.24
CDN \$/Euro	1.52	1.46	1.40
<b>Share information ('000s)</b>			
Shares outstanding - basic	113,451	111,991	107,718
Shares outstanding - diluted <sup>(1)</sup>	116,491	115,025	110,761
Weighted average shares outstanding - basic	112,725	111,393	107,513
Weighted average shares outstanding - diluted <sup>(1)</sup>	114,110	112,543	109,305

<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 Management's Discussion and Analysis.

**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", 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; estimated contingent resources; 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.

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.

## MESSAGE TO SHAREHOLDERS

While oil prices have now risen from the lows reached in Q1 2016, we continue to experience significant volatility in energy commodity prices and uncertainty as to the timing of a sustained price recovery. During this period of challenging economic conditions in the energy sector, a number of companies have been forced to undertake asset sales and dividend reductions or cancellations to remain viable. At Vermilion, we have always taken a conservative approach to managing our balance sheet, historically maintaining significantly lower leverage than many of our peers. Consequently, we entered the commodity price downturn in a position of relative financial strength, allowing us to maintain an adequate balance sheet through cost and investment reductions without the need to undertake asset sale or dividend reduction measures. Our first priority remains the protection of our balance sheet, followed by protection of our dividend. We believe our Company remains well positioned on both accounts. At the same time, we have been making very capital-efficient investments in our business to continue to record strong production growth per share.

We remain committed to preserving this sustainable business model. We are basing our cost and investment structure on the current commodity price strip, ensuring that fund flows from operations exceed our cash outflows for net dividends and exploration and development ("E&D") capital expenditures. During the first quarter, we reduced our planned E&D capital budget by \$50 million to enhance Vermilion's sustainability in the falling commodity price environment. The resulting \$235 million E&D budget represents a decrease of over 50% from 2015 levels and more than 65% from 2014 levels. Despite this significant reduction in capital investment, we still anticipate delivering production of between 62,500 to 63,500 boe/d, reflecting year-over-year production growth of 15%, or nearly 10% on a per share basis. Production additions from Corrib plus growth in other business units made possible through significantly improved capital efficiencies have enabled this strong per share growth despite significantly lower capital investment levels.

For 2016, we intend to adhere closely to our \$235 million E&D capital budget. Using recent commodity strip pricing and taking into account this planned level of spending, we expect to incur only minimal cash taxes, estimated at \$10 to \$20 million, and project a total payout ratio of less than 80%. Should a meaningful recovery in commodity prices occur in 2016, we expect to direct the vast majority of incremental cash flow to debt reduction rather than increasing capital spending. Conversely, if there is significant deterioration in commodity prices, we would seek to reduce our expenditures further to avoid incurring additional debt on our balance sheet.

Our international diversification provides structural pricing advantages that differentiate Vermilion from its peers. While European natural gas prices have been under pressure in 2016, they remain substantially above North American gas prices. In addition, our overseas oil production is indexed to Dated Brent, which continues to trade at a premium to WTI. Overall, the prices realized for our international production exceed those received by most North American producers and most particularly by our Canadian peers. Our price-advantaged Brent crude oil and European natural gas business units are anticipated to generate approximately 80% of Vermilion's 2016 fund flows from operations, and the majority of our 2016 capital expenditures are directed to these business units to exploit this advantage.

Vermilion's international exposure and diversified project inventory also provide flexibility to react to changing conditions and selectively allocate capital to the highest rate of return projects for a given commodity environment. This advantage is even more evident when capital availability is restricted. Since the announcement of our \$235 million capital budget, we have further revised some of our planned activities including the reinstatement of a two (0.9 net) well drilling program in the Netherlands, finding investment and cost reductions elsewhere in our budget to fund the Netherlands wells.

We have included the two Netherlands wells in our 2016 capital program because of the prolific productivity of our Netherlands gas reservoirs and the premium price received for our European natural gas. We plan to drill the Langezwaag-03 (42% working interest) and Andel-6ST (45% working interest) wells during Q3 2016. If successful, we expect to bring the wells on-stream late in the third and fourth quarters of 2016, respectively. Activities in France will continue to focus on our highly-economic workover and optimization activities. In Germany, the majority of our capital in 2016 will be directed to permitting and pre-drill activities for the planned drilling of the Burgmoor Z5 well and two potential exploration prospects in 2017.

Since the initiation of first gas at Corrib in Ireland on December 30, 2015, we have experienced robust well deliverability and minimal downtime. Net production in Q1 2016 averaged approximately 34 mmcf/d (5,650 boe/d). Field production is subject to limitations on maximum pipeline operating pressures that will remain in effect until the planned recertification process for the third party sales gas distribution pipeline network is concluded. Five of the six wells are capable of producing, with the remaining well to be brought online in the third quarter of 2016 following the conclusion of our offshore work program to lay a pipeline to the sixth well. Upon completion of the recertification process, production levels at Corrib are expected to rise to an estimated peak rate of 58 mmcf/d (9,700 boe/d), net to Vermilion. Corrib remains one of the drivers of our 2016 and 2017 production growth, and is expected to be an important contributor to free cash flow<sup>(1)</sup> in this and coming years.

Following our successful sidetrack well drilled from the Wandoo A platform in Q4 2015, we are planning a two-well drilling program in Q2 2016. Offshore drilling in Australia requires a great deal of advance contracting and logistical planning, which means that full-cycle costs are minimized by maintaining funding for this project in 2016 despite current oil price weakness. Furthermore, with service costs near their lows, it is an advantageous time to drill these high-quality sidetrack wells.

In Canada, our Mannville condensate-rich gas assets performed strongly in the first quarter with average production of 13,000 boe/d, an increase of 18% percent over the prior quarter. This significant production increase resulted from the combination of both operated and non-operated drilling and completion activity, as well as the re-start of non-operated wells that were previously shut-in due to infrastructure capacity constraints. Our drilling, completion, equip and tie-in ("DCET") costs continue to improve as a result of our ongoing focus on operational and process improvements and continued service cost reductions. Our DCET costs in the Mannville averaged \$3.6 million per well in the first quarter of 2016, a nearly 15% reduction as compared to our average DCET of \$4.2 million per well in 2015, and approximately a 40% reduction from our cost level when we initiated this play three years ago.

Similarly, cycle times and costs continue to trend lower in our Midale light oil development in southeast Saskatchewan. Since assuming operations in 2014, we have achieved more than a 35% reduction in average drilling days per well, as well as benefitting from lower service costs. Expected DCET costs for a typical one-mile Midale horizontal well are now \$1.9 million, down 35% as compared to \$2.9 million in 2014. In the first quarter we drilled six (4.5 net) oil wells in the Midale, including three (3.0 net) operated wells, to prevent mineral land expiries. All three operated wells had strong oil indicators, but we have elected to leave these wells standing uncompleted. While the wells are economic to complete, we believe that net present value will be enhanced by delaying completion and tie-in until oil prices improve.

In the United States, we are disclosing results for several wells drilled in our shallow Turner Sand play on the eastern flank of the Powder River Basin in Wyoming. The Seedy Draw North Federal 1H well was completed in Q3 2015 in the Turner Shurley Sand in the southern part of our contiguous 83,250 acre lease block. This well is significantly outperforming our 275 mbbl oil type curve established from a nearby well drilled by the previous operator. Peak production of approximately 300 bbls/d of oil was recorded in the third through fifth months of production. The Seedy Draw North Federal 1H is currently producing 200 bbls/d of oil (240 boed/d including gas production) in its ninth month of production, with cumulative oil production to-date of 63 mbbls.

Two additional wells drilled in the Turner Shurley Sand in Q4 2015 were completed during the first quarter. Both wells were completed with 20-stage fracturing treatments along 1,400 meter horizontal laterals at a vertical depth of approximately 1,500 meters. One of the wells (the Coyote Draw Federal 1H), located in the north part of our lease block, has been on production for one month at a current oil rate of 150 bbls/d, and is expected to continue to increase in production as load water is recovered and the well cleans up. The second well (the Reed Federal 17-1H) was drilled in the southern area, approximately one mile from our Seedy Draw North Federal 1H well. The Reed Federal 17-1H was successfully fracture stimulated, but we unfortunately junked almost the entire horizontal liner section when we attempted to drill out the frac plugs. The well is producing 65 bbls/d of oil from approximately 10% of the completed horizontal section. Despite the mechanical failure of the Reed Federal 17-1H, we consider these well results very encouraging in terms of productivity as we begin development of this large contiguous lease block in the Turner Sand.

We entered the current commodity downturn in a position of relative financial strength, and we took a number of actions throughout 2015 to preserve our balance sheet. During Q1 2016, we redeemed our senior unsecured notes that came due on February 10, 2016 using funds drawn against our revolving credit facility. Following the redemption, all of our debt is now classified as senior debt pursuant to the terms of the revolving credit facility. As a result, we requested, and received amendments from our lending syndicate to eliminate the consolidated total senior debt to consolidated EBITDA<sup>(2)</sup> financial covenant and increase the ratio of consolidated total senior debt to total capitalization financial covenant from 50% to 55%. The revolving credit facility limit of \$2.0 billion remains unchanged and we have approximately \$520 million of borrowing capacity available. We were in compliance with all covenants as of March 31, 2016 and expect, based on 2016 commodity strip pricing, to remain in compliance with the amended financial covenants.

We continue to prioritize the strength of our balance sheet and the long-term profitability of our business through our Profitability Enhancement Program ("PEP") initiative. Associated PEP cost savings related to capital spending, operating expense and G&A expenditures reached nearly \$90 million for full-year 2015. For 2016, we expect to deliver a further \$30 to \$40 million of cost reductions. Our focus on driving down costs has generated tangible results. Finding and development costs<sup>(3)</sup>, as estimated at year-end 2015, were down 48% year-over-year and our unit operating expenses for Q1 2016 are down 17% quarter-over-quarter and 9% year-over-year, reflecting both increased volumes and our reduced cost structure.

Vermilion was recently ranked 9<sup>th</sup> by Corporate Knights on the Future 40 Responsible Corporate Leaders in Canada list, an improvement over last year's ranking of 15<sup>th</sup>. We are also the highest rated oil and gas company on the list of top sustainability performers. This recognition reflects Vermilion's focus on financial results combined with exemplary environmental, social and governance performance.

Vermilion was recognized by the Great Place to Work<sup>®</sup> Institute as a Best Workplace in Canada, France, the Netherlands and Germany in 2016. Vermilion was the only energy company to rank on the Best Workplaces lists in Canada and in France. The Great Place to Work<sup>®</sup> awards recognize Vermilion's strong corporate culture, a key driver of Vermilion's leading long-term corporate performance.

In spite of the challenges posed by the current commodity environment, we continue to believe our long-term strategy will position Vermilion to exit this downturn stronger than ever. All Vermilion employees are shareholders, and management and directors hold approximately 6% of our outstanding shares, ensuring alignment of interests to deliver long-term value. We believe that our diversified asset portfolio and operational capabilities position us to protect our balance sheet, defend our dividend, and continue long-term growth.

*(“Anthony Marino”)*

Anthony Marino  
President & Chief Executive Officer  
May 5, 2016

(1) Non-GAAP Financial Measure. Please see the “Non-GAAP Financial Measures” section of Management’s Discussion and Analysis.

(2) Our covenants include financial measures defined within our revolving credit facility. Please see the “Financial Position Review” section of the Management’s Discussion and Analysis.

(3) Finding and development costs are used as a measure of capital efficiency and are calculated by dividing the applicable capital costs for the period, including the change in undiscounted future development capital, by the change in the reserves, incorporating revisions and production, for the same period.

## ORGANIZATIONAL UPDATE

We wish to acknowledge that Joe Killi and Kevin Reinhart are not standing for re-election as directors at the May 6, 2016 Annual General Meeting. Both individuals have been key contributors to Vermilion's success during their tenures with the Board and we would like to take this opportunity to thank them for their valuable counsel and wish them all the best in their future endeavours.

## MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is Management's Discussion and Analysis ("MD&A"), dated May 5, 2016, of Vermilion Energy Inc.'s ("Vermilion", "We", "Our", "Us" or the "Company") operating and financial results as at and for the three months ended March 31, 2016 compared with the corresponding period in the prior year.

This discussion should be read in conjunction with the unaudited condensed consolidated interim financial statements for the three months ended March 31, 2016 and the audited consolidated financial statements for the year ended December 31, 2015 and 2014, together with 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 months ended March 31, 2016 and comparative information have been prepared in Canadian dollars, except where another currency is indicated, and in accordance with IAS 34, "Interim Financial Reporting", as issued by the International Accounting Standard Board ("IASB").

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

- Fund flows from operations: This financial measure is calculated as cash flows from operating activities before changes in non-cash operating working capital and asset retirement obligations settled. 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 cash necessary to pay dividends, repay debt, fund asset retirement obligations and make capital investments.
- Netbacks: These financial measures are per boe and per mcf 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 third party crude oil and natural gas producers.

In addition, this MD&A includes references to certain financial measures which do not have standardized meanings prescribed by IFRS and are not disclosed in our financial statements. As such, these financial measures are considered non-GAAP financial measures and therefore are unlikely to be comparable with 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".

## 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.

This MD&A separately discusses each of our business units in addition to our corporate segment.

- Canada business unit: Relates to our assets in Alberta and Saskatchewan.
- France business unit: Relates to our operations in France in the Paris and Aquitaine Basins.
- Netherlands business unit: Relates to our operations in the Netherlands.
- Germany business unit: Relates to our operations in Germany.
- Ireland business unit: Relates to our 18.5% non-operated interest in the Corrib offshore natural gas field.
- Australia business unit: Relates to our operations in the Wandoo offshore crude oil field.
- United States business unit: Relates to our operations in Wyoming in the Powder River Basin.
- Corporate: Includes expenditures related to our global hedging program, financing expenses, and general and administration expenses that are primarily incurred in Canada and are not directly related to the operations of a specific business unit.



**CHANGE IN PRESENTATION**

Prior to 2016, we reported our condensate production in Canada and the Netherlands business units within the NGLs production line. Beginning in Q1 2016, we now report condensate production within the crude oil and condensate production line. We believe that this presentation better reflects the historical and forecasted pricing for condensate, which is more closely correlated with crude oil pricing than with pricing for propane, butane and ethane (collectively "NGLs" for the purposes of this report). Comparative periods have been adjusted to reflect this change.

**2015 REVIEW AND 2016 GUIDANCE**

On November 9, 2015 we announced preliminary 2016 capital expenditure guidance of \$350 million and production guidance of between 63,000-65,000 boe/d. On January 5, 2016, in response to the continued weakness in commodity prices we adjusted our 2016 capital expenditure guidance to \$285 million with corresponding production guidance of 62,500-63,500 boe/d. On February 29, 2016, we further revised our 2016 capital expenditure guidance to \$235 million as a result of continued commodity price deterioration. We maintained our production guidance of 62,500-63,500 boe/d. The February 29, 2016 reduction primarily reflects lower expected non-operated drilling activity in Canada, fewer workovers in France, and a deferral of our Netherlands pipeline twinning program.

The following table summarizes our 2016 guidance:

	<b>Date</b>	<b>Capital Expenditures (\$MM)</b>	<b>Production (boe/d)</b>
<b>2016 Guidance</b>			
2016 Guidance	November 9, 2015	350	63,000 to 65,000
2016 Guidance	January 5, 2016	285	62,500 to 63,500
2016 Guidance	February 29, 2016	235	62,500 to 63,500

## CONSOLIDATED RESULTS OVERVIEW

	Three Months Ended			% change	
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015	Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
<b>Production</b>					
Crude oil and condensate (bbls/d)	29,199	31,304	29,514	(7%)	(1%)
NGLs (bbls/d)	2,672	2,739	1,706	(2%)	57%
Natural gas (mmcf/d)	201.11	162.09	115.00	24%	75%
Total (boe/d)	65,389	61,058	50,386	7%	30%
Build (draw) in inventory (mbbls)	142	(93)	383		
<b>Financial metrics</b>					
Fund flows from operations (\$M)	93,667	136,441	120,795	(31%)	(22%)
Per share (\$/basic share)	0.83	1.22	1.12	(32%)	(26%)
Net (loss) earnings	(85,848)	(142,080)	1,275	(40%)	(6,833%)
Per share (\$/basic share)	(0.76)	(1.28)	0.01	(41%)	(7,700%)
Cash flows from operating activities (\$M)	73,883	164,863	22,647	(55%)	226%
Net debt (\$M)	1,367,063	1,381,951	1,388,603	(1%)	(2%)
Cash dividends (\$/share)	0.645	0.645	0.645	-	-
<b>Activity</b>					
Capital expenditures (\$M)	62,773	128,996	174,311	(51%)	(64%)
Acquisitions (\$M)	870	6,227	35	(86%)	2,386%
Gross wells drilled	12.00	8.00	29.00		
Net wells drilled	8.26	5.56	20.04		

## Operational review

- Recorded consolidated average production of 65,389 boe/d in Q1 2016, which was a 7% increase over Q4 2015. This quarter-over-quarter increase was driven by a full quarter of production from Corrib and increased production in Canada.
- Increased consolidated average production from Q1 2015 by 30%, primarily due to the addition of Corrib production in Ireland, as well as production growth in all our business units except Germany, where production modestly declined.
- Executed capital expenditures totalling \$62.8 million, primarily in Canada and France. In Canada, capital expenditures of \$29.8 million were 8% higher than Q4 2015 and related to the drilling of 8.3 net wells (2.6 net wells in Q4 2015). In France, capital expenditures of \$13.5 million were 44% lower than Q4 2015 and related primarily to accretive workovers and subsurface activity.

## Financial review

*Net (loss) earnings*

- The net loss for Q1 2016 was \$85.8 million (\$0.76/basic share), as compared to a net loss of \$142.1 million (\$1.28/basic share) in Q4 2015. The decrease in the net loss was primarily attributable to a lower impairment charge recognized in the quarter, partially offset by lower petroleum and natural gas sales due to weakening commodity prices.
- The net loss in Q1 2016 represented a decrease of \$87.1 million versus the comparable period in 2015. This decrease was driven primarily by lower petroleum and natural gas sales as a result of lower commodity prices, the impact of the de-recognition of certain deferred tax assets, an impairment charge recognized in Ireland, and the absence of a \$31.8 million court-awarded recovery recognized in Q1 2015. The impact of weakened commodity prices was partially offset by significant production growth, global cost reductions (including a 9% reduction in per unit operating expense), and gains on derivative instruments.

*Cash flows from operating activities*

- Absent changes in working capital, cash flows from operating activities decreased by 30% quarter-over-quarter due to lower petroleum and natural gas sales driven by lower commodity prices.
- Absent changes in working capital, cash flows from operating activities decreased by 22% for the three months ended March 31, 2016, versus the comparable period in 2015. This decrease was primarily related to lower petroleum and natural gas sales due to lower commodity prices, partially offset by realized gains on derivative instruments and lower current taxes.

*Fund flows from operations*

- Generated fund flows from operations of \$93.7 million during Q1 2016, a decrease of 31% from Q4 2015. This quarter-over-quarter decrease was primarily driven by unfavourable pricing variances on all commodities and lower volumes sold in Australia due to a build in inventory. The impact of lower pricing was minimized by a full quarter of production from Corrib and decreased operating costs resulting from global cost reductions.
- Fund flows from operations decreased by 22% versus Q1 2015. This decrease was the result of lower pricing on all commodities and the absence of the \$31.8 million court-awarded recovery recognized in Q1 2015, partially offset by global cost reductions, realized gains on derivative instruments, and lower current taxes.

*Net debt*

- Net debt decreased by \$14.9 million to \$1.37 billion for the three months ended March 31, 2016, as we maintained a payout ratio of 96%.

*Dividends*

- Declared dividends of \$0.215 per common share per month during the first quarter of 2016, totalling \$0.645 per common share for the quarter.

## COMMODITY PRICES

	Three Months Ended			% change	
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015	Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
<b>Average reference prices</b>					
Crude oil					
WTI (US \$/bbl)	33.45	42.18	48.63	(21%)	(31%)
Edmonton Sweet index (US \$/bbl)	29.76	39.72	41.83	(25%)	(29%)
Dated Brent (US \$/bbl)	33.89	43.69	53.97	(22%)	(37%)
Natural gas					
AECO (\$/mmbtu)	1.83	2.46	2.75	(26%)	(33%)
TTF (\$/mmbtu)	5.70	7.28	8.70	(22%)	(34%)
TTF (€/mmbtu)	3.76	4.98	6.23	(24%)	(40%)
NBP (\$/mmbtu)	5.97	7.41	9.01	(19%)	(34%)
NBP (€/mmbtu)	3.94	5.07	6.45	(22%)	(39%)
Henry Hub (\$/mmbtu)	2.87	3.03	3.70	(5%)	(22%)
Henry Hub (US \$/mmbtu)	2.09	2.27	2.98	(8%)	(30%)
<b>Average foreign currency exchange rates</b>					
CDN \$/US \$	1.37	1.34	1.24	2%	10%
CDN \$/Euro	1.52	1.46	1.40	4%	9%
<b>Average realized prices (\$/boe)</b>					
Canada	21.16	28.94	35.81	(27%)	(41%)
France	43.16	54.20	64.33	(20%)	(33%)
Netherlands	33.26	42.61	48.60	(22%)	(32%)
Germany	31.78	39.68	45.21	(20%)	(30%)
Ireland	33.07	-	-	100%	100%
Australia	46.93	58.74	83.80	(20%)	(44%)
United States	30.10	41.94	48.79	(28%)	(38%)
Consolidated	30.53	41.04	47.17	(26%)	(35%)
<b>Production mix (% of production)</b>					
% priced with reference to WTI	20%	22%	28%		
% priced with reference to AECO	25%	24%	20%		
% priced with reference to TTF and NBP	26%	20%	18%		
% priced with reference to Dated Brent	29%	34%	34%		

- Oil benchmarks continued to move lower throughout Q1 2016, pressured by the ongoing fundamental conditions. For Q1 2016, Dated Brent and WTI prices decreased by approximately 20% versus Q4 2015. On a year-over-year basis, WTI was down 31% and Dated Brent was down 37%.
- Crude oil prices set at Edmonton were equally as volatile during Q1 2016, averaging the quarter at US \$29.76/bbl, 25% lower quarter-over-quarter, and 29% lower year-over-year.
- AECO natural gas prices declined in Q1 2016 due to the warmer-than-normal winter which lessened demand. For Q1 2016, AECO averaged \$1.83/mmbtu, 26% lower quarter-over-quarter and down 33% year-over-year.
- A warmer winter in Europe combined with ample supply caused European natural gas prices to post a 22% quarter-over-quarter decline to average \$5.70/mmbtu at TTF. NBP performed slightly better than TTF, with a quarter-over-quarter loss of 19%. The smaller decrease was due to stronger demand from coal-to-gas switching for power generation in the UK. On a year-over-year basis, both TTF and NBP were down 34%.
- Despite exiting the first quarter with a stronger Canadian dollar versus the US dollar, the average exchange rate for the quarter still favoured a stronger US dollar. The Canadian dollar also weakened against the Euro, with Q1 2016 averaging 1.52 versus 1.46 in Q4 2015 and 1.40 in Q1 2015.

## FUND FLOWS FROM OPERATIONS

	Three Months Ended					
	Mar 31, 2016		Dec 31, 2015		Mar 31, 2015	
	\$M	\$/boe	\$M	\$/boe	\$M	\$/boe
Petroleum and natural gas sales	177,385	30.53	234,319	41.04	195,885	47.17
Royalties	(13,961)	(2.40)	(16,285)	(2.85)	(16,424)	(3.95)
Petroleum and natural gas revenues	163,424	28.13	218,034	38.19	179,461	43.22
Transportation	(10,390)	(1.79)	(10,147)	(1.78)	(9,540)	(2.30)
Operating	(55,628)	(9.58)	(65,645)	(11.50)	(43,851)	(10.56)
General and administration	(13,577)	(2.34)	(12,431)	(2.18)	(13,560)	(3.27)
PRRT	(128)	(0.02)	(1,054)	(0.18)	(2,354)	(0.57)
Corporate income taxes	(3,160)	(0.54)	3,113	0.55	(17,623)	(4.24)
Interest expense	(14,750)	(2.54)	(16,584)	(2.90)	(13,298)	(3.20)
Realized gain on derivative instruments	28,423	4.89	21,164	3.71	6,257	1.51
Realized foreign exchange (loss) gain	(652)	(0.11)	(252)	(0.04)	3,306	0.78
Realized other income	105	0.02	243	0.04	31,997	7.70
Fund flows from operations	93,667	16.12	136,441	23.91	120,795	29.07

The following table shows a reconciliation of the change in fund flows from operations:

(\$M)	Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
<b>Fund flows from operations – Comparative period</b>	<b>136,441</b>	<b>120,795</b>
Sales volume variance:		
Canada	684	6,322
France	(2,470)	11,538
Netherlands	(2,473)	12,812
Germany	(245)	(464)
Ireland	16,947	17,004
Australia	(23,000)	16,313
United States	(229)	545
Pricing variance on sold volumes:		
WTI	(13,270)	(18,885)
AECO	(5,658)	(9,195)
Dated Brent	(17,833)	(38,907)
TTF and NBP	(9,387)	(15,583)
Changes in:		
Royalties	2,324	2,463
Transportation	(243)	(850)
Operating	10,017	(11,777)
General and administration	(1,146)	(17)
PRRT	926	2,226
Corporate income taxes	(6,273)	14,463
Interest	1,834	(1,452)
Realized derivatives	7,259	22,166
Realized foreign exchange	(400)	(3,958)
Realized other income	(138)	(31,892)
<b>Fund flows from operations – Current period</b>	<b>93,667</b>	<b>93,667</b>

Fund flows from operations of \$93.7 million during Q1 2016 represented a decrease of 31% versus Q4 2015. This decrease relates primarily to lower pricing on all commodities and a 138,000 bbls build in inventory in Australia (compared to a draw of 97,000 bbls in Q4 2015). The impact of lower pricing was minimized by a full quarter of production from Corrib and global cost reductions, including a 15% decrease in operating costs.

Fund flows from operations decreased 22% for the three months ended March 31, 2016, versus the comparable period in 2015. The decrease was the result of lower pricing for all commodities and the absence of a \$31.8 million court-awarded recovery recognized in Q1 2015. The decrease in pricing was partially offset by global cost reductions (including a 9% reduction in per unit operating expense), realized gains on derivative instruments, and lower current taxes.

Fluctuations in fund flows from operations (and correspondingly net (loss) earnings and cash flows from operating activities) may occur as a result of changes in commodity prices and costs to produce petroleum and natural gas. In addition, fund flows from operations may be highly 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 in income.

**CANADA BUSINESS UNIT****Overview**

- Production and assets focused in West Pembina near Drayton Valley, Alberta and Northgate in southeast Saskatchewan.
- Potential for three significant resource plays sharing the same surface infrastructure in the West Pembina region in Alberta:
  - Cardium light oil (1,800m depth) – in development phase
  - Mannville condensate-rich gas (2,400 – 2,700m depth) – in development phase
  - Duvernay condensate-rich gas (3,200 – 3,400m depth) – in appraisal phase
- Canadian cash flows are fully tax-sheltered for the foreseeable future.

**Operational review**

	Three Months Ended			% change	
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015	Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
<b>Canada business unit</b>					
<b>Production</b>					
Crude oil and condensate (bbls/d)	10,317	10,413	12,163	(1%)	(15%)
NGLs (bbls/d)	2,633	2,710	1,706	(3%)	54%
Natural gas (mmcf/d)	97.16	87.90	61.78	11%	57%
Total (boe/d)	29,141	27,773	24,165	5%	21%
<b>Production mix (% of total)</b>					
Crude oil and condensate	35%	38%	50%		
NGLs	9%	10%	7%		
Natural gas	56%	52%	43%		
<b>Activity</b>					
Capital expenditures (\$M)	29,771	27,554	114,849	8%	(74%)
Acquisitions (\$M)	755	6,169	35		
Gross wells drilled	12.00	5.00	25.00		
Net wells drilled	8.26	2.56	16.04		

**Production**

- Q1 2016 average production in Canada increased by 5% quarter-over-quarter and 21% year-over-year, primarily attributable to strong organic production growth in our Mannville condensate-rich gas resource play.
- Cardium production averaged more than 7,500 boe/d in Q1 2016, a 5% decrease quarter-over-quarter.
- Mannville production averaged approximately 13,000 boe/d in Q1 2016, an 18% increase quarter-over-quarter and more than 2.5 times Q1 2015 production of approximately 4,850 boe/d.
- Production from our southeast Saskatchewan assets averaged approximately 2,700 boe/d in Q1 2016, an increase of 6% quarter-over-quarter.

**Activity review**

- Vermilion drilled six (5.7 net) operated wells and participated in the drilling of six (2.6 net) non-operated wells during Q1 2016.

*Cardium*

- In Q1 2016, no new operated wells were drilled, completed or brought on production. Two (0.31 net) non-operated wells were brought on production during the quarter.
- 2016 activity will focus on the optimization of existing assets.

*Mannville*

- During Q1 2016, we participated in a total of six (3.8 net) wells, including three (2.7 net) operated wells. Three (2.7 net) operated wells and four (1.5 net) non-operated wells were brought on production during the quarter.
- We completed a 3D seismic program in the northern portion of our Drayton Valley lands. The program covered 34 net sections, including lands acquired in 2015.
- Our 2016 program to drill or participate in six (3.8 net) wells was completed in the first quarter.

*Saskatchewan*

- We drilled three (3.0 net) operated Midale wells during Q1 2016 and participated in the drilling of three (1.5 net) non-operated Midale wells. Completion and tie-in of the three operated wells is currently planned for Q1 2017. Two of the three non-operated wells were placed on production in Q1 2016, with the remaining non-operated well to be placed on production in Q2 2016.
- Q1 2016 activity included the acquisition and processing of 3D seismic of 16 net sections (100% Vermilion interest) in the West Pinto area
- In 2016, we plan to drill or participate in seven (5.5 net) wells.

## Financial review

Canada business unit (\$M except as indicated)	Three Months Ended			% change	
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015	Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
Sales	56,110	73,952	77,884	(24%)	(28%)
Royalties	(5,498)	(7,146)	(8,592)	(23%)	(36%)
Transportation	(4,151)	(3,784)	(3,942)	10%	5%
Operating	(21,343)	(24,575)	(19,099)	(13%)	12%
General and administration	(2,476)	(3,669)	(4,015)	(33%)	(38%)
Fund flows from operations	22,642	34,778	42,236	(35%)	(46%)
<b>Netbacks (\$/boe)</b>					
Sales	21.16	28.94	35.81	(27%)	(41%)
Royalties	(2.07)	(2.80)	(3.95)	(26%)	(48%)
Transportation	(1.57)	(1.48)	(1.81)	6%	(13%)
Operating	(8.05)	(9.62)	(8.78)	(16%)	(8%)
General and administration	(0.94)	(1.44)	(1.85)	(35%)	(49%)
Fund flows from operations netback	8.53	13.60	19.42	(37%)	(56%)
<b>Realized prices</b>					
Crude oil and condensate (\$/bbl)	39.69	53.44	52.91	(26%)	(25%)
NGLs (\$/bbl)	7.31	7.89	22.37	(7%)	(67%)
Natural gas (\$/mmbtu)	1.93	2.57	2.97	(25%)	(35%)
Total (\$/boe)	21.16	28.94	35.81	(27%)	(41%)
<b>Reference prices</b>					
WTI (US \$/bbl)	33.45	42.18	48.63	(21%)	(31%)
Edmonton Sweet index (US \$/bbl)	29.76	39.72	41.83	(25%)	(29%)
Edmonton Sweet index (\$/bbl)	40.91	53.04	51.92	(23%)	(21%)
AECO (\$/mmbtu)	1.83	2.46	2.75	(26%)	(33%)

## Sales

- The realized price for our crude oil and condensate production in Canada is directly linked to WTI, but is also subject to market conditions in Western Canada. These market conditions can result in fluctuations in the pricing differential to WTI, as reflected by the Edmonton Sweet index price. The realized price of our NGLs in Canada is based on product specific differentials pertaining to trading hubs in the United States. The realized price of our natural gas in Canada is based on the AECO spot price in Canada.
- Q1 2016 sales per boe decreased versus all comparable periods, largely as the result of weakening crude oil and natural gas pricing.

## Royalties

- Royalties as a percentage of sales for Q1 2016 of 9.8% was consistent with the rate of 9.7% for Q4 2015.
- Royalties as a percentage of sales for Q1 2016 was lower than Q1 2015 (11.0%) due to the impact of lower reference prices on the sliding scale used to determine crude oil royalty rates.

## Transportation

- Transportation expense relates to the delivery of crude oil and natural gas production to major pipelines where legal title transfers.
- Transportation expense for Q1 2016 was higher than Q4 2015 and Q1 2015 as a result of increased natural gas production. On a year-over-year basis, the 13% decrease in per unit costs is due to an increased gas weighting and the lower per unit transportation costs associated with gas production.

## Operating

- Operating expense reductions of 13% were achieved in Q1 2016 versus Q4 2015 while growing production by 5%. The diligent focus on cost control and cost-cutting initiatives, including service cost negotiations impacting numerous cost drivers, has resulted in a 16% per unit reduction in costs from Q4 2015 and 8% from Q1 2015.

## General and administration

- General and administration expense decreased by 35% and 49% from Q4 2015 and Q1 2015 respectively. The decreases are consistent with continued cost-cutting initiatives to reduce our cost structure and preserve balance sheet strength.



## FRANCE BUSINESS UNIT

## Overview

- Entered France in 1997 and completed three subsequent acquisitions, including two in 2012.
- Largest oil producer in France, constituting approximately three-quarters of domestic oil production.
- Producing assets include large conventional fields with high working interests located in the Aquitaine and Paris Basins with an identified inventory of workover, infill drilling, and secondary recovery opportunities.
- Production is characterized by Brent-based crude pricing and low base decline rates.

## Operational review

	Three Months Ended			% change	
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015	Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
<b>France business unit</b>					
<b>Production</b>					
Crude oil (bbls/d)	12,220	12,537	11,463	(3%)	7%
Natural gas (mmcf/d)	0.44	1.36	-	(68%)	100%
Total (boe/d)	12,293	12,763	11,463	(4%)	7%
<b>Inventory (mmbbls)</b>					
Opening crude oil inventory	243	239	197		
Crude oil production	1,112	1,153	1,032		
Crude oil sales	(1,108)	(1,149)	(930)		
Closing crude oil inventory	247	243	299		
<b>Production mix (% of total)</b>					
Crude oil	99%	98%	100%		
Natural gas	1%	2%	-		
<b>Activity</b>					
Capital expenditures (\$M)	13,463	24,085	34,114	(44%)	(61%)
Acquisitions (\$M)	-	79	-		
Gross wells drilled	-	-	4.00		
Net wells drilled	-	-	4.00		

## Production

- Production decreased 4% versus the prior quarter, mainly due to a reduced capital program. Gas production from Vic Bilh was negatively impacted by third party restrictions at the SOBEGI terminal.
- Year-over-year production increased 7% due to production additions from our 2015 Champotran drilling program.

## Activity review

- During the quarter we completed a number of workover and optimization programs in the Aquitaine and Paris Basins.
- In 2016, our planned capital activity includes a program of approximately 15 well workovers.

## Financial review

France business unit (\$M except as indicated)	Three Months Ended			% change	
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015	Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
Sales	48,125	63,411	59,832	(24%)	(20%)
Royalties	(6,766)	(7,198)	(5,102)	(6%)	33%
Transportation	(3,713)	(4,275)	(3,011)	(13%)	23%
Operating	(14,320)	(15,792)	(10,826)	(9%)	32%
General and administration	(4,676)	(4,894)	(5,111)	(4%)	(9%)
Other income	-	-	31,775	-	(100%)
Current income taxes	(34)	4,529	(14,281)	(101%)	(100%)
Fund flows from operations	18,616	35,781	53,276	(48%)	(65%)
<b>Netbacks (\$/boe)</b>					
Sales	43.16	54.20	64.33	(20%)	(33%)
Royalties	(6.07)	(6.15)	(5.49)	(1%)	11%
Transportation	(3.33)	(3.65)	(3.24)	(9%)	3%
Operating	(12.84)	(13.50)	(11.64)	(5%)	10%
General and administration	(4.19)	(4.18)	(5.49)	-	(24%)
Other income	-	-	34.16	-	(100%)
Current income taxes	(0.03)	3.87	(15.35)	(101%)	(100%)
Fund flows from operations netback	16.70	30.59	57.28	(45%)	(71%)
<b>Realized prices</b>					
Crude oil (\$/bbl)	43.36	54.88	64.33	(21%)	(33%)
Natural gas (\$/mmbtu)	1.66	2.81	-	(41%)	100%
Total (\$/boe)	43.16	54.20	64.33	(20%)	(33%)
<b>Reference prices</b>					
Dated Brent (US \$/bbl)	33.89	43.69	53.97	(22%)	(37%)
Dated Brent (\$/bbl)	46.59	58.34	66.98	(20%)	(30%)

## Sales

- Crude oil in France is priced with reference to Dated Brent.
- Sales per boe decreased relative to all comparable periods, consistent with a decrease in the Dated Brent reference price. Compared to Q1 2015, the decrease in price was partially offset by increased sales volumes, resulting in a relatively lower decrease to sales.

## Royalties

- Royalties in France relate to two components: RCDM (levied on units of production and not subject to changes in commodity prices) and R31 (based on a percentage of sales).
- Royalties as a percentage of sales was 14.1% for Q1 2016, an increase over both Q4 2015 (11.4%) and Q1 2015 (8.5%) as a result of the impact of fixed RCDM royalties coupled with lower realized pricing.

## Transportation

- Transportation expense for Q1 2016 was lower versus Q4 2015 due to successful vessel cost renegotiations and a lower level of project activity at the Ambès terminal.
- Transportation expense increased year-over-year primarily due to an unfavorable foreign exchange impact and increased sales. When excluding the impact of foreign exchange, per unit costs decreased by 5% as a result of ongoing cost reduction initiatives.

**Operating**

- Operating expense decreased in Q1 2016 versus Q4 2015 as a result of a continued emphasis on cost reduction initiatives and savings from service contract renegotiations resulting in lower costs related to electricity, maintenance and labour usage. These cost reduction initiatives more than offset the unfavorable foreign exchange impact of a weakening Canadian dollar.
- Year-over-year, operating expenses increased on a dollar and per boe basis. The 7% increase in production over this period partially contributed to the increase, and, to a larger extent, the weakening of the Canadian dollar versus the Euro resulted in increased expense. After normalizing for the unfavorable foreign exchange impact, per unit costs were essentially flat year-over-year.

**General and administration**

- General and administration expense for Q1 2016 was 4% lower than Q4 2015 and 9% lower than Q1 2015 as a result of cost-cutting initiatives.

**Current income taxes**

- Current income taxes in France are applied to taxable income, after eligible deductions, at a statutory rate of 34.4% for 2016. Our France Business Unit is expected to incur minimal current income taxes for 2016. This is subject to change in response to commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.

**NETHERLANDS BUSINESS UNIT****Overview**

- Entered the Netherlands in 2004.
- Second largest onshore gas producer.
- Interests include 24 onshore licenses and two offshore licenses.
- Licenses include more than 800,000 net acres of land, 95% of which is undeveloped.

**Operational review**

	Three Months Ended			% change	
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015	Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
<b>Netherlands business unit</b>					
<b>Production</b>					
Condensate (bbls/d)	114	110	63	4%	81%
Natural gas (mmcf/d)	53.40	56.34	36.41	(5%)	47%
Total (boe/d)	9,015	9,500	6,132	(5%)	47%
<b>Activity</b>					
Capital expenditures (\$M)	2,996	18,810	4,333	(84%)	(31%)

**Production**

- Q1 2016 production decreased 5% versus the prior quarter mainly due to a decline in gas production from our Slootdorp-07 well.
- Year-over-year production increased 47%, primarily due to production additions from Diever-02 and Slootdorp-06/07 wells, and enhanced by debottlenecking at our Garijp Treatment Centre. The Diever-02 exploration well (45% working interest), which came on an extended production test in late October 2015, continues to produce approximately 13 mmcf/d (2,200 boe/d), net to Vermilion. Slootdorp-06/07, which are also on extended production tests, are currently producing approximately 23 mmcf/d (3,900 boe/d) net to Vermilion, combined.
- Production in the Netherlands is actively managed to optimize facility use and regulate declines.

**Activity review**

- Production and reservoir testing on our Slootdorp-06/07 wells will continue into Q2 2016, when permanent facility installation should be complete.
- Planning activities for the drilling of Langezwaag-03 (42% working interest) and Andel-6ST (45% working interest) were carried out during the quarter. We expect to drill these wells in Q3 2016, and if successful, we expect to have the wells on production prior to year end.
- In addition to the two (0.9 net) well drilling program, we are also planning permitting and optimization activities in 2016.

## Financial review

Netherlands business unit (\$M except as indicated)	Three Months Ended			% change	
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015	Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
Sales	27,286	37,243	26,818	(27%)	2%
Royalties	(460)	(224)	(926)	105%	(50%)
Operating	(5,976)	(6,263)	(5,826)	(5%)	3%
General and administration	(773)	(813)	(737)	(5%)	5%
Current income taxes	(2,200)	(2,930)	(2,388)	(25%)	(8%)
Fund flows from operations	17,877	27,013	16,941	(34%)	6%
<b>Netbacks (\$/boe)</b>					
Sales	33.26	42.61	48.60	(22%)	(32%)
Royalties	(0.56)	(0.26)	(1.68)	115%	(67%)
Operating	(7.28)	(7.17)	(10.56)	2%	(31%)
General and administration	(0.94)	(0.93)	(1.34)	1%	(30%)
Current income taxes	(2.68)	(3.35)	(4.33)	(20%)	(38%)
Fund flows from operations netback	21.80	30.90	30.69	(29%)	(29%)
<b>Realized prices</b>					
Condensate (\$/bbl)	32.24	48.30	52.93	(33%)	(39%)
Natural gas (\$/mmbtu)	5.55	7.09	8.09	(22%)	(31%)
Total (\$/boe)	33.26	42.61	48.60	(22%)	(32%)
<b>Reference prices</b>					
TTF (\$/mmbtu)	5.70	7.28	8.70	(22%)	(34%)
TTF (€/mmbtu)	3.76	4.98	6.23	(24%)	(40%)

## Sales

- The price of our natural gas in the Netherlands is based on the TTF day-ahead index. GasTerra, a state owned entity, continues to purchase all of the natural gas we produce in the Netherlands.
- Sales per boe decreased versus all comparable periods, consistent with a decrease in the TTF reference price. Compared to Q1 2015, the decrease in price was entirely offset by increased production.

## Royalties

- In the Netherlands, we pay overriding royalties on certain wells associated with an acquisition completed by the Netherlands business unit in October 2013. As such, fluctuations in royalty expense in the periods presented relate to the amount of production from those wells subject to overriding royalties.

## Transportation

- Our production in the Netherlands is not subject to transportation expense as gas is sold at the plant gate.

## Operating

- Operating expense decreased versus Q4 2015 on a dollar basis and increased slightly on a per unit basis. The dollar decrease was achieved as reduced maintenance activity levels more than offset a weaker Canadian dollar versus the Euro.
- Year-over-year, operating expense increases have been limited to 3% while growing production by 47%, resulting in a 31% per unit decrease in costs. When normalizing for the impact of the weaker Canadian dollar relative to the Euro for this period, absolute costs have decreased by 6% while per unit costs have decreased by 36% due to cost reduction initiatives being achieved while executing on significant production additions.

## General and administration

- Variations in general and administration expense generally relate to timing of expenditures, including the timing of allocations from Vermilion's Corporate segment.

## Current income taxes

- Current income taxes in the Netherlands apply to taxable income after eligible deductions at an implied tax rate of approximately 46%. For 2016, the effective rate on current taxes is expected to be between approximately 10% and 12% of pre-tax fund flows from operations. This rate is subject to change in response to commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.
- Current income taxes in Q1 2016 were lower compared to Q4 2015 as decreased revenues were offset by additional tax deductions taken for depletion in Q4 2015.

**GERMANY BUSINESS UNIT****Overview**

- Vermilion entered Germany in February 2014.
- Hold a 25% interest in a four partner consortium. Associated assets include four gas producing fields spanning 11 production licenses as well as an exploration license in surrounding fields. Total license area comprises 204,000 gross acres, of which 85% is in the exploration license.
- Entered into a farm-in agreement in July 2015 that provides Vermilion with participating interest in 18 onshore exploration licenses in northwest Germany, comprising approximately 850,000 net undeveloped acres of oil and natural gas rights. Vermilion will assume operatorship for 11 of the 18 licenses during the exploration phase.
- Awarded 110,000 net acres (100% working interest) across two exploration licenses in Lower Saxony in 2016.

**Operational review**

	Three Months Ended			% change	
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015	Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
<b>Germany business unit</b>					
<b>Production</b>					
Natural gas (mmcf/d)	15.96	16.17	16.80	(1%)	(5%)
Total (boe/d)	2,660	2,695	2,801	(1%)	(5%)
<b>Activity</b>					
Capital expenditures (\$M)	539	(441)	968	(222%)	(44%)

**Production**

- Q1 2016 production was relatively unchanged versus the prior quarter. Year-over-year production decreased 5%.

**Activity review**

- In 2016, the majority of activity will be associated with permitting and pre-drill activities for Burgmoor Z5 and two farm-in prospects, which are planned for 2017. In addition, we will continue our ongoing analysis of the proprietary geologic data associated with the farm-in assets.

## Financial review

Germany business unit (\$M except as indicated)	Three Months Ended			% change	
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015	Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
Sales	7,692	9,840	11,395	(22%)	(32%)
Royalties	(867)	(1,166)	(1,598)	(26%)	(46%)
Transportation	(887)	(508)	(894)	75%	(1%)
Operating	(2,593)	(4,788)	(1,999)	(46%)	30%
General and administration	(2,428)	(3,032)	(1,608)	(20%)	51%
Fund flows from operations	917	346	5,296	165%	(83%)
<b>Netbacks (\$/boe)</b>					
Sales	31.78	39.68	45.21	(20%)	(30%)
Royalties	(3.58)	(4.70)	(6.34)	(24%)	(44%)
Transportation	(3.67)	(2.05)	(3.55)	79%	3%
Operating	(10.71)	(19.31)	(7.93)	(45%)	35%
General and administration	(10.03)	(12.22)	(6.38)	(18%)	57%
Fund flows from operations netback	3.79	1.40	21.01	171%	(82%)
<b>Reference prices</b>					
TTF (\$/mmbtu)	5.70	7.28	8.70	(22%)	(34%)
TTF (€/mmbtu)	3.76	4.98	6.23	(24%)	(40%)

## Sales

- The price of our natural gas in Germany is based on the TTF month-ahead index.
- Sales per boe decreased versus all comparable periods, consistent with a decrease in the TTF reference price.

## Royalties

- Our production in Germany is subject to state and private royalties on sales after certain eligible deductions.
- Q1 2016 royalties as a percentage of sales of 11.3% was consistent with the Q4 2015 rate of 11.9% and lower than the Q1 2015 rate of 14.0%. The reduced rate year-over-year is a result of a reduction in state royalty rates.

## Transportation

- Transportation expense in Germany relates to costs incurred to deliver natural gas from the processing facility to the customer.
- Q1 2016 transportation expense increased on an absolute dollar and per unit basis versus Q4 2015 due to a favourable annual adjustment recorded in Q4 2015.
- Transportation costs for the quarter relative to Q1 2015 are consistent on an absolute and per unit basis.

## Operating

- Operating expenses for Germany primarily relate to tariffs charged for facility operations and gas processing.
- Q1 2016 operating expense was lower than Q4 2015 due in equal parts to charges for prior period maintenance expenditures and the inclusion of a full year gas processing tariff adjustment, both recorded in Q4 2015.
- Operating expense increased in Q1 2016 from Q1 2015 on an absolute and per unit basis due to increased maintenance activity.

## General and administration

- Q1 2016 general and administration expenses were lower than Q4 2015 and higher than Q1 2015. The reduction from Q4 2015 is due to timing of expenditures, while the increase from Q1 2015 is due to higher staffing levels and office costs incurred to support our farm-in agreement.

## Current income taxes

- Current income taxes in Germany apply to taxable income after eligible deductions at a statutory tax rate of approximately 24.2%. As a function of tax pools in Germany, Vermilion does not presently pay taxes in Germany.

**IRELAND BUSINESS UNIT****Overview**

- 18.5% non-operating interest in the offshore Corrib gas field located approximately 83 km off the northwest coast of Ireland.
- Project comprises six offshore wells, offshore and onshore sales and transportation pipeline segments as well as a natural gas processing facility.
- Corrib is expected to produce approximately 58 mmcf/d (9,700 boe/d) net to Vermilion at peak production rates.

**Operational and financial review**

Ireland business unit (\$M except as indicated)	Three Months Ended		
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015
<b>Production</b>			
Natural gas (mmcf/d)	33.90	0.12	-
Total (boe/d)	5,650	20	-
<b>Activity</b>			
Capital expenditures	3,076	12,493	12,955
<b>Financial Results</b>			
Sales	17,004	57	-
Transportation	(1,639)	(1,580)	(1,693)
Operating	(3,626)	(15)	-
General and administration	(1,188)	(714)	(512)
Fund flows from operations	10,551	(2,252)	(2,205)
<b>Netbacks (\$/boe)</b>			
Sales	33.07	-	-
Transportation	(3.19)	-	-
Operating	(7.05)	-	-
General and administration	(2.31)	-	-
Fund flows from operations netback	20.52	-	-
<b>Reference prices</b>			
NBP (\$/mmbtu)	5.97	7.41	9.01
NBP (€/mmbtu)	3.94	5.07	6.45

**Production**

- Natural gas began to flow from our Corrib gas project on December 30, 2015 and to date, well performance and facility runtimes have exceeded expectations.
- Production averaged 34 mmcf/d (5,650 boe/d) net to Vermilion, during Q1 2016.
- Following the completion of previously planned recertification activities associated with the third party gas distribution pipeline network, production volumes at Corrib are expected to rise to an estimated peak rate of approximately 58 mmcf/d (9,700 boe/d), net to Vermilion.

**Activity review**

- The export gas sales pipeline underwent intelligent pigging in Q1 2016. As part of the recertification process, confirmatory inspection digs on the export sales pipeline are planned for Q2 2016.
- Some subsea inspections, maintenance and repairs on the subsea systems are scheduled to take place in Q2 2016.
- Five of the six wells are capable of producing, with the remaining well to be brought online in the third quarter of 2016 following the conclusion of our offshore work program to lay a pipeline to the sixth well.

**Sales**

- The price of our natural gas in Ireland is based on the NBP index.
- Q1 2016 represented the first full quarter of sales from Corrib.



**Royalties**

- Our production in Ireland is not subject to royalties.

**Transportation**

- Transportation expense in Ireland relates to payments under a ship or pay agreement related to the Corrib project.
- Q1 2016 transportation expense is slightly higher than Q4 2015 due to foreign exchange. The expense is lower than Q1 2015 due to lower tariffs for the current gas year, which began in October 2015, under the ship or pay agreement.

**Operating**

- We expect per unit costs to decrease as production ramps up.

**General and administration**

- General and administration expense increased quarter-over-quarter and year-over-year due to increased corporate allocations as a result of achieving our first full quarter of production.

**AUSTRALIA BUSINESS UNIT****Overview**

- Entered Australia in 2005.
- Hold a 100% operated working interest in the Wandoo field, located approximately 80 km offshore on the northwest shelf of Australia.
- Production is operated from two off-shore platforms, and originates from 18 well bores and four lateral sidetrack wells.
- Wells that utilize horizontal legs (ranging in length from 500 to 3,000 plus metres) are located 600 metres below the seabed in approximately 55 metres of water depth.

**Operational review**

	Three Months Ended			% change	
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015	Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
<b>Australia business unit</b>					
<b>Production</b>					
Crude oil (bbls/d)	6,180	7,824	5,672	(21%)	9%
<b>Inventory (mmbbls)</b>					
Opening crude oil inventory	75	172	37		
Crude oil production	562	720	511		
Crude oil sales	(424)	(817)	(230)		
Closing crude oil inventory	213	75	318		
<b>Activity</b>					
Capital expenditures (\$M)	7,827	40,852	6,455	(81%)	21%
Gross wells drilled	-	1.00	-		
Net wells drilled	-	1.00	-		

**Production**

- Q1 2016 quarterly production decreased 21% quarter-over-quarter and increased 9% year-over-year.
- Production volumes are managed within corporate targets while meeting customer demands and the requirements of long-term supply agreements.
- We continue to plan for long-term production levels of between 6,000 and 8,000 bbls/d.

**Activity review**

- In Q1 2016, efforts were largely focused on facilities enhancement, including work relating to platform life extension, and preparation activities in advance of our upcoming drilling program.
- We plan to drill a two-well sidetrack program in Q2 2016.

## Financial review

Australia business unit (\$M except as indicated)	Three Months Ended			% change	
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015	Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
Sales	19,935	47,952	19,284	(58%)	3%
Operating	(7,491)	(13,941)	(5,886)	(46%)	27%
General and administration	(1,325)	(1,768)	(1,454)	(25%)	(9%)
PRRT	(128)	(1,054)	(2,354)	(88%)	(95%)
Corporate income taxes	(777)	1,201	(577)	(165%)	35%
Fund flows from operations	10,214	32,390	9,013	(68%)	13%
<b>Netbacks (\$/boe)</b>					
Sales	46.93	58.74	83.80	(20%)	(44%)
Operating	(17.63)	(17.08)	(25.58)	3%	(31%)
General and administration	(3.12)	(2.17)	(6.32)	44%	(51%)
PRRT	(0.30)	(1.29)	(10.23)	(77%)	(97%)
Corporate income taxes	(1.83)	1.47	(2.51)	(224%)	(27%)
Fund flows from operations netback	24.05	39.67	39.16	(39%)	(39%)
<b>Reference prices</b>					
Dated Brent (US \$/bbl)	33.89	43.69	53.97	(22%)	(37%)
Dated Brent (\$/bbl)	46.59	58.34	66.98	(20%)	(30%)

## Sales

- Crude oil in Australia is priced with reference to Dated Brent.
- Sales per boe decreased versus all comparable periods, consistent with a decrease in the Dated Brent reference price. Compared to Q4 2015, the decrease in price was combined with lower sales volumes, resulting in a larger decrease to sales. Compared to Q1 2015, the decrease in price was offset by higher sales volumes, resulting in relatively consistent sales.

## Royalties and transportation

- Our production in Australia is not subject to royalties or transportation expense as crude oil is sold directly at the Wandoo B platform.

## Operating

- Operating expense on a dollar basis decreased in Q1 2016 from Q4 2015 primarily due to a decrease in sold volumes. After adjusting for inventory, per unit costs were in-line with Q4 2015.
- Year-over-year, operating expense increased by 27%, however a significant increase in sales volumes resulted in per unit costs decreasing by 31%. The decrease in per unit costs is driven by a continued focus on cost reduction initiatives, including reduced helicopter and vessel costs.

## General and administration

- Q1 2016 general and administration costs decreased versus Q4 2015 and Q1 2015 due to cost-cutting initiatives.

## PRRT and corporate income taxes

- In Australia, current income taxes include both PRRT and corporate income taxes. PRRT is a profit based tax applied at a rate of 40% on sales less eligible expenditures, including operating expenses and capital expenditures. Corporate income taxes are applied at a rate of 30% on taxable income after eligible deductions, which include PRRT.
- For 2016, the effective tax rate for corporate income tax is expected to be between approximately 6% to 8% of pre-tax fund flows from operations and PRRT is expected to be between approximately 0% to 2% of pre-tax fund flows from operations. This is subject to change in response to commodity price fluctuations, the timing of capital expenditures and other eligible in-country adjustments.
- Q1 2016 combined corporate income taxes and PRRT were higher compared to Q4 2015, as decreased revenues were offset by additional tax deductions taken for corporate income tax depletion in Q4 2015.
- Q1 2016 combined corporate income taxes and PRRT were lower compared to Q1 2015 due to the recognition of increased capital spending deductions for PRRT purposes in Q1 2016.

## UNITED STATES BUSINESS UNIT

### Overview

- Entered the United States in September 2014.
- Interests include approximately 96,200 acres of land (98% undeveloped) in the Powder River Basin of northeastern Wyoming.
- Tight oil development targeting the Turner Sand at a depth of approximately 1,500 metres.

### Operational and financial review

United States business unit (\$M except as indicated)	Three Months Ended			% change	
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015	Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
<b>Production</b>					
Crude oil (bbls/d)	368	420	153	(12%)	141%
NGLs (bbls/d)	39	29	-	34%	100%
Natural gas (mmcf/d)	0.26	0.20	-	30%	100%
Total (boe/d)	450	483	153	(7%)	194%
<b>Activity</b>					
Capital expenditures	5,101	5,643	637	(10%)	701%
Acquisitions	115	(21)	-		
Gross wells drilled	-	2.00	-		
Net wells drilled	-	2.00	-		
<b>Financial Results</b>					
Sales	1,233	1,864	672	(34%)	83%
Royalties	(370)	(551)	(206)	(33%)	80%
Operating	(279)	(271)	(215)	3%	30%
General and administration	(1,132)	(897)	(1,080)	26%	5%
Fund flows from operations	(548)	145	(829)	(478%)	(34%)
<b>Netbacks (\$/boe)</b>					
Sales	30.10	41.94	48.79	(28%)	(38%)
Royalties	(9.03)	(12.40)	(14.98)	(27%)	(40%)
Operating	(6.82)	(6.11)	(15.61)	12%	(56%)
General and administration	(27.65)	(20.18)	(78.41)	37%	(65%)
Fund flows from operations netback	(13.40)	3.25	(60.21)	(512%)	(78%)
<b>Realized prices</b>					
Crude oil (\$/bbl)	35.80	47.59	48.79	(25%)	(27%)
NGLs (\$/bbl)	4.81	5.13	-	(6%)	100%
Natural gas (\$/mmbtu)	0.67	0.52	-	29%	100%
Total (\$/boe)	30.10	41.94	48.79	(28%)	(38%)
<b>Reference prices</b>					
WTI (US \$/bbl)	33.45	42.18	48.63	(21%)	(31%)
WTI (\$/bbl)	45.99	56.32	60.35	(18%)	(24%)
Henry Hub (US \$/mmbtu)	2.09	2.27	2.98	(8%)	(30%)
Henry Hub (\$/mmbtu)	2.87	3.03	3.70	(5%)	(22%)

### Production

- Q1 2016 production was relatively unchanged versus the prior quarter and nearly triple that of Q1 2015 due to production from our Seedy Draw well, which was drilled and completed in 2015.

**Activity review**

- In Q1 2016, we completed the two (2.0 net) wells drilled in the East Finn prospect during the prior quarter. One of the wells was placed on production at the end of Q1 2016. The other well experienced a mechanical failure during the completion operation which resulted in only 8% of the horizontal section being open to production. That well was placed on production subsequent to the quarter.

**Sales**

- The price of crude oil in the United States is directly linked to WTI, subject to market conditions in the United States.

**Royalties**

- Our production in the United States is subject to federal and private royalties, severance tax, and ad valorem tax.
- Royalties as a percentage of sales for Q1 2016 of approximately 30.0% was consistent with the rate for Q4 2015 (29.6%) and Q1 2015 (30.7%).

**Operating**

- Operating expense increased on an absolute dollar and per unit basis in Q1 2016 from Q4 2015. The increase is primarily due to the weakening of the Canadian dollar relative to the US dollar. On a per unit basis, costs are flat once adjusted for the impact of foreign exchange.
- Year-over-year the increase in operating expense has been held at 30% while production has increased 194%. As a result, per unit costs have decreased by 56%.

**General and administration**

- General and administration expenses increased in Q1 2016 by 26% from Q4 2015 and 5% from Q1 2015 due to timing of expenditures.

**CORPORATE****Overview**

- Our Corporate segment includes costs related to our global hedging program, financing expenses, and general and administration expenses that are primarily incurred in Canada and are not directly related to the operations of our business units.

**Financial review**

CORPORATE (\$M)	Three Months Ended		
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015
General and administration recovery	421	3,356	957
Current income taxes	(149)	313	(377)
Interest expense	(14,750)	(16,584)	(13,298)
Realized gain on derivatives	28,423	21,164	6,257
Realized foreign exchange (loss) gain	(652)	(252)	3,306
Realized other income	105	243	222
Fund flows from operations	13,398	8,240	(2,933)

**General and administration**

- The decrease in the recovery of general and administration costs for Q1 2016 versus Q4 2015 is due to the timing of expenditures and salary allocations to the various business unit segments.

**Current income taxes**

- Taxes in our corporate segment relate to holding companies that pay current taxes in foreign jurisdictions.

**Interest expense**

- The decrease in interest expense versus Q4 2015 is primarily due to the retiring of our 6.5% senior unsecured notes in February using funds from our revolving credit facility, which has a marginal rate of 3.3%.
- The increase in interest expense for Q1 2016 versus Q1 2015 is due to increased average borrowings under our revolving credit facility.

**Hedging**

- The nature of our operations results in exposure to fluctuations in commodity prices, interest rates and foreign currency exchange rates. We monitor and, when appropriate, use derivative financial instruments to manage our exposure to these fluctuations. All transactions of this nature entered into are related to an underlying financial position or to future crude oil and natural gas production. We do not use derivative financial instruments for speculative purposes. We have elected not to designate any of our derivative financial instruments as accounting hedges and thus account for changes in fair value in net (loss) earnings at each reporting period. We have not obtained collateral or other security to support our financial derivatives as we review the creditworthiness of our counterparties prior to entering into derivative contracts.
- Our hedging philosophy is to hedge solely for the purposes of risk mitigation. Our approach is to hedge centrally to manage our global risk (typically with an outlook of 12 to 18 months) up to 50% of net of royalty volumes through a portfolio of forward collars, swaps, and physical fixed price arrangements. We currently have European gas contracts up to 36 months forward as an exception to our typical horizon.
- We believe that our hedging philosophy and approach increases the stability of revenues, cash flows, and future dividends while also assisting us in the execution of our capital and development plans.
- The realized gain in Q1 2016 related primarily to amounts received on our crude oil and European natural gas hedges.
- A listing of derivative positions as at March 31, 2016 is included in "Supplemental Table 2" of this MD&A.

## FINANCIAL PERFORMANCE REVIEW

	Three Months Ended							
	Mar 31, 2016	Dec 31, 2015	Sep 30, 2015	Jun 30, 2015	Mar 31, 2015	Dec 31, 2014	Sep 30, 2014	Jun 30, 2014
<b>(\$M except per share)</b>								
Petroleum and natural gas sales	177,385	234,319	245,051	264,331	195,885	306,073	344,688	387,684
Net (loss) earnings	(85,848)	(142,080)	(83,310)	6,813	1,275	58,642	53,903	53,993
Net (loss) earnings per share								
Basic	(0.76)	(1.28)	(0.76)	0.06	0.01	0.55	0.50	0.51
Diluted	(0.76)	(1.28)	(0.76)	0.06	0.01	0.54	0.50	0.50

The following table shows a reconciliation of the change in net (loss) earnings:

(\$M)	Q1/16 vs. Q4/15	Q1/16 vs. Q1/15
<b>Net (loss) earnings - Comparative period</b>	(142,080)	1,275
Changes in:		
Fund flows from operations	(42,774)	(27,128)
Equity based compensation	696	(1,797)
Unrealized gain or loss on derivative instruments	(18,339)	29,024
Unrealized foreign exchange gain or loss	7,927	6,415
Unrealized other expense or income	147	174
Accretion	215	(434)
Depletion and depreciation	(17,986)	(34,841)
Deferred tax	9,485	(43,774)
Impairment	116,861	(14,762)
<b>Net loss - Current period</b>	<b>(85,848)</b>	<b>(85,848)</b>

The fluctuations in net (loss) earnings from period-to-period are caused by changes in both cash and non-cash based income and charges. Cash based items are reflected in fund flows from operations and include: sales, royalties, operating expenses, transportation, general and administration expense, current tax expense, interest expense, realized gains and losses on derivative instruments, and realized foreign exchange gains and losses. 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 amounts resulting from acquisitions or charges resulting from impairment or impairment recoveries.

**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 the Vermilion Incentive Plan ("VIP"). The expense is recognized over the vesting period based on the grant date fair value of awards, adjusted for the ultimate number of awards that actually vest as determined by the Company's achievement of performance conditions.

Equity based compensation in Q1 2016 was relatively consistent with Q4 2015. The increase of \$1.8 million as compared to Q1 2015 is due to the settlement of the employee bonus plan with equity in Q1 2016.

**Unrealized gain or loss on derivative instruments**

Unrealized gain or loss on derivative instruments arise as a result of changes in forecasted future commodity prices. 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 forecasted future commodity prices decline and vice-versa.

For the three months ended March 31 2016, we recognized an unrealized gain on derivative instruments of \$9.1 million, relating primarily to a gain on our global natural gas hedges, partially offset by a decrease in the value of crude oil and interest rate hedges. As at March 31, 2016, we have a net derivative asset position of \$77.4 million.

**Unrealized foreign exchange gain or loss**

As a result of Vermilion's international operations, Vermilion conducts business in currencies other than the Canadian dollar and has monetary assets and liabilities (including cash, receivables, payables, long-term debt, derivative assets and liabilities, and intercompany loans) denominated in such currencies. Vermilion's exposure to foreign currencies includes the US dollar, the Euro, and the Australian Dollar.

Unrealized foreign exchange gains and losses are the result of translating monetary assets and liabilities held in non-functional currencies to the respective functional currencies of Vermilion and its subsidiaries. Unrealized foreign exchange primarily results from the translation of Euro denominated financial assets and US dollar denominated financial liabilities. As such, an appreciation in the Euro against the Canadian dollar will result in an unrealized foreign exchange gain while an appreciation in the US dollar against the Canadian dollar will result in an unrealized foreign exchange loss (and vice-versa).

For the three months ended March 31, 2016, the Canadian dollar strengthened more significantly against the US dollar than the Euro, resulting in an unrealized foreign exchange gain of \$1.6 million.

**Accretion**

Fluctuations in accretion expense are primarily the result of changes in discount rates applicable to the balance of asset retirement obligations and additions resulting from drilling and acquisitions.

Q1 2016 accretion expense was relatively consistent with all comparative periods.

**Depletion and depreciation**

Fluctuations in depletion and depreciation expense are primarily the result of changes in produced crude oil and natural gas volumes.

Depletion and depreciation on a per boe basis for Q1 2016 of \$21.65 was higher as compared to \$18.88 in Q4 2015. The increase quarter-over-quarter is primarily due to a full quarter of Corrib production in Q1 2016. Depletion and depreciation on a per boe basis for Q1 2016 remained relatively consistent with the \$21.90 in Q1 2015 as the impact of a full quarter of Corrib production was offset with higher production from natural gas properties in Canada.

**Deferred tax**

Deferred tax expense (recovery) arises primarily as a result of changes in the accounting basis and tax basis for capital assets and asset retirement obligations and changes in available tax losses. The deferred tax expense for Q1 2016 largely pertains to the de-recognition of certain deferred tax assets.

**Impairment**

For the three months ended March 31, 2016, Vermilion recorded a non-cash impairment charge of \$14.8 million in Ireland as a result of a decline in the price forecast for European natural gas.

**FINANCIAL POSITION REVIEW****Balance sheet strategy**

We believe that our balance sheet supports our defined growth initiatives and our focus is on managing and maintaining a conservative balance sheet. To ensure that our balance sheet continues to support our defined growth initiatives, we regularly review whether forecasted fund flows from operations is sufficient to finance planned capital expenditures, dividends, and abandonment and reclamation expenditures. To the extent that forecasted fund flows from operations is not expected to be sufficient to fulfill such expenditures, we will evaluate our ability to finance any excess with debt (including borrowing using the unutilized capacity of our existing revolving credit facility), issue equity, or by reducing some or all categories of expenditures to ensure that total expenditures do not exceed available funds.

To ensure that we maintain a conservative balance sheet, we monitor the ratio of net debt to fund flows from operations and typically strive to maintain an internally targeted ratio of approximately 1.0 to 1.5 in a normalized commodity price environment. Where prices trend higher, we may target a lower ratio and conversely, in a lower commodity price environment, the acceptable ratio may be higher. At times, we will use our balance sheet to finance acquisitions and, in these situations, we are prepared to accept a higher ratio in the short term but will implement a strategy to reduce the ratio to acceptable levels within a reasonable period of time, usually considered to be no more than 12 to 24 months. This plan could potentially include an increase in hedging activities, a reduction in capital expenditures, an issuance of equity or the utilization of excess fund flows from operations to reduce outstanding indebtedness.

In the current low commodity price environment, Vermilion's net debt to fund flows ratio is expected to be higher than the internally targeted ratio. During this period, Vermilion will remain focused on maintaining a strong balance sheet by aligning capital expenditures within forecasted fund flows from operations, which is continually monitored for revised forward price estimates, as well as by hedging additional European natural gas volumes to maintain a diversified commodity portfolio.



**Long-term debt**

Our long-term debt as at March 31, 2016 consists entirely of borrowings against our revolving credit facility. We redeemed the senior unsecured notes that came due on February 10, 2016 using funds drawn against the revolving credit facility. Following the redemption, all of Vermilion's debt is now classified as senior debt pursuant to the terms of the revolving credit facility. As a result, Vermilion requested and received amendments from its lending syndicate to eliminate the consolidated total senior debt to consolidated EBITDA financial covenant and increase the ratio of consolidated total senior debt to total capitalization financial covenant from 50% to 55%. The revolving credit facility limit of \$2.0 billion remains unchanged. Vermilion was in compliance with all covenants as of March 31, 2016 and expects to remain in compliance based on 2016 commodity strip pricing as of May 5, 2016.

The applicable annual interest rates and the balances recognized on our balance sheet are as follows:

(\$M)	Annual Interest Rate		As at	
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2016	Dec 31, 2015
Revolving credit facility	3.3%	3.1%	1,429,988	1,162,998
Senior unsecured notes	6.5%	6.5%	-	224,901
Long-term debt	3.5%	3.7%	1,429,988	1,387,899

**Revolving Credit Facility**

The following table outlines the current terms of our revolving credit facility:

	As at	
	Mar 31, 2016	Dec 31, 2015
Total facility amount	\$2.0 billion	\$2.0 billion
Amount drawn	\$1.4 billion	\$1.2 billion
Letters of credit outstanding	\$24.7 million	\$25.2 million
Facility maturity date	31-May-19	31-May-19

In addition, the revolving credit facility was subject to the following covenants:

Financial covenant	Limit	As at	
		Mar 31, 2016	Dec 31, 2015
Consolidated total debt to consolidated EBITDA	4.0	2.47	2.23
Consolidated total senior debt to consolidated EBITDA	3.0	2.42	1.83
Consolidated total senior debt to total capitalization	50%	45%	36%

Our 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 "Finance lease obligation" 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.
- Total capitalization: Includes all amounts on our balance sheet classified as "Shareholders' equity" plus consolidated total debt as defined above.

**Net debt**

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

(\$M)	As at	
	Mar 31, 2016	Dec 31, 2015
Long-term debt	1,429,988	1,162,998
Current liabilities <sup>(1)</sup>	221,225	503,731
Current assets	(284,150)	(284,778)
Net debt	1,367,063	1,381,951
Ratio of net debt to annualized fund flows from operations	3.6	2.7

<sup>(1)</sup> Current liabilities at December 31, 2015 includes \$224,901 relating to the current portion of long-term debt.

As at March 31, 2016, long term debt, including the current portion, increased to \$1.43 billion (December 31, 2015 - \$1.39 billion) as a result of draws on the revolving credit facility during the current year to fund capital expenditures. The increase in long-term debt was offset by working capital changes, such that net debt remained relatively consistent at \$1.37 billion. Weaker commodity prices versus the prior periods decreased fund flows from operations, resulting in the ratio of net debt to annualized fund flows from operations increasing.

**Shareholders' capital**

During the three months ended March 31, 2016, we maintained monthly dividends at \$0.215 per share and declared dividends which totalled \$72.8 million.

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 31, 2013	\$0.200
January 2014 to Present	\$0.215

Our policy with respect to dividends is to be conservative and maintain a low ratio of dividends to fund flows from operations. During low commodity price cycles, we will initially maintain dividends and allow the ratio to rise. Should low commodity price cycles remain for an extended period of time, we will evaluate the necessity of changing the level of dividends, taking into consideration capital development requirements, debt levels, and acquisition opportunities.

As a further step to preserve our financial flexibility and conservatively exercise our access to capital, we amended our existing dividend reinvestment plan to include a Premium Dividend™ Component in February 2015. The Premium Dividend™ Component, when combined with our continuing Dividend Reinvestment Component, increases our access to the lowest cost sources of equity capital available. While the Premium Dividend™ results in a modest amount of equity issuance, we believe it represents the most prudent approach to preserving near-term balance sheet strength. We view implementation of a Premium Dividend™ as a short-term measure to maintain our financial flexibility while we continue to lower our unit costs and await further clarity on the direction of commodity prices. Both components of our program can be reduced or eliminated at the company's discretion, offering considerable flexibility. We will actively monitor our ongoing needs and manage our continued use of each component as circumstances dictate.

Although we expect to be able to maintain our current dividend, fund flows from operations may not be sufficient during this low commodity price environment to fund cash dividends, capital expenditures, and asset retirement obligations. We will evaluate our ability to finance any shortfalls with debt, issuances of equity, or by reducing some or all categories of expenditures to ensure that total expenditures do not exceed available funds.

The following table reconciles the change in shareholders' capital:

Shareholders' Capital	Number of Shares ('000s)	Amount (\$M)
<b>Balance as at December 31, 2015</b>	111,991	2,181,089
Shares issued for the DRIP <sup>(1)</sup>	1,354	47,990
Shares issued for equity based compensation	106	4,128
<b>Balance as at March 31, 2016</b>	113,451	2,233,207

<sup>(1)</sup> DRIP Refers to Vermilion's dividend reinvestment and Premium Dividend™ plans.

As at March 31, 2016, there were approximately 1.7 million VIP awards outstanding. As at May 5, 2016, there were approximately 113.9 million common shares issued and outstanding.

### ASSET RETIREMENT OBLIGATIONS

As at March 31, 2016, asset retirement obligations were \$319.0 million compared to \$305.6 million as at December 31, 2015.

The increase in asset retirement obligations is largely attributable to an overall decrease in the discount rates applied to the abandonment obligations, as well as accretion and additions from new wells drilled year-to-date.

### OFF BALANCE SHEET ARRANGEMENTS

We have certain lease agreements that are entered into in the normal course of operations, including operating leases for which no asset or liability value has been assigned to the consolidated balance sheet as at March 31, 2016.

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

### RISK MANAGEMENT

Vermilion is exposed to various market and operational risks. For a detailed discussion of these risks, please see Vermilion's Annual Report for the year ended December 31, 2015.

### 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 three months ended March 31, 2016. 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, 2015, available on SEDAR at [www.sedar.com](http://www.sedar.com) or on Vermilion's website at [www.vermilionenergy.com](http://www.vermilionenergy.com).

### INTERNAL CONTROL OVER FINANCIAL REPORTING

There was no change in Vermilion's internal control over financial reporting that occurred during the period covered by this MD&A that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

## Supplemental Table 1: Netbacks

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

	Three Months Ended March 31, 2016			Three Months Ended March 31, 2015		
	Oil, Condensate & NGLs \$/bbl	Natural Gas \$/mcf	Total \$/boe	Oil, Condensate & NGLs \$/bbl	Natural Gas \$/mcf	Total \$/boe
<b>Canada</b>						
Sales	33.11	1.93	21.16	49.15	2.97	35.81
Royalties	(4.03)	(0.08)	(2.07)	(5.87)	(0.23)	(3.95)
Transportation	(2.30)	(0.16)	(1.57)	(2.42)	(0.16)	(1.81)
Operating	(7.32)	(1.44)	(8.05)	(9.02)	(1.41)	(8.78)
Operating netback	19.46	0.25	9.47	31.84	1.17	21.27
General and administration			(0.94)			(1.85)
Fund flows from operations netback			8.53			19.42
<b>France</b>						
Sales	43.36	1.66	43.16	64.33	-	64.33
Royalties	(6.09)	(0.29)	(6.07)	(5.48)	-	(5.49)
Transportation	(3.35)	-	(3.33)	(3.24)	-	(3.24)
Operating	(12.84)	(2.24)	(12.84)	(11.64)	-	(11.64)
Operating netback	21.08	(0.87)	20.92	43.97	-	43.96
General and administration			(4.19)			(5.49)
Other income			-			34.16
Current income taxes			(0.03)			(15.35)
Fund flows from operations netback			16.70			57.28
<b>Netherlands</b>						
Sales	32.24	5.55	33.26	52.93	8.09	48.60
Royalties	-	(0.09)	(0.56)	-	(0.28)	(1.68)
Operating	-	(1.23)	(7.28)	-	(1.78)	(10.56)
Operating netback	32.24	4.23	25.42	52.93	6.03	36.36
General and administration			(0.94)			(1.34)
Current income taxes			(2.68)			(4.33)
Fund flows from operations netback			21.80			30.69
<b>Germany</b>						
Sales	-	5.30	31.78	-	7.53	45.21
Royalties	-	(0.60)	(3.58)	-	(1.06)	(6.34)
Transportation	-	(0.61)	(3.67)	-	(0.59)	(3.55)
Operating	-	(1.79)	(10.71)	-	(1.32)	(7.93)
Operating netback	-	2.30	13.82	-	4.56	27.39
General and administration			(10.03)			(6.38)
Fund flows from operations netback			3.79			21.01
<b>Ireland</b>						
Sales	-	5.51	33.07	-	-	-
Transportation	-	(0.53)	(3.19)	-	-	-
Operating	-	(1.18)	(7.05)	-	-	-
Operating netback	-	3.80	22.83	-	-	-
General and administration			(2.31)			-
Fund flows from operations netback			20.52			-
<b>Australia</b>						
Sales	46.93	-	46.93	83.80	-	83.80
Operating	(17.63)	-	(17.63)	(25.58)	-	(25.58)
PRRT <sup>(1)</sup>	(0.30)	-	(0.30)	(10.23)	-	(10.23)
Operating netback	29.00	-	29.00	47.99	-	47.99
General and administration			(3.12)			(6.32)
Corporate income taxes			(1.83)			(2.51)
Fund flows from operations netback			24.05			39.16

## Supplemental Table 1: Netbacks (Continued)

	Three Months Ended March 31, 2016			Three Months Ended March 31, 2015		
	Oil, Condensate & NGLs \$/bbl	Natural Gas \$/mcf	Total \$/boe	Oil, Condensate & NGLs \$/bbl	Natural Gas \$/mcf	Total \$/boe
<b>United States</b>						
Sales	32.84	0.67	30.10	48.79	-	48.79
Royalties	(9.73)	(0.40)	(9.03)	(14.98)	-	(14.98)
Operating	(7.54)	-	(6.82)	(15.61)	-	(15.61)
Operating netback	15.57	0.27	14.25	18.20	-	18.20
General and administration			(27.65)			(78.41)
Fund flows from operations netback			(13.40)			(60.21)
<b>Total Company</b>						
Sales	39.35	3.76	30.53	58.25	5.26	47.17
Realized hedging gain	3.18	1.07	4.89	0.75	0.43	1.51
Royalties	(4.30)	(0.11)	(2.40)	(5.21)	(0.37)	(3.95)
Transportation	(2.33)	(0.22)	(1.79)	(2.49)	(0.34)	(2.30)
Operating	(11.10)	(1.37)	(9.58)	(11.61)	(1.51)	(10.56)
PRRT <sup>(1)</sup>	(0.05)	-	(0.02)	(0.97)	-	(0.57)
Operating netback	24.75	3.13	21.63	38.72	3.47	31.30
General and administration			(2.34)			(3.27)
Interest expense			(2.54)			(3.20)
Realized foreign exchange (loss) gain			(0.11)			0.78
Other income			0.02			7.70
Corporate income taxes <sup>(1)</sup>			(0.54)			(4.24)
Fund flows from operations netback			16.12			29.07

<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 following tables outline Vermilion's outstanding risk management positions as at March 31, 2016:

<b>Crude Oil</b>	<b>Note</b>	<b>Volume</b>	<b>Strike Price(s)</b>
<b>WTI - Collar</b>			
July 2015 - June 2016	1	500 bbls/d	75.50 - 85.08 CAD \$
April 2016 - September 2016	1	500 bbls/d	52.25 - 64.40 CAD \$
April 2016 - September 2016	2	750 bbls/d	40.50 - 50.40 US \$
<b>Dated Brent - Collar</b>			
July 2015 - June 2016	3	1,000 bbls/d	80.50 - 93.49 CAD \$
July 2015 - June 2016	4	500 bbls/d	64.50 - 75.48 US \$
October 2015 - June 2016	5	250 bbls/d	82.00 - 94.55 CAD \$
January 2016 - June 2016	6	250 bbls/d	84.00 - 93.70 CAD \$
April 2016 - September 2016	5	250 bbls/d	52.00 - 64.80 CAD \$
<b>North American Natural Gas</b>			
<b>AECO - Collar</b>			
November 2015 - October 2016		10,000 GJ/d	2.56 - 3.23 CAD \$
January 2016 - December 2016		10,000 GJ/d	2.53 - 3.29 CAD \$
March 2016 - December 2016	7	5,000 GJ/d	2.05 - 2.77 CAD \$
April 2016 - October 2016		5,000 GJ/d	2.30 - 2.80 CAD \$
April 2016 - December 2016	8	2,500 GJ/d	2.10 - 2.92 CAD \$
November 2016 - October 2017	7	7,500 GJ/d	2.07 - 2.71 CAD \$
November 2016 - December 2017		10,000 GJ/d	2.21 - 2.86 CAD \$
January 2017 - December 2017		5,000 GJ/d	2.25 - 3.09 CAD \$
<b>AECO - Swap</b>			
April 2016 - October 2016	9	5,000 GJ/d	2.59 CAD \$

- (1) The contracted volumes increase to 1,250 bbls/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US\$/bbl multiplied by the Bank of Canada monthly average noon day rate).
- (2) The contracted volumes increase to 2,000 bbls/d for any monthly settlement periods above the contracted ceiling price.
- (3) The contracted volumes increase to 2,500 bbls/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US\$/bbl multiplied by the Bank of Canada monthly average noon day rate).
- (4) The contracted volumes increase to 1,000 bbls/d for any monthly settlement periods above the contracted ceiling price.
- (5) The contracted volumes increase to 750 bbls/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US\$/bbl multiplied by the Bank of Canada monthly average noon day rate).
- (6) The contracted volumes increase to 500 bbls/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US\$/bbl multiplied by the Bank of Canada monthly average noon day rate).
- (7) The contracted volumes increase to 10,000 GJ/d for any monthly settlement periods above the contracted ceiling price.
- (8) The contracted volumes increase to 7,500 GJ/d for any monthly settlement periods above the contracted ceiling price.
- (9) On the last business day of each month, the counterparty has the option to increase the contracted volumes to 10,000 GJ/d at the contracted price, for the following month.

## Supplemental Table 2: Hedges (Continued)

European Natural Gas	Note	Volume	Strike Price(s)
<b>NBP - Call</b>			
October 2016 - March 2017		2,638 GJ/d	4.64 GBP £
<b>NBP - Collar</b>			
April 2016 - March 2017		2,638 GJ/d	3.79 - 4.53 GBP £
July 2016 - December 2016	1	2,638 GJ/d	2.84 - 4.08 GBP £
October 2016 - March 2017	2	2,638 GJ/d	3.13 - 3.53 GBP £
October 2016 - December 2017	2	2,638 GJ/d	2.84 - 3.70 GBP £
January 2017 - December 2017	1	5,275 GJ/d	3.13 - 3.62 GBP £
January 2018 - December 2018		2,638 GJ/d	2.99 - 3.63 GBP £
<b>NBP - Put</b>			
April 2016 - September 2016		2,638 GJ/d	3.79 GBP £
<b>NBP - Swap</b>			
January 2016 - June 2016		5,184 GJ/d	6.24 EUR €
January 2016 - June 2016		2,592 GJ/d	6.82 US \$
July 2016 - March 2017		2,592 GJ/d	5.43 EUR €
October 2016 - December 2016		2,638 GJ/d	3.24 GBP £
January 2017 - December 2017	3	2,638 GJ/d	4.00 GBP £
January 2018 - December 2018	4	2,638 GJ/d	3.83 GBP £
<b>TTF - Call</b>			
October 2016 - March 2017		2,592 GJ/d	6.03 EUR €
<b>TTF - Collar</b>			
January 2016 - December 2016	5	2,592 GJ/d	5.76 - 6.50 EUR €
April 2016 - December 2016	6	12,960 GJ/d	5.58 - 6.21 EUR €
April 2016 - March 2017	7	5,184 GJ/d	5.28 - 6.35 EUR €
July 2016 - December 2016		2,592 GJ/d	5.00 - 5.63 EUR €
July 2016 - March 2017	5	2,592 GJ/d	5.07 - 6.56 EUR €
July 2016 - March 2018	5	2,592 GJ/d	5.32 - 6.54 EUR €
October 2016 - December 2017		2,592 GJ/d	5.00 - 5.89 EUR €
January 2017 - December 2017	8	7,776 GJ/d	5.00 - 6.15 EUR €
April 2017 - September 2017	5	2,592 GJ/d	3.61 - 4.24 EUR €
January 2018 - December 2018		5,184 GJ/d	4.17 - 5.03 EUR €
<b>TTF - Put</b>			
April 2016 - September 2016		2,592 GJ/d	5.21 EUR €
<b>TTF - Swap</b>			
January 2015 - June 2016		2,592 GJ/d	6.07 EUR €
January 2016 - June 2016		5,184 GJ/d	5.94 EUR €
April 2016 - December 2016		2,592 GJ/d	5.91 EUR €
July 2016 - June 2018		2,700 GJ/d	5.58 EUR €
October 2016 - December 2016		2,592 GJ/d	5.45 EUR €
January 2017 - December 2017	5	2,592 GJ/d	5.04 EUR €
<b>Fuel and Electricity</b>			
<b>GasOil - Swap</b>			
March 2016 - December 2016		125 bbls/d	42.55 US \$
<b>AESO - Swap</b>			
January 2016 - December 2016		93.6 MWh/d	38.58 CAD \$
<b>Interest Rate</b>			
<b>CDOR to fixed - Swap</b>			
September 2015 - September 2019		100,000,000 CAD \$/year	1.00 %
October 2015 - October 2019		100,000,000 CAD \$/year	1.10 %

(1) The contracted volumes increase to 7,913 GJ/d for any monthly settlement periods above the contracted ceiling price.

(2) The contracted volumes increase to 5,275 GJ/d for any monthly settlement periods above the contracted ceiling price.

(3) On the last business day of each month, the counterparty has the option to increase the contracted volumes by an additional 2,638 GJ/d at the contracted price, for the following month.

(4) On the last business day of each month, the counterparty has the option to increase the contracted volumes to 7,913 GJ/d at the contracted price, for the following month.

(5) The contracted volumes increase to 5,184 GJ/d for any monthly settlement periods above the contracted ceiling price.

(6) The contracted volumes increase to 15,552 GJ/d for any monthly settlement periods above the contracted ceiling price.

(7) The contracted volumes increase to 10,368 GJ/d for any monthly settlement periods above the contracted ceiling price.

(8) The contracted volumes increase to 18,144 GJ/d for any monthly settlement periods above the contracted ceiling price.

## Supplemental Table 3: Capital Expenditures

By classification (\$M)	Three Months Ended		
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015
Drilling and development	62,773	128,996	174,311
Exploration and evaluation	-	-	-
Capital expenditures	62,773	128,996	174,311
Property acquisition	870	6,227	35
Acquisitions	870	6,227	35

By category (\$M)	Three Months Ended		
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015
Land	1,039	819	742
Seismic	6,268	4,217	1,493
Drilling and completion	27,853	58,327	82,343
Production equipment and facilities	6,238	55,662	74,755
Recompletions	3,598	6,338	7,115
Other	17,777	3,633	7,863
Capital expenditures	62,773	128,996	174,311
Acquisitions	870	6,227	35
Total capital expenditures and acquisitions	63,643	135,223	174,346

By country (\$M)	Three Months Ended		
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015
Canada	30,526	33,723	114,884
France	13,463	24,164	34,114
Netherlands	2,996	18,810	4,333
Germany	539	(441)	968
Ireland	3,076	12,493	12,955
Australia	7,827	40,852	6,455
United States	5,216	5,622	637
Total capital expenditures and acquisitions	63,643	135,223	174,346



## Supplemental Table 4: Production

	Q1/16	Q4/15	Q3/15	Q2/15	Q1/15	Q4/14	Q3/14	Q2/14	Q1/14	Q4/13	Q3/13	Q2/13
<b>Canada</b>												
Crude oil & condensate (bbls/d)	10,317	10,413	11,030	11,843	12,163	12,681	12,755	14,108	10,390	8,719	7,969	8,885
NGLs (bbls/d)	2,633	2,710	2,678	2,094	1,706	1,444	1,005	1,364	1,118	1,699	1,897	1,725
Natural gas (mmcf/d)	97.16	87.90	71.94	64.66	61.78	58.36	57.07	57.59	49.53	41.43	43.40	43.69
Total (boe/d)	29,141	27,773	25,698	24,713	24,165	23,851	23,272	25,070	19,763	17,322	17,099	17,892
% of consolidated	44%	45%	47%	48%	48%	49%	47%	49%	42%	43%	41%	42%
<b>France</b>												
Crude oil (bbls/d)	12,220	12,537	12,310	12,746	11,463	11,133	11,111	11,025	10,771	11,131	11,625	10,390
Natural gas (mmcf/d)	0.44	1.36	1.47	1.03	-	-	-	-	-	-	5.23	4.19
Total (boe/d)	12,293	12,763	12,555	12,917	11,463	11,133	11,111	11,025	10,771	11,131	12,496	11,088
% of consolidated	19%	21%	22%	25%	23%	22%	22%	21%	23%	27%	30%	26%
<b>Netherlands</b>												
Condensate (bbls/d)	114	110	109	112	63	81	63	96	69	62	48	50
Natural gas (mmcf/d)	53.40	56.34	53.56	32.43	36.41	31.35	38.07	40.35	43.15	37.53	28.78	38.52
Total (boe/d)	9,015	9,500	9,035	5,517	6,132	5,306	6,407	6,822	7,260	6,318	4,845	6,470
% of consolidated	14%	16%	16%	11%	12%	11%	13%	13%	16%	15%	12%	15%
<b>Germany</b>												
Natural gas (mmcf/d)	15.96	16.17	14.00	16.18	16.80	17.71	15.38	16.13	10.64	-	-	-
Total (boe/d)	2,660	2,695	2,333	2,696	2,801	2,952	2,563	2,689	1,773	-	-	-
% of consolidated	4%	4%	4%	5%	6%	6%	5%	5%	4%	-	-	-
<b>Ireland</b>												
Natural gas (mmcf/d)	33.90	0.12	-	-	-	-	-	-	-	-	-	-
Total (boe/d)	5,650	20	-	-	-	-	-	-	-	-	-	-
% of consolidated	9%	-	-	-	-	-	-	-	-	-	-	-
<b>Australia</b>												
Crude oil (bbls/d)	6,180	7,824	6,433	5,865	5,672	6,134	6,567	6,483	7,110	6,189	7,070	7,363
% of consolidated	9%	13%	11%	11%	11%	12%	13%	12%	15%	15%	17%	17%
<b>United States</b>												
Crude oil (bbls/d)	368	420	226	123	153	195	-	-	-	-	-	-
NGLs (bbls/d)	39	29	-	-	-	-	-	-	-	-	-	-
Natural gas (mmcf/d)	0.26	0.20	-	-	-	-	-	-	-	-	-	-
Total (boe/d)	450	483	226	123	153	195	-	-	-	-	-	-
% of consolidated	1%	1%	-	-	-	-	-	-	-	-	-	-
<b>Consolidated</b>												
Crude oil, condensate & NGLs (bbls/d)	31,871	34,043	32,786	32,783	31,220	31,668	31,501	33,076	29,458	27,800	28,609	28,413
% of consolidated	49%	56%	58%	63%	62%	64%	63%	63%	63%	68%	69%	66%
Natural gas (mmcf/d)	201.11	162.09	140.97	114.29	115.00	107.42	110.52	114.08	103.32	78.96	77.41	86.40
% of consolidated	51%	44%	42%	37%	38%	36%	37%	37%	37%	32%	31%	34%
Total (boe/d)	65,389	61,058	56,280	51,831	50,386	49,571	49,920	52,089	46,677	40,960	41,510	42,813

## Supplemental Table 4: Production (Continued)

	2016	2015	2014	2013	2012	2011
<b>Canada</b>						
Crude oil and condensate (bbls/d)	10,317	11,357	12,491	8,387	7,659	4,701
NGLs (bbls/d)	2,633	2,301	1,233	1,666	1,232	1,297
Natural gas (mmcf/d)	97.16	71.65	55.67	42.39	37.50	43.38
Total (boe/d)	29,141	25,598	23,001	17,117	15,142	13,227
% of consolidated	44%	46%	47%	41%	40%	38%
<b>France</b>						
Crude oil (bbls/d)	12,220	12,267	11,011	10,873	9,952	8,110
Natural gas (mmcf/d)	0.44	0.97	-	3.40	3.59	0.95
Total (boe/d)	12,293	12,429	11,011	11,440	10,550	8,269
% of consolidated	19%	23%	22%	28%	28%	23%
<b>Netherlands</b>						
Condensate (bbls/d)	114	99	77	64	67	58
Natural gas (mmcf/d)	53.40	44.76	38.20	35.42	34.11	32.88
Total (boe/d)	9,015	7,559	6,443	5,967	5,751	5,538
% of consolidated	14%	14%	13%	15%	15%	16%
<b>Germany</b>						
Natural gas (mmcf/d)	15.96	15.78	14.99	-	-	-
Total (boe/d)	2,660	2,630	2,498	-	-	-
% of consolidated	4%	5%	5%	-	-	-
<b>Ireland</b>						
Natural gas (mmcf/d)	33.90	0.03	-	-	-	-
Total (boe/d)	5,650	5	-	-	-	-
% of consolidated	9%	-	-	-	-	-
<b>Australia</b>						
Crude oil (bbls/d)	6,180	6,454	6,571	6,481	6,360	8,168
% of consolidated	9%	12%	13%	16%	17%	23%
<b>United States</b>						
Crude oil (bbls/d)	368	231	49	-	-	-
NGLs (bbls/d)	39	7	-	-	-	-
Natural gas (mmcf/d)	0.26	0.05	-	-	-	-
Total (boe/d)	450	247	49	-	-	-
% of consolidated	1%	-	-	-	-	-
<b>Consolidated</b>						
Crude oil, condensate & NGLs (bbls/d)	31,871	32,716	31,432	27,471	25,270	22,334
% of consolidated	49%	60%	63%	67%	67%	63%
Natural gas (mmcf/d)	201.11	133.24	108.85	81.21	75.20	77.21
% of consolidated	51%	40%	37%	33%	33%	37%
Total (boe/d)	65,389	54,922	49,573	41,005	37,803	35,202

## Supplemental Table 5: Segmented Financial Results

(\$M)	Three Months Ended March 31, 2016								
	Canada	France	Netherlands	Germany	Ireland	Australia	United States	Corporate	Total
Total assets	1,584,947	833,145	195,413	159,522	838,240	240,352	44,585	176,136	4,072,340
Drilling and development	29,771	13,463	2,996	539	3,076	7,827	5,101	-	62,773
Oil and gas sales to external customers	56,110	48,125	27,286	7,692	17,004	19,935	1,233	-	177,385
Royalties	(5,498)	(6,766)	(460)	(867)	-	-	(370)	-	(13,961)
Revenue from external customers	50,612	41,359	26,826	6,825	17,004	19,935	863	-	163,424
Transportation	(4,151)	(3,713)	-	(887)	(1,639)	-	-	-	(10,390)
Operating	(21,343)	(14,320)	(5,976)	(2,593)	(3,626)	(7,491)	(279)	-	(55,628)
General and administration	(2,476)	(4,676)	(773)	(2,428)	(1,188)	(1,325)	(1,132)	421	(13,577)
PRRT	-	-	-	-	-	(128)	-	-	(128)
Corporate income taxes	-	(34)	(2,200)	-	-	(777)	-	(149)	(3,160)
Interest expense	-	-	-	-	-	-	-	(14,750)	(14,750)
Realized gain on derivative instruments	-	-	-	-	-	-	-	28,423	28,423
Realized foreign exchange loss	-	-	-	-	-	-	-	(652)	(652)
Realized other income	-	-	-	-	-	-	-	105	105
Fund flows from operations	22,642	18,616	17,877	917	10,551	10,214	(548)	13,398	93,667

**NON-GAAP FINANCIAL MEASURES**

This MD&A includes references to certain financial measures which do not have standardized meanings prescribed by IFRS and are not disclosed in our consolidated financial statements. As such, these financial measures are considered non-GAAP financial measures and therefore may not be comparable with similar measures presented by other issuers.

**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 our equity based compensation plans as determined using the treasury stock method.

**Free cash flow:** Represents fund flows from operations in excess of drilling and development and exploration and evaluation costs (collectively referred to as capital expenditures). We consider free cash flow to be a key measure as it is used 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.

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

**Payout:** We define payout as net dividends plus drilling and development costs, exploration and evaluation costs, dispositions, and asset retirement obligations settled. Management uses payout to assess the amount of cash distributed back to shareholders and re-invested in the business for maintaining production and organic growth.

**Fund flows from operations (excluding Corrib) and Payout (excluding Corrib):** Management excludes expenditures relating to the Corrib project in assessing fund flows from operations (a non-GAAP financial measure) and payout in order to assess our ability to generate cash and finance organic growth from our current producing assets. Beginning in Q1 2016, the Corrib project is considered a producing asset, so these financial measures are not applicable for the current period.

**Diluted shares outstanding:** Is 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.

**Cash dividends per share:** Represents cash dividends declared per share.

The following tables reconcile fund flows from operations (and excluding Corrib), net dividends, payout (and excluding Corrib), and diluted shares outstanding to their most directly comparable GAAP measures as presented in our financial statements:

	Three Months Ended		
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015
<b>(\$M)</b>			
Cash flows from operating activities	73,883	164,863	22,647
Changes in non-cash operating working capital	17,760	(33,343)	95,041
Asset retirement obligations settled	2,024	4,921	3,107
Fund flows from operations	93,667	136,441	120,795
Expenses related to Corrib	N/A	2,252	2,205
Fund flows from operations (excluding Corrib)	N/A	138,693	123,000

	Three Months Ended		
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015
<b>(\$M)</b>			
Dividends declared	72,847	71,965	69,390
Shares issued for the DRIP <sup>(1)</sup>	(47,990)	(46,764)	(21,378)
Net dividends	24,857	25,201	48,012
Drilling and development	62,773	128,996	174,311
Asset retirement obligations settled	2,024	4,921	3,107
Payout	89,654	159,118	225,430
Corrib drilling and development	N/A	(12,493)	(12,955)
Payout (excluding Corrib)	N/A	146,625	212,475

<sup>(1)</sup> DRIP Refers to Vermilion's dividend reinvestment and Premium Dividend™ plans.

	As at		
	Mar 31, 2016	Dec 31, 2015	Mar 31, 2015
<b>('000s of shares)</b>			
Shares outstanding	113,451	111,991	107,718
Potential shares issuable pursuant to the VIP	3,040	3,033	3,043
Diluted shares outstanding	116,491	115,024	110,761

**CONSOLIDATED BALANCE SHEETS**  
**(THOUSANDS OF CANADIAN DOLLARS, UNAUDITED)**

	Note	March 31, 2016	December 31, 2015
<b>ASSETS</b>			
<b>Current</b>			
Cash and cash equivalents		63,246	41,676
Accounts receivable		127,531	160,499
Crude oil inventory		17,340	13,079
Derivative instruments		62,381	55,214
Prepaid expenses		13,652	14,310
		284,150	284,778
Derivative instruments		15,015	13,128
Deferred taxes	6	99,174	135,753
Exploration and evaluation assets	3	304,033	308,192
Capital assets	2	3,369,968	3,467,369
		4,072,340	4,209,220
<b>LIABILITIES</b>			
<b>Current</b>			
Accounts payable and accrued liabilities		189,811	248,747
Current portion of long-term debt	5	-	224,901
Dividends payable	7	24,392	24,077
Income taxes payable		7,022	6,006
		221,225	503,731
Long-term debt	5	1,429,988	1,162,998
Finance lease obligation		23,028	23,565
Asset retirement obligations	4	318,981	305,613
Deferred taxes		337,657	354,654
		2,330,879	2,350,561
<b>SHAREHOLDERS' EQUITY</b>			
Shareholders' capital	7	2,233,207	2,181,089
Contributed surplus		124,655	107,946
Accumulated other comprehensive income		86,317	113,647
Deficit		(702,718)	(544,023)
		1,741,461	1,858,659
		4,072,340	4,209,220

**APPROVED BY THE BOARD**

("Joseph F. Killi")

Joseph F. Killi, Director

("Anthony Marino")

Anthony Marino, Director

**CONSOLIDATED STATEMENTS OF NET (LOSS) EARNINGS AND COMPREHENSIVE LOSS**  
**(THOUSANDS OF CANADIAN DOLLARS, EXCEPT SHARE AND PER SHARE AMOUNTS, UNAUDITED)**

	Note	Three Months Ended	
		March 31, 2016	March 31, 2015
<b>REVENUE</b>			
Petroleum and natural gas sales		177,385	195,885
Royalties		(13,961)	(16,424)
<b>Petroleum and natural gas revenue</b>		<b>163,424</b>	<b>179,461</b>
<b>EXPENSES</b>			
Operating		55,628	43,851
Transportation		10,390	9,540
Equity based compensation		20,837	19,040
(Gain) loss on derivative instruments		(37,477)	13,713
Interest expense		14,750	13,298
General and administration		13,577	13,560
Foreign exchange (gain) loss		(918)	1,539
Other income		(18)	(31,736)
Accretion	4	6,109	5,675
Depletion and depreciation	2, 3	125,798	90,957
Impairment	2	14,762	-
		<b>223,438</b>	<b>179,437</b>
<b>(LOSS) EARNINGS BEFORE INCOME TAXES</b>		<b>(60,014)</b>	<b>24</b>
<b>INCOME TAXES</b>			
Deferred	6	22,546	(21,228)
Current		3,288	19,977
		<b>25,834</b>	<b>(1,251)</b>
<b>NET (LOSS) EARNINGS</b>		<b>(85,848)</b>	<b>1,275</b>
<b>OTHER COMPREHENSIVE LOSS</b>			
Currency translation adjustments		(27,330)	(40,134)
<b>COMPREHENSIVE LOSS</b>		<b>(113,178)</b>	<b>(38,859)</b>
<b>NET (LOSS) EARNINGS PER SHARE</b>			
Basic		(0.76)	0.01
Diluted		(0.76)	0.01
<b>WEIGHTED AVERAGE SHARES OUTSTANDING ('000s)</b>			
Basic		112,725	107,513
Diluted		112,725	109,305

**CONSOLIDATED STATEMENTS OF CASH FLOWS**  
**(THOUSANDS OF CANADIAN DOLLARS, UNAUDITED)**

	Note	Three Months Ended	
		March 31, 2016	March 31, 2015
<b>OPERATING</b>			
Net (loss) earnings		(85,848)	1,275
Adjustments:			
Accretion	4	6,109	5,675
Depletion and depreciation	2, 3	125,798	90,957
Impairment	2	14,762	-
Unrealized (gain) loss on derivative instruments		(9,054)	19,970
Equity based compensation		20,837	19,040
Unrealized foreign exchange (gain) loss		(1,570)	4,845
Unrealized other expense		87	261
Deferred taxes	6	22,546	(21,228)
Asset retirement obligations settled	4	(2,024)	(3,107)
Changes in non-cash operating working capital		(17,760)	(95,041)
Cash flows from operating activities		73,883	22,647
<b>INVESTING</b>			
Drilling and development	2	(62,773)	(174,311)
Property acquisitions	2	(870)	(35)
Changes in non-cash investing working capital		(4,087)	12,143
Cash flows used in investing activities		(67,730)	(162,203)
<b>FINANCING</b>			
Increase in long-term debt		269,560	154,914
Repayment of senior unsecured notes	5	(225,000)	-
Decrease in finance lease obligation		(895)	-
Cash dividends		(24,542)	(47,923)
Cash flows from financing activities		19,123	106,991
Foreign exchange (loss) gain on cash held in foreign currencies		(3,706)	352
Net change in cash and cash equivalents		21,570	(32,213)
Cash and cash equivalents, beginning of period		41,676	120,405
Cash and cash equivalents, end of period		63,246	88,192
Supplementary information for operating activities - cash payments			
Interest paid		21,311	18,245
Income taxes paid		2,390	70,513

**CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY**  
**(THOUSANDS OF CANADIAN DOLLARS, UNAUDITED)**

	Note	Three Months Ended	
		March 31, 2016	March 31, 2015
<b>SHAREHOLDERS' CAPITAL</b>			
Balance, beginning of period		2,181,089	1,959,021
Equity based compensation		4,128	532
Shares issued for the DRIP <sup>(1)</sup>		47,990	21,378
Balance, end of period	7	2,233,207	1,980,931
<b>CONTRIBUTED SURPLUS</b>			
Balance, beginning of period		107,946	92,188
Equity based compensation		16,709	18,508
Balance, end of period		124,655	110,696
<b>ACCUMULATED OTHER COMPREHENSIVE INCOME</b>			
Balance, beginning of period		113,647	5,722
Currency translation adjustments		(27,330)	(40,134)
Balance, end of period		86,317	(34,412)
<b>DEFICIT</b>			
Balance, beginning of period		(544,023)	(35,585)
Net (loss) earnings		(85,848)	1,275
Dividends declared	7	(72,847)	(69,390)
Balance, end of period		(702,718)	(103,700)
<b>TOTAL SHAREHOLDERS' EQUITY</b>		<b>1,741,461</b>	<b>1,953,515</b>

<sup>(1)</sup> DRIP Refers to Vermilion's dividend reinvestment and Premium Dividend™ plans.



**NOTES TO THE CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS  
FOR THE THREE MONTHS ENDED MARCH 31, 2016 AND 2015  
(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 IAS 34, "Interim financial reporting" and have been prepared using the same accounting policies and methods of computation as Vermilion's consolidated financial statements for the year ended December 31, 2015.

These condensed consolidated interim financial statements should be read in conjunction with Vermilion's consolidated financial statements for the year ended December 31, 2015, which are contained within Vermilion's Annual Report for the year ended December 31, 2015 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 May 5, 2016.

**2. CAPITAL ASSETS**

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

(\$M)	Capital Assets
<b>Balance at December 31, 2015</b>	3,467,369
Additions	62,773
Property acquisitions	870
Changes in estimate for asset retirement obligations	13,312
Depletion and depreciation	(124,663)
Recognition of finance lease asset	708
Impairment	(14,762)
Foreign exchange	(35,639)
<b>Balance at March 31, 2016</b>	3,369,968

**Impairment**

On a quarterly basis, Vermilion performs an assessment as to whether any cash generating units ("CGUs") have indicators of impairment. When indicators of impairment are identified, Vermilion assesses the recoverable amount of the applicable CGU based on the higher of the estimated fair value less costs to sell and value in use as at the reporting date. The estimated recoverable amount takes into account commodity price forecasts, expected production, estimated costs and timing of development, and undeveloped land values.

As a result of declines in the European natural gas price forecast, which decreased expected cash flows, Vermilion recorded a non-cash impairment charge of \$14.8 million in the Ireland segment for the three months ended March 31, 2016. The recoverable amount of the CGU was determined using a value in use approach based on forecasted reserves and expected cash flows and an after-tax discount rate of 9%.

The determination of impairment is sensitive to changes in key judgments, including reserve revisions, changes in forward commodity prices and exchange rates, and changes in costs and timing of development. Changes in these key judgments would impact the recoverable amount of CGUs, therefore resulting in additional impairment charges or recoveries. For the three months ended March 31, 2016, a one percent increase in the assumed discount rate on expected cash flows of the Ireland CGU would result in an additional impairment of \$33.7 million, and a five percent decrease in forward commodity prices would result in an additional impairment of \$50.1 million.

The following table outlines the forward commodity price estimates that were used in the calculation of the recoverable amount:

	Forward Commodity Price Assumptions <sup>(1)</sup>									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025 <sup>(2)</sup>
NBP (EUR/mmbtu)	4.55	5.39	5.95	6.47	6.68	6.81	7.03	7.10	7.18	7.37

<sup>(1)</sup> Source: Average of GLJ Petroleum Consultants and Sproule price forecasts, effective April 1, 2016.

<sup>(2)</sup> Escalated at 1.75% per year thereafter.

### 3. EXPLORATION AND EVALUATION ASSETS

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

(\$M)	Exploration and Evaluation Assets
<b>Balance at December 31, 2015</b>	308,192
Changes in estimate for asset retirement obligations	8
Depreciation	(3,343)
Foreign exchange	(824)
<b>Balance at March 31, 2016</b>	304,033

### 4. ASSET RETIREMENT OBLIGATIONS

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

(\$M)	Asset Retirement Obligations
<b>Balance at December 31, 2015</b>	305,613
Additional obligations recognized	176
Obligations settled	(2,024)
Accretion	6,109
Changes in discount rates	13,144
Foreign exchange	(4,037)
<b>Balance at March 31, 2016</b>	318,981

### 5. LONG-TERM DEBT

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

(\$M)	As at	
	Mar 31, 2016	Dec 31, 2015
Revolving credit facility	1,429,988	1,162,998
Senior unsecured notes <sup>(1)</sup>	-	224,901
<b>Long-term debt</b>	<b>1,429,988</b>	<b>1,387,899</b>

<sup>(1)</sup> The senior unsecured notes, which had a principal balance of \$225.0 million, matured and were repaid on February 10, 2016 and were included in the current portion of long-term debt as at December 31, 2015.

#### Revolving Credit Facility

At March 31, 2016, Vermilion had in place a bank revolving credit facility totalling \$2 billion, of which approximately \$1.43 billion was drawn. The facility, which matures on May 31, 2019, is fully revolving up to the date of maturity.

The facility is extendable from time to time, but not more than once per year, for a period not longer than four years, 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. This facility bears interest at a rate applicable to demand loans plus applicable margins. For the three months ended March 31, 2016, the interest rate on the revolving credit facility was approximately 3.3% (2015 – 3.1%).

The amount available to Vermilion under this facility is reduced by certain outstanding letters of credit associated with Vermilion's operations totalling \$24.7 million as at March 31, 2016 (December 31, 2015 - \$25.2 million).

The facility is secured by various fixed and floating charges against the subsidiaries of Vermilion. As at March 31, 2016, under the terms of the facility, Vermilion must maintain:

- A ratio of total borrowings (defined as amounts classified as "Long-term debt", "Current portion of long term debt", and "Finance lease obligation" on the balance sheet and referred to collectively as consolidated total debt), to consolidated net earnings before interest, income taxes, depreciation, accretion and other certain non-cash items (defined as consolidated EBITDA) of not greater than 4.0.
- A ratio of consolidated total senior debt (defined as consolidated total debt excluding unsecured and subordinated debt) to consolidated EBITDA of not greater than 3.0.
- A ratio of consolidated total senior debt to total capitalization (defined as amounts classified as "Shareholders' equity" on the balance sheet plus consolidated total senior debt as defined above) of not greater than 50%.

As at March 31, 2016, Vermilion was in compliance with all financial covenants.

## 6. DEFERRED INCOME TAXES

For the three months ended March 31, 2016, Vermilion de-recognized an additional \$40.3 million (year ended December 31, 2015 - \$51.7 million) of deferred tax assets, relating to certain non-capital losses for which there is uncertainty as to the Company's ability to fully utilize such losses when applying forecasted commodity prices in effect as at March 31, 2016.

## 7. SHAREHOLDERS' CAPITAL

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

Shareholders' Capital	Number of Shares ('000s)	Amount (\$M)
<b>Balance as at December 31, 2015</b>	111,991	2,181,089
Shares issued for the DRIP	1,354	47,990
Shares issued for equity based compensation	106	4,128
<b>Balance as at March 31, 2016</b>	113,451	2,233,207

Dividends declared to shareholders for the three months ended March 31, 2016 were \$72.8 million (2015 - \$69.4 million).

Subsequent to the end of the period and prior to the condensed consolidated interim financial statements being authorized for issue, Vermilion declared dividends totalling \$24.5 million or \$0.215 per share.

## 8. SEGMENTED INFORMATION

Vermilion's operating activities in each business unit relate solely to the exploration, development and production of petroleum and natural gas. Vermilion has a Corporate head office located in Calgary, Alberta. Costs incurred in the Corporate segment relate to Vermilion's global hedging program and expenses incurred in financing and managing the Company's operating business units.

Vermilion's chief operating decision maker reviews the financial performance of the Company by assessing the fund flows from operations of each business unit individually. Fund flows from operations provides a measure of each business unit's ability to generate cash (that is not subject to short-term movements in non-cash operating working capital) necessary to pay dividends, fund asset retirement obligations, and make capital investments.

(\$M)	Three Months Ended March 31, 2016								Total
	Canada	France	Netherlands	Germany	Ireland	Australia	United States	Corporate	
Total assets	1,584,947	833,145	195,413	159,522	838,240	240,352	44,585	176,136	4,072,340
Drilling and development	29,771	13,463	2,996	539	3,076	7,827	5,101	-	62,773
Oil and gas sales to external customers	56,110	48,125	27,286	7,692	17,004	19,935	1,233	-	177,385
Royalties	(5,498)	(6,766)	(460)	(867)	-	-	(370)	-	(13,961)
Revenue from external customers	50,612	41,359	26,826	6,825	17,004	19,935	863	-	163,424
Transportation	(4,151)	(3,713)	-	(887)	(1,639)	-	-	-	(10,390)
Operating	(21,343)	(14,320)	(5,976)	(2,593)	(3,626)	(7,491)	(279)	-	(55,628)
General and administration	(2,476)	(4,676)	(773)	(2,428)	(1,188)	(1,325)	(1,132)	421	(13,577)
PRRT	-	-	-	-	-	(128)	-	-	(128)
Corporate income taxes	-	(34)	(2,200)	-	-	(777)	-	(149)	(3,160)
Interest expense	-	-	-	-	-	-	-	(14,750)	(14,750)
Realized gain on derivative instruments	-	-	-	-	-	-	-	28,423	28,423
Realized foreign exchange loss	-	-	-	-	-	-	-	(652)	(652)
Realized other income	-	-	-	-	-	-	-	105	105
Fund flows from operations	22,642	18,616	17,877	917	10,551	10,214	(548)	13,398	93,667

## 8. SEGMENTED INFORMATION (Continued)

(\$M)	Three Months Ended March 31, 2015								
	Canada	France	Netherlands	Germany	Ireland	Australia	United States	Corporate	Total
Total assets	1,968,024	905,476	202,428	161,455	817,638	256,003	15,317	136,057	4,462,398
Drilling and development	114,849	34,114	4,333	968	12,955	6,455	637	-	174,311
Oil and gas sales to external customers	77,884	59,832	26,818	11,395	-	19,284	672	-	195,885
Royalties	(8,592)	(5,102)	(926)	(1,598)	-	-	(206)	-	(16,424)
Revenue from external customers	69,292	54,730	25,892	9,797	-	19,284	466	-	179,461
Transportation	(3,942)	(3,011)	-	(894)	(1,693)	-	-	-	(9,540)
Operating	(19,099)	(10,826)	(5,826)	(1,999)	-	(5,886)	(215)	-	(43,851)
General and administration	(4,015)	(5,111)	(737)	(1,608)	(512)	(1,454)	(1,080)	957	(13,560)
PRRT	-	-	-	-	-	(2,354)	-	-	(2,354)
Corporate income taxes	-	(14,281)	(2,388)	-	-	(577)	-	(377)	(17,623)
Interest expense	-	-	-	-	-	-	-	(13,298)	(13,298)
Realized gain on derivative instruments	-	-	-	-	-	-	-	6,257	6,257
Realized foreign exchange gain	-	-	-	-	-	-	-	3,306	3,306
Realized other income	-	31,775	-	-	-	-	-	222	31,997
Fund flows from operations	42,236	53,276	16,941	5,296	(2,205)	9,013	(829)	(2,933)	120,795

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

(\$M)	Three Months Ended	
	Mar 31, 2016	Mar 31, 2015
Fund flows from operations	93,667	120,795
Equity based compensation	(20,837)	(19,040)
Unrealized gain (loss) on derivative instruments	9,054	(19,970)
Unrealized foreign exchange gain (loss)	1,570	(4,845)
Unrealized other expense	(87)	(261)
Accretion	(6,109)	(5,675)
Depletion and depreciation	(125,798)	(90,957)
Deferred taxes	(22,546)	21,228
Impairment	(14,762)	-
Net (loss) earnings	(85,848)	1,275

## 9. FINANCIAL INSTRUMENTS

### Determination of Fair Values

The level in the fair value hierarchy into which the fair value measurements are categorized is determined on the basis of the lowest level input that is significant to the fair value measurement. Transfers between levels on the fair value hierarchy are deemed to have occurred at the end of the reporting period.

Level 1 – Fair value measurement is determined by reference to unadjusted quoted prices in active markets for identical assets or liabilities.

Level 2 – Fair value measurement is determined based on inputs other than unadjusted quoted prices that are observable, either directly or indirectly.

Level 3 – Fair value measurement is based on inputs for the asset or liability that are not based on observable market data.

Cash and cash equivalents are classified as Level 1 measurements. Cash and cash equivalents, receivables, and payables approximate their value due to the short-term nature of those instruments.

Derivative assets, derivative liabilities, and the fair value of long-term debt outstanding on the revolving credit facility are classified as Level 2 measurements. The fair value for derivative assets and derivative liabilities are determined using pricing models incorporating future prices that are based on assumptions which are supported by prices from observable market transactions and are adjusted for credit risk. The fair value of long-term debt on the revolving credit facility approximates carrying value due to the use of short-term borrowing instruments at market rates of interest. Vermilion does not have any financial instruments classified as Level 3 measurements.

### Nature and Extent of Risks Arising from Financial Instruments

#### *Market risk:*

Vermilion's financial instruments are exposed to currency risk related to changes in foreign currency denominated financial instruments and commodity price risk related to outstanding derivatives. The following table summarizes the impact on comprehensive income before tax for the three months ended March 31, 2016 given changes in the relevant risk variables that Vermilion considers reasonably possible at the balance sheet date. The impact on comprehensive income before tax associated with changes in these risk variables for assets and liabilities that are not considered financial instruments are excluded from this analysis. This analysis does not attempt to reflect any interdependencies between the relevant risk variables.

Risk (\$M)	Description of change in risk variable	Before tax effect on comprehensive
		income - increase (decrease) March 31, 2016
Currency risk - Euro to Canadian	5% <b>increase</b> in strength of the Canadian dollar against the Euro	(3,535)
	5% <b>decrease</b> in strength of the Canadian dollar against the Euro	3,535
Currency risk - US \$ to Canadian	5% <b>increase</b> in strength of the Canadian dollar against the US \$	2,323
	5% <b>decrease</b> in strength of the Canadian dollar against the US \$	(2,323)
Commodity price risk	US \$5.00/bbl <b>increase</b> in crude oil price used to determine the fair value of derivatives	(3,330)
	US \$5.00/bbl <b>decrease</b> in crude oil price used to determine the fair value of derivatives	3,330
	€ 0.5/GJ <b>increase</b> in European natural gas price used to determine the fair value of derivatives	(23,184)
	€ 0.5/GJ <b>decrease</b> in European natural gas price used to determine the fair value of derivatives	23,184
Interest rate risk	1% <b>increase</b> in average Canadian prime interest rate	(2,329)
	1% <b>decrease</b> in average Canadian prime interest rate	2,329

**CORPORATE INFORMATION****DIRECTORS**

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

Larry J. Macdonald<sup>2, 3, 4, 5, 6</sup>  
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Catherine L. Williams<sup>3, 4</sup>  
Calgary, Alberta

<sup>1</sup> Chairman of the Board

<sup>2</sup> Lead Director

<sup>3</sup> Audit Committee

<sup>4</sup> Governance and Human Resources Committee

<sup>5</sup> Health, Safety and Environment Committee

<sup>6</sup> Independent Reserves Committee

**ABBREVIATIONS**

\$M	thousand dollars
\$MM	million dollars
AECO	the daily average benchmark price for natural gas at the AECO 'C' hub in southeast Alberta
bbi(s)	barrel(s)
bbbls/d	barrels per day
bcf	billion cubic feet
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
btu	British thermal units
CGU	Cash generating unit, the basis upon which Vermilion's assets are evaluated for potential impairments
DRIP	Dividend Reinvestment Plan
GJ	gigajoules
HH	Henry Hub, a reference price paid for natural gas in US dollars at Erath, Louisiana
mbbls	thousand barrels
mboe	thousand barrel of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmboc	million barrel of oil equivalent
mmbtu	million British thermal units
mmcf	million cubic feet
mmcf/d	million cubic feet per day
MWh	megawatt hour
NBP	the reference price paid for natural gas in the United Kingdom, quoted in pence per therm, at the National Balancing Point Virtual Trading Point operated by National Grid. Our production in Ireland is priced with reference to NBP.
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
TTF	the day-ahead price for natural gas in the Netherlands, quoted in MWh of natural gas, at the Title Transfer Facility Virtual Trading Point operated by Dutch TSO Gas Transport Services
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma

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Executive Vice President Business Development

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Executive Vice President & Chief Financial Officer

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Executive Vice President, People and Culture

Michael Kaluza  
Executive Vice President & Chief Operating Officer

Dion Hatcher  
Vice President Canada Business Unit

Terry Hergott  
Vice President Marketing

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Director Corporate HSE

Bryce Kremnica  
Director Field Operations – Canada Business Unit

Dean N. Morrison  
Director Investor Relations

Mike Prinz  
Director Information Technology & Information Systems

Jenson Tan  
Director New Ventures

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Corporate Secretary

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Managing Director - France Business Unit

Scott Scatter  
Managing Director - Netherlands Business Unit

Albrecht Moehring  
Managing Director - Germany Business Unit

Bryan Sralla  
Managing Director - Central & Eastern Europe Business Unit

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Canadian Imperial Bank of Commerce

National Bank of Canada

Royal Bank of Canada

The Bank of Nova Scotia

HSBC Bank Canada

La Caisse Centrale Desjardins du Québec

Wells Fargo Bank N.A., Canadian Branch

Alberta Treasury Branches

Bank of America N.A., Canada Branch

BNP Paribas, Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

Union Bank, Canada Branch

JPMorgan Chase Bank, N.A., Toronto Branch

Canadian Western Bank

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