VERMILION ENERGY

Q1 2015

FIRST QUARTER MANAGEMENT'S DISCUSSION & ANALYSIS

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DEFINED PRODUCTION GROWTH | RELIABLE & GROWING DIVIDENDS

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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.

All oil and natural gas reserve information contained in this document has been prepared and presented in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities. The actual oil and natural gas reserves and future production will be greater than or less than the estimates provided in this document. The estimated future net revenue from the production of oil and natural gas reserves does not represent the fair market value of these reserves.

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.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is Management's Discussion and Analysis ("MD&A"), dated May 7, 2015, 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, 2015 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, 2015 and the audited consolidated financial statements for the year ended December 31, 2014 and 2013, together with accompanying notes. Additional information relating to Vermilion, including its Annual Information Form, is available on SEDAR at www.sedar.com or on Vermilion's website at www.vermilionenergy.com.

The unaudited condensed consolidated interim financial statements for the three months ended March 31, 2015 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"). As such, these financial measures are considered additional GAAP or non-GAAP financial measures and therefore are unlikely to be comparable with similar financial measures presented by other issuers. These additional GAAP and non-GAAP financial measures include:

- Fund flows from operations: This additional GAAP 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 non-GAAP 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.

For a full description of these and other non-GAAP financial measures and a reconciliation of these measures to their most directly comparable GAAP measures, please refer to "ADDITIONAL AND NON-GAAP FINANCIAL MEASURES".

VERMILION'S BUSINESS

Vermilion is a Calgary, Alberta based international oil and gas producer focused on the acquisition, 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 25% contractual participation interest in a four-partner consortium 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, primarily incurred in Canada and not directly related to the operations of a specific business unit.

GUIDANCE

We first issued 2015 capital expenditure guidance of $525 million on December 8, 2014. We subsequently adjusted our 2015 capital expenditure guidance to $415 million on February 27, 2015, in response to the continued weakness in commodity prices. The $110 million reduction in capital reflects lower planned activity levels, including the deferral of our Australian drilling campaign. Despite the reduction in our capital budget, we are maintaining our previous production guidance of 55,000-57,000 boe/d.

The following table summarizes our 2015 guidance:

	Date	Capital Expenditures ($MM)	Production (boe/d)
2015 - Guidance			
2015 Guidance	December 8, 2014	525	55,000 to 57,000
2015 Guidance	February 27, 2015	415	55,000 to 57,000

SHAREHOLDER RETURN

Vermilion strives to provide investors with reliable and growing dividends in addition to sustainable, global production growth. The following table, as of March 31, 2015, reflects our trailing one, three, and five year performance:

Total return (1)	Trailing One Year	Trailing Three Year	Trailing Five Year
Dividends per Vermilion share	$2.58	$7.34	$11.90
Capital appreciation per Vermilion share	-$15.80	$7.24	$17.86
Total return per Vermilion share	-19.1%	31.7%	84.1%
Annualized total return per Vermilion share	-19.1%	9.6%	13.0%
Annualized total return on the S&P TSX High Income Energy Index	-22.1%	-3.6%	0.2%

(1) The above table includes non-GAAP financial measures which may not be comparable to other companies. Please see the "ADDITIONAL AND NON-GAAP FINANCIAL MEASURES" section of this MD&A.

CONSOLIDATED RESULTS OVERVIEW

	Three Months Ended			% change	
	Mar 31, 2015	Dec 31, 2014	Mar 31, 2014	Q1/15 vs. Q4/14	Q1/15 vs. Q1/14
Production					
Crude oil (bbls/d)	28,181	28,846	27,318	(2%)	3%
NGLs (bbls/d)	3,039	2,822	2,140	8%	42%
Natural gas (mmcf/d)	115.00	107.42	103.32	7%	11%
Total (boe/d)	50,386	49,571	46,677	2%	8%
Build (draw) in inventory (mbbl)	383	(238)	(98)		
Financial metrics					
Fund flows from operations ($M)	120,795	185,528	205,363	(35%)	(41%)
Per share ($/basic share)	1.12	1.73	2.01	(35%)	(44%)
Net earnings ($M)	1,275	58,642	102,788	(98%)	(99%)
Per share ($/basic share)	0.01	0.55	1.00	(98%)	(99%)
Cash flows from operating activities ($M)	22,647	229,146	178,238	(90%)	(87%)
Net debt ($M)	1,388,603	1,265,650	966,310	10%	44%
Cash dividends ($/share)	0.645	0.645	0.645	-	-
Activity					
Capital expenditures ($M)	174,311	166,243	196,375	5%	(11%)
Acquisitions ($M)	35	1,652	178,227	(98%)	(100%)
Gross wells drilled	29.00	26.00	24.00		
Net wells drilled	20.04	16.58	18.83		

Operational review

- Recorded consolidated average production of 50,386 boe/d during Q1 2015, which was a 2% increase above Q4 2014 production.
- Recorded a build in crude oil inventory in Australia (281,000 bbls) and France (102,000 bbls), which resulted in lower sold volumes versus the comparable quarters.
- Increased consolidated average production from Q1 2014 by 8%, primarily driven by incremental production from our acquisitions in southeast Saskatchewan in Q2 2014 and Germany, which was acquired with an effective date of February 1, 2014. In Canada, production growth of 22% compared to Q1 2014 resulted from continued development of the Cardium and Mannville plays in Alberta, coupled with incremental production from southeast Saskatchewan following our acquisition in April 2014 of Elkhorn Resources Inc. These production increases were partially offset by decreased production in the Netherlands, which was managed throughout the quarter to optimize facility use and regulate declines. Production in Australia also decreased due to active management to control inventory levels and meet marketing schedules.
- Activity during the quarter included capital expenditures totalling $174.3 million, incurred primarily in Canada, France, and Ireland. In Canada, capital expenditures totalling $114.8 million were 34% higher than the $85.4 million incurred in Q4 2014 and included costs related to facility work and the drilling of 16.04 net wells compared to 15.16 net wells in Q4 2014. In France, capital expenditures of $34.1 million related to the drilling of 4.0 net wells and workovers. In Ireland, $13.0 million of capital expenditures were incurred, the majority of which related primarily to facility commissioning activities, as well as the completion of the 4.9 km tunnel.

Financial review

Net earnings

- Net earnings for Q1 2015 were $1.3 million ($0.01/basic share) as compared to $58.6 million ($0.55/basic share) for Q4 2014. The decrease quarter-over-quarter is primarily attributable to lower petroleum and natural gas sales driven by lower commodity prices and lower sales volumes, as well as a $13.7 million loss on derivative instruments, compared to a $40.0 million gain in the prior quarter. The decrease in sales was partially offset by lower operating costs and royalties, as well as the awarded recovery of costs resulting from the oil spill at the Ambès terminal that occurred in 2007.
- Net earnings for Q1 2015 were lower as compared to Q1 2014 primarily due to the decrease in sales as a result of lower commodity prices, an unrealized loss of $20.0 million on derivative instruments, and a loss on foreign exchange of $1.5 million (compared to gains of $3.9 million and $20.0 million, respectively, in the prior year). This was partially offset by a decrease in operating costs, a realized gain on derivative instruments of $6.3 million, and the previously mentioned recovery in France.

Cash flows from operating activities

- Cash flows from operating activities decreased by 90% and 87% as compared to Q4 2014 and Q1 2014, respectively. The decrease is primarily related to lower sales and timing differences pertaining to working capital, partially offset by lower operating expenses and royalties.

Fund flows from operations

- Generated fund flows from operations of $120.8 million during Q1 2015, a decrease of $64.7 million (35%) versus Q4 2014. This quarter-over-quarter decrease was the result of lower sales and lower realized gains on derivative instruments. This was partially offset by lower royalties and operating expenses, as well as the previously mentioned recovery in France.
- Fund flows from operations decreased by $84.6 million (41%) versus Q1 2014. This decrease was primarily the result of commodity price decreases and lower volumes sold in Australia and France (due to inventory builds in the period). This was partially offset by higher sales volumes in Canada, Germany, and the United States due to incremental production from acquisitions occurring in 2014, as well as lower royalties, operating expenses, and the previously mentioned recovery in France.

Net debt

- Net debt increased by $123.0 million to $1.39 billion as at March 31, 2015, due to capital expenditures in Canada and Ireland coupled with the decrease in fund flows from operations, which was driven by weak commodity prices and lower sales volumes.

Dividends

- Declared dividends remained consistent at $0.215 per common share per month during the first quarter of 2015, totalling $0.645 per common share for the quarter.

COMMODITY PRICES

	Three Months Ended			% change	
	Mar 31, 2015	Dec 31, 2014	Mar 31, 2014	Q1/15 vs. Q4/14	Q1/15 vs. Q1/14
Average reference prices					
WTI (US $/bbl)	48.63	73.15	98.68	(34%)	(51%)
Edmonton Sweet index (US $/bbl)	41.83	66.79	90.43	(37%)	(54%)
Dated Brent (US $/bbl)	53.97	76.27	108.22	(29%)	(50%)
AECO ($/GJ)	2.60	3.41	5.42	(24%)	(52%)
TTF ($/GJ)	8.25	8.69	10.19	(5%)	(19%)
TTF (€/GJ)	5.91	6.12	6.75	(3%)	(12%)
Average foreign currency exchange rates					
CDN $/US $	1.24	1.14	1.10	9%	13%
CDN $/Euro	1.40	1.42	1.51	(1%)	(7%)
Average realized prices ($/boe)					
Canada	35.81	51.27	69.26	(30%)	(48%)
France	64.33	79.25	117.54	(19%)	(45%)
Netherlands	48.60	52.07	63.60	(7%)	(24%)
Germany	45.21	49.19	55.85	(8%)	(19%)
Australia	83.80	90.37	127.26	(7%)	(34%)
United States	48.79	74.08	-	(34%)	100%
Consolidated	47.17	63.79	88.67	(26%)	(47%)
Production mix (% of production)					
% priced with reference to WTI	28%	28%	25%		
% priced with reference to AECO	20%	20%	17%		
% priced with reference to TTF	18%	16%	19%		
% priced with reference to Dated Brent	34%	36%	39%		

Reference prices

- The first quarter of 2015 proved to be a challenging period for energy prices, particularly crude oil. For the three months ended March 31, 2015, the average price for Dated Brent was US$53.97/bbl, a decrease of 29% from Q4 2014 and 50% lower than Q1 2014.
- Downward pressure was even greater for North American crude grades as inventory builds and robust production left little fundamental support. During Q1 2015, WTI averaged US$48.63/bbl versus US$73.15/bbl in Q4 2014 and US$98.68/bbl in Q1 2014. Edmonton Sweet Index averaged US$41.83/bbl in Q1 2015, down 37% and 54% versus Q4 2014 and Q1 2014, respectively.
- AECO natural gas declined by 24% versus Q4 2014 and 52% versus Q1 2014 as warmer weather in Western Canada kept the supply/demand balance at a lower equilibrium.
- Despite lower quarter-over-quarter and year-over-year results, European natural gas performed relatively well due to both geopolitical and fundamental support. Compared to the previous quarter, TTF decreased 5% in Canadian dollar terms and 3% in Euro terms, whereas on a year-over-year basis, Q1 2015 TTF decreased 19% in Canadian dollar terms and 12% in Euro terms.
- US dollar strength was a highlight for the first quarter, posting sizeable gains against major currency pairs such as the Canadian dollar and the Euro. For the three months ended March 31, 2015, CDN $/US $ increased 9% and 13% as compared to Q4 2014 and Q1 2014, respectively.

Realized prices

- Consolidated realized price for Q1 2015 decreased by 26% and 47% as compared to Q4 2014 and Q1 2014, respectively. The decreases were the result of weaker crude oil and natural gas prices, partially offset by a weaker Canadian dollar versus the US dollar during Q1 2015 versus the comparable quarters.

FUND FLOWS FROM OPERATIONS

	Three Months Ended					
	Mar 31, 2015		Dec 31, 2014		Mar 31, 2014	
	$M	$/boe	$M	$/boe	$M	$/boe
Petroleum and natural gas sales	195,885	47.17	306,073	63.79	381,183	88.67
Royalties	(16,424)	(3.95)	(25,963)	(5.41)	(24,024)	(5.59)
Petroleum and natural gas revenues	179,461	43.22	280,110	58.38	357,159	83.08
Transportation expense	(9,540)	(2.30)	(9,489)	(1.98)	(9,861)	(2.29)
Operating expense	(43,851)	(10.56)	(59,881)	(12.48)	(57,986)	(13.49)
General and administration	(13,560)	(3.27)	(13,236)	(2.76)	(14,467)	(3.37)
PRRT	(2,354)	(0.57)	(13,568)	(2.83)	(20,239)	(4.71)
Corporate income taxes	(17,623)	(4.24)	(8,304)	(1.73)	(38,603)	(8.98)
Interest expense	(13,298)	(3.20)	(12,943)	(2.70)	(11,460)	(2.67)
Realized gain on derivative instruments	6,257	1.51	22,816	4.76	2,640	0.61
Realized foreign exchange gain (loss)	3,306	0.78	(179)	(0.03)	(2,041)	(0.47)
Realized other income	31,997	7.70	202	0.04	221	0.05
Fund flows from operations	120,795	29.07	185,528	38.67	205,363	47.76

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

($M)	Q1/15 vs. Q4/14	Q1/15 vs. Q1/14
Fund flows from operations – Comparative period	185,528	205,363
Sales volume variance:		
Canada	(2,893)	26,315
France	(8,789)	(8,235)
Netherlands	3,268	(6,434)
Germany	(951)	5,172
Australia	(50,175)	(60,690)
United States	(310)	672
Pricing variance on sold volumes:		
WTI	(27,784)	(57,543)
AECO	(4,281)	(14,068)
Dated Brent	(15,390)	(59,493)
TTF	(2,883)	(10,994)
Changes in:		
Royalties	9,539	7,600
Transportation	(51)	321
Operating expense	16,030	14,135
General and administration	(324)	907
PRRT	11,214	17,885
Corporate income taxes	(9,319)	20,980
Interest	(355)	(1,838)
Realized derivatives	(16,559)	3,617
Realized foreign exchange	3,485	5,347
Realized other income	31,795	31,776
Fund flows from operations – Current period	120,795	120,795

Fund flows from operations of $120.8 million during Q1 2015 represent a decrease of $64.7 million (35%) versus Q4 2014. This quarter-over-quarter decrease was principally the result of lower sales volumes and weaker commodity pricing. The decrease in sales included $50.3 million of pricing variance, of which $43.2 million was due to a decrease in crude oil prices, as well as a $59.9 million sales volume variance, of which $59.0 million related to Australia and France (due to inventory builds in the period). The decrease in royalties and operating expenses is consistent with decreased sales in the quarter, and the increase in other income is related to the previously mentioned recovery in France.

On a year-over-year basis, fund flows from operations decreased 41% for the three months ended March 31, 2015, versus the comparable period in 2014. The decreases were primarily the result of a $185.3 million decrease in sales, including a $142.1 million pricing variance driven by a $117.0 million variance attributable to declines in crude oil prices. The decrease also included a $43.2 million sales volume variance, of which $68.9 million related to Australia and France (due to inventory builds in the period) and was partially offset by a $31.5 million positive variance related to production from Canada and Germany. Lower revenue was partially offset by decreases in operating expenses and taxes, as well as the previously mentioned recovery in France.

Fluctuations in fund flows from operations (and correspondingly net 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 balance sheet. When the crude oil inventory is subsequently drawn down, the related expenses are recognized in fund flows from operations.

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:
  - 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	
Canada business unit	Mar 31, 2015	Dec 31, 2014	Mar 31, 2014	Q1/15 vs. Q4/14	Q1/15 vs. Q1/14
Production					
Crude oil (bbls/d)	10,893	11,384	9,437	(4%)	15%
NGLs (bbls/d)	2,976	2,741	2,071	9%	44%
Natural gas (mmcf/d)	61.78	58.36	49.53	6%	25%
Total (boe/d)	24,165	23,851	19,763	1%	22%
Production mix (% of total)					
Crude oil	45%	48%	48%		
NGLs	12%	11%	10%		
Natural gas	43%	41%	42%		
Activity					
Capital expenditures ($M)	114,849	85,442	114,939	34%	-
Acquisitions ($M)	35	1,671	4,768		
Gross wells drilled	25.00	23.00	20.00		
Net wells drilled	16.04	15.16	14.97		

Production

- Production in Canada increased by 1% quarter-over-quarter and by 22% year-over year. The year-over-year increase in average production volumes was primarily attributable to strong organic production growth in our Mannville condensate-rich gas resource play. We achieved increased Canadian production despite having approximately 1,600 boe/d of production offline as a result of plant capacity restrictions and interruptible service curtailments on the NGTL system.
- Cardium production averaged more than 9,800 boe/d in Q1 2015, a 2% decrease quarter-over-quarter. Some non-operated volume is currently constrained due to pipeline restrictions.
- Mannville production averaged approximately 4,850 boe/d in Q1 2015, a 12% increase quarter-over-quarter. As with Cardium production, non-operated Mannville volume was constrained due to pipeline restrictions.
- Production from our southeast Saskatchewan assets averaged approximately 2,800 boe/d in Q1 2015, a 5% decrease quarter-over-quarter. The North Portal Gas Plant was commissioned late in Q1. The plant will enable the processing of approximately 6,000 mcf/d (5,500 mcf/d net) of gas which was previously being flared.

Activity review

- Vermilion drilled a total of 14 (11.8 net) operated wells during Q1 2015.

  Cardium
  - We participated in a total of seven (3.1 net) wells, including drilling one (1.0 net) operated well and brought 10 (9.3 net) operated wells on production during Q1 2015.
  - Since 2009, we have drilled or participated in 285 (201.9 net) wells.
  - In 2015, we plan to drill or participate in the seven (3.1 net) wells executed in Q1, and complete, equip and tie-in an additional 8.2 net wells which were drilled in 2014.

  Mannville
  - During Q1 2015, we participated in a total of 13 (8.9 net) wells, including eight (6.7 net) operated wells and brought three (2.5 net) operated wells on production.
  - In 2015, we expect to drill or participate in approximately 28 (16.0 net) wells and complete, equip and tie-in an additional 1.0 net well which was drilled in 2014.

  Saskatchewan
  - We drilled and brought on production five (4.1 net) operated Midale wells during Q1 2015, completing our 2015 drilling activity in Saskatchewan.

Financial review

Canada business unit ($M except as indicated)	Three Months Ended Mar 31, 2015	Dec 31, 2014	Mar 31, 2014	% change Q1/15 vs. Q4/14	Q1/15 vs. Q1/14
Sales	77,884	112,494	123,180	(31%)	(37%)
Royalties	(8,592)	(15,626)	(12,663)	(45%)	(32%)
Transportation expense	(3,942)	(3,455)	(3,098)	14%	27%
Operating expense	(19,099)	(19,315)	(16,610)	(1%)	15%
General and administration	(4,015)	(2,840)	(2,868)	41%	40%
Fund flows from operations	42,236	71,258	87,941	(41%)	(52%)
Netbacks ($/boe)					
Sales	35.81	51.27	69.26	(30%)	(48%)
Royalties	(3.95)	(7.12)	(7.12)	(45%)	(45%)
Transportation expense	(1.81)	(1.57)	(1.74)	15%	4%
Operating expense	(8.78)	(8.80)	(9.34)	-	(6%)
General and administration	(1.85)	(1.29)	(1.61)	43%	15%
Fund flows from operations netback	19.42	32.49	49.45	(40%)	(61%)
Reference prices					
WTI (US $/bbl)	48.63	73.15	98.68	(34%)	(51%)
Edmonton Sweet index (US $/bbl)	41.83	66.79	90.43	(37%)	(54%)
Edmonton Sweet index ($/bbl)	51.92	75.85	99.79	(32%)	(48%)
AECO ($/GJ)	2.60	3.41	5.42	(24%)	(52%)

Sales

- The realized price for our crude oil production in Canada is directly linked to WTI but is subject to market conditions in Western Canada. These market conditions can result in fluctuations in the pricing differential, 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.
- Sales per boe decreased by 30% quarter-over-quarter as a result of a 37% decrease in Edmonton Sweet index pricing and a 24% decrease in AECO pricing. This decrease, coupled with relatively consistent production volumes, resulted in a 31% decrease in sales.
- On a year-over-year basis, sales per boe decreased by 48% for the three months ended March 31, 2015 versus the same period in 2014. Lower commodity prices were partially offset by a 22% increase in production due to production growth in the Cardium and Mannville resource plays and incremental production from our Saskatchewan acquisition, resulting in a 37% decrease in sales.

Royalties

- Royalty expense as a percentage of sales for Q1 2015 decreased to 11.0% versus the 13.9% for Q4 2014 as a result of the impact of lower prices on the sliding scale used to determine royalty rates.
- Royalty expense as a percentage of sales for Q1 2015 was relatively consistent with Q1 2014 (10.3%) despite lower pricing due to fewer wells benefiting from incentive royalty rates in the current quarter versus Q1 2014.

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 2015 was higher than Q4 2014 as a result of higher crude oil production subject to transportation costs coupled with a prior period amendment received from a pipeline.
- On a year-over-year basis, transportation expense for Q1 2015 was higher than Q1 2014 as a result of incremental trucking costs from Vermilion's Saskatchewan properties, which were acquired in Q2 2014.

Operating expense

- On a per boe and dollar basis, operating expenses were relatively unchanged quarter-over-quarter.
- Year-over-year, operating expense increased on a dollar basis due to incremental operating expenses associated with Vermilion's Saskatchewan properties. This dollar increase was offset by a wide range of cost reduction initiatives undertaken in response to commodity price weakness and an increase in production volumes resulting in reduced operating expense on a per boe basis.

General and administration

- General and administration expense in Canada was higher in Q1 2015 as compared to Q4 2014. This resulted from expenditure timing as well as higher allocations of shared costs to Vermilion's other operating jurisdictions in the prior quarter.
- Year-over-year, the increase in general and administration expense for Q1 2015 as compared to Q1 2014 is primarily associated with higher staffing levels required to support Vermilion's organic growth initiatives as well as the 2014 Saskatchewan acquisition.

FRANCE BUSINESS UNIT

Overview

- Entered France in 1997 and completed three subsequent acquisitions, including two in 2012.
- Largest oil producer in France.
- 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	
France business unit	Mar 31, 2015	Dec 31, 2014	Mar 31, 2014	Q1/15 vs. Q4/14	Q1/15 vs. Q1/14
Production					
Crude oil (bbls/d)	11,463	11,133	10,771	3%	6%
Inventory (mbbls)					
Opening crude oil inventory	197	214	269		
Crude oil production	1,032	1,024	969		
Crude oil sales	(930)	(1,041)	(1,000)		
Closing crude oil inventory	299	197	238		
Activity					
Capital expenditures ($M)	34,114	37,189	37,967	(8%)	(10%)
Gross wells drilled	4.00	1.00	2.00		
Net wells drilled	4.00	0.50	2.00		

Production

- Quarter-over-quarter and year-over-year production growth of 3% and 6%, respectively.
- In late September 2013, the third party Lacq processing facility that processed our Vic Bilh gas production was permanently closed. As a result, our Vic Bilh gas production has been temporarily shut-in while preparations to transfer to an alternative facility are completed. As a result of the shut-in, current production volumes remain 100% weighted to Brent-based crude.

Activity review

- Vermilion drilled four (4.0 net) wells in the Champotran field in the Paris Basin in Q1 2015, completing our planned France drilling program for 2015.
- In 2015, additional activity includes an 18-well workover program and the resumption of sales from a portion of our shut-in natural gas at Vic Bilh.

Financial review

France business unit ($M except as indicated)	Three Months Ended Mar 31, 2015	Dec 31, 2014	Mar 31, 2014	% change Q1/15 vs. Q4/14	Q1/15 vs. Q1/14
Sales	59,832	82,499	117,560	(27%)	(49%)
Royalties	(5,102)	(6,319)	(7,351)	(19%)	(31%)
Transportation expense	(3,011)	(4,096)	(4,753)	(26%)	(37%)
Operating expense	(10,826)	(13,544)	(16,420)	(20%)	(34%)
General and administration	(5,111)	(3,765)	(5,194)	36%	(2%)
Other income	31,775	-	-	100%	100%
Current income taxes	(14,281)	(6,132)	(25,264)	133%	(43%)
Fund flows from operations	53,276	48,643	58,578	10%	(9%)
Netbacks ($/boe)					
Sales	64.33	79.25	117.54	(19%)	(45%)
Royalties	(5.49)	(6.07)	(7.35)	(10%)	(25%)
Transportation expense	(3.24)	(3.94)	(4.75)	(18%)	(32%)
Operating expense	(11.64)	(13.01)	(16.42)	(11%)	(29%)
General and administration	(5.49)	(3.62)	(5.19)	52%	6%
Other income	34.16	-	-	100%	100%
Current income taxes	(15.35)	(5.89)	(25.26)	161%	(39%)
Fund flows from operations netback	57.28	46.72	58.57	23%	(2%)
Reference prices					
Dated Brent (US $/bbl)	53.97	76.27	108.22	(29%)	(50%)
Dated Brent ($/bbl)	66.98	86.62	119.42	(23%)	(44%)

Sales

- Crude oil production in France is priced with reference to Dated Brent.
- Sales per boe decreased by 19% quarter-over-quarter, consistent with a 29% decrease in the Dated Brent reference price. This decrease, coupled with an increase in ending inventory of 102,000 bbls, resulted in a 27% decrease in sales.
- On a year-over-year basis, sales per boe decreased by 45% for the three months ended March 31, 2015, as compared to the same period in 2014. This decrease was primarily driven by the 50% decrease in the Dated Brent reference price, and, combined with a build in inventory, resulted in a 49% decrease in 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 revenue).
- Royalties as a percentage of sales was 8.5% in Q1 2015, an increase over both Q4 2014 (7.7%) and Q1 2014 (6.3%) due to the impact of fixed RCDM royalties coupled with lower realized pricing.

Transportation

- Transportation expense decreased for Q1 2015 as compared to Q4 2014 primarily as a result of a reduced number of shipments from the Ambès terminal during the current quarter due to unusually high tides at the end of March coupled with reduced trucking activity.
- Transportation expense for Q1 2015 was $1.7 million lower than Q1 2014. This decrease related to reduced maintenance and project activity at the Ambès terminal coupled with cost savings associated with fewer shipments at the terminal due to the usage of larger shipping vessels.

Operating expense

- Operating expense was lower in Q1 2015 as compared to both Q4 2014 and Q1 2014 due to cost reduction initiatives undertaken in response to commodity price weakness including lower costs on downhole and other activities, lower labour usage and costs, and savings from service contract renegotiations. In addition, operating expense also decreased due to the impact of deferring costs following a build in crude oil inventory related to the aforementioned unusually high tides at the end of March.
- On a year-over-year basis, operating expenses further benefited from a favorable foreign exchange impact of a strengthening of the Canadian dollar versus the Euro.

General and administration

- General and administration expense for Q1 2015 was higher than Q4 2014 due to the timing of expenditures. On a year-over-year basis, Q1 2015 general and administration expense was relatively unchanged.

Other income

- During Q1 2015, Vermilion was awarded a judgment pertaining to costs incurred as a result of an oil spill at the Ambès oil terminal in France that occurred in 2007. As a result of the award $31.8 million (before taxes) was recognized as other income.

Current income taxes

- Current income taxes in France are applied to taxable income, after eligible deductions, at a statutory rate of 34.4% for 2015. In addition, a 10.7% temporary surtax is applicable for tax year 2015 if annual revenue exceeds €250 million. For 2015, the effective rate on current income taxes is expected to be between approximately 20% and 22%. 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 for Q1 2015 increased compared to Q4 2014 due to the accelerated depletion on certain assets in the prior year.
- Current income taxes for Q1 2015 decreased compared to Q1 2014. The decrease was the result of lower funds from operations as a result of the decline in the Dated Brent reference price.

NETHERLANDS BUSINESS UNIT

Overview

- Entered the Netherlands in 2004.
- Second largest onshore gas producer.
- Interests include 16 licenses in the northeast region, five licenses in the central region, and two offshore licenses.
- Licenses include more than 800,000 net acres of undeveloped land.
- High impact natural gas drilling and development.
- Natural gas produced in the Netherlands is priced off the TTF index, which receives a significant premium over North American gas prices.

Operational review

	Three Months Ended			% change	
Netherlands business unit	Mar 31, 2015	Dec 31, 2014	Mar 31, 2014	Q1/15 vs. Q4/14	Q1/15 vs. Q1/14
Production					
NGLs (bbls/d)	63	81	69	(22%)	(9%)
Natural gas (mmcf/d)	36.41	31.35	43.15	16%	(16%)
Total (boe/d)	6,132	5,306	7,260	16%	(16%)
Activity					
Capital expenditures ($M)	4,333	10,022	20,118	(57%)	(78%)
Gross wells drilled	-	2.00	2.00		
Net wells drilled	-	0.92	1.86		

Production

- Production increased 16% quarter-over-quarter due to increased production from our Langezwaag-02 well which was tied in January 23, 2015 and partially offset by the anticipated loss of production from our Middenmeer-3 well, which was fully depleted and taken off production in February 2015.
- Year-over-year production decreased 16%, as production volumes in Q1 2014 benefited from the increased throughput capacity following a retrofit at our Middenmeer Treatment Centre completed in late 2013.
- Production in the Netherlands is actively managed to optimize facility use and regulate declines.

Activity review

- Langezwaag-02 well (42% working interest), drilled in the Gorredijk concession during Q4 2014, was placed on production in Q1 2015 with an average rate of production from the Zechstein formation of 4.0 mmcf/d (with surface facility constraints).
- In 2015, we are planning a three-well development drilling program and expect to equip and tie-in four previous discovery wells.

Financial review

Netherlands business unit ($M except as indicated)	Three Months Ended Mar 31, 2015	Dec 31, 2014	Mar 31, 2014	% change Q1/15 vs. Q4/14	Q1/15 vs. Q1/14
Sales	26,818	25,420	41,554	5%	(35%)
Royalties	(926)	(1,171)	(2,208)	(21%)	(58%)
Operating expense	(5,826)	(6,200)	(6,042)	(6%)	(4%)
General and administration	(737)	(2,489)	(598)	(70%)	23%
Current income taxes	(2,388)	2,124	(3,788)	(212%)	(37%)
Fund flows from operations	16,941	17,684	28,918	(4%)	(41%)
Netbacks ($/boe)					
Sales	48.60	52.07	63.60	(7%)	(24%)
Royalties	(1.68)	(2.40)	(3.38)	(30%)	(50%)
Operating expense	(10.56)	(12.70)	(9.25)	(17%)	14%
General and administration	(1.34)	(5.10)	(0.91)	(74%)	47%
Current income taxes	(4.33)	4.35	(5.80)	(200%)	(25%)
Fund flows from operations netback	30.69	36.22	44.26	(15%)	(31%)
Reference prices					
TTF ($/GJ)	8.25	8.69	10.19	(5%)	(19%)
TTF (€/GJ)	5.91	6.12	6.75	(3%)	(12%)

Sales

- The price of our natural gas in the Netherlands is based on the TTF day-ahead index, as determined on the Title Transfer Facility Virtual Trading Point operated by Dutch TSO Gas Transport Services, plus various fees. GasTerra, a state owned entity, continues to purchase all of the natural gas we produce in the Netherlands.
- The 5% increase in sales quarter-over-quarter primarily related to a 16% increase in production, offset by a 7% decrease in sales per boe which is consistent with the 5% decrease in the Canadian dollar equivalent of the TTF reference price.
- On a year-over-year basis, sales per boe declined by 24% for the three months ended March 31, 2015, versus the comparable period in 2014. This was consistent with a 19% decrease in the TTF reference price in Canadian dollar terms, and, coupled with a 16% decrease in production, resulted in a 35% decrease in sales.

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 royalties expense in the quarters presented relate to the amount of production from those wells subject to overriding royalties.

Transportation expense

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

Operating expense

- Operating expense decreased for Q1 2015 as compared to both Q4 2014 and Q1 2014. The decrease from Q4 2014 was largely the result of reduced project work, including the absence of an emergency response exercise conducted in Q4 2014. This decrease, coupled with increased volumes quarter-over-quarter, resulted in a decrease in operating expense per boe.
- The decrease in operating expense from Q1 2014 was largely driven by a strengthening of the Canadian dollar versus the Euro. Operating expense per boe increased from the same quarter of the prior year due to lower production.

General and administration

- On a quarter-over-quarter basis, general and administration expenses decreased in Q1 2015 versus Q4 2014 as the fourth quarter included higher allocations from Vermilion's Corporate segment. On a year-over-year basis, general and administration expense for Q1 2015 was relatively consistent with Q1 2014.

Current income taxes

- Current income taxes in the Netherlands apply to taxable income after eligible deductions at a statutory tax rate of approximately 46%. For 2015, the effective rate on current taxes is expected to be between approximately 10% and 12%. 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 2015 were higher than Q4 2014. This increase was a result of higher tax deductions for depletion on two unsuccessful wells in Q4 2014, combined with accelerated tax deductions for certain capital expenditures and other eligible in-country tax adjustments also taken in Q4 2014.
- Current income taxes in Q1 2015 were lower than Q1 2014 as a result of decreased revenues from lower TTF reference prices.

GERMANY BUSINESS UNIT

Overview

- Vermilion entered Germany in February 2014 with the purchase of a 25% participation interest in a four-partner consortium.
- The assets include four gas producing fields across 11 production licenses and an exploration license in surrounding fields.
- Total license area comprises 204,000 gross acres, of which 85% is in the exploration license.

Operational review

Germany business unit	Three Months Ended Mar 31, 2015	Dec 31, 2014	Mar 31, 2014	% change Q1/15 vs. Q4/14	Q1/15 vs. Q1/14
Production					
Natural gas (mmcf/d)	16.80	17.71	10.64	(5%)	58%
Total (boe/d)	2,801	2,952	1,773	(5%)	58%
Activity					
Capital expenditures ($M)	968	563	196	72%	394%
Acquisitions ($M)	-	-	172,871		

Production

- Q1 2015 production of 2,801 boe/d represented a decrease of 5% as compared to the prior quarter. Year-over-year production increased 58%, due to Q1 2014 volumes only reflecting production from the acquisition's effective date of February 1, 2014.

Activity review

- Participating in the drilling of the Burgmoor Z3a sidetrack well (25% working interest), which was spud in Q1 2015. The well is expected to be tied in and placed on production in Q3 2015.

Financial review

Germany business unit ($M except as indicated)	Three Months Ended Mar 31, 2015	Dec 31, 2014	Mar 31, 2014	% change Q1/15 vs. Q4/14	Q1/15 vs. Q1/14
Sales	11,395	13,359	8,915	(15%)	28%
Royalties	(1,598)	(2,481)	(1,802)	(36%)	(11%)
Transportation expense	(894)	(218)	(422)	310%	112%
Operating expense	(1,999)	(2,862)	(1,554)	(30%)	29%
General and administration	(1,608)	(2,200)	(568)	(27%)	183%
Current income taxes	-	1,145	(537)	(100%)	(100%)
Fund flows from operations	5,296	6,743	4,032	(21%)	31%
Netbacks ($/boe)					
Sales	45.21	49.19	55.85	(8%)	(19%)
Royalties	(6.34)	(9.13)	(11.29)	(31%)	(44%)
Transportation expense	(3.55)	(0.80)	(2.64)	344%	34%
Operating expense	(7.93)	(10.54)	(9.74)	(25%)	(19%)
General and administration	(6.38)	(8.10)	(3.56)	(21%)	79%
Current income taxes	-	4.21	(3.36)	(100%)	(100%)
Fund flows from operations netback	21.01	24.83	25.26	(15%)	(17%)
Reference prices					
TTF ($/GJ)	8.25	8.69	10.19	(5%)	(19%)
TTF (€/GJ)	5.91	6.12	6.75	(3%)	(12%)

Sales
- The price of our natural gas in Germany is based on the TTF month-ahead index, as determined on the Title Transfer Facility Virtual Trading Point operated by Dutch TSO Gas Transport Services, plus various fees.
- The 15% decrease in sales quarter-over-quarter is due to an 8% decrease in sales per boe, consistent with the 5% decrease in the Canadian dollar equivalent of the TTF reference price, and a 5% decrease in production.
- On a year-over-year basis, sales per boe declined by 19%, consistent with a 19% decrease in the Canadian dollar equivalent of the TTF reference price. This was offset by a 58% increase in recorded production following the Q1 2014 acquisition, resulting in a 28% increase in sales.

Royalties expense
- Our production in Germany is subject to state and private royalties on sales after certain eligible deductions. As a percentage of sales, royalties are expected to range from 15% to 20% in 2015.
- Q1 2015 royalties as a percentage of sales of 14.0% was lower than the 18.6% for Q4 2014 and 20.2% for Q1 2014, primarily as a result of lower state royalty rates for 2015.

Transportation expense
- Transportation expense in Germany relates to costs incurred to deliver natural gas from the processing facility to the customer.
- Transportation expense for Q1 2015 was higher than Q4 2014 as the first quarter included a higher level of seasonal maintenance activity on transportation infrastructure. Q1 2014 included two months of costs due to the timing of our Germany acquisition and as such, was lower than the current quarter.

Operating expense
- Operating expenses for Germany are billed monthly by the joint venture operator and primarily relate to tariffs charged for gas processing.
- Q1 2015 had lower operating expense on both a dollar and per boe basis as compared to Q4 2014 due to gas processing tariff adjustments recorded in Q4 2014.
- Q1 2015 had higher operating expenses on a dollar basis than Q1 2014 as the first quarter of 2014 included two months of costs. On a per boe basis, the year-over-year decrease resulted from reduced gas processing tariffs in 2015.

General and administration
- General and administration expense decreased quarter-over-quarter as a result of the timing of allocations from Vermilion's Corporate segment.

Current income taxes
- Current income taxes in Germany apply to taxable income after eligible deductions at a statutory tax rate of approximately 24%. As a function of Germany's tax pools, the company 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)	Three Months Ended Mar 31, 2015	Dec 31, 2014	Mar 31, 2014	% change Q1/15 vs. Q4/14	Q1/15 vs. Q1/14
Transportation expense	(1,693)	(1,720)	(1,588)	(2%)	7%
General and administration	(512)	(579)	(282)	(12%)	82%
Fund flows from operations	(2,205)	(2,299)	(1,870)	(4%)	18%
Activity					
Capital expenditures	12,955	20,932	16,236	(38%)	(20%)

Activity review

- Our Corrib project in Ireland has continued to progress as expected. Project operator Shell E&P Ireland Limited is systematically preparing gas compression and other systems at the Bellanaboy gas processing terminal for safe and reliable processing of gas production. The Irish Environmental Protection Agency issued its Proposed Determination for the Corrib Industrial Emissions License ("IEL") in April 2015. Based on remaining terminal activities and typical approval timelines for the final form of the IEL, we estimate that the most likely date for start-up is approximately mid-year, with a modest range of outcomes around that estimate.
- Production at Corrib is expected to increase over the first few months toward peak production levels estimated at approximately 58 mmcf/d (approximately 9,700 boe/d), net to Vermilion.

Transportation expense

- Transportation expense in Ireland relates to payments under a ship or pay agreement related to the Corrib project.

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 21 producing well bores.
- 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.
- Contracted crude oil production is priced with reference to Dated Brent.

Operational review

Australia business unit	Three Months Ended Mar 31, 2015	Dec 31, 2014	Mar 31, 2014	% change Q1/15 vs. Q4/14	Q1/15 vs. Q1/14
Production					
Crude oil (bbls/d)	5,672	6,134	7,110	(8%)	(20%)
Inventory (mbbls)					
Opening crude oil inventory	37	258	130		
Crude oil production	511	564	640		
Crude oil sales	(230)	(785)	(707)		
Closing crude oil inventory	318	37	63		
Activity					
Capital expenditures ($M)	6,455	11,616	5,691	(44%)	13%

Production

- Quarterly production decreased 8% quarter-over-quarter and 20% 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 2015, efforts were largely focused on facilities enhancement and engineering studies, including inspection work relating to platform life extension and pigging of the export line.
- With the deferral of the drilling program, 2015 planned activities include ongoing facilities maintenance, enhancement, and refurbishment, as well as preparation and permitting activities in advance of our next drilling program.

Financial review

Australia business unit ($M except as indicated)	Three Months Ended Mar 31, 2015	Dec 31, 2014	Mar 31, 2014	% change Q1/15 vs. Q4/14	Q1/15 vs. Q1/14
Sales	19,284	70,971	89,974	(73%)	(79%)
Operating expense	(5,886)	(17,719)	(17,360)	(67%)	(66%)
General and administration	(1,454)	(1,628)	(1,206)	(11%)	21%
PRRT	(2,354)	(13,568)	(20,239)	(83%)	(88%)
Corporate income taxes	(577)	(4,799)	(8,841)	(88%)	(93%)
Fund flows from operations	9,013	33,257	42,328	(73%)	(79%)
Netbacks ($/boe)					
Sales	83.80	90.37	127.26	(7%)	(34%)
Operating expense	(25.58)	(22.56)	(24.55)	13%	4%
General and administration	(6.32)	(2.07)	(1.71)	205%	270%
PRRT	(10.23)	(17.28)	(28.63)	(41%)	(64%)
Corporate income taxes	(2.51)	(6.11)	(12.51)	(59%)	(80%)
Fund flows from operations netback	39.16	42.35	59.86	(8%)	(35%)
Reference prices					
Dated Brent (US $/bbl)	53.97	76.27	108.22	(29%)	(50%)
Dated Brent ($/bbl)	66.98	86.62	119.42	(23%)	(44%)

Sales

- Our production in Australia currently receives a premium to Dated Brent.
- During Q1 2015, inventory increased by 281,000 bbls versus a 221,000 bbls draw in Q4 2014 and a 67,000 bbls draw in Q1 2014.
- Sales per boe for Q1 2015 decreased by 7% versus Q4 2014 as a result of the 23% decrease in the Dated Brent reference price in Canadian dollar terms. This decrease was coupled with the aforementioned build in inventory, resulting in a 73% decrease in sales.
- Sales per boe for the three months ended March 31, 2015 decreased 34% versus the same period in 2014, consistent with a 44% decrease in the Dated Brent reference price in Canadian dollar terms. Combined with an increase in inventory, this resulted in a 79% decrease in sales.

Royalties and transportation expense

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

Operating expense

- The decrease in operating expense for Q1 2015 as compared to Q4 2014 and Q1 2014 was largely the result of a build in inventory during the quarter.
- Absent the impact of inventory adjustments, operating expenses on a dollar basis decreased for Q1 2015 as compared to both Q4 2014 and Q1 2014 as a result of savings from a wide range of cost reduction initiatives undertaken in response to commodity price weakness including reduced vessel usage and lower diesel consumption. On a per boe basis, these cost reductions were offset by lower production volumes causing increased per barrel costs.

General and administration

- General and administration expense for 2015 was relatively unchanged versus the comparative 2014 periods. The timing of expenditures resulted in variances from quarter-to-quarter.

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 2015, the combined corporate income tax and PRRT effective rate is expected to be between approximately 25% and 27%. This rate is subject to change in response to commodity price fluctuations, the timing of capital expenditures and other eligible in-country adjustments.
- Combined corporate income taxes and PRRT for Q1 2015 were lower relative to both comparable periods in 2014. The decrease was consistent with lower sales.

UNITED STATES BUSINESS UNIT

Overview
- Entered the United States in September 2014.
- Interests include approximately 68,000 acres of land (98% undeveloped) in the Powder River Basin of northeastern Wyoming.
- Promising tight oil development targeting the Turner Sand at a depth of approximately 1,500 metres.

Operational and financial review

United States business unit ($M except as indicated)	Three Months Ended Mar 31, 2015	Three Months Ended Dec 31, 2014	% change Q1/15 vs. Q4/14
Sales	672	1,330	(49%)
Royalties	(206)	(366)	(44%)
Operating expense	(215)	(241)	(11%)
General and administration	(1,080)	(959)	13%
Fund flows from operations	(829)	(236)	251%
Netbacks ($/boe)			
Sales	48.79	74.08	(34%)
Royalties	(14.98)	(20.38)	(26%)
Operating expense	(15.61)	(13.44)	16%
General and administration	(78.41)	(53.44)	47%
Fund flows from operations netback	(60.21)	(13.18)	357%
Reference prices			
WTI (US $/bbl)	48.63	73.15	(34%)
WTI ($/bbl)	60.35	83.08	(27%)
Production			
Crude oil (bbls/d)	153	195	(22%)
Activity			
Capital expenditures	637	460	38%

Activity review
- The most recently completed well on this land block (70% working interest) is currently producing approximately 130 bbls/d of oil in its tenth month of production, from an approximately 1,100 metre hydraulically-fractured horizontal lateral.
- Drilling commenced subsequent to the end of Q1 for the one well planned in the East Finn prospect for 2015.

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

Royalties expense
- Our production in the United States is subject to federal and private royalties, severance tax, and ad valorem tax at a combined rate of approximately 27.5% of sales.

Operating expense
- Operating expense was consistent with the prior quarter.

General and administration
- General and administration expense was consistent with the prior quarter.

CORPORATE

Overview

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

Financial review

	Three Months Ended		
($M)	Mar 31, 2015	Dec 31, 2014	Mar 31, 2014
General and administration	957	1,224	(3,751)
Current income taxes	(377)	(642)	(173)
Interest expense	(13,298)	(12,943)	(11,460)
Realized gain on derivatives	6,257	22,816	2,640
Realized foreign exchange gain (loss)	3,306	(179)	(2,041)
Realized other income	222	202	221
Fund flows from operations	(2,933)	10,478	(14,564)

General and administration

- General and administration expense for Q1 2015 was consistent with Q4 2014.
- On a year-over-year basis, the decrease in general and administration costs for the three months ended March 31, 2015, as compared to 2014 is due to a decrease in staff-related expenditures, general cost saving initiatives in response to declining crude prices, and increased salary allocations to the various segments.

Current income taxes

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

Interest expense

- Interest expense is incurred on our senior unsecured notes and on borrowings under our revolving credit facility. The increase in Q1 2015 versus Q4 2014 and Q1 2014 is due to increased 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 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) for up to 50% of net of royalty volumes through a portfolio of forward collars, swaps, and physical fixed price arrangements.
- 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 2015 related primarily to amounts received on our TTF, AECO, and Dated Brent derivatives, partially offset by payments made on our foreign exchange derivatives.
- A listing of derivative positions as at March 31, 2015 is included in "Supplemental Table 2" in this MD&A.

FINANCIAL PERFORMANCE REVIEW

	Three Months Ended							
($M except per share)	Mar 31, 2015	Dec 31, 2014	Sep 30, 2014	Jun 30, 2014	Mar 31, 2014	Dec 31, 2013	Sep 30, 2013	Jun 30, 2013
Petroleum and natural gas sales	195,885	306,073	344,688	387,684	381,183	325,108	327,185	311,966
Net earnings	1,275	58,642	53,903	53,993	102,788	101,510	67,796	106,198
Net earnings per share								
Basic	0.01	0.55	0.50	0.51	1.00	1.00	0.67	1.05
Diluted	0.01	0.54	0.50	0.50	0.99	0.98	0.66	1.04

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

($M)	Q1/15 vs. Q4/14	Q1/15 vs. Q1/14
Net earnings - Comparative period	58,642	102,788
Changes in:		
Fund flows from operations	(64,733)	(84,568)
Equity based compensation	(647)	(2,568)
Unrealized gain or loss on derivative instruments	(37,127)	(23,905)
Unrealized foreign exchange gain or loss	(859)	(26,845)
Unrealized other expense	484	(7)
Accretion	512	37
Depletion and depreciation	26,224	8,495
Deferred tax	18,779	27,848
Net earnings - Current period	1,275	1,275

The fluctuations in net earnings from quarter-to-quarter and from year-to-year 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 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 expense in Q1 2015 was relatively consistent as compared to Q4 2014. The increase of $2.6 million (16%) as compared to Q1 2014 is due to a higher number of VIP awards outstanding, as well as an upward revision of future performance condition assumptions that occurred in Q2 2014.

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, 2015, we recognized an unrealized loss on derivative instruments of $20.0 million, relating primarily to our TTF and US dollar swaps and collars. As at March 31, 2015, we have a net derivative asset position of $4.8 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, 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. As such, an appreciation in the Euro against the Canadian dollar will result in an unrealized foreign exchange gain, and vice-versa.

For the three months ended March 31, 2015, the Canadian dollar strengthened slightly versus the Euro, which partially offset by a weakening of the Canadian dollar versus the US dollar, resulting in an unrealized foreign exchange loss of $4.8 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 2015 accretion expense was relatively consistent compared to Q4 2014 and Q1 2014.

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 of $21.90 in Q1 2015 was lower as compared to $24.42 in Q4 2014 and $23.13 in Q1 2014. The decrease is due to increased production from the Mannville condensate-rich gas play in Canada and natural gas properties in the Netherlands, which have lower per boe depletion expense as compared to 2014.

Deferred tax

Deferred tax expense 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.

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) or issue equity.

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 1.3 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 longer term target ratio. During this period, Vermilion will remain focused on maintaining a strong balance sheet and will manage the business accordingly.

Long-term debt

Our long-term debt consists of our revolving credit facility and our senior unsecured notes. The applicable annual interest rates and the balances recognized on our balance sheet are as follows:

	Annual Interest Rate		As At	
($M)	Mar 31, 2015	Dec 31, 2014	Mar 31, 2015	Dec 31, 2014
Revolving credit facility	3.0%	3.1%	1,168,614	1,014,067
Senior unsecured notes [1]	6.5%	6.5%	224,235	224,013
Long-term debt	3.6%	3.8%	1,392,849	1,238,080

(1) The senior unsecured notes, which will mature on February 10, 2016, are included in the current portion of long-term debt as at March 31, 2015.

Revolving Credit Facility

On January 30, 2015, Vermilion exercised its option to increase its credit facility from $1.5 billion to $1.75 billion. Subsequent to Q1 2015, we negotiated a further expansion and extension of our existing revolving credit facilities from $1.75 billion to $2 billion with a maturity of May 2019. The facility bears interest at rates applicable to demand loans plus applicable margins. The following table outlines the terms of our revolving credit facility:

	As At	
	Mar 31, 2015	Dec 31, 2014
Total facility amount	$1.75 billion	$1.50 billion
Amount drawn	$1.2 billion	$1.0 billion
Letters of credit outstanding	$9.8 million	$8.6 million
Facility maturity date	31-May-17	31-May-17

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

		As At	
Financial covenant	Limit	Mar 31, 2015	Dec 31, 2014
Consolidated total debt to consolidated EBITDA	4.0	1.55	1.21
Consolidated total senior debt to consolidated EBITDA	3.0	1.30	0.99
Consolidated total senior debt to total capitalization	50%	35%	31%

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

- Consolidated total debt: Includes all amounts classified as "Long-term debt" on our balance sheet, including the current portion.
- 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 "Long-term debt", including the current portion, and "Shareholders' equity".

Vermilion was in compliance with its financial covenants for all periods presented.

Senior Unsecured Notes

We have outstanding senior unsecured notes that are senior unsecured obligations and rank pari passu with all our other present and future unsecured and unsubordinated indebtedness. The following table outlines the terms of these notes:

Total issued and outstanding amount	$225.0 million
Interest rate	6.5% per annum
Issued date	February 10, 2011
Maturity date	February 10, 2016

Vermilion may redeem all or part of the senior unsecured notes at 100% of their principal amount plus any accrued and unpaid interest. The notes were initially recognized at fair value net of transaction costs and are subsequently measured at amortized cost using an effective interest rate of 7.1%.

Net debt

Net debt is reconciled to its most directly comparable GAAP measure, long-term debt, as follows:

	As At	
($M)	Mar 31, 2015	Dec 31, 2014
Long-term debt	1,168,614	1,238,080
Current liabilities[1]	549,580	365,729
Current assets	(329,591)	(338,159)
Net debt	1,388,603	1,265,650
Ratio of net debt to annualized fund flows from operations	2.9	1.6

[1] Includes the current portion of long-term debt, which, as at March 31, 2015, represents the senior unsecured notes that will mature on February 10, 2016.

Long term debt, including the current portion, as at March 31, 2015 increased to $1.39 billion from $1.24 billion as at December 31, 2014 as a result of draws on the revolving credit facility during the current year to fund capital expenditures, particularly relating to development expenditures in Canada and Ireland. The increase in long-term debt resulted in an increase to net debt from $1.27 billion to $1.39 billion. As a result of this increase to long-term debt and weak commodity prices, the ratio of net debt to fund flows from operations increased from 1.6 times as at December 31, 2014 to 2.9 times as at March 31, 2015.

Shareholders' capital

During the three months ended March 31, 2015, we maintained monthly dividends at $0.215 per share and declared dividends which totalled $69.4 million.

The following table outlines our dividend payment history:

Date	Monthly dividend per unit or share
January 2003 to December 2007	$0.17
January 2008 to December 2012	$0.19
January 2013 to December 31, 2013	$0.20
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 price commodity 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. In a further step to preserve our financial flexibility and conservatively exercise our access to capital, an amendment to our existing DRIP to include a Premium Dividend™ Component was announced in February 2015. The Premium Dividend™ Component, when combined with our continuing Dividend Reinvestment Component, is expected to increase our access, at the election of shareholders, to the lowest cost sources of equity capital available. While the Premium Dividend™ is expected to result 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 turned off 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. It is not currently expected that Vermilion will be required to change its dividend in 2015.

Although we currently expect to be able to maintain our current dividend, fund flows from operations may not be sufficient during this period 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)
Balance as at December 31, 2014	107,303	1,959,021
Issuance of shares pursuant to the dividend reinvestment plan	405	21,378
Shares issued pursuant to the bonus plan	10	532
Balance as at March 31, 2015	107,718	1,980,931

As at March 31, 2015, there were approximately 1.8 million VIP awards outstanding. As at May 7, 2015, there were approximately 109.3 million common shares issued and outstanding.

ASSET RETIREMENT OBLIGATIONS

As at March 31, 2015, asset retirement obligations were $377.0 million compared to $350.8 million as at December 31, 2014.

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, 2015.

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, 2014.

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 changes to our critical accounting estimates used in applying accounting policies for the three months ended March 31, 2015. 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, 2014, available on SEDAR at www.sedar.com or on Vermilion's website at 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, 2015			Three Months Ended March 31, 2014		
	Oil & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Oil & NGLs $/bbl	Natural Gas $/mcf	Total $/boe
Canada						
Sales	49.15	2.97	35.81	95.25	5.50	69.26
Royalties	(5.87)	(0.23)	(3.95)	(10.75)	(0.34)	(7.12)
Transportation	(2.42)	(0.16)	(1.81)	(2.27)	(0.17)	(1.74)
Operating	(9.02)	(1.41)	(8.78)	(10.99)	(1.17)	(9.34)
Operating netback	31.84	1.17	21.27	71.24	3.82	51.06
General and administration			(1.85)			(1.61)
Fund flows from operations netback			19.42			49.45
France						
Sales	64.33	-	64.33	117.54	-	117.54
Royalties	(5.48)	-	(5.49)	(7.35)	-	(7.35)
Transportation	(3.24)	-	(3.24)	(4.75)	-	(4.75)
Operating	(11.64)	-	(11.64)	(16.42)	-	(16.42)
Operating netback	43.97	-	43.96	89.02	-	89.02
General and administration			(5.49)			(5.19)
Other income			34.16			-
Current income taxes			(15.35)			(25.26)
Fund flows from operations netback			57.28			58.57
Netherlands						
Sales	52.93	8.09	48.60	106.96	10.53	63.60
Royalties	-	(0.28)	(1.68)	-	(0.57)	(3.38)
Operating	-	(1.78)	(10.56)	-	(1.56)	(9.25)
Operating netback	52.93	6.03	36.36	106.96	8.40	50.97
General and administration			(1.34)			(0.91)
Current income taxes			(4.33)			(5.80)
Fund flows from operations netback			30.69			44.26
Germany						
Sales	-	7.53	45.21	-	9.31	55.85
Royalties	-	(1.06)	(6.34)	-	(1.88)	(11.29)
Transportation	-	(0.59)	(3.55)	-	(0.44)	(2.64)
Operating	-	(1.32)	(7.93)	-	(1.62)	(9.74)
Operating netback	-	4.56	27.39	-	5.37	32.18
General and administration			(6.38)			(3.56)
Current income taxes			-			(3.36)
Fund flows from operations netback			21.01			25.26
Australia						
Sales	83.80	-	83.80	127.26	-	127.26
Operating	(25.58)	-	(25.58)	(24.55)	-	(24.55)
PRRT (1)	(10.23)	-	(10.23)	(28.63)	-	(28.63)
Operating netback	47.99	-	47.99	74.08	-	74.08
General and administration			(6.32)			(1.71)
Corporate income taxes			(2.51)			(12.51)
Fund flows from operations netback			39.16			59.86
United States						
Sales	48.79	-	48.79	-	-	-
Royalties	(14.98)	-	(14.98)	-	-	-
Operating	(15.61)	-	(15.61)	-	-	-
Operating netback	18.20	-	18.20	-	-	-
General and administration			(78.41)			-
Fund flows from operations netback			(60.21)			-
Total Company						
Sales	58.25	5.26	47.17	111.62	7.99	88.67
Realized hedging gain	0.75	0.43	1.51	0.26	0.21	0.61
Royalties	(5.21)	(0.37)	(3.95)	(6.72)	(0.60)	(5.59)
Transportation	(2.49)	(0.34)	(2.30)	(2.58)	(0.30)	(2.29)
Operating	(11.61)	(1.51)	(10.56)	(16.43)	(1.38)	(13.49)
PRRT (1)	(0.97)	-	(0.57)	(7.36)	-	(4.71)
Operating netback	38.72	3.47	31.30	78.79	5.92	63.20
General and administration			(3.27)			(3.37)
Interest expense			(3.20)			(2.67)
Realized foreign exchange gain (loss)			0.78			(0.47)
Other income			7.70			0.05
Corporate income taxes (1)			(4.24)			(8.98)
Fund flows from operations netback			29.07			47.76

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

Supplemental Table 2: Hedges

The following tables outline Vermilion's outstanding risk management positions as at March 31, 2015:

	Note	Volume	Strike Price(s)
Crude Oil			
WTI - Collar			
January 2015 - June 2015	1	250 bbl/d	75.00 - 82.75 US $
March 2015 - May 2015		1,000 bbl/d	48.00 - 59.23 US $
April 2015 - June 2015	2	500 bbl/d	54.50 - 66.28 US $
Dated Brent - Collar			
March 2015 - May 2015		1,000 bbl/d	52.00 - 62.21 US $
March 2015 - June 2015		250 bbl/d	58.00 - 69.35 US $
April 2015 - September 2015	1	250 bbl/d	60.00 - 74.15 US $
North American Natural Gas			
AECO - Collar			
April 2015 - October 2015		2,500 GJ/d	2.75 - 3.52 CAD $
April 2015 - December 2015		2,500 GJ/d	2.75 - 3.52 CAD $
AECO - Swap			
April 2015 - October 2015	3	10,000 GJ/d	2.98 CAD $
April 2015 - December 2015	4	2,500 GJ/d	2.99 CAD $
AECO Basis - Fixed Price Differential			
January 2015 - December 2015		5,000 mmbtu/d	Nymex HH less 0.68 US $
April 2015 - October 2015		7,500 mmbtu/d	Nymex HH less 0.62 US $
Nymex HH - Collar			
April 2015 - October 2015		10,000 mmbtu/d	3.36 - 4.01 US $
April 2015 - December 2015		2,500 mmbtu/d	3.50 - 4.11 US $
November 2015 - March 2016	5	5,000 mmbtu/d	3.25 - 3.86 US $

(1) The contracted volumes increase to 750 boe/d for any monthly settlement periods above the contracted ceiling price.
(2) The contracted volumes increase to 1,500 boe/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 10,000 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 by an additional 2,500 GJ/d at the contracted price, for the following month.
(5) The contracted volumes increase to 10,000 mmbtu/d for any monthly settlement periods above the contracted ceiling price.

European Natural Gas			
NBP - Swap			
July 2015 - March 2016		2,592 GJ/d	6.42 EUR €
October 2015 - March 2016		10,368 GJ/d	6.54 EUR €
January 2016 - June 2016		2,592 GJ/d	6.32 EUR €
January 2016 - June 2016		2,592 GJ/d	6.82 US $
TTF - Collar			
January 2015 - December 2015		2,592 GJ/d	6.11 - 6.83 EUR €
TTF - Swap			
January 2015 - December 2015		11,664 GJ/d	6.45 EUR €
January 2015 - March 2016		5,184 GJ/d	6.40 EUR €
January 2015 - June 2016		2,592 GJ/d	6.07 EUR €
February 2015 - March 2016		5,184 GJ/d	6.24 EUR €
April 2015 - December 2015		2,592 GJ/d	6.30 EUR €
April 2015 - March 2016		5,832 GJ/d	6.18 EUR €
October 2015 - December 2015		2,592 GJ/d	5.69 EUR €
October 2015 - March 2016		2,592 GJ/d	6.64 EUR €

Electricity			
AESO - Swap			
January 2016 - December 2016		31.2 MWh/d	39.00 CAD $
AESO - Swap (Physical)			
January 2013 - December 2015		72.0 MWh/d	53.17 CAD $

US Dollar			
USD - Collar			
January 2015 - June 2015	1	5,000,000 US $/month	1.162 - 1.181 CAD $
February 2015 - December 2015		2,500,000 US $/month	1.180 - 1.223 CAD $
USD - Forward			
February 2015 - December 2015		2,500,000 US $/month	1.198 CAD $

(1) Vermilion has upside participation on this hedge up to the limit price of 1.253 CAD; above which, settlement will occur at the conditional call level of 1.181 CAD.

Supplemental Table 3: Capital Expenditures

By classification ($M)	Three Months Ended Mar 31, 2015	Dec 31, 2014	Mar 31, 2014
Drilling and development	174,311	151,395	168,840
Exploration and evaluation	-	14,848	27,535
Capital expenditures	174,311	166,243	196,375
Property acquisition	35	1,652	178,227
Acquisitions	35	1,652	178,227

By category ($M)	Three Months Ended Mar 31, 2015	Dec 31, 2014	Mar 31, 2014
Land	742	1,457	4,753
Seismic	1,493	7,598	3,432
Drilling and completion	82,343	69,691	106,536
Production equipment and facilities	74,755	77,272	68,755
Recompletions	7,115	7,696	4,226
Other	7,863	2,529	8,673
Capital expenditures	174,311	166,243	196,375
Acquisitions	35	1,652	178,227
Total capital expenditures and acquisitions	174,346	167,895	374,602

By country ($M)	Three Months Ended Mar 31, 2015	Dec 31, 2014	Mar 31, 2014
Canada	114,884	87,113	119,707
France	34,114	37,189	37,967
Netherlands	4,333	10,022	20,118
Germany	968	563	173,067
Ireland	12,955	20,932	16,236
Australia	6,455	11,616	5,691
United States	637	460	-
Corporate	-	-	1,816
Total capital expenditures and acquisitions	174,346	167,895	374,602

Supplemental Table 4: Production

	Q1/15	Q4/14	Q3/14	Q2/14	Q1/14	Q4/13	Q3/13	Q2/13	Q1/13	Q4/12	Q3/12	Q2/12
Canada												
Crude oil (bbls/d)	10,893	11,384	11,469	12,676	9,437	8,719	7,969	8,885	7,966	7,983	7,322	7,757
NGLs (bbls/d)	2,976	2,741	2,291	2,796	2,071	1,699	1,897	1,725	1,335	1,106	1,204	1,321
Natural gas (mmcf/d)	61.78	58.36	57.07	57.59	49.53	41.43	43.40	43.69	41.04	31.41	35.54	41.32
Total (boe/d)	24,165	23,851	23,272	25,070	19,763	17,322	17,099	17,892	16,140	14,323	14,449	15,965
% of consolidated	48%	49%	47%	49%	42%	43%	41%	42%	41%	40%	40%	40%
France												
Crude oil (bbls/d)	11,463	11,133	11,111	11,025	10,771	11,131	11,625	10,390	10,330	9,843	9,767	9,931
Natural gas (mmcf/d)	-	-	-	-	-	-	5.23	4.19	4.21	3.91	3.39	3.57
Total (boe/d)	11,463	11,133	11,111	11,025	10,771	11,131	12,496	11,088	11,032	10,495	10,333	10,526
% of consolidated	23%	22%	22%	21%	23%	27%	30%	26%	29%	29%	28%	27%
Netherlands												
NGLs (bbls/d)	63	81	63	96	69	62	48	50	96	70	41	84
Natural gas (mmcf/d)	36.41	31.35	38.07	40.35	43.15	37.53	28.78	38.52	36.91	33.03	34.59	33.74
Total (boe/d)	6,132	5,306	6,407	6,822	7,260	6,318	4,845	6,470	6,248	5,574	5,806	5,707
% of consolidated	12%	11%	13%	13%	16%	15%	12%	15%	16%	15%	16%	15%
Germany												
Natural gas (mmcf/d)	16.80	17.71	15.38	16.13	10.64	-	-	-	-	-	-	-
Total (boe/d)	2,801	2,952	2,563	2,689	1,773	-	-	-	-	-	-	-
% of consolidated	6%	6%	5%	5%	4%	-	-	-	-	-	-	-
Australia												
Crude oil (bbls/d)	5,672	6,134	6,567	6,483	7,110	6,189	7,070	7,363	5,287	5,873	5,958	6,970
% of consolidated	11%	12%	13%	12%	15%	15%	17%	17%	14%	16%	16%	18%
United States												
Crude oil (bbls/d)	153	195	-	-	-	-	-	-	-	-	-	-
Consolidated												
Crude oil & NGLs (bbls/d)	31,220	31,668	31,501	33,076	29,458	27,800	28,609	28,413	25,014	24,875	24,292	26,063
% of consolidated	62%	64%	63%	63%	63%	68%	69%	66%	65%	69%	66%	67%
Natural gas (mmcf/d)	115.00	107.42	110.52	114.08	103.32	78.96	77.41	86.40	82.16	68.34	73.52	78.63
% of consolidated	38%	36%	37%	37%	37%	32%	31%	34%	35%	31%	34%	33%
Total (boe/d)	50,386	49,571	49,920	52,089	46,677	40,960	41,510	42,813	38,707	36,265	36,546	39,168

	2015	2014	2013	2012	2011	2010
Canada						
Crude oil (bbls/d)	10,893	11,248	8,387	7,659	4,701	2,778
NGLs (bbls/d)	2,976	2,476	1,666	1,232	1,297	1,427
Natural gas (mmcf/d)	61.78	55.67	42.39	37.50	43.38	43.91
Total (boe/d)	24,165	23,001	17,117	15,142	13,227	11,524
% of consolidated	48%	47%	41%	40%	38%	36%
France						
Crude oil (bbls/d)	11,463	11,011	10,873	9,952	8,110	8,347
Natural gas (mmcf/d)	-	-	3.40	3.59	0.95	0.92
Total (boe/d)	11,463	11,011	11,440	10,550	8,269	8,501
% of consolidated	23%	22%	28%	28%	23%	26%
Netherlands						
NGLs (bbls/d)	63	77	64	67	58	35
Natural gas (mmcf/d)	36.41	38.20	35.42	34.11	32.88	28.31
Total (boe/d)	6,132	6,443	5,967	5,751	5,538	4,753
% of consolidated	12%	13%	15%	15%	16%	15%
Germany						
Natural gas (mmcf/d)	16.80	14.99	-	-	-	-
Total (boe/d)	2,801	2,498	-	-	-	-
% of consolidated	6%	5%	-	-	-	-
Australia						
Crude oil (bbls/d)	5,672	6,571	6,481	6,360	8,168	7,354
% of consolidated	11%	13%	16%	17%	23%	23%
United States						
Crude oil (bbls/d)	153	49	-	-	-	-
Consolidated						
Crude oil & NGLs (bbls/d)	31,220	31,432	27,471	25,270	22,334	19,941
% of consolidated	62%	63%	67%	67%	63%	62%
Natural gas (mmcf/d)	115.00	108.85	81.21	75.20	77.21	73.14
% of consolidated	38%	37%	33%	33%	37%	38%
Total (boe/d)	50,386	49,573	41,005	37,803	35,202	32,132

Supplemental Table 5: Segmented Financial Results

	Three Months Ended March 31, 2015								
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	United States	Corporate	Total
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 expense	(3,942)	(3,011)	-	(894)	(1,693)	-	-	-	(9,540)
Operating expense	(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

ADDITIONAL AND NON-GAAP FINANCIAL MEASURES

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

Fund flows from operations: We define fund flows from operations as cash flows from operating activities before changes in non-cash operating working capital and asset retirement obligations settled. Management believes that by excluding the temporary impact of changes in non-cash operating working capital, fund flows from operations provides a measure of our ability to generate cash (that is not subject to short-term movements in non-cash operating working capital) necessary to pay dividends, repay debt, fund asset retirement obligations and make capital investments. As we have presented fund flows from operations in the "Segmented Information" note of our unaudited condensed consolidated interim financial statements for the three months ended March 31, 2015, we consider fund flows from operations to be an additional GAAP financial measure.

Free cash flow: Represents fund flows from operations in excess of 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 plan. 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, exploration and evaluation, 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 (an additional GAAP financial measure) and payout in order to assess our ability to generate cash and finance organic growth from our current producing assets.

Net debt: We define net debt as the sum of long-term debt and working capital. Management uses net debt, and the **ratio of net debt to fund flows from operations**, to analyze our financial position and leverage. Please refer to the preceding "Net Debt" section for a reconciliation of the net debt non-GAAP financial measure.

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.

Netbacks: Per boe and per mcf measures used in the analysis of operational activities.

Total returns: Includes cash dividends per share and the change in Vermilion's share price on the Toronto Stock Exchange.

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

	Three Months Ended		
($M)	Mar 31, 2015	Dec 31, 2014	Mar 31, 2014
Cash flows from operating activities	22,647	229,146	178,238
Changes in non-cash operating working capital	95,041	(49,865)	24,474
Asset retirement obligations settled	3,107	6,247	2,651
Fund flows from operations	120,795	185,528	205,363
Expenses related to Corrib	2,205	2,299	1,870
Fund flows from operations (excluding Corrib)	123,000	187,827	207,233

	Three Months Ended		
($M)	Mar 31, 2015	Dec 31, 2014	Mar 31, 2014
Dividends declared	69,390	69,119	66,007
Issuance of shares pursuant to the dividend reinvestment plan	(21,378)	(20,980)	(18,885)
Net dividends	48,012	48,139	47,122
Drilling and development	174,311	151,395	168,840
Exploration and evaluation	-	14,848	27,535
Asset retirement obligations settled	3,107	6,247	2,651
Payout	225,430	220,629	246,148
Corrib drilling and development	(12,955)	(20,932)	(16,236)
Payout (excluding Corrib)	212,475	199,697	229,912

	As At		
('000s of shares)	Mar 31, 2015	Dec 31, 2014	Mar 31, 2014
Shares outstanding	107,718	107,303	102,453
Potential shares issuable pursuant to the VIP	3,043	3,031	2,714
Diluted shares outstanding	110,761	110,334	105,167

DIRECTORS

Larry J. Macdonald [1, 3, 4, 5]
Chairman & CEO, Point Energy Ltd.
Calgary, Alberta

Lorenzo Donadeo
Calgary, Alberta

Claudio A. Ghersinich [2, 5]
Executive Director, Carrera Investments Corp.
Calgary, Alberta

Joseph F. Killi [2, 3]
Chairman, Parkbridge Lifestyle Communities Inc.
Vice Chairman, Realex Properties Corp.
Calgary, Alberta

Loren M. Leiker [5]
Houston, Texas

William F. Madison [4, 5]
Sugar Land, Texas

Timothy R. Marchant [4, 5]
Calgary, Alberta

Sarah E. Raiss [3, 4]
Calgary, Alberta

Kevin J. Reinhart [2, 3]
Calgary, Alberta

Catherine L. Williams [2, 3]
Calgary, Alberta

1 Chairman of the Board
2 Audit Committee
3 Governance and Human Resources Committee
4 Health, Safety and Environment Committee
5 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
bbl(s)	barrel(s)
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrel of oil equivalent, including: crude oil, natural gas liquids and natural gas (converted on the basis of one boe for six mcf of natural gas)
boe/d	barrel of oil equivalent per day
GJ	gigajoules
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
mmboe	million barrel of oil equivalent
mmcf	million cubic feet
mmcf/d	million cubic feet per day
MWh	megawatt hour
NGLs	natural gas liquids
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

OFFICERS AND KEY PERSONNEL

CANADA

Lorenzo Donadeo, P.Eng.
Chief Executive Officer

Anthony Marino, P.Eng.
President & Chief Operating Officer

John D. Donovan, FCA
Executive Vice President Business Development

Curtis W. Hicks, CA
Executive Vice President & Chief Financial Officer

Mona Jasinski, M.B.A., C.H.R.P.
Executive Vice President, People and Culture

Terry Hergott, CMA
Vice President Marketing

Michael Kaluza, P.Eng.
Vice President Canada Business Unit

Daniel Goulet, P.Eng.
Director Corporate HSE

Dion Hatcher, P.Eng.
Director Alberta Foothills – Canada Business Unit

Bryce Kremnica, P.Eng.
Director Field Operations – Canada Business Unit

Dean N. Morrison, CFA
Director Investor Relations

Mike Prinz
Director Information Technology & Information Systems

Jenson Tan, P.Eng.
Director New Ventures

Robert (Bob) J. Engbloom, LL.B
Corporate Secretary

UNITED STATES

Daniel G. Anderson
Managing Director – U.S. Business Unit

Timothy R. Morris
Director, U.S. Business Development – U.S. Business Unit

EUROPE

Gerard Schut, P.Eng.
Vice President European Operations

Darcy Kerwin, P.Eng.
Managing Director - France Business Unit

Neil Wallace
Managing Director - Netherlands Business Unit

Albrecht Moehring
Managing Director - Germany Business Unit

AUSTRALIA

Bruce D. Lake, P.Eng.
Managing Director
Australia Business Unit

AUDITORS

Deloitte LLP
Calgary, Alberta

BANKERS

The Toronto-Dominion Bank

Bank of Montreal

Canadian Imperial Bank of Commerce

Royal Bank of Canada

The Bank of Nova Scotia

National Bank of Canada

Alberta Treasury Branches

HSBC Bank Canada

La Caisse Centrale Desjardins du Québec

Wells Fargo Bank N.A., Canadian Branch

Bank of America N.A., Canada Branch

BNP Paribas, Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

JPMorgan Chase Bank, N.A., Toronto Branch

Union Bank, Canada Branch

Canadian Western Bank

Goldman Sachs Lending Partners LLC

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GLJ Petroleum Consultants Ltd.
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LEGAL COUNSEL

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Calgary, Alberta

TRANSFER AGENT

Computershare Trust Company of Canada

STOCK EXCHANGE LISTINGS

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

EXCELLENCE

We aim for exceptional results in everything we do.

TRUST

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

RESPECT

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

RESPONSIBILITY

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

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