VERMILION ENERGY

Q3 2015

THIRD QUARTER MANAGEMENT'S DISCUSSION & ANALYSIS

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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.

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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 crude 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 crude 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 November 5, 2015, of Vermilion Energy Inc.'s ("Vermilion", "We", "Our", "Us" or the "Company") operating and financial results as at and for the three and nine months ended September 30, 2015 compared with the corresponding periods in the prior year.

This discussion should be read in conjunction with the unaudited condensed consolidated interim financial statements for the three and nine months ended September 30, 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 and nine months ended September 30, 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 operations in Germany.
- Ireland business unit: Relates to our 18.5% non-operated interest in the Corrib offshore natural gas field.
- Australia business unit: Relates to our operations in the Wandoo offshore crude oil field.
- United States business unit: Relates to our operations in Wyoming in the Powder River Basin.
- Corporate: Includes expenditures related to our global hedging program, financing expenses, and general and administration expenses, 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. That reduction reflected lower planned activity levels, including the deferral of our Australian drilling program. On August 10, 2015 we announced an increase in our capital expenditure guidance of $70 million to $485 million following the reinstatement of the Australian drilling program as well as additional funding for projects in Canada, France and Ireland. We are maintaining our previous production guidance of 55,000-57,000 boe/d, albeit towards the lower end of our guidance range due to later-than-originally expected first gas from Corrib. On November 9, 2015 we announced preliminary 2016 capital expenditure guidance of $350 million and affirmed production guidance of between 63,000-65,000 boe/d.

The following table summarizes our 2015 and 2016 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
2015 Guidance	August 10, 2015	485	55,000 to 57,000
2016 - Guidance			
2016 Guidance	November 9, 2015	350	63,000 to 65,000

SHAREHOLDER RETURN

Vermilion strives to provide investors with reliable and growing dividends in addition to sustainable, global production growth. The following table, as of September 30, 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	$7.49	$12.05
Capital appreciation per Vermilion share	-$25.21	-$3.23	$4.35
Total return per Vermilion share	-33.2%	9.2%	42.5%
Annualized total return per Vermilion share	-33.2%	3.0%	7.3%
Annualized total return on the S&P TSX High Income Energy Index	-42.4%	-12.5%	-5.7%

[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		Nine Months Ended		% change
	Sep 30, 2015	Jun 30, 2015	Sep 30, 2014	Q3/15 vs. Q2/15	Q3/15 vs. Q3/14	Sep 30, 2015	Sep 30, 2014	2015 vs. 2014
Production								
Crude oil (bbls/d)	28,164	28,916	29,147	(3%)	(3%)	28,420	28,890	(2%)
NGLs (bbls/d)	4,622	3,867	2,354	20%	96%	3,849	2,463	56%
Natural gas (mmcf/d)	140.97	114.29	110.52	23%	28%	123.51	109.33	13%
Total (boe/d)	56,280	51,831	49,920	9%	13%	52,854	49,574	7%
Build (draw) in inventory (mbbl)	(85)	(121)	104			177	74	
Financial metrics								
Fund flows from operations ($M)	129,435	129,496	197,898	-	(35%)	379,726	619,337	(39%)
Per share ($/basic share)	1.17	1.18	1.85	(1%)	(37%)	3.48	5.90	(41%)
Net earnings (loss)	(83,310)	6,813	53,903	(1,323%)	(255%)	(75,222)	210,684	(136%)
Per share ($/basic share)	(0.76)	0.06	0.50	(1,367%)	(252%)	(0.69)	2.01	(134%)
Cash flows from operating activities ($M)	122,230	134,668	235,010	(9%)	(48%)	279,545	562,840	(50%)
Net debt ($M)	1,363,043	1,377,902	1,243,438	(1%)	10%	1,363,043	1,243,438	10%
Cash dividends ($/share)	0.645	0.645	0.645	-	-	1.935	1.935	-
Activity								
Capital expenditures ($M)	93,381	90,173	190,033	4%	(51%)	357,865	521,481	(31%)
Acquisitions ($M)	22,155	480	40,847	4,516%	(46%)	22,670	600,213	(96%)
Gross wells drilled	11.00	5.00	26.00			45.00	63.00	
Net wells drilled	6.91	3.61	20.31			30.56	45.86	

Operational review

- Recorded consolidated average production of 56,280 boe/d during Q3 2015, which was a 9% increase over Q2 2015 as a result of production growth in the Netherlands, Australia, and Canada, driven primarily by new wells on production.
- Increased consolidated average production for the three and nine months ended September 30, 2015 by 13% and 7%, respectively, versus the comparable periods in 2014, primarily due to growth in the Netherlands, Canada, and France.
- Activity during the quarter included capital expenditures totalling $93.4 million, incurred primarily in Canada, Ireland, and France. In Canada, capital expenditures totalling $37.2 million were 70% higher than the $21.9 million incurred in Q2 2015 and related to the drilling of 6.91 net wells (0.5 net wells in Q2 2015), with activity influenced by spring breakup in Q2 2015. In Ireland, capital expenditures of $20.7 million were incurred, the majority of which related to subsurface activities and facility commissioning. In France, capital expenditures of $17.4 million were consistent with the $16.7 million incurred in Q2 2015 and related to accretive workovers and subsurface activity.

Financial review

Net earnings (loss)

- The net loss for Q3 2015 was $83.3 million ($0.76/basic share) as compared to net earnings of $6.8 million ($0.06/basic share) in Q2 2015. The decrease in net earnings (loss) was primarily attributable to a non-cash impairment charge ($104.0 million after-tax) recognized in Q3 2015 following a steep decline in forward commodity prices. In addition, the change in net earnings (loss) for Q3 2015 saw lower petroleum and natural gas sales driven by lower commodity prices, partially offset by higher sold volumes, impacts from unrealized gains on derivative instruments and foreign exchange, and lower current income taxes.
- The net loss incurred for the three and nine months ended September 30, 2015 represented decreases of $137.2 million and $285.9 million, respectively, versus the comparative periods in 2014. These decreases were driven primarily by the aforementioned impairment charge recognized in the current period and lower petroleum and natural gas sales as a result of lower commodity prices. These declines were partially offset by decreases in royalties and taxes, as well as gains on derivative instruments and the impact of unrealized foreign exchange gains. In the nine months ended September 30, 2015, the decrease in net earnings was partially offset by the recovery of $31.8 million (before taxes) recognized in Q1 2015 following a judgment in favor of Vermilion for costs incurred as a result of a 2007 oil spill at the Ambès oil terminal in France that occurred shortly after Vermilion acquired the asset.

Cash flows from operating activities

- Cash flows from operating activities decreased by 48% and 50% for the three and nine months ended September 30, 2015, respectively, versus the comparable periods in 2014. These decreases primarily relate to lower revenue due to lower commodity prices and timing differences pertaining to working capital, partially offset by foreign exchange gains and lower current taxes.
- Absent changes in working capital, cash flows from operating activities was consistent quarter-over-quarter.

Fund flows from operations

- Generated fund flows from operations of $129.4 million during Q3 2015, consistent with fund flows from operations generated in Q2 2015. Fund flows from operations were impacted by lower sales, driven by lower realized prices but partially offset by higher volumes sold, a realized gain on derivative instruments, and a favorable current tax variance.
- Fund flows from operations decreased 35% and 39% for the three and nine months ended September 30, 2015, respectively, versus the comparable periods in 2014. These decreases were primarily driven by lower crude oil pricing, partially offset by higher sold volumes as well as favorable royalty and current tax variances, consistent with lower commodity prices. The decrease in fund flows from operations for the nine months ended September 30, 2015 was partially offset by the previously mentioned recovery of costs in France.

Net debt

- Net debt increased by $97.4 million to $1.36 billion for the nine months ended September 30, 2015 due to capital expenditures in Canada, Ireland and Australia, partially offset by fund flows from operations which were comparatively lower due to weaker commodity prices in 2015.

Dividends

- Declared dividends remained consistent at $0.215 per common share per month during the third quarter of 2015, totalling $0.645 per common share and $1.935 per common share for the three and nine months ended September 30, 2015, respectively.

COMMODITY PRICES

	Three Months Ended			% change		Nine Months Ended		% change
	Sep 30, 2015	Jun 30, 2015	Sep 30, 2014	Q3/15 vs. Q2/15	Q3/15 vs. Q3/14	Sep 30, 2015	Sep 30, 2014	2015 vs. 2014
Average reference prices								
WTI (US $/bbl)	46.43	57.94	97.17	(20%)	(52%)	51.00	99.61	(49%)
Edmonton Sweet index (US $/bbl)	43.01	55.08	89.24	(22%)	(52%)	46.64	92.17	(49%)
Dated Brent (US $/bbl)	50.26	61.92	101.85	(19%)	(51%)	55.39	106.57	(48%)
AECO ($/GJ)	2.75	2.52	3.81	9%	(28%)	2.62	4.56	(43%)
TTF ($/GJ)	8.04	7.94	7.26	1%	11%	8.08	8.41	(4%)
TTF (€/GJ)	5.52	5.84	5.04	(5%)	10%	5.76	5.68	1%
Average foreign currency exchange rates								
CDN $/US $	1.31	1.23	1.09	7%	20%	1.26	1.09	15%
CDN $/Euro	1.46	1.36	1.44	7%	1%	1.40	1.48	(5%)
Average realized prices ($/boe)								
Canada	32.78	40.59	64.85	(19%)	(49%)	36.34	68.58	(47%)
France	60.96	71.96	107.99	(15%)	(44%)	65.66	114.36	(43%)
Netherlands	49.42	47.63	45.73	4%	8%	48.70	52.80	(8%)
Germany	44.36	43.31	36.43	2%	22%	44.30	44.68	(1%)
Australia	68.20	80.87	119.07	(16%)	(43%)	76.46	124.59	(39%)
United States	51.60	60.57	-	(15%)	100%	52.95	-	100%
Consolidated	46.56	54.65	76.80	(15%)	(39%)	49.48	82.73	(40%)
Production mix (% of production)								
% priced with reference to WTI	24%	27%	28%			26%	27%	
% priced with reference to AECO	22%	21%	18%			21%	18%	
% priced with reference to TTF	20%	16%	18%			18%	18%	
% priced with reference to Dated Brent	34%	36%	36%			35%	37%	

Reference prices

- Despite higher demand, crude oil markets moved lower over the three months ended September 30, 2015 as global production edged higher. As compared to Q2 2015, WTI fell by 20% to average US $46.43/bbl while Dated Brent was down 19% to average US $50.26/bbl.
- Crude oil prices set at Edmonton were volatile in Q3 2015 due to fluctuations in supply and refining demand, with the reference price declining by 22% over the prior quarter to average US $43.01/bbl.
- Pipeline constraints and a relatively warm summer proved to be supportive factors for AECO natural gas, with prices increasing 9% quarter-over-quarter to average $2.75/GJ.
- European natural gas held firm in Canadian dollar terms quarter-over-quarter, averaging $8.04/GJ for the three months ended September 30, 2015, up 1% over the previous quarter, while TTF natural gas pricing, based on Euro per gigajoule, was down 5% quarter-over-quarter.
- The US dollar continued to strengthen against the Canadian dollar during Q3 2015 driven by the combination of weakening crude oil prices and larger interest rate spreads. For the three months ended September 30, 2015, 1 US dollar bought 1.31 Canadian dollars, which is 7% more than the previous quarter and 20% more than the same period in 2014.

Realized prices

- Consolidated realized price decreased by 15% for Q3 2015 as compared to Q2 2015. This decrease was the result of weakening crude oil pricing, partially offset by a slight improvement in North American natural gas pricing.
- Consolidated realized price for the three and nine months ended September 30, 2015 decreased by 39% and 40%, respectively, as compared to the comparable periods in 2014. These decreases were driven by a weakening of crude oil and North American natural gas pricing, as well as changes in production mix, which included increased relative NGL and natural gas volume on the production mix in Canada.

FUND FLOWS FROM OPERATIONS

	Three Months Ended						Nine Months Ended			
	Sep 30, 2015		Jun 30, 2015		Sep 30, 2014		Sep 30, 2015		Sep 30, 2014	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Petroleum and natural gas sales	245,051	46.56	264,331	54.65	344,688	76.80	705,267	49.48	1,113,555	82.73
Royalties	(17,100)	(3.25)	(16,111)	(3.33)	(29,000)	(6.46)	(49,635)	(3.48)	(82,037)	(6.09)
Petroleum and natural gas revenues	227,951	43.31	248,220	51.32	315,688	70.34	655,632	46.00	1,031,518	76.64
Transportation expense	(11,090)	(2.11)	(10,883)	(2.25)	(10,979)	(2.45)	(31,513)	(2.21)	(32,872)	(2.44)
Operating expense	(57,826)	(10.99)	(58,616)	(12.12)	(56,227)	(12.53)	(160,293)	(11.25)	(172,426)	(12.81)
General and administration	(13,088)	(2.49)	(14,505)	(3.00)	(16,262)	(3.62)	(41,153)	(2.89)	(48,491)	(3.60)
PRRT	(99)	(0.02)	(3,371)	(0.70)	(13,834)	(3.08)	(5,824)	(0.41)	(46,772)	(3.47)
Corporate income taxes	(12,383)	(2.35)	(17,344)	(3.59)	(17,454)	(3.89)	(47,350)	(3.32)	(88,692)	(6.59)
Interest expense	(15,420)	(2.93)	(14,550)	(3.01)	(12,918)	(2.88)	(43,268)	(3.04)	(36,712)	(2.73)
Realized gain on derivative instruments	10,854	2.06	3,081	0.64	8,837	1.97	20,192	1.42	13,896	1.03
Realized foreign exchange gain (loss)	309	0.06	(2,740)	(0.57)	812	0.17	875	0.06	(642)	(0.05)
Realized other income	227	0.04	204	0.04	235	0.05	32,428	2.28	530	0.04
Fund flows from operations	129,435	24.58	129,496	26.76	197,898	44.08	379,726	26.64	619,337	46.02

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

($M)	Q3/15 vs. Q2/15	Q3/15 vs. Q3/14	2015 vs. 2014
Fund flows from operations – Comparative period	129,496	197,898	619,337
Sales volume variance:			
Canada	1,563	5,575	21,485
France	8,590	27,004	27,133
Netherlands	15,660	11,159	1,418
Germany	(1,322)	(768)	3,240
Australia	(9,574)	4,948	(25,421)
United States	585	1,075	2,424
Pricing variance on sold volumes:			
WTI	(16,203)	(56,611)	(165,078)
AECO	662	(10,324)	(35,040)
Dated Brent	(20,970)	(86,359)	(230,151)
TTF	1,729	4,664	(8,298)
Changes in:			
Royalties	(989)	11,900	32,402
Transportation	(207)	(111)	1,359
Operating expense	790	(1,599)	12,133
General and administration	1,417	3,174	7,338
PRRT	3,272	13,735	40,948
Corporate income taxes	4,961	5,071	41,342
Interest	(870)	(2,502)	(6,556)
Realized derivatives	7,773	2,017	6,296
Realized foreign exchange	3,049	(503)	1,517
Realized other income	23	(8)	31,898
Fund flows from operations – Current period	129,435	129,435	379,726

Fund flows from operations of $129.4 million during Q3 2015 was consistent with fund flows from operations generated in Q2 2015. Fund flows from operations was impacted by weaker crude oil pricing, offset by higher sales volumes and favorable current tax variances. Sales decreased by $19.3 million, which included a $34.8 million unfavorable pricing variance driven by weaker crude oil prices partially offset by a $15.5 million sales volumes variance driven by increased sales in the Netherlands and France. In France, the increase in sold volumes resulted from a draw in inventory of 101,000 bbls (as compared to a build of 41,000 bbls in Q2 2015). This decrease in sales was offset by lower PRRT and corporate income taxes, as well as realized gains on both derivatives and foreign exchange.

Fund flows from operations decreased by 35% and 39% for the three and nine months ended September 30, 2015, respectively, versus the comparable periods in the prior year. These decreases were primarily driven by unfavorable crude oil and natural gas pricing variances, partially offset by favorable royalty and current income tax variances. For the three months ended September 30, 2015, the decrease in fund flows from operations was further offset by a favorable sales volume variance of $49.0 million including an increase in sold volumes in France of $27.0 million. For the nine months ended September 30, 2015, the decrease in fund flows from operations was partially offset by a $30.3 million favorable sales volume variance driven by France and Canada, as well as the recognition of the $31.8 million (before taxes) recovery in France recognized in Q1 2015.

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

Canada business unit	Three Months Ended Sep 30, 2015	Jun 30, 2015	Sep 30, 2014	% change Q3/15 vs. Q2/15	Q3/15 vs. Q3/14	Nine Months Ended Sep 30, 2015	Sep 30, 2014	% change 2015 vs. 2014
Production								
Crude oil (bbls/d)	9,195	10,182	11,469	(10%)	(20%)	10,083	11,202	(10%)
NGLs (bbls/d)	4,513	3,755	2,291	20%	97%	3,754	2,387	57%
Natural gas (mmcf/d)	71.94	64.66	57.07	11%	26%	66.16	54.76	21%
Total (boe/d)	25,698	24,713	23,272	4%	10%	24,864	22,714	9%
Production mix (% of total)								
Crude oil	36%	41%	49%			41%	49%	
NGLs	18%	15%	10%			15%	11%	
Natural gas	46%	44%	41%			44%	40%	
Activity								
Capital expenditures ($M)	37,224	21,881	97,393	70%	(62%)	173,954	249,300	(30%)
Acquisitions ($M)	8,062	384	27,883			8,481	413,977	
Gross wells drilled	11.00	1.00	22.00			37.00	51.00	
Net wells drilled	6.91	0.50	16.86			23.45	35.12	

Production

- Average production in Canada increased by 4% quarter-over-quarter, 10% year-over-year and 9% year-to-date, primarily due to strong organic production growth in our Mannville condensate-rich gas resource play. Q3 2015 volumes were negatively impacted by approximately 900 boe/d of production offline as a result of third-party plant capacity restrictions. Approximately 2,400 boe/d is awaiting equip and tie in, which is anticipated to be completed in Q4 2015, but this production is expected to remain shut-in due to third party processing constraints.
- Cardium production averaged approximately 9,300 boe/d in Q3 2015, essentially flat quarter-over-quarter.
- Mannville production averaged more than 7,000 boe/d in Q3 2015, a 25% increase quarter-over-quarter.
- Production from our southeast Saskatchewan assets averaged approximately 3,000 boe/d in Q3 2015, a decrease of 9% quarter-over-quarter. The North Portal Gas Plant was commissioned late in Q1 2015. The plant enables the processing of approximately 5,500 mcf/d (920 boe/d) net of natural gas which was previously being flared.

Activity review

- Vermilion drilled five (4.5 net) operated wells and participated in the drilling of six (2.4 net) non-operated wells during Q3 2015.

  Cardium
  - During Q3 2015, no new wells were drilled or brought on production.
  - Year-to-date, we have drilled or participated in seven (3.1 net) wells and 18 (11.9 net) wells were placed on production. For the remainder of the year, we plan to participate in the drilling of two (0.3 net) non-operated wells.

  Mannville
  - During Q3 2015, we drilled five (4.5 net) operated wells and brought four (3.0 net) operated wells on production. We also participated in the drilling of six (2.4 net) non-operated wells and six (2.5 net) non-operated wells were placed on production.
  - Year-to-date, we have drilled or participated in 25 (16.3 net) wells and 19 (12.0 net) wells were placed on production. For the remainder of the year, we plan to drill two (0.6 net) operated wells, and place two (2.0 net) operated and three (1.3 net) non-operated wells on production.

  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 ($M except as indicated)	Three Months Ended Sep 30, 2015	Jun 30, 2015	Sep 30, 2014	% change Q3/15 vs. Q2/15	Q3/15 vs. Q3/14	Nine Months Ended Sep 30, 2015	Sep 30, 2014	% change 2015 vs. 2014
Sales	77,493	91,284	138,853	(15%)	(44%)	246,661	425,294	(42%)
Royalties	(6,638)	(5,768)	(19,034)	15%	(65%)	(20,998)	(49,937)	(58%)
Transportation expense	(4,131)	(4,469)	(4,048)	(8%)	2%	(12,542)	(11,170)	12%
Operating expense	(23,877)	(21,534)	(19,074)	11%	25%	(64,510)	(56,863)	13%
General and administration	(3,694)	(5,510)	(4,523)	(33%)	(18%)	(13,219)	(13,951)	(5%)
Fund flows from operations	39,153	54,003	92,174	(27%)	(58%)	135,392	293,373	(54%)
Netbacks ($/boe)								
Sales	32.78	40.59	64.85	(19%)	(49%)	36.34	68.58	(47%)
Royalties	(2.81)	(2.56)	(8.89)	10%	(68%)	(3.09)	(8.05)	(62%)
Transportation expense	(1.75)	(1.99)	(1.89)	(12%)	(7%)	(1.85)	(1.80)	3%
Operating expense	(10.10)	(9.58)	(8.91)	5%	13%	(9.50)	(9.17)	4%
General and administration	(1.56)	(2.45)	(2.11)	(36%)	(26%)	(1.95)	(2.25)	(13%)
Fund flows from operations netback	16.56	24.01	43.05	(31%)	(62%)	19.95	47.31	(58%)
Reference prices								
WTI (US $/bbl)	46.43	57.94	97.17	(20%)	(52%)	51.00	99.61	(49%)
Edmonton Sweet index (US $/bbl)	43.01	55.08	89.24	(22%)	(52%)	46.64	92.17	(49%)
Edmonton Sweet index ($/bbl)	56.32	67.72	97.21	(17%)	(42%)	58.77	100.87	(42%)
AECO ($/GJ)	2.75	2.52	3.81	9%	(28%)	2.62	4.56	(43%)

Sales

- The realized price for our crude oil production in Canada is directly linked to WTI, but is also subject to market conditions in Western Canada. These market conditions can result in fluctuations in the pricing differential to WTI, as reflected by the Edmonton Sweet index price. The realized price of our NGLs in Canada is based on product specific differentials pertaining to trading hubs in the United States. The realized price of our natural gas in Canada is based on the AECO spot price in Canada.
- Sales per boe decreased by 19% quarter-over-quarter as a result of a 17% decrease in Edmonton Sweet index pricing in Canadian dollar terms offset by a 9% increase in AECO pricing. The pricing decrease for crude oil production, coupled with the increased relative NGL and natural gas volume on the production mix, more than offset a 4% increase in Canadian production volumes, resulting in a 15% decrease in sales.
- On a year-over-year basis, sales per boe decreased by 49% and 47% for the three and nine months ended September 30, 2015, largely as the result of weakening crude oil and natural gas pricing. In both periods, the lower pricing was slightly offset by an increase in production volumes of approximately 10%, resulting in a decrease in sales of 44% and 42% for the three and nine months ended September 30, 2015, respectively.

Royalties

- Royalties as a percentage of sales for Q3 2015 increased to 8.6% as compared to Q2 2015 of 6.3% despite lower reference prices (which would typically result in lower royalty rates) due to the timing of when par prices used in the royalty calculations were set. This timing difference resulted in lower crude oil royalty rates for Q2 2015 and higher crude oil royalty rates for Q3 2015. In addition, an annual favorable gas cost allowance (“GCA”) adjustment in Alberta resulted in gas royalties being in a recovery position for the second quarter.
- Royalties as a percentage of sales for the three and nine months ended September 30, 2015 decreased to 8.6% and 8.5% versus 13.7% and 11.7% for the same periods in 2014 due to the impact of lower reference prices on the sliding scale used to determine crude oil royalty rates.

Transportation

- Transportation expense relates to the delivery of crude oil and natural gas production to major pipelines where legal title transfers.
- Transportation expense for Q3 2015 was lower than Q2 2015 as a result of lower transportation rates for our Alberta natural gas liquids production.
- Transportation expense for the nine months ended September 30, 2015 was higher than the same period in the prior year as a result of incremental trucking costs from Vermilion’s Saskatchewan properties, which were acquired in April 2014.

Operating expense

- Operating expenses were higher on a dollar and per boe basis for Q3 2015 versus both Q2 2015 and Q3 2014 as a result of higher gas processing fees attributable to increased production being processed at third party facilities.
- Year-over-year operating expense increased on a dollar basis by approximately 13% due to incremental operating expense associated with Vermilion's Saskatchewan properties acquired in Q2 2014 and the aforementioned higher gas processing fees. This dollar increase was partially offset by increased production, resulting in a 4% increase in operating expense per boe.

General and administration

- General and administration expense decreased for Q3 2015 versus both Q2 2015 and Q3 2014 as a result of timing of expenditures.
- Year-over-year, general and administration expense for the nine months ended September 30, 2015 were 5% lower than 2014 due to a focus on cost reduction initiatives.

Impairment

- For the three months ended September 30, 2015, Vermilion recorded an impairment charge of $143.0 million related to the light crude oil play in Saskatchewan, Canada. These impairment charges were a result of declines in the price forecasts for crude oil in Canada which decreased the expected future cash flows from the cash generating unit ("CGU").

FRANCE BUSINESS UNIT

Overview

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

Operational review

	Three Months Ended			% change		Nine Months Ended		% change
France business unit	Sep 30, 2015	Jun 30, 2015	Sep 30, 2014	Q3/15 vs. Q2/15	Q3/15 vs. Q3/14	Sep 30, 2015	Sep 30, 2014	2015 vs. 2014
Production								
Crude oil (bbls/d)	12,310	12,746	11,111	(3%)	11%	12,176	10,970	11%
Natural gas (mmcf/d)	1.47	1.03	-	43%	100%	0.84	-	100%
Total (boe/d)	12,555	12,917	11,111	(3%)	13%	12,316	10,970	12%
Inventory (mbbls)								
Opening crude oil inventory	340	299	179			197	268	
Crude oil production	1,133	1,160	1,022			3,324	2,995	
Crude oil sales	(1,234)	(1,119)	(987)			(3,282)	(3,049)	
Closing crude oil inventory	239	340	214			239	214	
Production mix (% of total)								
Crude oil	98%	99%	100%			99%	100%	
Natural gas	2%	1%	-			1%	-	
Activity								
Capital expenditures ($M)	17,369	16,697	35,082	4%	(50%)	68,180	110,663	(38%)
Acquisitions ($M)	142	96	-			238	-	
Gross wells drilled	-	-	3.00			4.00	7.00	
Net wells drilled	-	-	3.00			4.00	7.00	

Production

- Ongoing workover and optimization activities resulted in stable quarter-over-quarter production. Production increased for the current quarter and year-to-date periods as compared to the same periods in the prior year due to production additions from our 2015 Champotran drilling program and workovers.

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 a 26-well workover program and the resumption of sales from a portion of our shut-in natural gas at Vic Bilh, which was brought on-line in Q2 2015.

Financial review

France business unit ($M except as indicated)	Three Months Ended Sep 30, 2015	Jun 30, 2015	Sep 30, 2014	% change Q3/15 vs. Q2/15	Q3/15 vs. Q3/14	Nine Months Ended Sep 30, 2015	Sep 30, 2014	% change 2015 vs. 2014
Sales	76,552	81,627	106,576	(6%)	(28%)	218,011	348,753	(37%)
Royalties	(8,038)	(6,620)	(6,978)	21%	15%	(19,760)	(22,125)	(11%)
Transportation expense	(4,566)	(3,526)	(4,741)	29%	(4%)	(11,103)	(14,879)	(25%)
Operating expense	(11,998)	(12,102)	(15,215)	(1%)	(21%)	(34,926)	(48,185)	(28%)
General and administration	(5,338)	(4,874)	(6,411)	10%	(17%)	(15,323)	(17,164)	(11%)
Other income	-	-	-	-	-	31,775	-	100%
Current income taxes	(4,696)	(9,316)	(10,744)	(50%)	(56%)	(28,293)	(60,769)	(53%)
Fund flows from operations	41,916	45,189	62,487	(7%)	(33%)	140,381	185,631	(24%)
Netbacks ($/boe)								
Sales	60.96	71.96	107.99	(15%)	(44%)	65.66	114.36	(43%)
Royalties	(6.40)	(5.84)	(7.07)	10%	(9%)	(5.95)	(7.26)	(18%)
Transportation expense	(3.64)	(3.11)	(4.80)	17%	(24%)	(3.34)	(4.88)	(32%)
Operating expense	(9.55)	(10.67)	(15.42)	(10%)	(38%)	(10.52)	(15.80)	(33%)
General and administration	(4.25)	(4.30)	(6.50)	(1%)	(35%)	(4.61)	(5.63)	(18%)
Other income	-	-	-	-	-	9.57	-	100%
Current income taxes	(3.74)	(8.21)	(10.89)	(54%)	(66%)	(8.52)	(19.93)	(57%)
Fund flows from operations netback	33.38	39.83	63.31	(16%)	(47%)	42.29	60.86	(31%)
Reference prices								
Dated Brent (US $/bbl)	50.26	61.92	101.85	(19%)	(51%)	55.39	106.57	(48%)
Dated Brent ($/bbl)	65.81	76.12	110.95	(14%)	(41%)	69.79	116.63	(40%)

Sales

- Crude oil in France is priced with reference to Dated Brent.
- Sales per boe decreased by 15% quarter-over-quarter, consistent with a 14% decrease in the Canadian dollar equivalent of the Dated Brent reference price. This decrease was partially offset by a 101,000 bbls draw in inventory during the quarter, resulting in a 6% decrease in sales.
- On a year-over-year basis, sales decreased by 28% and 37% for the three and nine months ended September 30, 2015, respectively. In both periods, this was consistent with a decrease in the Dated Brent reference price, and was partially offset by increases in sold volumes, largely driven by increases in production.

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 10.5% for Q3 2015 versus 8.1% for Q2 2015 due to the impact of fixed RCDM royalties coupled with lower realized pricing.
- Royalties as a percentage of sales was 10.5% and 9.1% for the three and nine months ended September 30, 2015, an increase over both comparable periods in 2014 as a result of the impact of fixed RCDM royalties coupled with lower realized pricing.

Transportation

- Transportation expense increased for Q3 2015 as compared to Q2 2015 due to a higher number of shipments from the Ambès terminal during the current quarter.
- Transportation expense decreased for both the three and nine months ended September 30, 2015 as compared to the same periods in 2014 due to a lower level of 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

- On a dollar and per boe basis, Q3 2015 operating expense was lower than Q2 2015 despite unfavorable foreign exchange impacts of a weaker Canadian dollar and an inventory draw during the current quarter as a result of lower electricity costs and reduced major project activity.
- Operating expense on a dollar and per boe basis decreased for the three and nine months ended September 30, 2015 versus the same periods in 2014 due to a number of cost reduction initiatives undertaken in response to commodity price weakness. These cost reduction initiatives included lower costs on downhole and other activities, lower labour usage and costs, as well as savings from service contract renegotiations.
- In addition, on a year-over-year basis, operating expenses further decreased due to the favorable foreign exchange impact of the strengthening of the Canadian dollar versus the Euro and the deferral of costs following a build in crude oil inventory in the year-to-date 2015 period.

General and administration

- General and administration expense for Q3 2015 was 10% higher than Q2 2015 and 17% lower than Q3 2014. These fluctuations in general and administration expense for the quarters presented primarily result from variances in the timing of spending, including the timing of allocations from our Corporate segment.
- Year-to-date 2015 general and administration expense was 11% lower than the 2014 period due to the impact of a number of cost reduction initiatives undertaken in response to commodity price weakness, including a reduction in third party consultant expenditures.

Other income

- Included in the results for the nine months ended September 30, 2015 is a judgment award 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 (as a percentage of the statutory rate) 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 13% and 15%. This rate is subject to change in response to commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.
- Q3 2015 current income taxes decreased compared to Q2 2015 and Q3 2014 due to decreased revenues and additional tax deductions taken for depletion.
- Current income taxes for the nine months ended September 30, 2015 decreased versus the comparative period in 2014 mainly due to 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		Nine Months Ended		% change
Netherlands business unit	Sep 30, 2015	Jun 30, 2015	Sep 30, 2014	Q3/15 vs. Q2/15	Q3/15 vs. Q3/14	Sep 30, 2015	Sep 30, 2014	2015 vs. 2014
Production								
NGLs (bbls/d)	109	112	63	(3%)	73%	95	76	25%
Natural gas (mmcf/d)	53.56	32.43	38.07	65%	41%	40.86	40.50	1%
Total (boe/d)	9,035	5,517	6,407	64%	41%	6,905	6,827	1%
Activity								
Capital expenditures ($M)	5,297	18,885	10,087	(72%)	(47%)	28,515	51,718	(45%)
Gross wells drilled	-	2.00	1.00			2.00	5.00	
Net wells drilled	-	1.86	0.45			1.86	3.74	

Production

- Q3 production represented a new record for our Netherlands Business Unit at 9,035 boe/d which is an increase of 64% from the prior quarter. This increase is primarily attributable to placing two wells (Slootdorp-06/07 – 92.8% working interest) on production for an extended production test. These two wells, drilled in the prior quarter, contributed approximately 24 mmcf/d (4,000 boe/d) to the average production rate during the quarter.
- Production for Q3 2015 increased by 41%, as compared to Q3 2014 due to the Sloopdorp-06/07 wells. For the year to date period, production was consistent with the prior year as the third quarter production additions from Slootdorp-06/07 were largely offset by the loss of production from our Middenmeer-3 well, which was fully depleted and taken offline in February 2015. The depletion of this well occurred as expected. The turnaround at the Garijp Treatment Centre during Q2 2015 further impacted current year production.
- Production in the Netherlands is actively managed to optimize facility use and regulate declines.

Activity review

- During Q2, Vermilion drilled two (1.9 net) wells, Slootdorp-06 and Slootdorp-07. These wells are currently on sales during an extended production test to size additional production equipment.
- During the quarter, we continued to execute numerous debottlenecking activities to enhance deliverability from the Slootdorp wells.
- The Diever-02 exploration well (45% working interest), drilled in 2014, came on production in early November for an extended production test at a gross rate of 28.5 mmcf/d (4,750 boe/d). Because of current pipeline constraints in the multi-well system that Diever-02 produces into, Vermilion's net incremental production increase from this well is limited to approximately 6 mmcf/d (1,000 boe/d), net to Vermilion.

Financial review

Netherlands business unit ($M except as indicated)	Three Months Ended Sep 30, 2015	Jun 30, 2015	Sep 30, 2014	% change Q3/15 vs. Q2/15	Q3/15 vs. Q3/14	Nine Months Ended Sep 30, 2015	Sep 30, 2014	% change 2015 vs. 2014
Sales	41,083	23,913	26,960	72%	52%	91,814	98,395	(7%)
Royalties	(638)	(1,294)	(942)	(51%)	(32%)	(2,858)	(3,843)	(26%)
Operating expense	(5,243)	(5,414)	(5,409)	(3%)	(3%)	(16,483)	(17,841)	(8%)
General and administration	(2,154)	(454)	(204)	374%	956%	(3,345)	(1,128)	197%
Current income taxes	(4,487)	(2,347)	(1,189)	91%	277%	(9,222)	(6,278)	47%
Fund flows from operations	28,561	14,404	19,216	98%	49%	59,906	69,305	(14%)
Netbacks ($/boe)								
Sales	49.42	47.63	45.73	4%	8%	48.70	52.80	(8%)
Royalties	(0.77)	(2.58)	(1.60)	(70%)	(52%)	(1.52)	(2.06)	(26%)
Operating expense	(6.31)	(10.78)	(9.18)	(41%)	(31%)	(8.74)	(9.57)	(9%)
General and administration	(2.59)	(0.90)	(0.35)	188%	640%	(1.77)	(0.61)	190%
Current income taxes	(5.40)	(4.67)	(2.02)	16%	167%	(4.89)	(3.37)	45%
Fund flows from operations netback	34.35	28.70	32.58	20%	5%	31.78	37.19	(15%)
Reference prices								
TTF ($/GJ)	8.04	7.94	7.26	1%	11%	8.08	8.41	(4%)
TTF (€/GJ)	5.52	5.84	5.04	(5%)	10%	5.76	5.68	1%

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.
- Sales per boe increased by 4% quarter-over-quarter, consistent with a slight increase in the Canadian dollar equivalent TTF reference price. This increase in sales per boe combined with a 64% increase in production resulted in a 72% increase in sales.
- On a year-over-year basis, sales per boe increased by 8% and decreased by 8% for the three and nine months ended September 30, 2015, respectively, consistent with movements in the Canadian dollar equivalent of the TTF reference price for the respective periods. For the three months ended September 30, 2015, the 11% increase in the Canadian dollar equivalent of the TTF reference price was coupled with a 41% increase in production, resulting in a 52% increase in sales. For the nine months ended September 30, 2015, a 4% decrease in the Canadian dollar equivalent of the TTF reference price was combined with consistent production volumes, resulting in a 7% 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 royalty expense in the periods 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 on a dollar basis decreased slightly for Q3 2015 versus both Q2 2015 and Q3 2014 primarily as a result of the timing of expenditures. These slight decreases, coupled with significantly higher production from our Slootdorp-06 and Slootdorp-07 wells, resulted in a 41% decrease in operating expense per boe quarter-over-quarter (31% year-over-year).
- On a year-to-date basis, operating expense on a dollar and per boe basis decreased approximately 8% due to the favorable foreign exchange impact of a stronger Canadian dollar coupled with reduced facility operation expenditures following cost reduction initiatives undertaken in response to commodity price weakness.

General and administration

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

Current income taxes

- Current income taxes in the Netherlands apply to taxable income after eligible deductions at a statutory tax rate of approximately 46%. For 2015, the effective rate on current taxes is expected to be between approximately 11% and 13%. 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 Q3 2015 were higher compared to Q2 2015 and Q3 2014 due to increased revenues and accelerated tax deductions recognized in 2014.
- Current income taxes for the nine months ended September 30, 2015 were higher compared to 2014 as decreased revenues in 2015 were offset with accelerated tax deductions recognized in 2014.

GERMANY BUSINESS UNIT

Overview

- Vermilion entered Germany in February 2014.
- Holds a 25% interest in a four partner consortium. Associated assets include four gas producing fields spanning 11 production licenses as well as an exploration license in surrounding fields. Total license area comprises 204,000 gross acres, of which 85% is in the exploration license.
- Entered into a farm-in agreement in Q3 2015 that will provide Vermilion with participating interest in 19 onshore exploration licenses in northwest Germany, comprising approximately 850,000 net undeveloped acres of oil and natural gas rights. Vermilion will assume operatorship for 11 of the 19 licenses during the exploration phase. The farm-in agreement is expected to close around year-end.

Operational review

	Three Months Ended			% change		Nine Months Ended		% change
Germany business unit	Sep 30, 2015	Jun 30, 2015	Sep 30, 2014	Q3/15 vs. Q2/15	Q3/15 vs. Q3/14	Sep 30, 2015	Sep 30, 2014	2015 vs. 2014
Production								
Natural gas (mmcf/d)	14.00	16.18	15.38	(13%)	(9%)	15.65	14.07	11%
Total (boe/d)	2,333	2,696	2,563	(13%)	(9%)	2,608	2,345	11%
Activity								
Capital expenditures ($M)	1,605	3,231	1,358	(50%)	18%	5,804	2,184	166%
Acquisitions ($M)	-	-	-			-	172,871	
Gross wells drilled	-	1.00	-			1.00	-	
Net wells drilled	-	0.25	-			0.25	-	

Production

- Q3 2015 production of 2,333 boe/d represented a decrease of 13% quarter-over-quarter and a decrease of 9% year-over-year due to a planned maintenance shutdown during the quarter. Year-to-date production increased 11% versus prior year, due to 2014 volumes only reflecting production from the acquisition's effective date of February 1, 2014.

Activity review

- The Burgmoor Z3a sidetrack well (25% working interest), which was completed in Q2 2015, was tied-in and placed on production in Q3 2015.

Financial review

Germany business unit ($M except as indicated)	Three Months Ended Sep 30, 2015	Jun 30, 2015	Sep 30, 2014	% change Q3/15 vs. Q2/15	Q3/15 vs. Q3/14	Nine Months Ended Sep 30, 2015	Sep 30, 2014	% change 2015 vs. 2014
Sales	9,523	10,626	8,591	(10%)	11%	31,544	28,603	10%
Royalties	(1,477)	(2,238)	(2,046)	(34%)	(28%)	(5,313)	(6,132)	(13%)
Transportation expense	(627)	(1,240)	(675)	(49%)	(7%)	(2,761)	(2,149)	28%
Operating expense	(2,796)	(1,373)	(2,227)	104%	26%	(6,168)	(5,824)	6%
General and administration	(1,311)	(1,435)	(1,090)	(9%)	20%	(4,354)	(2,488)	75%
Current income taxes	-	-	(146)	-	(100%)	-	(1,189)	(100%)
Fund flows from operations	3,312	4,340	2,407	(24%)	38%	12,948	10,821	20%
Netbacks ($/boe)								
Sales	44.36	43.31	36.43	2%	22%	44.30	44.68	(1%)
Royalties	(6.88)	(9.12)	(8.68)	(25%)	(21%)	(7.46)	(9.58)	(22%)
Transportation expense	(2.92)	(5.05)	(2.86)	(42%)	2%	(3.88)	(3.36)	15%
Operating expense	(13.03)	(5.60)	(9.44)	133%	38%	(8.66)	(9.10)	(5%)
General and administration	(6.11)	(5.85)	(4.62)	4%	32%	(6.12)	(3.89)	57%
Current income taxes	-	-	(0.62)	-	(100%)	-	(1.86)	(100%)
Fund flows from operations netback	15.42	17.69	10.21	(13%)	51%	18.18	16.89	8%
Reference prices								
TTF ($/GJ)	8.04	7.94	7.26	1%	11%	8.08	8.41	(4%)
TTF (€/GJ)	5.52	5.84	5.04	(5%)	10%	5.76	5.68	1%

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 10% decrease in sales quarter-over-quarter is due to a 13% decrease in production, partially offset by a 2% increase in sales per boe, consistent with a slight increase in the Canadian dollar equivalent of the TTF reference price.
- On a year-over-year basis, sales per boe increased by 22% and declined by 1% for the three and nine months ended September 30, 2015, respectively, consistent with movements in the Canadian dollar equivalent of the TTF reference price in the respective periods. For the three months ended September 30, 2015, the increase in sales per boe was partially offset by a 9% decrease in production, resulting in an 11% increase in sales. For the nine months ended September 30, 2015, production increased by 11% which, coupled with consistent sales per boe, resulted in a 10% increase in sales.

Royalties

- 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.
- Q3 2015 royalties as a percentage of sales of 15.5% were lower than the 21.1% for Q2 2015 due to adjustments for prior period royalties recorded in the second quarter. Year-to-date royalties as a percentage of sales of 16.8% were lower than the 21.4% for the comparable periods in 2014 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.
- Q3 2015 transportation expense was lower than Q2 2015 due to final adjustments for 2014 recorded in the second quarter. Year-to-date transportation expense was higher than the comparable period in 2014 due to the aforementioned adjustments and the inclusion of only eight months of expense in 2014 due to the timing of our Germany acquisition.

Operating expense

- Operating expenses for Germany are billed monthly by the joint venture operator and primarily relate to tariffs charged for facility operations and gas processing.
- Q3 2015 had higher operating expense versus both Q2 2015 and Q3 2014 due to a higher level of project activity during the current quarter. Year-to-date operating expense was higher on a dollar basis than the comparable period in 2014 due to the inclusion of only eight months of expense in 2014 due to the timing of our Germany acquisition.

General and administration

- General and administration expense increased quarter-over-quarter and year-over-year due to staffing and expenditures relating to our Germany farm-in agreement.

Current income taxes

- Current income taxes in Germany apply to taxable income after eligible deductions at a statutory tax rate of approximately 24%. As a function of tax pools in Germany, Vermilion does not presently pay taxes in Germany.

IRELAND BUSINESS UNIT

Overview

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

Operational and financial review

Ireland business unit ($M)	Three Months Ended Sep 30, 2015	Three Months Ended Jun 30, 2015	Three Months Ended Sep 30, 2014	% change Q3/15 vs. Q2/15	% change Q3/15 vs. Q3/14	Nine Months Ended Sep 30, 2015	Nine Months Ended Sep 30, 2014	% change 2015 vs. 2014
Transportation expense	(1,766)	(1,648)	(1,515)	7%	17%	(5,107)	(4,674)	9%
General and administration	(663)	(628)	(334)	6%	99%	(1,803)	(868)	108%
Fund flows from operations	(2,429)	(2,276)	(1,849)	7%	31%	(6,910)	(5,542)	25%
Activity								
Capital expenditures	20,694	20,267	30,050	2%	(31%)	53,916	73,507	(27%)

Activity review

- On September 1, 2015, the operator, Shell E&P Ireland Limited declared the project ready for service.
- On October 8, 2015, the Irish Environmental Protection Agency issued its final determination in support of the Corrib Industrial Emissions License.
- Prior to commencing gas production, receipt of Ministerial Consent is required from Ireland's Department of Communications, Environment, and Natural Resources.
- Following first gas production, expected in approximately mid-Q4 2015, volumes at Corrib are expected to rise over a period of approximately six months to a peak rate of approximately 58 mmcf/d (9,700 boe/d) net to Vermilion by mid-2016.

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

	Three Months Ended			% change		Nine Months Ended		% change
Australia business unit	Sep 30, 2015	Jun 30, 2015	Sep 30, 2014	Q3/15 vs. Q2/15	Q3/15 vs. Q3/14	Sep 30, 2015	Sep 30, 2014	2015 vs. 2014
Production								
Crude oil (bbls/d)	6,433	5,865	6,567	10%	(2%)	5,993	6,718	(11%)
Inventory (mbbls)								
Opening crude oil inventory	156	318	189			37	130	
Crude oil production	592	534	604			1,636	1,834	
Crude oil sales	(576)	(696)	(535)			(1,501)	(1,706)	
Closing crude oil inventory	172	156	258			172	258	
Activity								
Capital expenditures ($M)	7,966	6,468	15,985	23%	(50%)	20,889	32,667	(36%)

Production

- Quarterly production increased 10% quarter-over-quarter and decreased 2% 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 Q3 2015, efforts were largely focused on maintenance work, facilities enhancement and preparations for the 2015 drilling program.
- The horizontal sidetrack drill program commenced in early October after the arrival of the drilling rig at the Wandoo A platform in late September. Vermilion expects that the well will be completed and placed on production during the fourth quarter.
- Additional 2015 planned activities include ongoing facilities maintenance, enhancement, and refurbishment.

Financial review

Australia business unit ($M except as indicated)	Three Months Ended Sep 30, 2015	Jun 30, 2015	Sep 30, 2014	% change Q3/15 vs. Q2/15	Q3/15 vs. Q3/14	Nine Months Ended Sep 30, 2015	Sep 30, 2014	% change 2015 vs. 2014
Sales	39,325	56,204	63,708	(30%)	(38%)	114,813	212,510	(46%)
Operating expense	(13,766)	(18,083)	(14,302)	(24%)	(4%)	(37,735)	(43,713)	(14%)
General and administration	(1,391)	(1,141)	(1,378)	22%	1%	(3,986)	(4,245)	(6%)
PRRT	(99)	(3,371)	(13,834)	(97%)	(99%)	(5,824)	(46,772)	(88%)
Corporate income taxes	(2,720)	(5,134)	(5,148)	(47%)	(47%)	(8,431)	(19,678)	(57%)
Fund flows from operations	21,349	28,475	29,046	(25%)	(26%)	58,837	98,102	(40%)
Netbacks ($/boe)								
Sales	68.20	80.87	119.07	(16%)	(43%)	76.46	124.59	(39%)
Operating expense	(23.87)	(26.02)	(26.73)	(8%)	(11%)	(25.13)	(25.63)	(2%)
General and administration	(2.41)	(1.64)	(2.58)	47%	(7%)	(2.65)	(2.49)	6%
PRRT	(0.17)	(4.85)	(25.86)	(96%)	(99%)	(3.88)	(27.42)	(86%)
Corporate income taxes	(4.72)	(7.39)	(9.62)	(36%)	(51%)	(5.61)	(11.54)	(51%)
Fund flows from operations netback	37.03	40.97	54.28	(10%)	(32%)	39.19	57.51	(32%)
Reference prices								
Dated Brent (US $/bbl)	50.26	61.92	101.85	(19%)	(51%)	55.39	106.57	(48%)
Dated Brent ($/bbl)	65.81	76.12	110.95	(14%)	(41%)	69.79	116.63	(40%)

Sales

- Crude oil in Australia is priced with reference to Dated Brent.
- During Q3 2015, inventory increased by 16,000 bbls, compared to a draw of 162,000 bbls in Q2 2015 and a build of 69,000 bbls in Q3 2014.
- Sales per boe decreased 16% in Q3 2015 versus Q2 2015, consistent with a 14% decrease in the Canadian dollar equivalent of the Dated Brent reference price. This decrease in sales per boe, combined with a decrease in sales volumes due to the absence of a significant inventory draw in the period, resulted in a 30% decrease in sales.
- On a year-over-year basis, sales per boe decreased by 43% and 39% for the three and nine months ended September 30, 2015, consistent with a decrease in the Canadian dollar equivalent of the Dated Brent reference price. For the three months ended September 30, 2015, the decline in pricing was slightly offset by higher sold volumes (due to a higher inventory build in the comparative period), resulting in a 38% decrease in sales. For the nine months ended September 30, 2015, the decline in pricing was coupled with a decrease in sold volumes driven by decreased production, resulting in a 46% 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

- Operating expense decreased in Q3 2015 versus Q2 2015 as a result of a slight build in inventory during the third quarter versus a 162,000 bbl draw in inventory during the second quarter.
- Year-over-year, operating expense decreased on both a dollar and per barrel basis largely as the result of savings from cost reduction initiatives, including reduced vessel usage, lower diesel consumption, and reduced staffing costs. These favorable variances were further enhanced by the impact of a weaker Australian dollar in 2015.

General and administration

- Fluctuations in general and administration expense for the three and nine months versus the comparable periods were largely a result of the timing of expenditures.

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 15% and 17%. 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 the three and nine months ended September 30, 2015 were lower than the comparable periods as a result of decreased revenues and increased capital spending in the 2015 periods.

UNITED STATES BUSINESS UNIT

Overview

- Entered the United States in September 2014.
- Interests include approximately 90,700 acres of land (98% undeveloped) in the Powder River Basin of northeastern Wyoming.
- Tight oil development targeting the Turner Sand at a depth of approximately 1,500 metres.

Operational and financial review

United States business unit ($M except as indicated)	Three Months Ended Sep 30, 2015	Three Months Ended Jun 30, 2015	% change Q3/15 vs. Q2/15	Nine Months Ended Sep 30, 2015
Sales	1,075	677	59%	2,424
Royalties	(309)	(191)	62%	(706)
Operating expense	(146)	(110)	33%	(471)
General and administration	(896)	(963)	(7%)	(2,939)
Fund flows from operations	(276)	(587)	(53%)	(1,692)
Netbacks ($/boe)				
Sales	51.60	60.57	(15%)	52.95
Royalties	(14.83)	(17.08)	(13%)	(15.42)
Operating expense	(6.98)	(9.88)	(29%)	(10.28)
General and administration	(43.03)	(86.12)	(50%)	(64.20)
Fund flows from operations netback	(13.24)	(52.51)	(75%)	(36.95)
Reference prices				
WTI (US $/bbl)	46.43	57.94	(20%)	51.00
WTI ($/bbl)	60.80	71.23	(15%)	64.26
Production				
Crude oil (bbls/d)	226	123	84%	168
Activity				
Capital expenditures	3,226	2,744	18%	6,607
Acquisitions	12,785	-		12,785
Gross wells drilled	-	1.00		-
Net wells drilled	-	1.00		-

Activity review

- Vermilion completed the Seedy Draw North well (100% working interest) in the East Finn prospect area in Q3 2015, which was drilled in Q2 2015.
- During the quarter, we consolidated our ownership interest in the eastern Powder River Basin of Wyoming to a 100% working interest through the US $9.6 million acquisition of the remaining 30% interest that was previously outstanding. The acquisition encompassed an estimated 0.9 mmboe of 2P reserves and an additional 22,000 net acres.

Sales

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

Royalties

- Our production in the United States is subject to federal and private royalties, severance tax, and ad valorem tax. Q3 2015 royalties as a percentage of sales of 28.7% was relatively consistent with Q2 2015 (28.2%).

Operating expense

- Operating expense on a dollar basis was higher than the previous quarter due to incremental fuel and electricity purchases for the Seedy Draw North well, which was brought on line at the end of August. As a result of incremental production from this well, operating expense on a per barrel basis decreased quarter-over-quarter from $9.88/boe to $6.98/boe.

General and administration

- General and administration expense decreased slightly by 7% quarter-over-quarter due to the timing of expenditures.

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			Nine Months Ended	
($M)	Sep 30, 2015	Jun 30, 2015	Sep 30, 2014	Sep 30, 2015	Sep 30, 2014
General and administration recovery (expense)	2,359	500	(2,322)	3,816	(8,647)
Current income taxes	(480)	(547)	(227)	(1,404)	(778)
Interest expense	(15,420)	(14,550)	(12,918)	(43,268)	(36,712)
Realized gain on derivatives	10,854	3,081	8,837	20,192	13,896
Realized foreign exchange gain (loss)	309	(2,740)	812	875	(642)
Realized other income	227	204	235	653	530
Fund flows from operations	(2,151)	(14,052)	(5,583)	(19,136)	(32,353)

General and administration

- The increase in the recovery of general and administration costs for the three and nine months ended September 30, 2015 versus the comparable periods in the prior year is due to a decrease in staff-related expenditures, general cost saving initiatives in response to declining crude oil prices, and increased salary allocations to the various business unit segments.

Current income taxes

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

Interest expense

- The increase in interest expense in Q3 2015 versus the comparable periods in the prior year is primarily due to increased borrowings under our revolving credit facility. The increase in interest expense for the three and nine months ended September 30, 2015 versus the comparable periods in 2014 was further driven by interest expense related to the finance lease recognized in Q1 2015.

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 (loss) at each reporting period. We have not obtained collateral or other security to support our financial derivatives as we review the creditworthiness of our counterparties prior to entering into derivative contracts.
- Our hedging philosophy is to hedge solely for the purposes of risk mitigation. Our approach is to hedge centrally to manage our global risk (typically with an outlook of 12 to 18 months) up to 50% of net of royalty volumes through a portfolio of forward collars, swaps, and physical fixed price arrangements.
- We 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 Q3 2015 related primarily to amounts received on our Dated Brent, WTI, and TTF derivatives, partially offset by payments made on our foreign exchange derivatives.
- A listing of derivative positions as at September 30, 2015 is included in “Supplemental Table 2” in this MD&A.

FINANCIAL PERFORMANCE REVIEW

	Three Months Ended							
($M except per share)	Sep 30, 2015	Jun 30, 2015	Mar 31, 2015	Dec 31, 2014	Sep 30, 2014	Jun 30, 2014	Mar 31, 2014	Dec 31, 2013
Petroleum and natural gas sales	245,051	264,331	195,885	306,073	344,688	387,684	381,183	325,108
Net earnings (loss)	(83,310)	6,813	1,275	58,642	53,903	53,993	102,788	101,510
Net earnings (loss) per share								
Basic	(0.76)	0.06	0.01	0.55	0.50	0.51	1.00	1.00
Diluted	(0.76)	0.06	0.01	0.54	0.50	0.50	0.99	0.98

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

($M)	Q3/15 vs. Q2/15	Q3/15 vs. Q3/14	2015 vs. 2014
Net earnings - Comparative period	6,813	53,903	210,684
Changes in:			
Fund flows from operations	(61)	(68,463)	(239,611)
Equity based compensation	1,113	(2,053)	(4,290)
Unrealized gain or loss on derivative instruments	27,915	24,220	5,941
Unrealized foreign exchange gain or loss	9,927	26,825	28,757
Unrealized other expense	(105)	288	(27)
Accretion	(486)	(135)	139
Depletion and depreciation	(37,697)	(44,684)	(42,433)
Deferred tax	52,271	69,789	108,618
Impairment	(143,000)	(143,000)	(143,000)
Net loss - Current period	(83,310)	(83,310)	(75,222)

The fluctuations in net earnings (loss) 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 Q3 2015 was lower than Q2 2015 due to a lower number of awards outstanding. For the three and nine months ended September 30, 2015, equity based compensation expense was higher versus the comparable periods in 2014 due to a higher number of awards outstanding.

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 nine months ended September 30, 2015, we recognized an unrealized gain on derivative instruments of $16.2 million, relating primarily to our TTF, Dated Brent, and WTI swaps and collars. As at September 30, 2015, we have a net derivative asset position of $40.9 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 and nine months ended September 30, 2015, the Canadian dollar weakened versus the Euro and the US dollar, resulting in an unrealized foreign exchange gain of $15.0 million and $15.1 million, respectively.

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.

Q3 2015 accretion expense was relatively consistent with all comparative periods.

Depletion and depreciation

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

Depletion and depreciation on a per boe basis for Q3 2015 of $28.28 was higher as compared to $22.98 in Q2 2015. The increase is primarily due to increased production from natural gas properties in the Netherlands which have higher per boe depletion expense. For the three and nine months ended September 30, 2015, depletion and depreciation on a per boe basis increased from $23.21 to $28.28 for the three month period and from $22.92 to $24.62 for the nine month period. These increases were primarily driven by the aforementioned increased production from natural gas properties in the Netherlands, as well as increased light crude oil production from Saskatchewan, Canada which was acquired in April of 2014.

Deferred tax

Deferred tax expense (recovery) arises primarily as a result of changes in the accounting basis and tax basis for capital assets and asset retirement obligations and changes in available tax losses. The increase in deferred tax recovery largely pertains to the tax effect on the $143.0 million impairment charge recorded in Q3 2015 and increased depletion primarily associated with higher global production.

Impairment

For the three months ended September 30, 2015, Vermilion recorded an impairment charge of $143.0 million related to the light crude oil play in Saskatchewan, Canada. These impairment charges were a result of declines in the price forecasts for crude oil in Canada which decreased the expected future cash flows from the CGU.

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 its 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)	Sep 30, 2015	Dec 31, 2014	Sep 30, 2015	Dec 31, 2014
Revolving credit facility	2.9%	3.1%	1,270,154	1,014,067
Senior unsecured notes [1]	6.5%	6.5%	224,679	224,013
Long-term debt	3.5%	3.8%	1,494,833	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 September 30, 2015.

Revolving Credit Facility

On January 30, 2015, Vermilion increased its credit facility from $1.5 billion to $1.75 billion. During Q2 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	
	Sep 30, 2015	Dec 31, 2014
Total facility amount	$2.0 billion	$1.5 billion
Amount drawn	$1.3 billion	$1.0 billion
Letters of credit outstanding	$29.3 million	$8.6 million
Facility maturity date	31-May-19	31-May-17

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

		As at	
Financial covenant	Limit	Sep 30, 2015	Dec 31, 2014
Consolidated total debt to consolidated EBITDA	4.0	2.16	1.21
Consolidated total senior debt to consolidated EBITDA	3.0	1.80	0.99
Consolidated total senior debt to total capitalization	50%	36%	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", "Current portion of long-term debt", and "Finance lease obligation" on our balance sheet.
- Consolidated total senior debt: Defined as consolidated total debt excluding unsecured and subordinated debt.
- Consolidated EBITDA: Defined as consolidated net earnings before interest, income taxes, depreciation, accretion and certain other non-cash items.
- Total capitalization: Includes all amounts on our balance sheet classified as "Long-term debt", "Current portion of long-term debt", "Finance lease obligation", 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)	Sep 30, 2015	Dec 31, 2014
Long-term debt	1,270,154	1,238,080
Current liabilities [1]	474,885	365,729
Current assets	(381,996)	(338,159)
Net debt	1,363,043	1,265,650
Ratio of net debt to annualized fund flows from operations	2.7	1.6

[1] Includes the current portion of long-term debt, which, as at September 30, 2015, represents the senior unsecured notes that will mature on February 10, 2016.

Long term debt, including the current portion, as at September 30, 2015, increased to $1.49 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, Ireland and Australia. The increase in long-term debt resulted in an increase to net debt from $1.27 billion to $1.36 billion. As a result of this increase to long-term debt coupled with weak commodity prices, the ratio of net debt to fund flows from operations increased from 1.6 times as at December 31, 2014 to 2.7 times for the nine months ended September 30, 2015.

Shareholders' capital
During the nine months ended September 30, 2015, we maintained monthly dividends at $0.215 per share and declared dividends which totalled $211.6 million.

The following table outlines our dividend payment history:

Date	Monthly dividend per unit or share
January 2003 to December 2007	$0.170
January 2008 to December 2012	$0.190
January 2013 to December 31, 2013	$0.200
January 2014 to Present	$0.215

Our policy with respect to dividends is to be conservative and maintain a low ratio of dividends to fund flows from operations. During low commodity price cycles, we will initially maintain dividends and allow the ratio to rise. Should low commodity price cycles remain for an extended period of time, we will evaluate the necessity of changing the level of dividends, taking into consideration capital development requirements, debt levels and acquisition opportunities. 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, increases our access to the lowest cost sources of equity capital available. While the Premium Dividend™ results in a modest amount of equity issuance, we believe it represents the most prudent approach to preserving near-term balance sheet strength. We view implementation of a Premium Dividend™ as a short-term measure to maintain our financial flexibility while we continue to lower our unit costs and await further clarity on the direction of commodity prices. Both components of our program can be 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.

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 and Premium Dividend™ plans	2,188	108,269
Vesting of equity based awards	1,158	56,855
Share-settled dividends on vested equity based awards	135	7,561
Shares issued pursuant to the employee savings and bonus plans	34	1,658
Balance as at September 30, 2015	110,818	2,133,364

As at September 30, 2015, there were approximately 1.7 million VIP awards outstanding. As at November 5, 2015, there were approximately 111.2 million common shares issued and outstanding.

ASSET RETIREMENT OBLIGATIONS

As at September 30, 2015, asset retirement obligations were $384.3 million compared to $350.8 million as at December 31, 2014.

The increase in asset retirement obligations is largely attributable to accretion and additions from new wells drilled year-to-date, as well as changes in foreign exchange.

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 September 30, 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 material changes to our critical accounting estimates used in applying accounting policies for the nine months ended September 30, 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 September 30, 2015			Nine Months Ended September 30, 2015			Three Months Ended September 30, 2014	Nine Months Ended September 30, 2014
	Oil & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Oil & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Total $/boe	Total $/boe
Canada								
Sales	46.36	2.88	32.78	51.54	2.88	36.34	64.85	68.58
Royalties	(4.72)	(0.10)	(2.81)	(5.30)	(0.05)	(3.09)	(8.89)	(8.05)
Transportation	(2.37)	(0.17)	(1.75)	(2.49)	(0.17)	(1.85)	(1.89)	(1.80)
Operating	(11.37)	(1.44)	(10.10)	(10.31)	(1.41)	(9.50)	(8.91)	(9.17)
Operating netback	27.90	1.17	18.12	33.44	1.25	21.90	45.16	49.56
General and administration			(1.56)			(1.95)	(2.11)	(2.25)
Fund flows from operations netback			16.56			19.95	43.05	47.31
France								
Sales	61.75	2.93	60.96	66.26	2.36	65.66	107.99	114.36
Royalties	(6.46)	(0.55)	(6.40)	(6.00)	(0.33)	(5.95)	(7.07)	(7.26)
Transportation	(3.70)	-	(3.64)	(3.38)	-	(3.34)	(4.80)	(4.88)
Operating	(9.62)	(0.95)	(9.55)	(10.57)	(1.04)	(10.52)	(15.42)	(15.80)
Operating netback	41.97	1.43	41.37	46.31	0.99	45.85	80.70	86.42
General and administration			(4.25)			(4.61)	(6.50)	(5.63)
Other income			-			9.57	-	-
Current income taxes			(3.74)			(8.52)	(10.89)	(19.93)
Fund flows from operations netback			33.38			42.29	63.31	60.86
Netherlands								
Sales	46.65	8.24	49.42	50.63	8.11	48.70	45.73	52.80
Royalties	-	(0.13)	(0.77)	-	(0.26)	(1.52)	(1.60)	(2.06)
Operating	-	(1.06)	(6.31)	-	(1.48)	(8.74)	(9.18)	(9.57)
Operating netback	46.65	7.05	42.34	50.63	6.37	38.44	34.95	41.17
General and administration			(2.59)			(1.77)	(0.35)	(0.61)
Current income taxes			(5.40)			(4.89)	(2.02)	(3.37)
Fund flows from operations netback			34.35			31.78	32.58	37.19
Germany								
Sales	-	7.39	44.36	-	7.38	44.30	36.43	44.68
Royalties	-	(1.15)	(6.88)	-	(1.24)	(7.46)	(8.68)	(9.58)
Transportation	-	(0.49)	(2.92)	-	(0.65)	(3.88)	(2.86)	(3.36)
Operating	-	(2.17)	(13.03)	-	(1.44)	(8.66)	(9.44)	(9.10)
Operating netback	-	3.58	21.53	-	4.05	24.30	15.45	22.64
General and administration			(6.11)			(6.12)	(4.62)	(3.89)
Current income taxes			-			-	(0.62)	(1.86)
Fund flows from operations netback			15.42			18.18	10.21	16.89
Australia								
Sales	68.20	-	68.20	76.46	-	76.46	119.07	124.59
Operating	(23.87)	-	(23.87)	(25.13)	-	(25.13)	(26.73)	(25.63)
PRRT (1)	(0.17)	-	(0.17)	(3.88)	-	(3.88)	(25.86)	(27.42)
Operating netback	44.16	-	44.16	47.45	-	47.45	66.48	71.54
General and administration			(2.41)			(2.65)	(2.58)	(2.49)
Corporate income taxes			(4.72)			(5.61)	(9.62)	(11.54)
Fund flows from operations netback			37.03			39.19	54.28	57.51
United States								
Sales	51.60	-	51.60	52.95	-	52.95	-	-
Royalties	(14.83)	-	(14.83)	(15.42)	-	(15.42)	-	-
Operating	(6.98)	-	(6.98)	(10.28)	-	(10.28)	-	-
Operating netback	29.79	-	29.79	27.25	-	27.25	-	-
General and administration			(43.03)			(64.20)	-	-
Fund flows from operations netback			(13.24)			(36.95)	-	-

	Three Months Ended September 30, 2015			Nine Months Ended September 30, 2015			Three Months Ended September 30, 2014	Nine Months Ended September 30, 2014
	Oil & NGLs	Natural Gas	Total	Oil & NGLs	Natural Gas	Total	Total	Total
	$/bbl	$/mcf	$/boe	$/bbl	$/mcf	$/boe	$/boe	$/boe
Total Company								
Sales	56.57	5.36	46.56	61.48	5.18	49.48	76.80	82.73
Realized hedging gain	1.78	0.41	2.06	0.81	0.39	1.42	1.97	1.03
Royalties	(4.59)	(0.22)	(3.25)	(4.68)	(0.27)	(3.48)	(6.46)	(6.09)
Transportation	(2.44)	(0.27)	(2.11)	(2.38)	(0.33)	(2.21)	(2.45)	(2.44)
Operating	(12.94)	(1.36)	(10.99)	(12.96)	(1.44)	(11.25)	(12.53)	(12.81)
PRRT [1]	(0.03)	-	(0.02)	(0.67)	-	(0.41)	(3.08)	(3.47)
Operating netback	38.35	3.92	32.25	41.60	3.53	33.55	54.25	58.95
General and administration			(2.49)			(2.89)	(3.62)	(3.60)
Interest expense			(2.93)			(3.04)	(2.88)	(2.73)
Realized foreign exchange gain (loss)			0.06			0.06	0.17	(0.05)
Other income			0.04			2.28	0.05	0.04
Corporate income taxes [1]			(2.35)			(3.32)	(3.89)	(6.59)
Fund flows from operations netback			24.58			26.64	44.08	46.02

[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 September 30, 2015:

	Note	Volume	Strike Price(s)
Crude Oil			
WTI - Collar			
July 2015 - October 2015	1	250 bbl/d	60.00 - 72.40 US $
July 2015 - December 2015	2	750 bbl/d	75.00 - 82.60 CAD $
July 2015 - December 2015	1	250 bbl/d	61.00 - 69.75 US $
July 2015 - March 2016	3	250 bbl/d	75.00 - 83.45 CAD $
July 2015 - June 2016	4	500 bbl/d	75.50 - 85.08 CAD $
October 2015 - December 2015	3	250 bbl/d	70.00 - 82.95 CAD $
Dated Brent - Collar			
July 2015 - October 2015	5	250 bbl/d	65.00 - 74.40 US $
July 2015 - June 2016	6	1,000 bbl/d	80.50 - 93.49 CAD $
July 2015 - June 2016	7	500 bbl/d	64.50 - 75.48 US $
October 2015 - December 2015	8	1,000 bbl/d	79.38 - 92.45 CAD $
October 2015 - June 2016	9	250 bbl/d	82.00 - 94.55 CAD $
January 2016 - June 2016	3	250 bbl/d	84.00 - 93.70 CAD $

	Note	Volume	Strike Price(s)
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 $
October 2015 - December 2015		2,500 GJ/d	2.55 - 3.19 CAD $
November 2015 - March 2016		2,500 GJ/d	2.50 - 3.76 CAD $
November 2015 - October 2016		10,000 GJ/d	2.56 - 3.23 CAD $
January 2016 - December 2016		10,000 GJ/d	2.53 - 3.29 CAD $
April 2016 - October 2016		2,500 GJ/d	2.50 - 2.88 CAD $
AECO - Swap			
April 2015 - October 2015	10	10,000 GJ/d	2.98 CAD $
April 2015 - December 2015	11	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	12	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 and is settled on the monthly average price (monthly average US $/bbl multiplied by the Bank of Canada monthly average noon day rate).
(3) The contracted volumes increase to 500 boe/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US $/bbl multiplied by the Bank of Canada monthly average noon day rate).
(4) The contracted volumes increase to 1,250 boe/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US $/bbl multiplied by the Bank of Canada monthly average noon day rate).
(5) The contracted volumes increase to 500 boe/d for any monthly settlement periods above the contracted ceiling price.
(6) The contracted volumes increase to 2,500 boe/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US $/bbl multiplied by the Bank of Canada monthly average noon day rate).
(7) The contracted volumes increase to 1,000 boe/d for any monthly settlement periods above the contracted ceiling price.
(8) The contracted volumes increase to 2,000 boe/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US $/bbl multiplied by the Bank of Canada monthly average noon day rate).
(9) The contracted volumes increase to 750 boe/d for any monthly settlement periods above the contracted ceiling price and is settled on the monthly average price (monthly average US $/bbl multiplied by the Bank of Canada monthly average noon day rate).
(10) 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.
(11) 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.
(12) The contracted volumes increase to 10,000 mmbtu/d for any monthly settlement periods above the contracted ceiling price.

	Note	Volume	Strike Price(s)
European Natural Gas			
NBP - Call			
October 2016 - March 2017		2,638 GJ/d	4.64 GBP £
NBP - Collar			
April 2016 - March 2017		2,638 GJ/d	3.79 - 4.53 GBP £
NBP - Put			
April 2016 - September 2016		2,638 GJ/d	3.79 GBP £
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		5,184 GJ/d	6.24 EUR €
January 2016 - June 2016		2,592 GJ/d	6.82 US $
July 2016 - March 2017		2,592 GJ/d	5.43 EUR €
TTF - Call			
October 2016 - March 2017		2,592 GJ/d	6.03 EUR €
TTF - Collar			
January 2015 - December 2015		2,592 GJ/d	6.11 - 6.83 EUR €
January 2016 - December 2016	1	2,592 GJ/d	5.76 - 6.50 EUR €
April 2016 - December 2016	2	12,960 GJ/d	5.58 - 6.21 EUR €
April 2016 - March 2017	3	5,184 GJ/d	5.28 - 6.35 EUR €
July 2016 - December 2016		2,592 GJ/d	5.00 - 5.63 EUR €
July 2016 - March 2017	1	2,592 GJ/d	5.07 - 6.56 EUR €
July 2016 - March 2018	1	2,592 GJ/d	5.32 - 6.54 EUR €
October 2016 - December 2017		2,592 GJ/d	5.00 - 5.89 EUR €
January 2017 - December 2017		2,592 GJ/d	5.00 - 5.63 EUR €
TTF - Put			
April 2016 - September 2016		2,592 GJ/d	5.21 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 €
January 2016 - June 2016		5,184 GJ/d	5.94 EUR €
April 2016 - December 2016		2,592 GJ/d	5.91 EUR €
July 2016 - June 2018		2,700 GJ/d	5.58 EUR €
October 2016 - December 2016		2,592 GJ/d	5.45 EUR €
Electricity			
AESO - Swap			
January 2016 - December 2016		62.4 MWh/d	37.13 CAD $
AESO - Swap (Physical)			
January 2013 - December 2015		72.0 MWh/d	53.17 CAD $
US Dollar			
USD - Collar			
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 $
Interest Rate			
CDOR to fixed - Swap			
September 2015 - September 2019		100,000,000 CAD $/year	1.00 %

(1) The contracted volumes increase to 5,184 GJ/d for any monthly settlement periods above the contracted ceiling price.
(2) The contracted volumes increase to 15,552 GJ/d for any monthly settlement periods above the contracted ceiling price.
(3) The contracted volumes increase to 10,368 GJ/d for any monthly settlement periods above the contracted ceiling price.

Supplemental Table 3: Capital Expenditures

By classification ($M)	Three Months Ended Sep 30, 2015	Three Months Ended Jun 30, 2015	Three Months Ended Sep 30, 2014	Nine Months Ended Sep 30, 2015	Nine Months Ended Sep 30, 2014
Drilling and development	93,381	90,173	180,479	357,865	467,294
Exploration and evaluation	-	-	9,554	-	54,187
Capital expenditures	93,381	90,173	190,033	357,865	521,481
Property acquisition	22,155	480	40,847	22,670	219,074
Corporate acquisition	-	-	-	-	381,139
Acquisitions	22,155	480	40,847	22,670	600,213

By category ($M)	Three Months Ended Sep 30, 2015	Three Months Ended Jun 30, 2015	Three Months Ended Sep 30, 2014	Nine Months Ended Sep 30, 2015	Nine Months Ended Sep 30, 2014
Land	763	1,469	2,346	2,974	8,049
Seismic	810	1,723	6,135	4,026	11,436
Drilling and completion	39,712	31,976	93,386	154,031	242,005
Production equipment and facilities	44,589	43,957	68,964	163,301	198,266
Recompletions	3,948	9,288	10,853	20,351	28,538
Other	3,559	1,760	8,349	13,182	33,187
Capital expenditures	93,381	90,173	190,033	357,865	521,481
Acquisitions	22,155	480	40,847	22,670	600,213
Total capital expenditures and acquisitions	115,536	90,653	230,880	380,535	1,121,694

By country ($M)	Three Months Ended Sep 30, 2015	Three Months Ended Jun 30, 2015	Three Months Ended Sep 30, 2014	Nine Months Ended Sep 30, 2015	Nine Months Ended Sep 30, 2014
Canada	45,286	22,265	125,276	182,435	663,277
France	17,511	16,793	35,082	68,418	110,663
Netherlands	5,297	18,885	10,087	28,515	51,718
Germany	1,605	3,231	1,358	5,804	175,055
Ireland	20,694	20,267	30,050	53,916	73,507
Australia	7,966	6,468	15,985	20,889	32,667
United States	16,011	2,744	11,175	19,392	11,175
Corporate	1,166	-	1,867	1,166	3,632
Total capital expenditures and acquisitions	115,536	90,653	230,880	380,535	1,121,694

Supplemental Table 4: Production

	Q3/15	Q2/15	Q1/15	Q4/14	Q3/14	Q2/14	Q1/14	Q4/13	Q3/13	Q2/13	Q1/13	Q4/12
Canada												
Crude oil (bbls/d)	9,195	10,182	10,893	11,384	11,469	12,676	9,437	8,719	7,969	8,885	7,966	7,983
NGLs (bbls/d)	4,513	3,755	2,976	2,741	2,291	2,796	2,071	1,699	1,897	1,725	1,335	1,106
Natural gas (mmcf/d)	71.94	64.66	61.78	58.36	57.07	57.59	49.53	41.43	43.40	43.69	41.04	31.41
Total (boe/d)	25,698	24,713	24,165	23,851	23,272	25,070	19,763	17,322	17,099	17,892	16,140	14,323
% of consolidated	47%	48%	48%	49%	47%	49%	42%	43%	41%	42%	41%	40%
France												
Crude oil (bbls/d)	12,310	12,746	11,463	11,133	11,111	11,025	10,771	11,131	11,625	10,390	10,330	9,843
Natural gas (mmcf/d)	1.47	1.03	-	-	-	-	-	-	5.23	4.19	4.21	3.91
Total (boe/d)	12,555	12,917	11,463	11,133	11,111	11,025	10,771	11,131	12,496	11,088	11,032	10,495
% of consolidated	22%	25%	23%	22%	22%	21%	23%	27%	30%	26%	29%	29%
Netherlands												
NGLs (bbls/d)	109	112	63	81	63	96	69	62	48	50	96	70
Natural gas (mmcf/d)	53.56	32.43	36.41	31.35	38.07	40.35	43.15	37.53	28.78	38.52	36.91	33.03
Total (boe/d)	9,035	5,517	6,132	5,306	6,407	6,822	7,260	6,318	4,845	6,470	6,248	5,574
% of consolidated	16%	11%	12%	11%	13%	13%	16%	15%	12%	15%	16%	15%
Germany												
Natural gas (mmcf/d)	14.00	16.18	16.80	17.71	15.38	16.13	10.64	-	-	-	-	-
Total (boe/d)	2,333	2,696	2,801	2,952	2,563	2,689	1,773	-	-	-	-	-
% of consolidated	4%	5%	6%	6%	5%	5%	4%	-	-	-	-	-
Australia												
Crude oil (bbls/d)	6,433	5,865	5,672	6,134	6,567	6,483	7,110	6,189	7,070	7,363	5,287	5,873
% of consolidated	11%	11%	11%	12%	13%	12%	15%	15%	17%	17%	14%	16%
United States												
Crude oil (bbls/d)	226	123	153	195	-	-	-	-	-	-	-	-
Consolidated												
Crude oil & NGLs (bbls/d)	32,786	32,783	31,220	31,668	31,501	33,076	29,458	27,800	28,609	28,413	25,014	24,875
% of consolidated	58%	63%	62%	64%	63%	63%	63%	68%	69%	66%	65%	69%
Natural gas (mmcf/d)	140.97	114.29	115.00	107.42	110.52	114.08	103.32	78.96	77.41	86.40	82.16	68.34
% of consolidated	42%	37%	38%	36%	37%	37%	37%	32%	31%	34%	35%	31%
Total (boe/d)	56,280	51,831	50,386	49,571	49,920	52,089	46,677	40,960	41,510	42,813	38,707	36,265

	YTD 2015	2014	2013	2012	2011	2010
Canada						
Crude oil (bbls/d)	10,083	11,248	8,387	7,659	4,701	2,778
NGLs (bbls/d)	3,754	2,476	1,666	1,232	1,297	1,427
Natural gas (mmcf/d)	66.16	55.67	42.39	37.50	43.38	43.91
Total (boe/d)	24,864	23,001	17,117	15,142	13,227	11,524
% of consolidated	47%	47%	41%	40%	38%	36%
France						
Crude oil (bbls/d)	12,176	11,011	10,873	9,952	8,110	8,347
Natural gas (mmcf/d)	0.84	-	3.40	3.59	0.95	0.92
Total (boe/d)	12,316	11,011	11,440	10,550	8,269	8,501
% of consolidated	23%	22%	28%	28%	23%	26%
Netherlands						
NGLs (bbls/d)	95	77	64	67	58	35
Natural gas (mmcf/d)	40.86	38.20	35.42	34.11	32.88	28.31
Total (boe/d)	6,905	6,443	5,967	5,751	5,538	4,753
% of consolidated	13%	13%	15%	15%	16%	15%
Germany						
Natural gas (mmcf/d)	15.65	14.99	-	-	-	-
Total (boe/d)	2,608	2,498	-	-	-	-
% of consolidated	5%	5%	-	-	-	-
Australia						
Crude oil (bbls/d)	5,993	6,571	6,481	6,360	8,168	7,354
% of consolidated	12%	13%	16%	17%	23%	23%
United States						
Crude oil (bbls/d)	168	49	-	-	-	-
Consolidated						
Crude oil & NGLs (bbls/d)	32,269	31,432	27,471	25,270	22,334	19,941
% of consolidated	61%	63%	67%	67%	63%	62%
Natural gas (mmcf/d)	123.51	108.85	81.21	75.20	77.21	73.14
% of consolidated	39%	37%	33%	33%	37%	38%
Total (boe/d)	52,854	49,573	41,005	37,803	35,202	32,132

Supplemental Table 5: Segmented Financial Results

	Three Months Ended September 30, 2015								
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	United States	Corporate	Total
Drilling and development	37,224	17,369	5,297	1,605	20,694	7,966	3,226	-	93,381
Oil and gas sales to external customers	77,493	76,552	41,083	9,523	-	39,325	1,075	-	245,051
Royalties	(6,638)	(8,038)	(638)	(1,477)	-	-	(309)	-	(17,100)
Revenue from external customers	70,855	68,514	40,445	8,046	-	39,325	766	-	227,951
Transportation expense	(4,131)	(4,566)	-	(627)	(1,766)	-	-	-	(11,090)
Operating expense	(23,877)	(11,998)	(5,243)	(2,796)	-	(13,766)	(146)	-	(57,826)
General and administration	(3,694)	(5,338)	(2,154)	(1,311)	(663)	(1,391)	(896)	2,359	(13,088)
PRRT	-	-	-	-	-	(99)	-	-	(99)
Corporate income taxes	-	(4,696)	(4,487)	-	-	(2,720)	-	(480)	(12,383)
Interest expense	-	-	-	-	-	-	-	(15,420)	(15,420)
Realized gain on derivative instruments	-	-	-	-	-	-	-	10,854	10,854
Realized foreign exchange gain	-	-	-	-	-	-	-	309	309
Realized other income	-	-	-	-	-	-	-	227	227
Fund flows from operations	39,153	41,916	28,561	3,312	(2,429)	21,349	(276)	(2,151)	129,435

	Nine Months Ended September 30, 2015								
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	United States	Corporate	Total
Total assets	1,769,222	902,777	219,221	172,664	947,592	223,261	36,955	231,009	4,502,701
Drilling and development	173,954	68,180	28,515	5,804	53,916	20,889	6,607	-	357,865
Oil and gas sales to external customers	246,661	218,011	91,814	31,544	-	114,813	2,424	-	705,267
Royalties	(20,998)	(19,760)	(2,858)	(5,313)	-	-	(706)	-	(49,635)
Revenue from external customers	225,663	198,251	88,956	26,231	-	114,813	1,718	-	655,632
Transportation expense	(12,542)	(11,103)	-	(2,761)	(5,107)	-	-	-	(31,513)
Operating expense	(64,510)	(34,926)	(16,483)	(6,168)	-	(37,735)	(471)	-	(160,293)
General and administration	(13,219)	(15,323)	(3,345)	(4,354)	(1,803)	(3,986)	(2,939)	3,816	(41,153)
PRRT	-	-	-	-	-	(5,824)	-	-	(5,824)
Corporate income taxes	-	(28,293)	(9,222)	-	-	(8,431)	-	(1,404)	(47,350)
Interest expense	-	-	-	-	-	-	-	(43,268)	(43,268)
Realized gain on derivative instruments	-	-	-	-	-	-	-	20,192	20,192
Realized foreign exchange gain	-	-	-	-	-	-	-	875	875
Realized other income	-	31,775	-	-	-	-	-	653	32,428
Fund flows from operations	135,392	140,381	59,906	12,948	(6,910)	58,837	(1,692)	(19,136)	379,726

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 and nine months ended September 30, 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			Nine Months Ended	
($M)	Sep 30, 2015	Jun 30, 2015	Sep 30, 2014	Sep 30, 2015	Sep 30, 2014
Cash flows from operating activities	122,230	134,668	235,010	279,545	562,840
Changes in non-cash operating working capital	5,082	(6,390)	(41,789)	93,733	46,788
Asset retirement obligations settled	2,123	1,218	4,677	6,448	9,709
Fund flows from operations	129,435	129,496	197,898	379,726	619,337
Expenses related to Corrib	2,429	2,276	1,849	6,910	5,542
Fund flows from operations (excluding Corrib)	131,864	131,772	199,747	386,636	624,879

	Three Months Ended			Nine Months Ended	
($M)	Sep 30, 2015	Jun 30, 2015	Sep 30, 2014	Sep 30, 2015	Sep 30, 2014
Dividends declared	71,244	70,976	68,896	211,610	203,613
Issuance of shares pursuant to the dividend reinvestment and Premium Dividend™ plans	(44,590)	(42,301)	(20,416)	(108,269)	(58,450)
Net dividends	26,654	28,675	48,480	103,341	145,163
Drilling and development	93,381	90,173	180,479	357,865	467,294
Exploration and evaluation	-	-	9,554	-	54,187
Asset retirement obligations settled	2,123	1,218	4,677	6,448	9,709
Payout	122,158	120,066	243,190	467,654	676,353
Corrib drilling and development	(20,694)	(20,267)	(30,050)	(53,916)	(73,507)
Payout (excluding Corrib)	101,464	99,799	213,140	413,738	602,846

	As at		
('000s of shares)	Sep 30, 2015	Jun 30, 2015	Sep 30, 2014
Shares outstanding	110,818	109,806	106,921
Potential shares issuable pursuant to the VIP	2,825	2,820	2,828
Diluted shares outstanding	113,643	112,626	109,749

DIRECTORS

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Calgary, Alberta

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[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
NGTL	NOVA Gas Transmission Ltd., a wholly owned subsidiary of TransCanada is the owner of a gas transmission system known as the NGTL system. The NGTL system is a 23,500 km pipeline that gathers natural gas for both use in Alberta, and to deliver it to provincial border points for export to North American markets.
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

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Mona Jasinski, M.B.A., C.H.R.P.
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National Bank of Canada

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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

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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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