Prairie Provident Resources Inc.

Management's Discussion and Analysis
For the Three and Nine Months Ended September 30, 2017

Dated: November 9, 2017

Advisories

In this management's discussion and analysis ("MD&A"), unless otherwise indicated or the context otherwise requires, the terms "we", "us", "our", "PPR", "Prairie Provident" and "the Company": (i) when used in reference to periods prior to September 12, 2016, refer to Lone Pine Resources Inc. ("Lone Pine Resources") and Lone Pine Resources Canada Ltd. ("LPR Canada", now Prairie Provident Resources Canada Ltd., collectively, "Lone Pine"); and (ii) when used in reference to the period following September 12, 2016, refers to Prairie Provident Resources Inc., as parent corporation, together with its wholly-owned subsidiaries, Prairie Provident Resources Canada Ltd. (formerly Lone Pine Resources Canada Ltd.), Lone Pine Resources Inc. and Arsenal Energy Inc. ("Arsenal"). This MD&A presents the results for the historical Lone Pine properties for the period up to September 12, 2016 and for the combination of Lone Pine and Arsenal after September 12, 2016. See "Arrangement Agreement" section for details.

The following MD&A provides management's analysis of the Company's results of operations, financial position and outlook as at and for the three and nine months ended September 30, 2017. This MD&A is dated November 9, 2017 and should be read in conjunction with the audited consolidated financial statements of PPR as at and for the year ended December 31, 2016 (the "2016 Annual Financial Statements") and the 2016 annual MD&A (the "Annual MD&A"), both dated March 30, 2017. Additional information relating to PPR, including the Company's December 31, 2016 Annual Information Form, is available on SEDAR at www.sedar.com.

All financial information has been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

Unless otherwise noted, all financial information provided herein is reported in Canadian dollars. Production volumes are presented on a working-interest basis, before royalties.

This MD&A contains forward-looking statements and non-IFRS measures. Readers are cautioned that the MD&A should be read in conjunction with the Company's disclosures under the headings "Forward-Looking Statements" and "Non-IFRS Measures" included at the end of this MD&A.

Abbreviations

The following is a list of abbreviations that may be used in this MD&A:

bbl	barrel
bbl/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Mboe	thousands of barrels of oil equivalent
mmboe	millions of barrels of oil equivalent
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
mmbtu	million British Thermal Units
GJ	gigajoule
AECO	AECO "C" hub price index for Alberta natural gas
CGU	cash-generating-unit
DD&A	depreciation, depletion and amortization
E&E	exploration and evaluation
GAAP	generally accepted accounting principles
G&A	general and administrative
P&D	production and development
PSU	performance share unit
DSU	deferred restricted share unit
RSU	restricted share unit
WTI	West Texas Intermediate

Financial and Operational Highlights

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s except per unit amounts)	**2017**	2016	**2017**	2016
Financial				
Oil and natural gas revenue	**17,611**	9,334	**58,501**	25,688
Net loss	**(11,985)**	(11,588)	**(3,657)**	(51,614)
Per share – basic & diluted	**(0.10)**	(0.12)	**(0.03)**	(0.53)
Adjusted Funds from Operations[1]	**4,536**	1,810	**17,530**	6,152
Per share – basic & diluted	**0.04**	0.02	**0.16**	0.06
Capital expenditures and acquisitions (net of proceeds from dispositions)	**4,794**	11,024	**57,947**	22,957
Production Volumes				
Crude oil (bbls/d)	**3,185**	1,722	**3,160**	1,796
Natural gas (Mcf/d)	**12,799**	7,269	**13,661**	8,230
Natural gas liquids (bbls/d)	**188**	104	**235**	120
Total (boe/d)	**5,506**	3,038	**5,672**	3,288
% Liquids	**61%**	60%	**60%**	58%
Average Realized Prices				
Crude oil ($/bbl)	**50.63**	48.50	**53.93**	43.04
Natural gas ($/Mcf)	**1.84**	2.23	**2.62**	1.77
Natural gas liquids ($/bbl)	**34.98**	16.51	**34.28**	15.39
Total ($/boe)	**34.77**	33.40	**37.78**	28.51
Operating Netback ($/boe)[2]				
Realized price	**34.77**	33.40	**37.78**	28.51
Royalties	**(4.27)**	(3.76)	**(5.30)**	(2.91)
Operating costs	**(20.94)**	(20.60)	**(18.95)**	(19.11)
Operating netback	**9.56**	9.04	**13.53**	6.49
Realized gains on derivative instruments	**4.39**	8.08	**2.63**	9.30
Operating netback, after realized gains on derivative instruments	**13.95**	17.12	**16.16**	15.79

2017 corporate developments:

- On March 22, 2017, PPR acquired oil and natural gas assets in the Greater Red Earth area of Northern Alberta (the "Red Earth Assets") for cash consideration of $40.9 million (the "Red Earth Acquisition"). The assets acquired include high quality and low decline oil production which is complementary to PPR's existing operations at Evi in the Peace River Arch area. The acquisition further enhances the Company's size and competitive position through an increased liquids ratio, lower corporate decline and increased operating netbacks. In conjunction with the closing of the Red Earth Acquisition, PPR amended its credit facility to increase its borrowing capacity to $65.0 million (the "Amended Credit Facility").

- On March 16, 2017, the Company issued 5,195,000 flow-through common shares with respect to Canadian Exploration Expenses ("CEE") at $0.77 per share and 5,971,000 subscription receipts ("Subscription Receipts") at $0.67 per unit for total gross proceeds of $8.0 million. The proceeds from the sale of Subscription Receipts were held in escrow until the closing of the Red Earth Acquisition, upon which, the purchasers of the Subscription Receipts automatically received, for every Subscription Receipt held, one PPR common share and one-half of one common share warrant (each whole warrant, a "Warrant"). Each Warrant entitles the holder to

[1,2] Adjusted funds from operations and operating netback are non-IFRS measures and are defined below under "Other Advisories".

acquired one common share at an exercise price of $0.87 per share until March 16, 2019. On April 12, 2017, the over-allotment option was partially exercised, resulting in the issuance of an additional 146,170 CEE flow-through common shares at $0.77 per share and 338,650 Subscription Receipts at $0.67 per share for total gross proceeds of $0.3 million.

- Subsequent to the third quarter, on October 31, 2017 PPR completed a two-part debt financing transaction (the “Financing Transaction”). The transaction includes a three-year USD $40 million senior secured revolving note facility (the "Revolving Facility"), under which USD $31 million principal amount of senior secured revolving notes due October 31, 2020 ("Secured Notes") were issued at closing, and an issue of USD $16 million principal amount of four-year senior subordinated notes due October 31, 2021. The overall debt structure expanded the Company’s borrowing base from CAD $65 million to approximately CAD $72 million (applying a USD/CAD exchange rate of USD $1.00 to CAD $1.29) and extended the term of its debt instruments.

Year-to-date 2017 highlights include:

- Production averaged 5,672 boe/day (60% liquids), representing a 73% increase compared to the first nine months of 2016 due to production additions from the Arsenal acquisition (see “Arrangement Agreement” below), the Red Earth Acquisition and the 2016 and 2017 Wheatland development program which resulted in 15 wells being brought on production in 2016 and six wells being brought on production in the first nine months of 2017. Production additions were partially offset by extended downtime due to third party outages and wet weather conditions experienced during the second and third quarters and natural declines.

- Operating netback after realized hedging gains were $16.16/boe for 2017 year-to-date, an increase of $0.37/boe from the same period in 2016. The increase was due to higher realized prices by $9.27/boe, offset by lower realized gains on derivative instruments of $6.67/boe and higher royalties by $2.39/boe than the same period in 2016.

- Adjusted funds from operations were $17.5 million, an increase of $11.4 million compared the corresponding nine months in 2016, primarily due to higher operating netbacks after realized hedging gains, higher production and lower G&A expenses.

- Capital expenditures and acquisitions (net of $0.3 million in proceeds from dispositions) in the first nine months of 2017 were $57.9 million, including $40.9 million for the Red Earth Acquisition. Excluding acquisitions and dispositions, capital expenditures were $16.5 million including $11.9 million directed to the Wheatland development program, $2.0 million spent in the Princess area and $1.0 million allocated to the Evi Waterflood project. Wheatland expenditures included the (i) tie-in and bringing on-stream two gross wells drilled in the fourth quarter of 2016, (ii) construction of facilities and pipeline in the area, and (iii) the drilling, completion, equipping and tie-in costs of five gross wells. Of the five wells drilled in 2017, two were brought on-stream in the second quarter of 2017, another two were brought on production in July and August 2017 and the last one was a dry exploratory well targeting a new geological structure; it was drilled in conjunction with the satisfaction of the flow-through share commitment (see “Contractual Obligations and Commitments” section below for further explanation). Capital expenditures in the Princess area were directed to the drilling of one gross well and the tie-in of two standing wells.

- Net loss during the first nine months of 2017 was $3.7 million, compared to a net loss of $51.6 million in the comparable period of 2016. The $48.0 million decrease in net loss was the result of an $11.4 million increase in adjusted funds from operations (see “Other Advisories” below), and positive variances in several non-cash items, including a $23.4 million decrease in impairment, a $19.8 million increase in unrealized derivative gains, a decrease in accretion costs of $10.4 million and an increase of $3.9 million in gains on business combination, offset by a $9.1 million decrease in foreign exchange gains and an increase of $12.1 million in DD&A.

- Exited the quarter with borrowings of $50.5 million drawn against the Amended Credit Facility and a working capital deficit (as defined in “Other Advisories” below) of $7.8 million (excluding bank debt classified as current as of September 30, 2017 since it was refinanced as part of the Financing Transaction). As compared to the second quarter of 2017, the working capital deficit excluding bank debt increased by $0.4 million while bank debt decreased by $0.2 million.

Third quarter 2017 highlights include:

- Production averaged 5,506 boe/day (61% liquids), a 81% increase compared to the third quarter of 2016 due to production additions from the Arsenal acquisition, the Red Earth Acquisition and the Wheatland drilling program. Partially offsetting these increases were natural production declines and downtime related to wet weather conditions, scheduled turnaround of the Evi main battery and other minor maintenance.

- Operating netbacks after realized hedging gains were $13.95/boe for the third quarter of 2017, a decrease of $3.17/boe from the third quarter of 2016. The decrease was primarily due to lower realized gains on derivative instruments, partially offset by higher realized prices.

- Adjusted funds from operations were $4.5 million, a 151% increase as compared to the third quarter of 2016 primarily due to higher production offset by lower operating netback after realized hedging gains.

- Capital expenditures were $4.8 million, primarily directed to the Wheatland and Princess development programs. In the Princess area, PPR drilled one well and began construction of pipelines for the tie-ins of two standing wells, which are expected to bring on new production in the fourth quarter of 2017. In Wheatland, the Company drilled one exploratory well and tied-in two wells that were drilled in the first quarter of 2017 in the Wheatland area. Our third quarter activity was reduced due to a conscious decision to defer our capital spending in response to commodity prices during the quarter.

- Net loss in the third quarter of 2017 was $12.0 million, compared to a net loss of $11.6 million in the same period of 2016. The slight increase in net loss was due to higher non-cash expenses, offset by higher funds from operations. The net loss in the third quarter of 2017 included impairment losses of $3.4 million (Q3 2016 – $1.7 million), unrealized loss on derivative instruments of $2.6 million (Q3 2016 – $1.9 million) and depletion and depreciation of $8.6 million (Q3 2016 – $4.2 million).

Outlook

During the third quarter of 2017, commodity prices faced downward pressure as the rebalancing of global oil supply and demand remained uncertain. In light of the commodity price environment, we made a conscious decision to scale back our 2017 capital program and to defer certain projects to 2018 to preserve liquidity and to protect project economics. Looking to the fourth quarter of 2017, our operations will be focused on bringing a Princess well drilled during the third quarter on production and completing the tie-in of two standing wells in the same area.

On October 1, 2017, Prairie Provident sold certain non-core gas-weighted assets. The divested assets were experiencing challenging economics due to soft gas prices and recent increases in third-party processing costs. While the disposition reduces our average daily production by approximately 400 boe/d, it reduces our corporate decommissioning liabilities and results in a marginal impact on adjusted funds from operations.

PPR remains true to our corporate strategy, and conservatively executed our capital program while seeking to control costs and manage debt levels. We continue to focus on improving corporate netbacks by targeting higher value product streams (oil and condensate-rich liquids) and are taking steps to improve capital efficiencies through pad drilling as well as focusing on operating areas that have underutilized infrastructure capacity. While focusing on oil properties or properties with lower gas/oil ratios may result in lower than anticipated production, by targeting higher netbacks, we anticipate minimal impact to adjusted funds from operations and a better return on the capital we employ.

Encouragingly, oil prices have trended up through the latter half of October and into early November, we will continue to monitor pricing conditions for hedging opportunities and will adjust our pace of development to ensure optimal rates of return on investments. If oil prices remain favorable, we have the flexibility to accelerate our development. Our scalable approach centers around our core strategy – delivering growth through funds from operations.

PPR is maintaining its full year 2017 capital budget of approximately $25 million (including approximately $6 million for land, seismic, abandonment and reclamation activities). Despite the non-core asset sale in October 2017, the deferral of 2017 capital spending and lower than budgeted commodity prices, we expect full year Adjusted EBITDAX remain at around $25 million - $27 million.

Arrangement Agreement

On September 12, 2016, Lone Pine and Arsenal completed a business combination by way of a plan of arrangement ("Arrangement") whereby Lone Pine and Arsenal became direct or indirect wholly-owned subsidiaries of Prairie Provident Resources Inc. (see Note 1 to the Annual Financial Statements).

The acquisition of Arsenal common shares was accounted for as a business combination using the acquisition method of accounting whereby PPR was deemed to be the acquirer of the Arsenal business and the assets and liabilities assumed were recorded at their fair values. Transaction costs associated with the acquisition are expensed when incurred.

Business Combination

On March 22, 2017, PPR acquired oil and natural gas properties in the Greater Red Earth area of Northern Alberta for cash consideration of $40.9 million. The assets acquired include high quality and low decline oil production which is complementary to PPR's existing operations at Evi in the Peach River Arch area of Northern Alberta and further enhances the Company's size and competitive position in the area. The Greater Red Earth asset acquired included producing assets with production at acquisition of approximately 1,100 boe/d (98% liquids weighting) and approximately 78,000 net acres of undeveloped land. The acquisition was funded through the Company's credit facility, which was amended on March 22, 2017 with an increased borrowing base of $65 million, and through the gross proceeds from a bought-deal equity financing of $8.0 million ($7.0 million net of share issuance costs), which closed on March 16, 2017. Under the bought-deal financing, the Company issued 5,195,000 flow-through common shares with respect to CEE at $0.77 per share and 5,971,000 Subscription Receipt at $0.67 per share for gross proceeds of $8.0 million. The proceeds from the sale of Subscription Receipts were held in escrow until the closing of the Red Earth Acquisition, upon which, the purchasers of the Subscription Receipts automatically received, for every Subscription Receipt held, one PPR common share and one-half of one common share purchase warrant (each whole warrant, a "Warrant"). Each Warrant entitles the holder to acquire one common share at an exercise price of $0.87 per share until March 16, 2019. Pursuant to the bought-deal financing, the underwriters' had an over-allotment option to purchase, at any time prior to April 15, 2017, up to an additional 15% of the number of flow-through common shares and Subscription Receipts initially offered. On April 12, 2017, the over-allotment option was partially exercised, resulting in the issuance of an additional 146,170 CEE flow-through common shares at $0.77 per share and 338,650 Subscription Receipts at $0.67 per share for total gross proceeds of $0.3 million ($0.3 million net of share issuance costs).

Subsequent Event

On October 31, 2017, PPR completed a two-part debt financing transaction. The transaction includes a three-year USD $40 million senior secured revolving note facility (the "Revolving Facility"), under which USD $31 million principal amount of senior secured revolving notes due October 31, 2020 ("Secured Notes") were issued at closing, and an issue of USD $16 million principal amount of four-year senior subordinated notes due October 31, 2021 ("Subordinated Notes"). The overall debt structure expanded the Company's borrowing base from CAD $65 million to approximately CAD $72 million (applying a USD/CAD exchange rate of USD $1.00 to CAD $1.29) and extended the term of its debt instruments. All notes were issued at par by Prairie Provident Resources Inc.'s wholly-owned subsidiary, Prairie Provident Resources Canada Ltd. ("PPR Canada"), and are guaranteed by the Prairie Provident Resources Inc. and certain of its other subsidiaries.

Contemporaneously with the closing of the financing, the Company issued to the Subordinated Noteholders warrants to purchase up to 2,318,000 common shares, or 2% of the PPR's outstanding shares, at an exercise price of CAD $0.549 (subject to adjustment in certain circumstances) with a 5-year term expiring on October 31, 2022. The exercise price represents a 20% premium over the 30-day weighted-average trading price of the Company's common shares at closing.

Approximately $43 million (or CAD $55.5 million) of the proceeds from the Financing Transaction was used to repay and to retire the Amended Credit Facility and to cash collateralize approximately CAD $4.8 million in outstanding letters of credit issued for ordinary business operations.

Following the closing of the financing, the Company's long-term debt, less funds collateralized for outstanding letters of credit and cash proceeds remained from the transaction, was approximately CAD $53 million (applying a USD/CAD exchange rate of USD $1.00 to CAD $1.29).

Revolving Facility

The Revolving Facility is a borrowing base facility that provides for total revolving commitments equal to the lesser of USD $40 million and the then-applicable borrowing base determined by the secured noteholders in accordance with their customary procedures and standards having regard to, among other things, the Company's proved reserves. The borrowing base is subject to a semi-annual redetermination following scheduled delivery of year-end and mid-year reserves reports on or before March 31 and September 30 for each year during the term. The first borrowing base redetermination will occur in April 2018 based on delivery of the 2017 year-end reserves report in late March 2018.

The Revolving Facility is a three-year facility, and all Secured Notes issued thereunder will mature October 31, 2020. PPR can make further draws under the Revolving Facility on or before October 31, 2019, subject at all times to the then-applicable commitment amount. The Secured Notes are repayable at the Company's election at par plus interest and any applicable breakage costs, without reduction in the aggregate commitment under the Revolving Facility.

Based on USD $31 million principal amount of Secured Notes having been issued at closing, the Company has 22.5% borrowing capacity available under the Revolving Facility, or approximately CAD $12 million based on a current USD/CAD exchange rate of approximately USD $1.00 to CAD $1.29.

The Revolving Facility is ultimately denominated in United States dollars but accommodates Canadian dollar denominated advances up to the lesser of CAD $18 million and the Canadian dollar equivalent of USD $10 million. Based on a current USD/CAD exchange rate of approximately USD $1.00 to CAD $1.29, the current Canadian dollar sublimit under the Revolving Facility is approximately CAD $12.9 million. Of all Secured Notes issued at closing, CAD $12.9 million are denominated Canadian dollar.

Amounts borrowed under the Revolving Facility can be drawn in the form of USD or CAD prime advances bearing interest based on reference bank USD and CAD prime lending rates announced from time to time, or LIBOR advances (in the case of USD amounts) or CDOR advances (in the case of CAD amounts) bearing interest based on LIBOR and CDOR rates in effect from time to time, plus an applicable margin. Applicable margins per annum are as follows:

(i) for CDOR advances and Canadian dollar prime advances, the margins are between 350 and 500 basis points ("bps");

(ii) for LIBOR advances and US dollar prime advances, the margins range from 325 to 475 bps; and

(iii) standby fees on any undrawn borrowing capacity are between 50 to 87.5 bps per annum.

The note purchase agreement for the Revolving Facility and related parent and subsidiary guarantees contain various covenants on the part of the Company and its subsidiaries. Included among the covenants are commitments by PPR to meet certain financial tests, calculated in accordance with the note purchase agreement, with respect to:

- total leverage, pursuant to which the ratio of adjusted indebtedness to EBITDAX for the four quarters most recently ended cannot exceed 3.5 to 1.0;
- senior leverage, pursuant to which the ratio of senior adjusted indebtedness to EBITDAX for the four quarters most recently ended cannot exceed 3.0 to 1.0;
- asset coverage, pursuant to which the ratio of adjusted net present value of estimated future net revenue from proved reserves (discounted at 10% per annum) to adjusted indebtedness as of the date of any reserves report cannot be less than 1.3 to 1.0; and
- current ratio, pursuant to which the ratio of consolidated current assets, plus any undrawn capacity under the Revolving Facility, to consolidated current liabilities at the end of any fiscal quarter cannot be less than 1.0 to 1.0.

Subordinated Notes

The Subordinated Notes are four-year instruments with a scheduled maturity date of October 31, 2021. They bear interest at 15% per annum, payable quarterly in arrears on the 30th day of January, April, July and October in each year, with up to 5% per annum payable in kind at the election of PPR. The amount of any such in kind payment will become additional principal owing in respect of the Subordinated Notes, payable at the maturity date.

The note purchase agreement for the Subordinated Notes and related parent and subsidiary guarantees contain various covenants on the part of the Company and its subsidiaries, including commitments by PPR Canada to meet the similar financial tests described above.

Results of Operations

Production

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	**2017**	2016
Crude oil (bbls/d)	**3,185**	1,722	**3,160**	1,796
Natural gas (Mcf/d)	**12,799**	7,269	**13,661**	8,230
Natural gas liquids (bbls/d)	**188**	104	**235**	120
Total (boe/d)	**5,506**	3,038	**5,672**	3,288
Liquids Weighting	**61%**	60%	**60%**	58%

PPR's production for the three and nine months ended September 30, 2017 increased by 81% and 73% respectively compared to the corresponding periods in 2016. The increases were primarily the result of additions from the Arsenal acquisition, the Red Earth Acquisition and the Wheatland drilling program. The Arsenal acquisition contributed incremental production in the three and nine months ended September 30, 2017 of approximately 750 boe/d and 920 boe/d, respectively. The successful drilling program at Wheatland resulted in increased production in the three and nine months ended September 30, 2017 of approximately 1,100 boe/d and 1,150 boe/d, respectively. Production related to the Red Earth Acquisition, has been included in PPR's operating results since the closing date of the acquisition on March 22, 2017. This resulted in added production of approximately 900 boe/d and 650 boe/d for the three and nine months ended September 30, 2017, respectively.

Partially offsetting the production increases in the third quarter were natural production declines and extended downtime primarily in the Evi area related to wet weather conditions, a scheduled turnaround of the Evi main battery and other minor maintenance of approximately 270 boe/d. The Company made a conscious decision to delay the timing of the third quarter 2017 capital program to preserve liquidity and to protect project economics given the volatile commodity price environment in the quarter. The second quarter capital program had also been delayed for the same rationale, in addition to the seasonal impacts of spring break up and delayed scheduling of frac crews. As such, these delays resulted in lower than anticipated production additions for the three and nine months ended September 30, 2017. Year-to-date production was also impacted by the integration of the Red Earth assets acquired as certain assets experienced downtime initially as they had been behind their scheduled maintenance.

The liquids-weighting for the three and nine months ended September 30, 2017 was relatively consistent with the respective periods in 2016. Increases in the liquids-weighting related to the properties acquired in the Red Earth Acquisition, which have a liquids weighting of approximately 98%, were offset by increases in production in the Wheatland area which have a lower liquids-weighting.

Subsequent to the end of the third quarter of 2017, the Company sold certain non-core, natural gas weighted, producing properties that were classified as held for sale as at September 30, 2017. The disposition of these properties is expected to reduce fourth quarter 2017 production by approximately 400 boe/d, however, it is expected to have a neutral impact on cash flows from operating activities for the same period.

Revenue

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per unit amounts)	**2017**	2016	**2017**	2016
Revenue				
Crude oil	**14,835**	7,684	**46,521**	21,180
Natural gas	**2,171**	1,492	**9,781**	4,002
Natural gas liquids	**605**	158	**2,199**	506
Oil and natural gas revenue	**17,611**	9,334	**58,501**	25,688
Average Realized Prices				
Crude oil ($/bbl)	**50.63**	48.50	**53.93**	43.04
Natural gas ($/Mcf)	**1.84**	2.23	**2.62**	1.77
Natural gas liquids ($/bbl)	**34.98**	16.51	**34.28**	15.39
Total ($/boe)	**34.77**	33.40	**37.78**	28.51
Benchmark Prices				
Crude oil - WTI ($/bbl)	**60.34**	58.90	**64.61**	54.56
Crude oil - Edmonton Light Sweet ($/bbl)	**56.26**	54.24	**60.38**	49.60
Natural gas - AECO monthly index-7A ($/Mcf)	**2.04**	2.20	**2.58**	1.85
Natural gas - AECO daily index - 5A ($/Mcf)	**1.46**	2.32	**2.31**	1.85
Exchange rate - US$/CDN$	**0.80**	0.77	**0.77**	0.76

PPR's third quarter 2017 revenue increased by 89% or $8.3 million from the third quarter of 2016. The 93% increase in crude oil revenue incorporates an 85% increase in oil production and a 4% rise in realized prices. The 46% increase in natural gas revenue was the result of a 76% increase in production partially offset by a 17% decrease in realized prices. The movements in PPR's realized prices correlated with those observed in the benchmark prices. The increase in the overall average realized prices of 4% reflected the underlying trends of the oil and liquids pricing, as the Company is more liquids-weighted.

On a year-to-date basis, revenue increased by 128% or $32.8 million, compared to the same period in 2016. The 120% increase in crude oil revenue and the 144% increase in natural gas revenue reflected higher production volumes, which rose by 76% and 66%, respectively, and increases in realized prices of crude oil and natural gas of 25% and 48%, respectively. The higher realized prices reflected the increases in benchmark prices. The increase in the overall average realized prices of 33% also incorporated a slightly higher liquids-weighted production mix in the first nine months of 2017 than in the same period in 2016

Royalties

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2017**	2016	**2017**	2016
Royalties	**2,164**	1,050	**8,202**	2,623
Per boe	**4.27**	3.76	**5.30**	2.91
Percentage of revenue	**12.3%**	11.2%	**14.0%**	10.2%

The majority of PPR's royalties are paid to the Crown, which are based on various sliding scales that are dependent on incentives, production volumes and commodity prices. Production in the Wheatland area is subject to flat royalty rates of between 5% and 17.5%, with average royalties rates which are higher than the average royalty rate of the remaining properties. On a percentage of revenue basis, royalties for the three and nine months ended September 30, 2017 increased from the corresponding periods in 2016 due to royalties incurred on additional Wheatland production, higher royalties burden on the acquired Arsenal properties and higher benchmark prices.

Commodity Price and Risk Management

PPR enters into derivative risk management contracts to manage exposure to commodity price fluctuations and to protect and provide certainty on a portion of the Company's cash flows. PPR considers these derivative contracts to be an effective means to manage cash flows from operations.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2017**	2016	**2017**	2016
Realized gain on derivatives	**2,222**	2,257	**4,075**	8,381
Unrealized gain (loss) on derivatives	**(2,586)**	(1,936)	**7,743**	(12,043)
Total gain (loss) on derivatives	**(364)**	321	**11,818**	(3,662)
Per boe				
Realized gain on derivatives	**4.39**	8.08	**2.63**	9.30
Unrealized gain (loss) on derivatives	**(5.11)**	(6.93)	**5.00**	(13.37)
Total gain (loss) on derivatives	**(0.72)**	1.15	**7.63**	(4.06)

Realized gains and losses on derivative risk management contracts represent the cash settlements of outstanding contracts while unrealized gains and losses on derivative risk management reflect changes in mark-to-market positions of outstanding contracts in the current period. Both realized and unrealized gains and losses on derivate contracts vary based on fluctuations related to the specific terms of outstanding contracts in the related period including contract types, contract quantities and fluctuations in underlying commodity reference prices.

As of September 30, 2017, the Company held the following outstanding derivative contracts:

Commodity Contract	Notional Quantity	Remaining Term	Reference	Weighted Average Price		Contract Type
Oil	500 bbls/d	October 1, 2017 – December 31, 2017	CDN$ WTI	$	87.78	Swap
Oil	500 bbls/d	October 1, 2017 – December 31, 2017	CDN$ WTI	$	65.00/72.00	Collar
Oil	250 bbls/d	October 1, 2017 – December 31, 2017	CDN$ WTI	$	65.00/75.00	Collar
Oil	500 bbls/d	October 1, 2017 – December 31, 2017	CDN$ WTI	$	58.00/67.50	Collar
Oil	400 bbls/d	October 1, 2017 – December 31, 2017	CDN$ WTI	$	70.00/85.00	Collar
Light Oil [(1)] Differential	1,000 bbls/d	October 1, 2017 – December 31, 2017	CDN$ MSW	$	-5.70	Swap
Natural Gas	6,050 GJ/d	October 1, 2017 – December 31, 2017	AECO 7A Monthly Index	$	2.79	Swap
Natural Gas	800 GJ/d	October 1, 2017 – December 31, 2017	AECO 7A Monthly Index	$	2.95	Swap
Oil	500 bbls/d	January 1, 2018 – December 31, 2018	USD$ WTI	$	65.00	Sold Call Option
Oil	800 bbls/d	January 1, 2018 – December 31, 2018	CDN$ WTI	$	58.00/ 67.50	Collar
Natural Gas	2,500 GJ/d	January 1, 2018 – March 31, 2018	AECO 7A Monthly Index	$	3.12	Swap
Natural Gas	1,500 GJ/d	January 1, 2018 – December 31, 2018	AECO 7A Monthly Index	$	2.76	Swap
Natural Gas	1,500 GJ/d	January 1, 2018 – December 31, 2018	AECO 7A Monthly Index	$	2.76	Sold Call Option
Oil	400 bbls/d	January 1, 2019 – December 31, 2019	CDN$ WTI	$	85.00	Sold Call Option
Natural Gas	2,000 GJ/d	January 1, 2019 – March 31, 2019	AECO 7A Monthly Index	$	2.73	Swap

(1) Settled on the monthly average Mixed Sweet Blend ("MSW") Differential to WTI

All derivatives contracts outstanding as at September 30, 2017 were entered with PPR's credit facility lenders to minimize the need to post any collateral. The Company manages the credit risk exposure related to its ongoing risk management program by entering derivative contracts with counterparties that have acceptable credit ratings, including commercial banks and integrated energy companies.

Subsequent to September 30, 2017, the Company entered into the following derivative contracts:

Commodity Contract	Notional Quantity	Remaining Term	Reference	Weighted Average Price		Contract Type
Oil	1,200 bbls/d	January 1, 2018 – March 31, 2018	USD$ WTI	$	57.13	Swap
Oil	1,100 bbls/d	April 1, 2018 – June 30, 2018	USD$ WTI	$	56.63	Swap
Oil	1,000 bbls/d	July 1, 2018 – September 30, 2018	USD$ WTI	$	55.65	Swap
Oil	900 bbls/d	October 1, 2018 – December 31, 2018	USD$ WTI	$	54.55	Swap
Oil	600 bbls/d	January 1, 2019 – March 31, 2019	USD$ WTI	$	53.53	Swap
Oil	250 bbls/d	April 1, 2019 – May 31, 2019	USD$ WTI	$	52.65	Swap
Oil	325 bbls/d	April 1, 2019 – June 30, 2019	USD$ WTI	$	52.75	Swap

Operating Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2017**	2016	**2017**	2016
Lease operating expense	**7,560**	4,237	**20,383**	12,397
Transportation and processing	**1,864**	1,116	**5,859**	3,546
Production and property taxes	**1,182**	404	**3,096**	1,270
Total operating expenses	**10,606**	5,757	**29,338**	17,213
Per boe	**20.94**	20.60	**18.95**	19.11

Compared to the same periods in 2016, lease operating expense for the three and nine months ended September 30, 2017 increased by 78% and 64%, respectively, which were entirely attributable to increases in production by 81% and 73%. Lease operating expenses for the first nine months of 2017 increased by a lesser extent as the underlying production because it was mitigated by the absence of $1.0 million of site clean-up and remediation costs that were included in the first quarter of 2016. These site clean- up costs were subsequently offset by a $0.9 million insurance recovery that was received in the fourth quarter of 2016.

Transportation and processing expense for the three and nine months ended September 30, 2017 increased by 67% and 65%, respectively, as compared to the same periods in 2016. The increases were also due to increased production.

Production and property tax expense for the three and nine months ended September 30, 2017 increased by $0.8 million and $1.8 million, respectively, as compared to the same periods in 2016. The increases primarily related to properties acquired in the Arsenal acquisition and the Red Earth Acquisition.

Operating expenses on a per boe basis were 2% higher in the third quarter of 2017 as compared to the same period in 2016. The increase included approximately $0.3 million of costs incurred for a turnaround at the Evi main battery in the third quarter of 2017 and the inclusion of the Red Earth properties that have higher operating expenses on a per boe basis. The year-to-date 2017 operating costs were slightly lower than the year-to-date 2016 operating costs that incorporated costs related to the Wheatland wellhead pipe breach incident. In 2017, PPR incurred additional maintenance and workover expenses on the recently acquired Red Earth properties as they had been behind their maintenance schedule and experiencing some outages. Wet weather conditions at Evi and Wheatland during spring break-up further contributed to increased lease operating and maintenance costs in 2017.

Operating Netback

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ per boe)	**2017**	2016	**2017**	2016
Revenue	**34.77**	33.40	**37.78**	28.51
Royalties	**(4.27)**	(3.76)	**(5.30)**	(2.91)
Operating costs	**(20.94)**	(20.60)	**(18.95)**	(19.11)
Operating netback	**9.56**	9.04	**13.53**	6.49
Realized gains on derivative instruments	**4.39**	8.08	**2.63**	9.30
Operating netback, after realized gains on derivative instruments	**13.95**	17.12	**16.16**	15.79

PPR's third quarter 2017 operating netback after realized hedging gains decreased by $3.17/boe compared to the third quarter of 2016. Decreases in realized gains on derivative instruments and increases in royalties and operating expenses were partially offset by increases in realized revenue. The operating netback for the nine months ended September 30, 2017 were $0.37/boe higher than the comparative period in 2016. Increases in realized revenue and decreases in operating costs were partially offset by decreases in realized gains on derivative instruments and increases in royalties.

General and Administrative Expenses ("G&A")

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2017**	2016	**2017**	2016
Gross cash G&A expenses	**2,714**	3,148	**8,155**	8,829
Gross share-based compensation expense	**211**	54	**570**	197
Less amounts capitalized	**(537)**	(264)	**(1,510)**	(934)
Net G&A expenses	**2,388**	2,938	**7,215**	8,092
Per boe	**4.71**	10.51	**4.66**	8.98

For the three months and nine months ended September 30, 2017, gross cash G&A were $0.4 million and $0.7 million lower than the respective periods in 2016 notwithstanding PPR has grown its production significantly and became a public company within the last year.

Changes in gross share-based compensation expense relate to the number of units granted, the timing of grants, the fair value of units on the grant date, and the vesting period over which the related expense is recognized. The increases in gross share-based compensation expense was the result of share-based incentive awards granted to employees, officers and directors in the fourth quarter of 2016 and the first quarter of 2017. Additionally, beginning in the second quarter of 2017, deferred restricted share units ("DSUs") are granted to non-management directors on a quarterly basis in-lieu of a portion of fees previously paid in cash.

Capitalized G&A varies with the composition and compensation levels of technical departments and their time attributed to capital projects. The increase in capitalized G&A for the three and nine months ended September 30, 2017 compared to the same periods in 2016 related to the increased staffing levels in the technical departments subsequent to the Arrangement.

Share-based compensation

In conjunction with the closing of the Arrangement, the Company adopted new long-term incentive plans for employees and directors pursuant to which share-based incentive awards are granted. Prior to the Arrangement, share-based compensation related to restricted share units, which were settled with PPR common shares in the fourth quarter of 2016 and in the first quarter of 2017.

In the first nine months of 2017, the Company granted 1,969,795 stock options to employees, officers and directors at a weighted average exercise price of $0.75 per share. Options granted vest evenly over a three-year period and will expire five years after the grant date. As at September 30, 2017, 2,684,469 stock options were outstanding, of which 250,724 were exercisable.

The Company issued 354,905 performance share units ("PSUs") to certain officers of the Company in the first nine months of 2017. These PSUs will vest on December 15, 2019 and are subject to a multiplier from 0 to 2 based on share performance relative to a selected peer group. PSUs will be settled in common shares or cash at the discretion of the Company; however, it is PPR's intention to settle the PSUs in common shares and the plan has accounted for as equity settled. As at September 30, 2017, 471,332 PSUs were outstanding.

During the year-to-date 2017 period, the Company issued 166,116 DSUs to non-management directors of the Company. DSUs vest in their entirety on the grant date and will be settled when a director ceases to be a member of the board of directors. DSUs may be settled in common shares or cash at the discretion of the Company. It is PPR's intention to settle the PSUs in common shares and the plan has accounted for as equity settled. As at September 30, 2017, there were 166,116 DSUs outstanding.

Finance Costs

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2017**	2016	**2017**	2016
Interest expense	**633**	138	**1,467**	500
Accretion expenses	**553**	3,476	**1,576**	11,938
Total finance cost	**1,186**	3,614	**3,043**	12,438
Per boe	**2.34**	12.93	**1.97**	13.81

Interest expense is primarily related to interest incurred related to the Company's credit facilities. There were no borrowings outstanding for the majority of the three and nine months ended September 30, 2016 and interest incurred in this period primarily comprised of the amortization of deferred financing charges, recognition of standby fees and interest on outstanding letters of credit. The increase in interest expense by $0.5 million and $1.0 million from the three and nine months ended September 30, 2016 related to increased borrowings under the Company's credit facilities during the 2017. The weighted average effective interest rate on credit facility borrowings for the three and nine months ended September 30, 2017 was 3.8% and 3.5%, respectively (2016 – 2.0% and 2.0%, respectively, on letters of credit outstanding).

Accretion charges are non-cash expenses. Historically, the Company's accretion expense was primarily comprised of accretion on preferred shares. Pursuant to the Arrangement, outstanding preferred shares were exchanged for PPR common shares and as such accretion expense on preferred shares is no longer recognized after September 12, 2016 (see Preferred Shares under the Capital Resources section below). During the three and nine months ended September 30, 2016, the Company recognized $3.1 and $11.0 million, respectively, of accretion charges on the preferred shares. The remaining accretion charges primarily related to the decommissioning liabilities, which increased by $0.2 million and $0.7 million, respectively, during the three and nine months ended September 30, 2017 from the same periods in the prior year as a result of additional decommissioning liabilities acquired from the Arsenal acquisition and the Red Earth Acquisition.

Gain (Loss) on Foreign Exchange

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2017**	2016	**2017**	2016
Realized gain (loss) on foreign exchange	**214**	(39)	**411**	32
Unrealized gain (loss) on foreign exchange	**130**	(378)	**247**	9,693
Gain (loss) on foreign exchange	**344**	(417)	**658**	9,725

Foreign exchange gains (losses) incurred in the three and nine months ended September 30, 2016 related mainly to the previously outstanding US dollar denominated preferred shares (see Preferred Shares under the Capital Resources section below). The weakening (strengthening) of the Canadian dollar during a given period would result in unrealized foreign exchange loss (gain) on the preferred shares. Pursuant to the Arrangement, outstanding preferred shares were exchanged for PPR common shares on September 12, 2016 and as such foreign exchange fluctuations of the US dollar had a reduced impact in the three and nine months ended September 30, 2017.

As a result of the Financing Transaction completed on October 31, 2017 (see "Subsequent Event"), borrowings in US dollars will increase the Company's exposures to foreign exchange risks. The Company's realized prices are also exposed to fluctuations of the US dollar and Canadian dollar exchange rate, which serves as natural hedges to the US denominated debt. Therefore, the Company plans to enter into commodity hedges in US dollars to maintain such natural economic hedges.

Exploration and Evaluation Expense

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2017**	2016	**2017**	2016
Exploration and evaluation expense	**1,100**	15	**1,166**	49
Per boe	**2.17**	0.05	**0.75**	0.05

Third quarter and year-to-date 2017 exploration and evaluation expenses include costs related to a dry exploration well drilled in the third quarter of 2017 in the Wheatland area and undeveloped land expiries. The exploratory well was drilled in conjunction with the satisfaction of the flow-through share commitment (see "Contractual Obligations and Commitments" section below for further explanation) and the related expenditures qualify as CEE. Third quarter and year-to-date 2016 exploration and evaluation expenses were comprised of undeveloped land expiries.

Depletion and Depreciation

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2017**	2016	**2017**	2016
Depletion and depreciation	**8,636**	4,234	**26,061**	13,935
Per boe	**17.05**	15.15	**16.83**	15.47

Depletion and depreciation rates are subject to change based on changes in the carrying value of the asset base, changes in future development costs, reserve updates and changes in production by area. The increase in the depletion rate for the three and nine months ended September 30, 2017 from the comparable periods in 2016 incorporated the assets and related reserves acquired through the Arrangement and the Red Earth Acquisition.

Impairment Loss

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2017**	2016	**2017**	2016
E&E impairment	**—**	882	**—**	25,872
E&E impairment – decommissioning asset	**—**	(18)	**—**	(18)
Total E&E impairment	**—**	864	**—**	25,854
P&D impairment	**3,400**	—	**3,400**	—
P&D impairment – decommissioning asset	**—**	848	**—**	848
P&D inventory impairment	**—**	—	**—**	200
Total P&D impairment	**3,400**	848	**3,400**	1,048
Inventory impairment (recovery)	**—**	—	**—**	(125)
Total impairment loss	**3,400**	1,712	**3,400**	26,777

Third quarter and year-to-date 2017 P&D impairment includes the write down of assets classified as held for sale to their fair value less cost of disposal. The assets classified as held for sale as at September 30, 2017 were sold in the fourth quarter of 2017.

Third quarter 2016 E&E impairment losses were recognized relating to leases that were due to expire in the next twelve months in the Evi CGU offset by minor impairment recoveries related to decreases in the decommissioning liabilities estimates of certain E&E assets that have been fully impaired. In addition, year-to-date 2016 E&E impairment losses were incurred on assets in the Quebec exploratory area as a result of a shift in management development priorities.

Third quarter 2016 $0.8 million P&D impairment losses related to changes in estimated decommissioning liabilities of certain properties with zero carrying value. Year-to-date 2016 P&D impairment included of $0.2 million related to the write-down of certain surplus equipment.

Capital Expenditures[1]

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2017**	2016	**2017**	2016
Drilling and completion	**1,635**	8,360	**8,944**	14,424
Equipment, facilities and pipelines	**2,199**	1,601	**5,162**	6,580
Land	**80**	677	**385**	755
Capitalized overhead and other	**871**	386	**1,967**	1,218
Total expenditures	**4,785**	11,024	**16,458**	22,977
Acquisitions – cash consideration	**—**	—	**41,829**	—
Proceeds from disposals of property	**9**	—	**(340)**	(20)
Total – net	**4,794**	11,024	**57,947**	22,957

PPR focused its capital activities during the third quarter of 2017 in the Wheatland and Princess areas. In the Princess area, PPR drilled one well and began construction of pipelines for the tie-ins of two standing wells. In Wheatland, the Company drilled one well and tied-in two wells that were drilled in the first quarter of 2017 in the Wheatland area. Year-to-date capital activities also included drilling and completion of four gross (4.0 net) wells, equipping and tie-in of two Wheatland wells that were drilled and completed in 2016, construction of facilities and pipelines in the Wheatland area as well as advancing the Evi waterflood project. Additionally, in the first quarter of 2017 the Company incurred $41.8 million on acquisitions of oil and natural gas properties, of which $40.9 million was for the Red Earth Acquisition (see “Business Combinations” above).

[1] Capital expenditures include expenditures on E&E assets.

Four of the six wells drilled in 2017 were on production as at September 30, 2017. The Princess well drilled in the third quarter of 2017 is expected to be completed and on production in the fourth quarter of 2017. Additionally, the two standing wells in the Princess area are also expected to come on production in the fourth quarter of 2017. The well drilled in Wheatland in the third quarter of 2017 was dry and the related expenditures were fully expensed through E&E expense in the third quarter of 2017. The Wheatland well was exploratory in nature targeting a new geological structure; it was drilled in conjunction with the satisfaction of the flow-through share commitment (see "Contractual Obligations and Commitments" section below for further explanation) and the related expenditures qualify as CEE.

During the third quarter of 2016, the Company drilled and completed eight gross wells. Year-to-date 2016 capital expenditures also included drilling, completion, equip and tie-in costs for the three gross (2.9 net) wells, the equip and tie-in of three gross wells drilled in 2015, as well as, construction of a multi-well battery and multiple pipelines at the Wheatland area. Additional capital expenditures were spent on the second phase of the Evi waterflood.

Transaction Costs

Transaction costs incurred in the three months ended September 30, 2017 were $0.2 million, with $0.1 million related to the Red Earth Acquisition and $0.1 million related to the Arrangement (2016 – $1.5 million related to the Arrangement). Year-to-date transaction costs of $1.0 million included $0.6 million related to the Red Earth Acquisition and $0.4 million related to the Arrangement (2016 – $1.8 million related to the Arrangement). Transaction costs were comprised primarily of legal fees and professional fees.

Decommissioning Liabilities

The Company's decommissioning liabilities at September 30, 2017 were $112.6 million (December 31, 2016 – $97.7 million) to provide for future remediation, abandonment and reclamation of PPR's oil and gas properties. The $14.9 million increase in decommissioning liabilities was primarily due to the Red Earth Acquisition and related change in estimates, partially offset by settlements of decommissioning obligations of $4.9 million. The Company completed the majority of its 2017 decommissioning program in the first quarter of 2017 in a winter access only area.

Decommissioning obligations acquired through business combination and asset acquisition are initially measured at fair value using a credit-adjusted risk free rate of 5.7% to discount estimated future cash flows. In accordance with PPR's accounting policy, decommissioning obligations are carried on the financial statements using risk-free discount rates. The revaluation of the acquired decommissioning obligations to the risk-free rates as disclosed above resulted in an increase to the carrying values of decommissioning liabilities of $11.5 million, which was included in changes in estimates.

The undiscounted and inflated decommissioning obligation liabilities, based on an inflation rate of 1.7%, were estimated at $175.6 million. While the provision for decommissioning liabilities is based on management's best estimates of future costs, discount rates, timing and the economic lives of the assets, there is uncertainty regarding the amount and timing of incurring these costs.

Capital Resources and Liquidity

Capital Resources

Working Capital

At September 30, 2017, PPR had a working capital deficit (as defined in "Other Advisories" below) of $58.1 million (December 31, 2016 – $4.4 million). The working capital deficit as at September 30, 2017 included $50.3 million of outstanding bank debt under the Amended Credit Facility because the maturity date of the Amended Credit Facility was within the following 12 months. On October 31, 2017, the Amended Credit Facility was fully repaid and retired as part of the Financing Transaction, and was replaced by long-term debt under the Revolving Facility and the Subordinated Notes (see "Subsequent Event" section above). Excluding bank debt, the working capital deficit was $7.8 million, an increase of $3.2 million from December 31, 2016. The increase in the working capital deficit, excluding bank debt, was primarily due to using cash on-hands to fund a portion of the Red Earth Acquisition.

The working capital deficit, excluding bank debt, decreased by $5.3 million from its peak of $13.1 million as at March 31, 2017 as PPR paid down its current liabilities using borrowings under the credit facility and adjusted funds from operations (see "Other Advisories" below). In the second and third quarter, PPR decided to defer a portion of the capital program and applied the funds towards reduction of its current liabilities.

Amended Credit Facility

Under PPR's credit facility, the Company had outstanding debt at September 30, 2017 of $50.3 million (December 31, 2016 – $15.0 million), net of deferred financing costs and prepaid interest of $0.2 million (December 31, 2016 – $0.5 million) and $4.7 million of letters of credit issued (December 31, 2016 – $5.4 million).

On March 22, 2017, the Company amended its credit facility with a syndicate of banks. Under the Amended Credit Facility, PPR had a $55 million syndicated revolving term facility and a $10 million operating facility. As discussed above, given the maturity date of the Amended Credit Facility was within the following 12 months, related debt outstanding under the facility was classified as current on the statement of financial position as of September 30, 2017. On October 31, 2017, debt outstanding under the Amended Credit Facility was fully repaid and retired.
The Amended Credit Facility includes terms and covenants that place limitations on certain types of activities, including restrictions or requirements with respect to additional debt, liens, asset sales, hedging activities, investments, dividends and mergers and acquisitions. The Amended Credit Facility also includes two financial covenants where at the end of each applicable quarterly period:

(i) total debt outstanding (including bank indebtedness and outstanding letters of credit) to Adjusted EBITDAX (as defined below) for a trailing 12-month period is required to be less than 3.0 to 1.0 (1.9 to 1.0 as at September 30, 2017); and
(ii) current assets to current liabilities (including available borrowing capacity and excluding derivative instruments and facility borrowings classified as current) is required to be greater than 1.0 to 1.0 (1.1 to 1.0 as at September 30, 2017).

As at September 30, 2017, the Company was in compliance with all covenants under the Amended Credit Facility.

Shareholders' Equity

At September 30, 2017, PPR had consolidated share capital of $121.5 million (December 31, 2016 – $115.1 million) and had 115.9 million outstanding common shares. In addition, PPR had 2.7 million stock options (December 31, 2016 – 0.8 million), 0.5 million PSUs (December 31, 2016 – 0.1 million) (which will be settled subject to a performance multiplier from 0 to 2), 0.2 million DSUs, 3.2 million warrants (December 31, 2016 – nil) and zero RSUs (December 31, 2016 – 0.1 million) outstanding as at September 30, 2017.

Contemporaneously with the closing of the financing, the Company issued to the Subordinated Noteholders to purchase up to 2,318,000 common shares, or 2% of the PPR's outstanding shares, at an exercise price of CAD $0.549 (subject to adjustment in certain circumstances) with a 5-year term expiring on October 31, 2022. The exercise price represents a 20% premium over the then 30-day weighted-average trading price of the Company.

As of the date of this MD&A, PPR has the same amount of common shares outstanding as at September 30, 2017.

Preferred Shares

Pursuant to the Arrangement, all outstanding LPR Canada preferred shares ("Preferred Shares") were exchanged for PPR common shares at an exchange ratio of 0.81, whereby 60.9 million PPR common shares were issued. As the preferred shareholders were also common shareholders of PPR, the transaction was in substance an equity contribution to the Company. Upon the exchange, PPR derecognized the Preferred Shares and the Preferred Share conversion liability (collectively, "Preferred Share Liabilities") and recorded the PPR common shares at the carrying value of the Preferred Share Liabilities, resulting in an increase to the share capital of $193.9 million without any recognition of gains or losses.

Capital Management and Liquidity

PPR's objective when managing capital is to maintain a flexible capital structure in order to meet its financial obligations and allow it to execute on its planned capital expenditure program. The Company's long-term goal is to fund current period capital expenditures necessary for the replacement of production declines and decommissioning expenditures using only funds from operations. Value-creating activities may be financed with a combination of funds from operations and other sources of capital. The Company considers its capital structure to include shareholders' equity, the available borrowing under outstanding debt agreements and working capital. PPR intends to manage the capital structure of the Company to provide a strong financial position that is capable of funding the future growth of the Company. The Company monitors the current and forecasted capital structure and makes adjustments on an ongoing basis in order to maintain the liquidity needed to satisfy the funding requirements of the Company. Modifications to PPR's capital structure can be accomplished through issuing common shares, issuing new debt or replacing existing debt, adjusting capital spending and acquiring or disposing of assets.

During the first quarter of 2017, PPR closed the Red Earth Acquisition for cash consideration of $40.9 million (see "Business Combination"). The transaction was funded through net proceeds of $7.3 million from the issuance of common shares in 2017 and borrowings under the Amended Credit Facility, which resulted in an increase in the Company's debt leverage. Though PPR has increased its debt leverage, PPR also expects its future funds flow to increase as a result of the Red Earth Acquisition.

Subsequent to the third quarter, on October 31, 2017, the Company closed a two-part debt financing transaction (see "Subsequent Event" section). The transaction includes a three-year USD $40 million senior secured revolving note facility, under which USD $31 million principal amount of senior secured revolving notes due October 31, 2020 were issued at closing, and an issue of USD $16 million principal amount of four-year senior subordinated notes due October 31, 2021. The overall debt structure expanded the Company's borrowing base from CAD $65 million to approximately CAD $72 million (applying a USD/CAD exchange rate of USD $1.00 to CAD $1.29) and extended the term of its debt instruments.

PPR anticipates its future development to be funded primarily with cash flows from operations, while maintaining a balanced capital structure. PPR monitors its capital structure based on the ratio of total debt to trailing twelve months Adjusted EBITDAX (as defined in "Other Advisories" below). Total debt to Adjusted EBITDAX provides a measure of the Company's ability to manage its debt levels under current operating conditions. The Company's goal is to manage this ratio well within the financial covenants imposed on it under its outstanding debt agreements. Total debt to Adjusted EBITDAX at September 30, 2017 was 1.9 to 1.0 (2016 – 1.2 to 1.0), which was well below the financial covenant requirement of 3.0 to 1.0 under the Amended Credit Facility. The Company plans to maintain a prudent financial position by actively managing its capital program with careful consideration of the commodity pricing environment in order to optimize leverage, liquidity and cash flows.

PPR's management believes that with the high quality reserve base and development inventory, solid hedging program and steady base cash flows, the Company is well positioned to execute its business strategy. The Company remains committed to maintaining a strong financial position while continuing to maximize shareholder return through its long-term growth strategies. The Company has determined that its current financial obligations, including current commitments and working capital deficit are adequately funded from the available borrowing capacity and from funds from operations.

Contractual Obligations and Commitments

Contractual obligations and commitments are outlined in Note 20 of the Annual Financial Statements. There were no significant changes during the first six months of 2017 except as outlined below.

Lease Acquisition Capital Commitment

Under the lease acquisition capital commitment, the Company had committed to annual capital expenditures pursuant to the acquisition of approximately 73,500 net undeveloped acres in the Wheatland area. For the first two years of the leases (which ended on June 30, 2017), if the average WTI prices for a calendar quarter were below US$50/bbl, PPR may defer a portion of the drilling commitment from that commitment period to be allocated over the remaining term. Average WTI prices for the first two calendar quarters of the second commitment period were below US$50/bbl and the deferral option was exercised in the second quarter of 2017 to extend the remaining 2017 capital commitment to July 1, 2018. As of September 30, 2017, the Company has incurred $10.5 million (December 31, 2016 – $1.6 million) towards the remaining total lease acquisition capital commitment of $35.0 million. In the event that PPR does not incur the minimum capital expenditures by the end of a given commitment period, the shortfall may be payable to the vendor. The Company expects to fulfill the remainder of its lease acquisition capital commitment through its ongoing capital program in Wheatland. The lease acquisition capital commitment is further described in Note 20 of the Annual Financial Statements.

Flow-through Share Commitment

Pursuant to the bought deal financing which closed on March 16, 2017 and the related over-allotment option, the Company issued 5,341,170 flow-through common shares with respect to CEE at $0.77 per share. As defined by the Income Tax Act, the Company has until December 31, 2018 to incur $4.1 million of CEE costs related to this flow-through common share issuance.

During the first nine months of 2017, the Company incurred a total of $4.8 million towards the $4.9 million flow-through share commitment related to the December 2016 flow-through share issuance. The lease acquisition capital commitment as described above and the flow-through share capital commitments may be fulfilled by the same exploration expenditures.

Supplemental Information

Financial – Quarterly extracted information

($000)	2017 Q3	2017 Q2	2017 Q1	2016 Q4	2016 Q3	2016 Q2	2016 Q1	2015 Q4
Oil and natural gas revenue	17,611	21,682	19,208	17,060	9,334	9,151	7,203	8,783
Royalties	(2,164)	(3,009)	(3,029)	(2,270)	(1,050)	(924)	(649)	(746)
Unrealized (loss) gain on Derivatives	(2,586)	4,471	5,858	(7,231)	(1,936)	(10,959)	852	(730)
Realized gain on derivatives	2,222	1,150	703	1,362	2,257	2,539	3,585	4,921
Revenue net of realized and unrealized gains (losses) on derivative instruments	15,083	24,294	22,740	8,921	8,605	(193)	10,991	12,228
Net earnings (loss)	(11,985)	1,066	7,262	(8,782)	(11,588)	(43,223)	3,197	(15,390)
Per share – basic [(1)]	(0.10)	0.01	0.07	(0.09)	(0.12)	(0.44)	0.03	(0.16)
Per share – diluted [(2)]	(0.10)	0.01	0.07	(0.09)	(0.12)	(0.44)	0.03	(0.16)
Adjusted funds from operations [(3)]	4,536	7,060	5,934	7,107	1,810	3,252	1,090	7,007
Per share – basic [(4)]	0.04	0.06	0.06	0.07	0.02	0.03	0.01	0.07
Per share – diluted [(5)]	0.04	0.06	0.06	0.07	0.02	0.03	0.01	0.07

1,2,4,5 As the historical financial statements were prepared on a combined and consolidated basis it is not possible to measure per share amounts until subsequent to the closing of the Arrangement on September 12, 2016 when Lone Pine and Arsenal were brought under a common parent entity. The Company calculated per share information for the current and historical periods by assuming that the common shares issued upon the closing of the Arrangement at September 12, 2016 were outstanding since the beginning of the period. Diluted per share information is calculated with consideration to the effect of outstanding restricted share units as converted to PPR equivalent units.

3 Adjusted funds from operations is a non-IFRS measure and is defined below under “Other Advisories”.

Over the past eight quarters, the Company's oil and natural gas revenue have fluctuated primarily due to changes in production and movement in the commodity prices. The Company's production has varied due to its successful capital development program at Wheatland, the Arrangement with Arsenal, the Red Earth Acquisition and natural declines. Movements in oil and natural gas revenue attributable to fluctuations in commodity prices were partially mitigated by realized gain on derivatives, even though there were significant swings in unrealized gains/losses on derivatives. Despite earning positive adjusted funds from operations in the past eight quarters, the Company incurred net losses in several quarters due to non-cash expenses, including unrealized derivative losses, impairments to D&P and E&E assets, DD&A, and accretion expense and foreign exchange losses related to the Preferred Shares. As the Preferred Shares were exchanged for PPR common shares upon the Arrangement, accretion expense and foreign exchange gains/losses were reduced considerably in the past four quarters.

Third quarter 2017 oil and natural gas revenue fell back from its peak in the second quarter of 2017 as a result of commodity price declines resulting in lower blended realized prices and lower production volumes. The third quarter net loss of $12.0 million was attributable to non-cash items including $3.4 million of impairment losses, $2.6 million of unrealized losses on derivative instruments and $8.6 million of depletion and depreciation expense.

Second quarter 2017 oil and natural gas revenue was the highest compared to the previous six quarters as a result of the highest production volumes including a full quarter of production from the Red Earth Acquisition and added production from the Arrangement with Arsenal. The quarter also had the highest blended realized prices as a result of commodity price improvements, as well as a higher liquids weighting in the quarter compared to the previous six quarters and following quarter. Net income in the second quarter of 2017 incorporated non-cash unrealized gains of $4.5 million on derivative instruments.

First quarter 2017 oil and natural gas revenue increased, compared to the previous six quarters due to increased production volume including production from the Arrangement with Arsenal and ten days of production from the Red Earth Acquisition, as well as due to recoveries in crude oil prices from prior quarters. Net income of $7.3 million in the first quarter of 2017 was largely the result of non-cash items including a gain of $4.3 million on the

Red Earth Acquisition, unrealized gains on derivative instruments of $5.9 million and a gain of $0.5 million in the disposition of non-core properties.

Oil and natural gas revenue and adjusted funds from operations increased significantly in the fourth quarter of 2016 as production significantly increased, coupled with the recovery of commodity prices from the previous four quarters. The net loss of $8.8 million in the fourth quarter of 2016 was attributable to unrealized losses on derivative instruments of $7.2 million and depletion and depreciation of $7.4 million.

The net loss of $11.6 million in the third quarter of 2016 was the result of non-cash expenses including impairment of $1.7 million, non-cash accretion of $3.5 million, unrealized losses on derivative instruments of $1.9 million and depletion and depreciation of $4.2 million, which exceeded adjusted funds from operations.

PPR experienced $43.2 million of net loss in the second quarter of 2016, the most significant in the past 8 quarters, mainly due to the recognition of $25.0 million of impairment charges against its E&E assets in Quebec and unrealized losses on derivative instruments of $11.0 million.

The net earnings of $3.2 million in the first quarter of 2016 was primarily the result of unrealized foreign exchange gains of $10.7 million related to the translation of the US dollar denominated preferred share liability and realized gains on derivative instruments of $3.6 million.

The net loss of $15.4 million in the fourth quarter of 2015 was mainly due to impairment charges of $7.3 million on E&E assets and unrealized foreign exchange losses of $5.3 million related to the translation of the US dollar denominated preferred share liability.

Internal Control over Financial Reporting and Officer Certifications

Internal control over financial reporting is a process designed to provide reasonable assurance that all the assets are safeguarded and transactions are appropriately authorized, and to facilitate the preparation of relevant, reliable and timely information. Due to inherent limitations, internal control over financial reporting may not prevent or detect all misstatements due to fraud or error.

The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal controls over financial reporting as defined in NI 52-109. The control framework PPR's officers used to design and evaluate the Company's internal controls over financial reporting is the Internal Control – Integrated Framework (2013) by The Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). There have been no changes in the Company's internal controls over financial reporting during the period from January 1, 2017 to September 30, 2017 that have materially affected, or are reasonably likely to materially affect the Company's internal controls over financial reporting.

Changes in Accounting Policies

The Interim Financial Statements have been prepared on a basis consistent with the accounting, estimation and valuation policies described in the Annual Financial Statements. PPR did not adopt any new accounting policies or standards during the third quarter of 2017.

There were no new or amended standards issued during the three months ended September 30, 2017 that are applicable to PPR in future periods. Previously issued new or amended accounting standards and pronouncements that are applicable to PPR in future periods are as follows:

- In April 2016, the IASB issued its final amendments to IFRS 15 – Revenue from Contracts with Customers ("IFRS 15") which replaces IAS 11 – Construction Contracts, IAS 18 – Revenue and several revenue-related interpretations. The new standard establishes a single revenue recognition framework that applies to contracts with customers and requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. IFRS 15 is effective for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. The standard may be applied retrospectively or using a modified retrospective approach. The Company primarily enters into non-complex and routine revenue contracts with customers that require daily physical delivery of produced volumes priced at the current daily or monthly average spot price. Performance obligations are met upon delivery of the volumes at the processing facility and the transaction price is established based on the date of delivery. The Company has inventoried its revenue streams and underlying contracts with customers and is in the process of completing its review and documentation of such contracts. At this point, it is expected that the adoption of the new standard could result in presentation changes in revenue and royalties, which will not affect net income or loss. In addition, the Company will expand the disclosures in the notes to its financial statements as outlined in IFRS 15 including disaggregating revenue streams by product type;

- In July 2014, the IASB completed the final elements of IFRS 9 - Financial Instruments. The Standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 - Financial Instruments: Recognition and Measurement. IFRS 9, as amended, includes a principle-based approach for classification and measurement of financial assets, a single 'expected loss' impairment model and a substantially-reformed approach to hedge accounting. The Standard will come into effect for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. Based on a preliminary assessment, the Company does not expect the 'expected loss' impairment model to have a material impact on its consolidated financial statements. The Company does not currently apply hedge accounting to its derivative financial instruments and does not expect to apply hedge accounting upon adoption of IFRS 9; and

- In January 2016, the IASB issued IFRS 16 - Leases, which replaces IAS 17 – Leases. For lessees, IFRS 16 removes the classification of leases as financing or operating leases, effectively treating all leases as finance leases which requires the recognition of lease assets and lease obligations. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements and may continue to be treated as operating leases. The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15 Revenue from Contracts with Customers. The Company intends to adopt IFRS 16 on January 1, 2019 and is in the process of identifying and reviewing contracts that fall within the scope of the new standard. The extent of the impact on the adoption of the standard has not yet been determined.

Operational and Other Risk Factors

PPR's operations are conducted in the same business environment as most other oil and gas operators and the business risks are very similar. Significant risks are summarized in the Annual MD&A and have remained unchanged during the first six months of 2017. Additional risks are provided in the "Risk Factors" section of the 2016 Annual Information Form filed on SEDAR at www.sedar.com.

Forward-Looking Information

Certain statements and information in this MD&A may constitute forward-looking information that are subject to a number of risks and uncertainties, many of which are beyond the Company's control. All information regarding the Company's strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking information. The words "could," "believe," "anticipate," "intend," "plan," "estimate," "expect," "may," "continue," "predict," "potential," "project" and similar expressions are intended to identify forward-looking information, although not all forward-looking information contain such identifying words.

Forward-looking information may include statements with respect to, among other things:

- estimates of the Company's oil and natural gas reserves;
- estimates of the Company's future oil, natural gas and NGL production, including estimates of any increases or decreases in the Company's production;
- estimates of future capital expenditures;
- estimates and judgements related to common shares and preferred shares valuations;
- the Company's future financial condition and results of operations;
- the source of funding for the Company's activities, including development costs;
- the Company's ability to meet its capital commitment;
- the Company's future revenues, cash flows and expenses;
- the Company's access to capital and expectations with respect to liquidity and capital resources;
- the Company's future business strategy and other plans and objectives for future operations;
- the Company's future development opportunities and production mix;
- the Company's outlook on oil, natural gas and NGL prices;
- the anticipated benefits of merger and acquisitions;
- the Company's ability to incur CEE;
- the amount, nature and timing of future capital expenditures, including future development costs;
- the Company's ability to access the capital markets to fund capital and other expenditures;
- the Company's new financing arrangements;
- the Company's expectations regarding the Company's ability to raise capital and to add reserves and grow production through acquisitions, exploration and development;
- the Company's assessment of the Company's counterparty risk and the ability of the Company's counterparties to perform their future obligations; and
- the impact of federal, provincial, territorial and local political, legislative, regulatory and environmental developments in Canada.

PPR believes the expectations and forecasts reflected in the Company's forward-looking information are reasonable, but PPR can give no assurance that they will prove to be correct. Readers are cautioned that these forward-looking information can be affected by inaccurate assumptions and are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond the Company's control, incident to the exploration for and development, production and sale of oil and natural gas. When considering forward-looking information, you should keep in mind the assumptions, risk factors and other cautionary statements that include, among other things:

- the volatility of oil, natural gas and NGL prices, and the related differentials between realized prices and benchmark prices;
- a continuation of depressed natural gas prices;
- the availability of capital on economic terms to fund the Company's significant capital expenditures and acquisitions;
- the Company's ability to obtain adequate financing to pursue other business opportunities;
- the Company's ability to reach an agreement with counterparties to new financing arrangements on terms and conditions that are acceptable to the Company or at least as favorable to the Company than those of the existing credit facilities, or will improve PPR's liquidity profile;
- the Company's ability to generate sufficient cash flow from operations or obtain adequate financing to fund the Company's capital expenditures and meet working capital needs;
- the Company's ability to replace and sustain production;

- a lack of available drilling and production equipment, and related services and labor;
- the Company's ability to successfully integrate the acquired assets;
- increases in costs of drilling, completion and production equipment and related services and labor;
- unsuccessful exploration and development drilling activities;
- regulatory and environmental risks associated with exploration, drilling and production activities;
- declines in the value of the Company's oil and natural gas properties, resulting in impairments;
- the adverse effects of changes in applicable tax, environmental and other regulatory legislation;
- a deterioration in the demand for the Company's products;
- the risks and uncertainties inherent in estimating proved oil and natural gas reserves and in projecting future rates of production and the timing of expenditures;
- the risks of conducting exploratory drilling operations in new or emerging plays;
- intense competition with companies with greater access to capital and staffing resources;
- the risks of conducting operations in Canada and the impact of pricing differentials, fluctuations in foreign currency exchange rates and political developments on the financial results of the Company's operations; and
- the uncertainty related to the pending litigation against us.

Should one or more of the risks or uncertainties described above or elsewhere in this MD&A occur, or should underlying assumptions prove incorrect, the Company's actual results and plans could differ materially from those expressed in any forward-looking information. Readers are cautioned not to place undue reliance on the forward-looking information, which speaks only as of the date of this MD&A, and the Company undertakes no obligation to update this information to reflect events or circumstances after the delivery of this MD&A. All forward-looking information, expressed or implied, included in this MD&A are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking information that the Company may make or persons acting on the Company's behalf may issue.

Other Advisories

Volumetric Conversion

The oil and gas industry commonly expresses production volumes and reserves on a "barrel of oil equivalent" basis ("boe") whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved analysis of results and comparisons with other industry participants.

Throughout the MD&A, the Company has used the 6:1 boe measure, which is the approximate energy equivalency of the two commodities at the burner tip. Boe does not represent a value equivalency at the wellhead nor at the plant gate, which is where PPR sells its production volumes and therefore may be a misleading measure, particularly if used in isolation. Given that the value ration based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a 6:1 conversion may be misleading as an indication of value.

Non-IFRS Measures

The Company uses terms within the MD&A that do not have a standardized prescribed meaning under IFRS and these measurements may not be comparable with the calculation of similar measurements used by other companies. The non-IFRS measures used in this report are summarized as follows:

Working Capital

Working capital (deficit) is calculated as current assets less current liabilities excluding the current portion of derivative instruments, the current portion of decommissioning liabilities and the flow-through share premium. This measure is used to assist management and investors in understanding liquidity at a specific point in time. The current portion of derivatives instruments is excluded as management intends to hold derivative contracts through to maturity rather than realizing the value at a point in time through liquidation. The current portion of decommissioning expenditures is excluded as these costs are discretionary and the current portion of flow-through share premium liabilities are excluded as it is a non-monetary liability.

The following table provides a calculation of working capital (deficit):

($000s)	September 30, 2017	December 31, 2016
Current assets	13,381	17,539
Less current derivative instrument assets	(1,712)	—
Current assets excluding current derivatives instruments	11,669	17,539
Current liabilities	70,318	28,120
Less flow-through share premium	(7)	(390)
Less current derivative instrument liabilities	—	(2,311)
Less current portion of decommissioning liability	(500)	(3,500)
Current liabilities excluding current derivatives instruments and current portion of decommissioning liabilities	69,811	21,919
Working capital deficit	(58,142)	(4,380)

Operating Netback

Operating netback is a non-IFRS measure commonly used in the oil and gas industry. This measurement assists management and investors to evaluate the specific operating performance at the oil and gas lease level. Operating netbacks included in this report were determined by taking (oil and gas revenues less royalties less operating costs) divided by gross working interest production. Operating netback, including realized commodity gains and losses, adjusts the operating netback for only realized gains and losses on derivative instruments.

Adjusted Funds from Operations

Adjusted funds from operations is calculated based on cash flow from operating activities before changes in non-cash working capital, transaction costs, restructuring costs, decommissioning expenditures and other non-recurring items. Management believes that such a measure provides an insightful assessment of PPR's operation performance on a continuing basis by eliminating certain non-cash charges and charges that are non-recurring or discretionary and utilizes the measure to assess its ability to finance operating activities, capital expenditures and debt repayments. Adjusted funds from operations as presented is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. Adjusted funds from operations per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of earnings per share.

The following table reconciles cash flow from operating activities to adjusted funds from operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2017**	2016	**2017**	2016
Cash flow from operating activities	**5,983**	2,088	**10,975**	4,522
Changes in non-cash working capital	**(2,222)**	(2,147)	**352**	(3,828)
Funds from Operations	**3,761**	(59)	**11,327**	694
Other	**215**	222	**276**	410
Settlement of decommissioning liabilities	**351**	141	**4,903**	2,883
Restructuring costs	**—**	—	**—**	392
Transaction costs	**209**	1,506	**1,024**	1,773
Adjusted Funds from Operations	**4,536**	1,810	**17,530**	6,152

Adjusted EBITDAX

The Company monitors its capital structure and liquidity based on the ratio of Debt to Adjusted EBITDAX as defined below. The ratio provides a measure of the Company's ability to manage its debt levels under current operating conditions. "Debt" refers to the Company's borrowings under its outstanding debt agreements (for the third quarter of 2017, the Amended Credit Facility). "Adjusted EBITDAX" corresponds to defined terms in the Company's Amended Credit Facility agreement and means net earnings before financing charges, foreign exchange gain (loss), E&E expense, income taxes, depreciation, depletion, amortization, other non-cash items of expense and non-recurring items, adjusted for major acquisitions and material dispositions assuming that such transactions had occurred on the first day of the applicable calculation period. As transaction costs related to the Arrangement are non-recurring costs, Adjusted EBITDAX has been calculated, excluding transaction costs, as a meaningful measure of continuing operating cash flows. For purposes of calculating covenants under the Amended Credit Facility, Adjusted EBITDAX is determined using financial information from the most recent four consecutive fiscal quarters. In future periods, the calculation of Adjusted EBITAX will corresponds to defined terms in the Company's Revolving Facility and Subordinated Notes. Under these agreements, Adjusted EBITDAX is also determined using the most recently completed four consecutive fiscal quarters.

The following is a reconciliation of Adjusted EBITDAX to the nearest IFRS measure, net loss before income tax:

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2017**	2016	**2017**	2016
Net earnings (loss) before income tax	**(12,107)**	(11,588)	**(4,040)**	(51,614)
Add (deduct):				
Interest	**633**	138	**1,467**	500
Depletion and depreciation	**8,636**	4,234	**26,061**	13,935
Exploration and evaluation expense	**1,100**	15	**1,166**	49
EBITDAX	**(1,738)**	(7,210)	**24,654**	(37,130)
Unrealized (gain) loss on derivative Instruments	**2,586**	1,936	**(7,743)**	12,043
Impairment loss	**3,400**	1,712	**3,400**	26,777
Accretion	**553**	3,476	**1,576**	11,938
Loss (gain) on foreign exchange	**(344)**	417	**(658)**	(9,725)
Reorganization costs[1]	**—**	—	**—**	392
Share-based compensation	**195**	52	**523**	189
Loss (gain) on sale of properties	**9**	—	**(539)**	73
Loss (gain) on business combination	**—**	—	**(3,893)**	—
Transaction costs	**209**	1,506	**1,024**	1,773
Pro-forma impact of acquisition	**—**	1,108	**2,394**	3,206
Adjusted EBITDAX	**4,870**	3,006	**20,738**	9,536

[1] Reorganization cost includes share-based compensation related to terminations.