PRAIRIE PROVIDENT RESOURCES

Prairie Provident Resources Inc.

Management's Discussion and Analysis
For the Three Months and Year Ended December 31, 2017

Dated: March 28, 2018

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. ("PPR Canada"), 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. 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 Energy Inc. after September 12, 2016. See "Arrangement Agreement" section for details.

The following MD&A of PPR provides management's analysis of the Company's results of operations, financial position and outlook as at and for the three months and year ended December 31, 2017. This MD&A is dated March 28, 2018 and should be read in conjunction with the audited combined and consolidated financial statements of PPR as at and for the year ended December 31, 2017 (the "2017 Annual Financial Statements"). Additional information relating to PPR, including the Company's December 31, 2017 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
USD	U.S. dollars
CAD	Canadian dollars
US	United States
CDN	Canadian

Financial and Operational Highlights

	Three Months Ended December 31,		Year Ended December 31,	
($000s except per unit amounts)	**2017**	2016	**2017**	2016
Financial				
Oil and natural gas revenue	**20,510**	17,060	**79,011**	42,748
Net loss	**(44,145)**	(8,782)	**(47,802)**	(60,396)
Per share – basic & diluted[1]	**(0.38)**	(0.09)	**(0.42)**	(0.62)
Adjusted Funds from operations[2]	**5,545**	7,107	**23,075**	13,259
Per share – basic & diluted[3]	**0.05**	0.07	**0.20**	0.14
Net capital expenditures	**6,251**	11,918	**64,198**	34,875
Production Volumes				
Crude oil (bbls/d)	**3,233**	2,653	**3,178**	2,012
Natural gas (Mcf/d)	**9,200**	12,300	**12,537**	9,253
Natural gas liquids (bbls/d)	**106**	142	**202**	126
Total (boe/d)	**4,872**	4,845	**5,470**	3,680
% Liquids	**69%**	58%	**62%**	58%
Average Realized Prices				
Crude oil ($/bbl)	**62.01**	54.28	**56.01**	46.75
Natural gas ($/Mcf)	**1.81**	3.09	**2.47**	2.21
Natural gas liquids ($/bbl)	**54.86**	24.49	**37.08**	17.91
Total ($/boe)	**45.76**	38.27	**39.57**	31.74
Operating Netback ($/boe)[4]				
Realized price	**45.76**	38.27	**39.57**	31.74
Royalties	**(4.84)**	(5.09)	**(5.20)**	(3.63)
Operating costs	**(20.78)**	(13.92)	**(19.36)**	(17.39)
Operating netback	**20.14**	19.26	**15.01**	10.72
Realized gains on derivative instruments	**1.90**	3.06	**2.47**	7.23
Operating netback, after realized gains on derivative instruments	**22.04**	22.32	**17.48**	17.95

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 Red Earth Assets 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 rate and increased operating netbacks.

- 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

1,3 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.

2,4 Adjusted funds from operations and Operating Netback are non-IFRS measures and are defined below under "Other Advisories".

one-half of one common share 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. 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.

- On October 31, 2017 PPR completed a two-part debt financing transaction (the “Financing Transaction”) with a global investment management firm that resulted in an increase in the Company’s borrowing base to US$56 million (or CDN$72 million[1]) from CDN$65 million and extended the term of its debt instruments. The Financing Transaction included: (i) a three-year, US$40 million senior secured revolving note facility (the “Revolving Facility”), under which US$31 million principal amount of senior secured revolving notes due October 31, 2020 (“Secured Notes”) were issued at closing, and (ii) US$16 million principal amount of four-year senior subordinated notes (“Subordinated Notes”) due October 31, 2021.

Annual Operational & Financial Highlights

- Annual production averaged 5,470 boe/d (62% liquids), a 49% increase over 2016 due to production additions from the Red Earth Acquisition, the Arsenal acquisition (see “Arrangement Agreement” below) and PPR’s 2016/2017 development program that brought nine Wheatland wells on production in 2017. Production additions were partially offset by the disposition of certain non-core natural-gas weighted properties, natural declines, extended third-party facility downtime, and adverse weather conditions experienced during 2017. An uncertain oil pricing environment during the first half of 2017 led the Company to postpone its 2017 capital program to preserve liquidity and protect project economics. This deferral, coupled with the disposition of non-core assets reduced year-over-year production growth.

- Operating netback[2] after realized hedging gains was $17.48/boe for 2017, a decrease of $0.47/boe from 2016. The decrease was primarily due to lower realized gains on derivative instruments of $4.76/boe, higher operating expenses of $1.97/boe and higher royalty expenses of $1.57/boe, offset by higher realized prices of $7.83/boe.

- Adjusted funds from operations[3] totaled $23.1 million, a $9.8 million increase over the $13.3 million generated in 2016. Adjusted EBITDAX[4] was $27.8 million, a 64% increase over 2016. Increased adjusted funds from operations and adjusted EBITDAX were primarily due to higher production, partially offset by reduced gains on derivative instruments.

- Capital expenditures and acquisitions (net of $1.4 million in proceeds for dispositions) during 2017 totaled $64.2 million, including $40.9 million for the Red Earth Acquisition. Excluding acquisitions and dispositions, capital expenditures were $23.7 million including $13.6 million directed to the Wheatland drilling program, $6.2 million to Princess area, of which $2.1 million was for land and seismic, and $1.1 million allocated to continued advancement of the Evi waterflood. The 2017 drilling program focused on exploration efforts to delineate PPR’s prospects at Wheatland and to meet its flow-through share commitments (see “Contractual Obligations and Commitments”) and was funded with adjusted funds from operations.

- At Wheatland, activity included tying-in and bringing onto production two gross wells that were drilled in the fourth quarter of 2016; drilling, completing, equipping and tying-in of five gross wells, and area facility and pipeline construction. Of the five Wheatland wells drilled in 2017, two were brought on-stream in the second quarter of 2017, two were brought on production through July and August 2017, and the final was an

---

1 Translated at the applicable USD to CAD exchange rate of 1.29 at the time of the Financing Transaction.

2,3,4 Operating Netback, Adjusted funds from operations and Adjusted EBITDAX are non-IFRS measures and are defined below under “Other Advisories”.

exploratory well targeting a new geological structure that was drilled pursuant to the flow-through share commitment (see "Contractual Obligations and Commitments" section below for further explanation) and proved unsuccessful. At Princess, activity included drilling one gross well and tying-in two standing wells.

- As a result of prolonged weakness in the current and forecast price environment for natural gas and to a lesser extent, crude oil, PPR recorded impairment losses of $34.2 million in 2017, including $30.7 million related to production and development ("P&D") assets in the Wheatland and Princess cash generating units ("CGUs"). A $3.4 million charge was recorded for the write-down of non-core gas properties classified as 'held for sale' as at September 30, 2017, that were sold in the fourth quarter of 2017.

- Net loss was $47.8 million in 2017 compared to a net loss of $60.4 million in 2016. The decrease resulted from a $9.8 million increase in adjusted funds from operations and positive variances in several non-cash items. The non-cash variances included a $20.1 million decrease in unrealized derivative losses, a $10.3 million decrease in accretion costs and a $3.9 million increase in gains on a business combination, offset by a $7.9 million decrease in foreign exchange gains, a $13.5 million increase in DD&A, a $7.5 million increase in impairment losses and a $4.8 million increase in exploration and evaluation expense.

- At year-end 2017, PPR had borrowings of US$31.2 million drawn against the US$40 million Revolving Facility and US$16.0 million on its Subordinated Notes plus a working capital deficit[1] of $2.2 million. When compared to the third quarter of 2017, the working capital deficit excluding bank debt decreased by $5.6 million while long-term debt increased by $5.5 million primarily due to borrowing from the Revolving Facility to fund restricted cash held for outstanding letters for credit.

- PPR has extended its lease acquisition commitment to March 31, 2019 and provided the Company spends $37.5 million towards the $45 million commitment by March 31, 2019, its remaining commitments will be further extended until September 30, 2019. At year-end, 2017, the Company had incurred a total of $21.3 million towards the total capital commitment. In the first quarter of 2018, PPR further incurred approximately $6 million. PPR expects to fulfill the remaining capital commitment through its planned capital program.

Fourth Quarter 2017 Operational & Financial Highlights

- Average production in the fourth quarter of 2017 was 4,872 boe/d. Excluding the impact from divesting certain non-core natural-gas weighted properties, average production increased by approximately 9% over the same period in 2016. The Company's conscious effort to focus on oil and natural gas liquids opportunities resulted in oil and liquids weighting increasing to 69% for the quarter, compared to 58% for the same period in 2016.

- Adjusted funds from operations totaled $5.5 million in the fourth quarter of 2017, a $1.6 million decrease from the same period of 2016, primarily due to higher interest expenses and lower realized hedging gains.

- Operating netbacks after realized hedging gains were $22.04/boe for the fourth quarter of 2017, a decrease of $0.28/boe from the fourth quarter of 2016. Higher realized prices were offset by higher operating expenses and lower realized gains on derivative instruments.

- Capital expenditures prior to acquisitions or dispositions in the quarter were $7.2 million, with approximately $4.0 million directed towards drilling, completion and tie-in activities, primarily in Wheatland, Princess and Evi, $2.1 million directed to land and seismic in the Princess area and the remaining to capitalized G&A. The land and seismic purchase at Princess is complementary to our existing landholdings and provides additional step out locations to our core play.

---

1 Working Capital Deficit is a non-IFRS measure and is defined in "Other Advisories" below.

- Net loss of $44.1 million during the fourth quarter of 2017 compares to a net loss of $8.8 million in the comparable quarter of 2016, primarily due to a $30.8 million impairment related to weak forecast pricing, a $3.7 million increase in exploration and evaluation expense and lower adjusted funds from operations.

Outlook

Prairie Provident's business strategy has been built on a balanced approach, utilizing predictable funds flows from our low decline oil assets to fuel growth developments. The Company's priorities continue to focus on maintaining a strong balance sheet while delivering accretive value growth for its shareholders. PPR's capital allocation process takes into account a number of factors including rate-of-return, project payout period and reserves addition cost. In response to the broader commodity price environment, the Company will continue to focus on improving corporate netbacks by targeting higher value production streams while striving to lower costs through various operational initiatives such as pad drilling and evaluating opportunities to acquire underutilized infrastructure in core operating areas.

On January 29, 2018, Prairie Provident's Board of Directors approved a $26 million capital program for 2018 (excluding abandonment and reclamation expenditures and capitalized G&A) designed to support long-term profitability and balance sheet strength through the continued development of oil-weighted opportunities within its low-risk asset base. The capital program anticipates continued development of PPR's Wayne property at Wheatland, ongoing drilling and completions at Princess, and further expansion of the attractive waterflood recovery at Evi.

Prairie Provident will continue to actively manage expected commodity price volatility over the near-term, while taking steps to mitigate price risk, including executing an active risk management program. PPR intends to continue adding positions to its rolling three-year hedge book which currently provides protection to approximately 60% of its 2018 forecast base volumes (net of royalties) and is expected to support adjusted funds from operations through 2020 and beyond. Operationally, the Company will remain focused on capturing capital and operating efficiencies and protecting its financial position.

Full-year 2018 guidance estimates remain unchanged from those presented in the Company's release dated January 29, 2018 and are outlined in the table below. Additional details on Prairie Provident's 2018 capital program and guidance can be found on the Company's website at www.ppr.ca.

2018 Budget & Guidance Summary

Production guidance	5,200 - 5,600 boe/d
Liquids weighting	68 - 71%
Capital expenditures (excluding abandonment and reclamation expenditures and capitalized G&A)	$26 million
Operating expense	$17.00 - 18.50/boe
Operating netback[1]	$20.50 – 22.00/boe
2018 year-end long-term debt (net of cash collateralized for letters of credit)	$58 million
Financial Assumptions	
Oil (WTI)	US$63.00/bbl
Oil (WCS)	C$51.50/bbl
Natural gas (AECO)	C$1.40/mcf
Edmonton Light/WTI differential	C$6.00
USD/CAD exchange rate	0.81

1 Operating netback is a non-IFRS measure (see "Other Advisories" below).

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 were 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 included 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 assets acquired included producing assets with production of approximately 1,100 boe/d (98% liquids weighting) at acquisition and approximately 78,000 net acres of undeveloped land. Funding for the acquisition was provided 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 Receipts 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).

Results of Operations

Production

	Three Months Ended December 31,		Year Ended December 31,	
	2017	2016	**2017**	2016
Crude oil (bbls/d)	**3,233**	2,653	**3,178**	2,012
Natural gas (Mcf/d)	**9,200**	12,300	**12,537**	9,253
Natural gas liquids (bbls/d)	**106**	142	**202**	126
Total (boe/d)	**4,872**	4,845	**5,470**	3,680
Liquids Weighting	**69%**	58%	**62%**	58%

PPR's production for the three months ended December 31, 2017 increased by 1%, compared to the corresponding periods in 2016. Production increases in the fourth quarter 2017 were primarily the result of additions from the Red Earth Acquisition as well as ongoing drilling and completions activities. In the Princess area, one well that was drilled in the third quarter of 2017 and two standing wells were all tied-in and came on production late in the fourth quarter of 2017, which had minimal impact on production for the period due to timing. The increases were partially offset by disposed production of approximately 400 boe/d from certain non-core, natural gas properties, approximately 100 boe/d shut-in production due to extreme cold weather and natural declines. As a result of the timing of capital activities in the Wheatland area during 2016 and 2017, Wheatland production was relatively consistent in the fourth quarter of 2017 and the fourth quarter of 2016.

Average 2017 production increased by 49%, compared to 2016. Production related to the Red Earth Acquisition has been included in PPR's operating results since the closing date of March 22, 2017. This resulted in the additional production of approximately 860 boe/d and 700 boe/d for the three months and year ended December 31, 2017, respectively. Further contributing to the year-over year production increase was approximately 670 boe/d from the Arsenal acquisition which closed on September 12, 2016, and approximately 800 boe/d related to the 2016 and 2017 drilling programs at Wheatland.

In light of the volatile commodity price environment that prevailed during 2017, the Company made a conscious decision to defer its 2017 capital program to preserve liquidity and protect project economics and expended $23.7 million of exploration and development capital out of its $25 million - $35 million of capital budget. These delays resulted in lower than anticipated production additions for the three months and year ended December 31, 2017. Annual production was also impacted by assets divestitures and the integration of the acquired Red Earth Assets as PPR took certain production off-line to catch up the required maintenance.

In response to an improving outlook for oil prices through mid to late 2017, PPR took steps to increase its liquids-weighting for the three months and year ended December 31, 2017 by 11% and 4%, respectively. Liquids-weighting increases were due to additions from the Red Earth Acquisition (oil and liquids represents approximately 98% of production) and the disposition of approximately 400 boe/d of certain non-core natural gas weighted properties.

Revenue

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per unit amounts)	**2017**	2016	**2017**	2016
Revenue				
Crude oil	**18,445**	13,248	**64,966**	34,428
Natural gas	**1,530**	3,492	**11,311**	7,494
Natural gas liquids	**535**	320	**2,734**	826
Oil and natural gas revenue	**20,510**	17,060	**79,011**	42,748
Average Realized Prices				
Crude oil ($/bbl)	**62.01**	54.28	**56.01**	46.75
Natural gas ($/Mcf)	**1.81**	3.09	**2.47**	2.21
Natural gas liquids ($/bbl)	**54.86**	24.49	**37.08**	17.91
Total ($/boe)	**45.76**	38.27	**39.57**	31.74
Benchmark Prices				
Crude oil - WTI ($/bbl)	**70.45**	65.78	**66.08**	57.38
Crude oil - Edmonton Light Sweet ($/bbl)	**68.63**	61.13	**62.46**	52.50
Natural gas - AECO monthly index-7A ($/Mcf)	**1.95**	2.76	**2.42**	2.08
Natural gas - AECO daily index - 5A ($/Mcf)	**1.69**	3.05	**2.15**	2.15
Exchange rate - US$/CDN$	**0.79**	0.75	**0.77**	0.76

PPR's fourth quarter 2017 revenue increased by 20% or $3.5 million over the fourth quarter of 2016. The 39% increase in crude oil revenue resulted from a 22% increase in oil production and a 14% increase in realized oil prices. The 56% decrease in natural gas revenue resulted from a 25% decrease in natural gas production and a 41% decrease in realized natural gas prices. PPR's realized product prices generally correlate to changes in the benchmark prices. The 20% increase in per boe realized price reflects the higher liquids-weighted production mix in fourth quarter 2017 compared to 2016.

Annual 2017 revenue increased by 85% or $36.3 million compared to 2016, driven by an 89% increase in crude oil revenue and a 51% increase in natural gas revenue. Oil and natural gas production rose by 58% and 35%, respectively. Revenue was also supported by increases in realized prices of crude oil and natural gas of 20% and 12%, respectively, which reflect the increases in the benchmark prices. PPR's per boe realized price increased by 25%, reflecting a higher liquids-weighted production mix in 2017 compared to 2016.

Royalties

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2017**	2016	**2017**	2016
Royalties	**2,171**	2,270	**10,373**	4,893
Per boe	**4.84**	5.09	**5.20**	3.63
Percentage of revenue	**10.6%**	13.3%	**13.1%**	11.4%

The majority of PPR's royalties are paid to the Crown, which are based on various sliding scales that depend on incentives, production volumes and commodity prices. Production in the Wheatland area is subject to royalty rates that range between 5% and 17.5%, with blended average royalty rates that are higher than PPR's average royalty rate on its other properties. As a percentage of revenue, royalties for the three months ended December 31, 2017 decreased by approximately 4% from the same period in 2016 due to favourable prior period adjustments. For the full 2017 year, royalties as a percentage of revenue increased from 2016 due to royalties incurred on additional Wheatland production, full year impact from the Arsenal properties that bear higher royalties burden and higher benchmark prices.

Commodity Price 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 flow from operations.

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2017**	2016	**2017**	2016
Realized gain on derivatives	**851**	1,362	**4,926**	9,743
Unrealized gain (loss) on derivatives	**(6,960)**	(7,231)	**783**	(19,274)
Total gain (loss) on derivatives	**(6,109)**	(5,869)	**5,709**	(9,531)
Per boe				
Realized gain on derivatives	**1.90**	3.06	**2.47**	7.23
Unrealized gain (loss) on derivatives	**(15.53)**	(16.22)	**0.39**	(14.31)
Total gain (loss) on derivatives	**(13.63)**	(13.17)	**2.86**	(7.08)

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 derivative 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.

The Company's realized prices are exposed to fluctuations in the US dollar and Canadian dollar exchange rate, which serve as natural hedges to the US dollar denominated debt. Therefore, the Company has entered into commodity hedges in US dollars to maintain a natural economic hedge.

As of December 31, 2017, the Company held the following outstanding derivative contracts:

Crude Oil Commodity Risk Management Contracts

Commodity Contract	**Notional Quantity**	**Remaining Term**	**Reference**		**Weighted Average Price**	**Contract Type**
Oil	1,200 bbls/d	January 1, 2018 – March 31, 2018	US$ WTI	$	57.13	Swap
Oil	1,100 bbls/d	April 1, 2018 – June 30, 2018	US$ WTI	$	56.63	Swap
Oil	1,000 bbls/d	July 1, 2018 – September 30, 2018	US$ WTI	$	55.65	Swap
Oil	900 bbls/d	October 1, 2018 – December 31, 2018	US$ WTI	$	54.55	Swap
Oil	500 bbls/d	January 1, 2018 – December 31, 2018	US$ WTI	$	65.00	Sold Call Option
Oil	800 bbls/d	January 1, 2018 – December 31, 2018	CDN$ WTI	$	58.00/ 67.50	Collar
Oil	600 bbls/d	January 1, 2019 – March 31, 2019	US$ WTI	$	53.53	Swap
Oil	250 bbls/d	April 1, 2019 – May 31, 2019	US$ WTI	$	52.65	Swap
Oil	325 bbls/d	April 1, 2019 – June 30, 2019	US$ WTI	$	52.75	Swap
Oil	500 bbls/d	July 1, 2019 – September 30, 2019	US$ WTI	$	52.50	Swap
Oil	450 bbls/d	October 1, 2019 – December 31, 2019	US$ WTI	$	52.00	Swap
Oil	400 bbls/d	January 1, 2019 – December 31, 2019	CDN$ WTI	$	85.00	Sold Call Option
Oil	400 bbls/d	January 1, 2019 – December 31, 2019	US$ WTI	$	52.50/60.00	Collar
Oil	275 bbls/d	January 1, 2019 – December 31, 2019	US$ WTI	$	50.00/57.00	Collar
Oil	450 bbls/d	January 1, 2020 – March 31, 2020	US$ WTI	$	51.50	Swap
Oil	425 bbls/d	April 1, 2020 – June 30, 2020	US$ WTI	$	51.00	Swap
Oil	400 bbls/d	July 1, 2020 – September 30, 2020	US$ WTI	$	50.75	Swap
Oil	400 bbls/d	October 1, 2020 – December 31, 2020	US$ WTI	$	50.50	Swap
Oil	275 bbls/d	January 1, 2020 – December 31, 2020	US$ WTI	$	60.50	Swap
Oil	175 bbls/d	January 1, 2020 – December 31, 2020	US$ WTI	$	49.00/ 54.75	Collar

Natural Gas Commodity Risk Management Contracts

Commodity Contract	**Notional Quantity**	**Remaining Term**	**Reference**	**Weighted Average Price**		**Contract Type**
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
Natural Gas	3,000 GJ/d	January 1, 2019 – March 31, 2019	AECO 7A Monthly Index	$	2.73	Swap

Derivative contract counterparties have entered into inter-creditor agreements with the Company’s lender to eliminate cash margin requirements.

Operating Expenses

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2017**	2016	**2017**	2016
Lease operating expense	**7,152**	4,118	**27,535**	16,515
Transportation and processing	**1,392**	1,582	**7,251**	5,128
Production and property taxes	**768**	504	**3,864**	1,774
Total operating expenses	**9,312**	6,204	**38,650**	23,417
Per boe	**20.78**	13.92	**19.36**	17.39

Lease operating expense for the fourth quarter and full year 2017 increased by 74% and 67%, respectively, from the same periods in 2016. The increases were partially due to a 1% and 49% increase in production for the fourth quarter and full year, respectively.

Lease operating expense for the fourth quarter of 2016 reflects the impact of a $0.9 million insurance recovery received in that period related to a breach of an above-ground section of wellhead piping that occurred on January 22, 2016. The Company incurred $1.0 million of site clean-up and remediation costs which were recorded as lease operating expenses in the first quarter of 2016. In the three months and year ended December 31, 2017, higher lease operating expenses relative to the same periods in 2016 reflect the impact of the Red Earth Assets which required PPR to incur incremental winter maintenance costs in the fourth quarter of 2017.

Transportation and processing expense for the three months ended December 31, 2017 decreased by $0.2 million compared to the same period in 2016, and increased by $2.1 million for the year ended December 31, 2017 compared to 2016. The decrease in the fourth quarter processing costs from the same period in 2016 was largely related to lower natural gas production resulting in reduced third-party natural gas processing and transportation costs. The higher charges for full year 2017 primarily reflect costs associated with increased natural gas production, largely stemming from increased production from the Wheatland area.

Production and property tax expense for the three months and year ended December 31, 2017 increased by $0.3 million and $2.1 million, respectively, as compared to the same periods in 2016. The increases primarily related to properties acquired in the Red Earth Acquisition and a full year impact from the Arsenal acquisition.

Operating expenses on a per boe basis were higher in the fourth quarter of 2017 compared to the same period in 2016 as PPR's production mix shifted to liquids-weighted products that attract higher operating expense per boe, as well as the $0.9 million insurance recovery received in the fourth quarter of 2016. Full-year 2017 per boe lease operating costs were also impacted by additional maintenance and workover expenses on the acquired Red Earth Assets that were behind on their maintenance schedule.

Operating Netback

	Three Months Ended December 31,		Year Ended December 31,	
($ per boe)	**2017**	2016	**2017**	2016
Revenue	**45.76**	38.27	**39.57**	31.74
Royalties	**(4.84)**	(5.09)	**(5.20)**	(3.63)
Operating costs	**(20.78)**	(13.92)	**(19.36)**	(17.39)
Operating netback	**20.14**	19.26	**15.01**	10.72
Realized gains on derivative instruments	**1.90**	3.06	**2.47**	7.23
Operating netback, after realized gains on derivative instruments	**22.04**	22.32	**17.48**	17.95

PPR's operating netback after realized hedging gains decreased by $0.28/boe and $0.47/boe, respectively, for the three months and year ended December 31, 2017, compared to the corresponding periods in 2016. For the fourth quarter of 2017, increased operating costs and decreased realized gains on derivative instruments were partially offset by increased realized prices and decreased royalties. For 2017, decreases in realized gains on derivative instruments and increases in operating costs and royalties were partially offset by increases in realized prices.

General and Administrative Expenses ("G&A")

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2017**	2016	**2017**	2016
Gross cash G&A expenses	**3,374**	3,043	**11,529**	11,872
Gross share-based compensation expense	**202**	195	**772**	392
Less amounts capitalized	**(573)**	(500)	**(2,083)**	(1,434)
Net G&A expenses	**3,003**	2,738	**10,218**	10,830
Per boe	**6.70**	6.14	**5.12**	8.04

For the three months ended December 31, 2017, gross cash G&A increased by $0.3 million compared to the same period in 2016, and decreased by $0.3 million for the full year 2017 over 2016. The annual decrease is the result of cost management initiatives notwithstanding PPR has grown its production significantly and became a public company during 2016.

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 were 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") were 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 months and year ended December 31, 2017 compared to the same periods in 2016 related to 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.

During 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 December 31, 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 during 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. As at December 31, 2017, 471,332 PSUs were outstanding.

During 2017, the Company issued 243,368 deferred share units ("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. As at December 31, 2017, there were 243,368 DSUs outstanding.

Subsequent to December 31, 2017, the Company granted 1,922,274 restricted share units ("RSUs") to officers and employees. RSUs vest evenly over a three-year period.

PSUs, DSUs and RSUs may be settled in common shares or cash at the discretion of the Company, however, it is PPR's intention to settle the share units in common shares. As such, these units have been accounted for as equity settled.

Finance Costs

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2017**	2016	**2017**	2016
Interest expense	**1,561**	230	**3,028**	730
Accretion expenses	**556**	451	**2,132**	12,389
Total finance cost	**2,117**	681	**5,160**	13,119
Per boe	**4.72**	1.53	**2.58**	9.74

Interest expense is primarily comprised of interest incurred related to the Company's outstanding borrowings. For the majority of 2016, there were no borrowings outstanding on the Company's Amended Credit Facility; the Company started drawing on the facility in late September 2016. Interest expense incurred in the periods without outstanding borrowings was primarily comprised of the amortization of deferred financing charges, recognition of standby fees and interest on outstanding letters of credit. The $1.3 million and $2.3 million increases in interest expense for the three months and year ended December 31, 2017 compared to the respective periods in 2016 related to increased average borrowings, higher effective interest rates on the Revolving Facility and Subordinated Notes than the previously outstanding Amended Credit Facility and higher amortization of deferred financing fees. The weighted average effective interest rate for the three months and year ended December 31, 2017 was 7.6% and 4.7%, respectively (2016 – 2.6% and 2.3%, respectively).

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 months and year ended December 31, 2016, the Company recognized $nil and $11.0 million, respectively, of accretion charges on the preferred shares. The remaining accretion charges primarily related to decommissioning liabilities, which increased by $0.1 million and $0.7 million during the fourth quarter and year ended December 31, 2017, respectively, from the same periods in 2016, due to additional decommissioning liabilities acquired from the Arsenal acquisition and the Red Earth Acquisition.

Gain (Loss) on Foreign Exchange

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2017**	2016	**2017**	2016
Realized gain (loss) on foreign exchange	**(309)**	(135)	**102**	(103)
Unrealized gain (loss) on foreign exchange	**1,272**	(80)	**1,519**	9,613
Gain (loss) on foreign exchange	**963**	(215)	**1,621**	9,510

Foreign exchange gains (losses) incurred in the three months and year ended December 31, 2017 related largely to borrowings denominated in US dollars (see "Capital Resources and Liquidity" section below). Foreign exchange gains incurred in 2016 were primarily related 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. Under the Arrangement, outstanding preferred shares were exchanged for PPR common shares on September 12, 2016.

Exploration and Evaluation Expense ("E&E")

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2017**	2016	**2017**	2016
Exploration and evaluation expense	**3,711**	9	**4,877**	58
Per boe	**8.28**	0.02	**2.44**	0.04

Fourth quarter 2017 E&E expenses primarily related to leases that were surrendered in the Wheatland area associated with the extension of the Lease Acquisition Capital Commitment (see "Contractual Obligations and Commitments" below). In addition to the surrendered leases, 2017 annual exploration and evaluation expenses included 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. Fourth quarter and annual 2016 E&E expenses were comprised of undeveloped land expiries.

Depletion and Depreciation

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2017**	2016	**2017**	2016
Depletion and depreciation	**8,814**	7,409	**34,875**	21,344
Per boe	**19.66**	16.62	**17.47**	15.85

Depletion and depreciation rates are subject to variances 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 fourth quarter of 2017 from the comparable period in 2016 reflects the assets and associated reserves acquired through the Red Earth Acquisition as well as changes in assumptions used in the Company's independent annual reserves evaluation. The increased per boe rate in 2017 compared to 2016 also reflects the impact of the Arrangement for a full year.

Impairment Loss

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2017**	2016	**2017**	2016
E&E impairment	**—**	—	**—**	25,872
E&E impairment – decommissioning asset	**(17)**	13	**(17)**	(5)
Total E&E impairment	**(17)**	13	**(17)**	25,867
P&D impairment	**30,700**	—	**34,100**	—
P&D impairment – decommissioning asset	**115**	(25)	**115**	823
P&D inventory impairment	**—**	—	**—**	200
Total P&D impairment	**30,815**	(25)	**34,215**	1,023
Inventory impairment (recovery)	**(21)**	(42)	**(21)**	(167)
Total impairment loss	**30,777**	(54)	**34,177**	26,723

Fourth quarter 2017 P&D impairment primarily includes $30.7 million related to the Wheatland and Princess CGUs that was triggered by continued and prolonged declines in forecasted oil and natural gas prices. The remaining P&D impairment and a nominal E&E impairment recovery related to changes in decommissioning liabilities of certain properties having zero carrying value.

In addition to the factors described above, the 2017 P&D impairment included $3.4 million related to the write-down of assets classified as 'held for sale' to their fair value less cost of disposal, which were sold in the fourth quarter of 2017.

In the fourth quarter of 2016, impairment related to changes in estimated decommissioning liabilities of certain properties with zero carrying values. Annual 2016 impairment losses included $25.0 million of E&E impairment losses recognized in the second quarter of 2016 against assets in the Quebec exploratory area. Due to a shift in management development priorities, $0.9 million of E&E impairment was recognized against leases that were due to expire within twelve months in the Evi CGU. In addition, $0.2 million surplus equipment was written off. For the fourth quarter 2016 and full-year 2016, the Company recorded a nominal amount and $0.2 million, respectively, of inventory recoveries, as the result of increases in the net realizable value of oil inventory.

Capital Expenditures[1]

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2017**	2016	**2017**	2016
Drilling and completion	**2,180**	6,438	**11,124**	20,862
Equipment, facilities and pipelines	**1,854**	4,769	**7,016**	11,349
Land	**2,075**	7	**2,460**	762
Capitalized overhead and other	**1,120**	704	**3,087**	1,922
Total expenditures	**7,229**	11,918	**23,687**	34,895
Acquisitions – cash consideration	**54**	—	**41,883**	—
Proceeds from disposals of property	**(1,032)**	—	**(1,372)**	(20)
Total – net	**6,251**	11,918	**64,198**	34,875

1 Capital expenditures include expenditures on E&E assets.

PPR focused its capital activities during the fourth quarter of 2017 in the Princess, Wheatland and Evi areas. In the Princess area, PPR completed and tied-in one well drilled in the third quarter of 2017, concluded construction of pipelines for the tie-ins of two standing wells and purchased land and seismic in the area for $2.1 million. In the Wheatland area, capital spending was focused on production optimization as well as costs related to the extension of the Lease Acquisition Capital Commitment (see "Contractual Obligations and Commitments" below). Fourth quarter 2017 capital expenditures in the Evi area were focused on the recompletion of three wells designed to access additional uphole zones in a wellbore.

In addition to fourth quarter 2017 capital activities, full-year 2017 capital activities also included the drilling of five gross (4.7 net) wells, equipping and tie-in two wells drilled in the fourth quarter 2016 at Wheatland, construction of facilities and pipelines in the Wheatland area and advancement of the Evi waterflood project. Additionally, in the first quarter of 2017, the Company incurred $41.8 million to acquire oil and natural gas properties, of which $40.9 million was for the Red Earth Acquisition (see "Business Combinations" above).

As of December 31, 2017, five of the six wells drilled in 2017 were on production, of which four were in Wheatland, and one in Princess. In addition, the two standing wells in the Princess area commenced production late in the fourth quarter of 2017. A single well drilled in Wheatland during the third quarter of 2017 was unsuccessful, and the related expenditures were recorded in E&E expense in the same quarter. This exploratory well targeted a new

geological structure and was drilled to satisfy the flow-through share commitment (see "Contractual Obligations and Commitments" section below for further explanation) with the related expenditures qualifying as CEE.
During the fourth quarter of 2016, the Company drilled and completed three gross wells (2.95 net wells), one of which was tied-in and came on production by the end of the year. Year-to-date 2016 capital expenditures also included drilling, completion, equip and tie-in costs for the 11 gross (9.7 net) wells drilled in the first three quarters of 2016, 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 towards the second phase of the Evi waterflood.

Transaction Costs

Transaction costs incurred in the three months ended December 31, 2017 were $0.1 million, primarily related to the Red Earth Acquisition (2016 – $0.5 million related to the Arrangement). Full year 2017 transaction costs of $1.1 million included $0.7 million related to the Red Earth Acquisition and $0.4 million related to the Arrangement (2016 – $2.3 million related to the Arrangement). Transaction costs were comprised largely of legal and professional fees.

Decommissioning Liabilities

PPR's decommissioning liabilities at December 31, 2017 were $112.8 million (December 31, 2016 - $97.7 million) to provide for future remediation, abandonment and reclamation of the Company's oil and natural gas properties. The $15.1 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 totaling $5.1 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 combinations and asset acquisitions were initially measured at fair value using a credit-adjusted risk-free rate of 5.7%. In accordance with PPR's accounting policy, decommissioning obligations are estimated and carried on the financial statements using risk-free discount rates. The revaluation of the acquired decommissioning obligations to the risk-free rates resulted in an increase to the carrying values of decommissioning liabilities by $11.5 million, which were presented as changes in estimates.

The Company has estimated the undiscounted total future liabilities of approximately $171.5 million spanning over the next 55 years, based on an inflation rate of 1.7% (December 31, 2016 – $141.1 million). Of the estimated undiscounted total future liabilities, $10.1 million is estimated to be settled over the next five years primarily for regulatory compliance. The Company has successfully achieved cost savings through economy of scale by managing its decommissioning activities on an area or project basis. As such, the Company may elect to spend more than the regulatory requirements to capture the economic benefits.

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.

Income Tax

At December 31, 2017, the Company had $403.6 million (December 31, 2016 – $325.7 million) of federal tax pools in Canada related to the exploration, development and production of oil and gas available for deduction against future Canadian taxable income. In addition, the Company had Canadian tax loss carry-forwards in the amount of $179.9 million (December 31, 2016 – $153.1 million), scheduled to expire in the years 2026 to 2037.

As of December 31, 2017 and December 31, 2016, the Company did not recognize any deferred tax assets in the combined and consolidated statements of financial position for deductible temporary differences and unused tax losses. This is due to insufficient evidence to indicate that it was probable that future taxable profits in excess of profits arising from the reversal of existing temporary difference would be generated to utilize the existing deferred tax assets.

Capital Resources and Liquidity

Capital Resources

Working Capital

At December 31, 2017, the Company had a working capital deficit (as defined in "Other Advisories" below) of $2.2 million (December 31, 2016 – $4.4 million). The decrease in the working capital deficit from December 31, 2016 is primarily related to lower accounts payable and accrued liabilities outstanding as at December 31, 2017 due to the expenditures on, and the related timing of, capital projects.

Revolving Facility

On October 31, 2017, the Company entered into a US$40 million (CDN$50.2 million using the year end exchange rate of $1.0000 USD to $1.2545 CAD) borrowing base Revolving Facility with a maturity date of October 31, 2020. The Company can make further draws on the facility on or before October 31, 2019. The Revolving Facility is denominated in USD, but accommodates CAD advances up to the lesser of CDN$18 million or US$10 million. As at December 31, 2017, the Company has drawn US$21 million (CDN$26.3 million equivalent) of USD denominated notes and CDN$12.9 million of CAD denominated notes under the Revolving Facility. All notes were issued at par by PPR Canada and are guaranteed by Prairie Provident Resources Inc. and certain of its other subsidiaries and secured by a US$200 million debenture.

The determination of the borrowing base is made by the lenders, in their sole discretion, taking into consideration the estimated value of PPR's oil and natural gas properties in accordance with the lenders' customary practices for oil and gas loans. The borrowing base is subject to a semi-annual redetermination, with the next redetermination scheduled for April of 2018.

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 CAD prime advances, the margins are between 350 and 500 basis points ("bps");
- (ii) for LIBOR advances and USD 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.

As at December 31, 2017, PPR had outstanding letters of credit of $4.8 million. The letters of credit are issued by a financial institution at which PPR has a $4.9 million cash deposit to cover letters of credit. The related deposit is classified as restricted cash on the statement of financial position and the balance is invested in short-term market deposits with maturity dates of one year or less when purchased.

As at December 31, 2017, $2.0 million of deferred costs related to the Revolving Facility was netted against its carrying value (December 31, 2016 – $0.4 million related to the Amended Credit Facility).

Subordinate Senior Notes

On October 31, 2017, the Company obtained four-year US$16 million (CDN $20.1 million using the year end exchange rate of $1.0000 USD to $1.2545 CAD) subordinated Senior Notes with a maturity date of October 31, 2021. They bear interest at 15% per annum, payable quarterly in arrears with up to 5% per annum deferrable at the election of PPR. The amount of any such deferred payment will become additional principal owing in respect of the Senior Notes payable at the maturity date. The terms of the Revolving Facility require that PPR Canada make the maximum deferred payment election. In conjunction with the Senior Notes, the Company issued 2,318,000 warrants with an exercise price of $0.549 with a five-year term expiring October 31, 2022. The warrants issued were classified as a financial liability due to a cashless exercise provision and will be measured at fair value upon issuance and at each subsequent reporting period, with the changes in fair value recorded in the consolidated statement of income (loss). The fair value of these warrants is determined using the Black-Scholes option pricing model. The value of the warrant liability as at December 31, 2017 was $0.5 million.

As at December 31, 2017, $0.9 million of deferred costs related to PPR's Senior Notes was netted against its carrying value (December 31, 2016 – $nil).

Covenants

The note purchase agreement for the Revolving Facility, the subordinated Senior Note agreement and related parent and subsidiary guarantees contain various covenants on the part of the Company and its subsidiaries including 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 note purchase agreement for the Revolving Facility and the subordinated Senior Note purchase agreement include the same financial covenants, with less restrictive thresholds under the subordinated Senior Note agreement for certain covenants. The financial covenants are as follows:

- total leverage, pursuant to which the ratio of adjusted indebtedness to EBITDAX (as defined below) for the four quarters most recently ended cannot exceed 3.5 to 1.0 (Senior Notes – 3.75 to 1.00) (as at December 31, 2017— 2.0 to 1.0);
- senior leverage, pursuant to which the ratio of senior adjusted indebtedness to EBITDAX (as defined below) for the four quarters most recently ended cannot exceed 3.0 to 1.0 (Senior Notes – 3.25 to 1.00) (as at December 31, 2017 — 2.0 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 (Senior Notes – 1.3 to 1.00) (2.1 to 1.0 as at December 31, 2017); 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 – 0.85 to 1.00) (as at December 31, 2017— 1.5 to 1.0). Under the agreements, current assets exclude derivative assets while current liabilities excludes the current portion of long-term debt, the decommissioning obligations, derivative liabilities and non-cash liabilities.

The Company was in compliance with all covenants as at December 31, 2017.

Amended Credit Facility

On October 31, 2017, the Company used proceeds from the Revolving Facility and Subordinated Notes to repay and retire its previously outstanding Amended 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. The Amended Credit Facility was collateralized by a demand debenture from PPR and each of its restricted subsidiaries in the amount of $500 million granting a first priority security interest over all present and after-acquired personal property and a first floating charge over all other present and after-acquired property, together with a fixed charge and mortgage over its existing borrowing base assets. A fixed charge and mortgage over after-acquired borrowing base assets will only be granted under certain circumstances.

As at December 31, 2016, under the Amended Credit Facility PPR had outstanding long-term debt of $15.0 million and had issued $5.4 million of letters of credit.

Shareholders' Equity

At December 31, 2017, PPR had consolidated share capital of $121.5 million (2016 – $115.1 million) and had 115.9 million outstanding common shares. In addition, PPR had 2.7 million options (2016 – 0.8 million), 0.5 million PSUs (2016 – 0.1 million) (which will be settled subject to a performance multiplier ranging from 0 to 2), 0.2 million DSUs (2016 – nil), 5.5 million warrants (2016 – nil) and zero RSUs (2016 – 0.1 million) outstanding as at December 31, 2017.

On November 28, 2017, the Toronto Stock Exchange ("TSX") accepted the Company's notice to make a normal course issuer bid ("NCIB") to purchase its outstanding common shares on the open market. The TSX authorized the Company to purchase up to 4,900,000 common shares during the period from December 1, 2017 to November 30, 2018. Shares purchased under the bid will be cancelled. Transactions under the NCIB will depend on future market conditions. Prairie Provident retains discretion whether to make purchases under the NCIB, and to determine the timing, amount and acceptable price of any such purchases, subject at all times to applicable TSX and other regulatory requirements. There were no shares purchased under the bid as at December 31, 2017. Subsequent to December 31, 2017, the Company purchased and cancelled 15,000 shares under the NCIB.

As of the date of this MD&A, there are 115.9 million common shares, 1.9 million RSUs, 2.7 million stock options, 0.5 million PSUs, and 5.5 million outstanding warrants.

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 objectives when managing capital are 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 its current and forecasted capital structure and makes adjustments on an ongoing basis in order to maintain the liquidity needed to satisfy its funding requirements. 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, the Company also expects its future funds from operations to increase as a result of the Red Earth Acquisition.

On October 31, 2017, the Company closed the Financing Transaction which expanded the Company's borrowing base from CDN $65 million to approximately CDN $70 million (applying a USD/CAD exchange rate of US$1.00 to CDN$1.25) 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 December 31, 2017 was 2.0 to 1.0 (2016 – 1.2 to 1.0), which was well below the financial covenant requirement of 3.5 to 1.0 under the Revolving Facility. The Company plans to maintain a prudent financial position by actively managing its capital program with careful consideration of the commodity price environment 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 adjusted funds from operations.

Contractual Obligations, Commitments and Contingencies

The Company has non-cancellable contractual obligations summarized as follows:

	2018	2019	2020	2021	2022	Thereafter	Total
Debt	4,259	4,364	43,341	26,471	—	—	78,435
Operating Leases – net	1,511	1,680	2,153	2,187	182	—	7,713
Firm transportation agreements	2,271	2,264	114	38	16	—	4,703
Capital commitments	250	23,733	1,000	—	—	—	24,983
Flow-through share commitment	3,665	—	—	—	—	—	3,665
Other agreements	219	188	80	29	30	293	839
Total	12,175	32,229	46,688	28,725	228	293	120,338

Included in 'Operating Leases – net' are sublease recoveries in the amount of $1.9 million over the contractual period.

The flow-through share commitment relates to flow-through shares issued by PPR in 2017 and will be met by incurring CEE as defined in the *Income Tax Act* and renouncing the related income tax deductions to investors.

The 2019 capital commitments are pursuant to a lease acquisition agreement as described below. The capital commitments and flow-through share commitment may be fulfilled by the same exploration expenditures. The 2020 capital commitment relates to land acquired in 2017 and is comprised of a four well drilling commitment. The costs included in the schedule above represent estimated drilling costs in the area.

In addition, the Company has estimated future decommissioning liabilities on its interests in wells and facilities in the total amount of $171.5 million on an undiscounted basis, inflated at 1.7%, of which $10.1 million is estimated to be incurred over the next five years.

Capital Commitments

Lease Acquisition Capital Commitment

Under the lease acquisition capital commitment, the Company has committed to annual capital expenditures for three years ending July 1, 2018 pursuant to the acquisition of approximately 73,500 net undeveloped acres in the Wheatland area. In the fourth quarter of 2017, the agreement was amended whereby certain leases totaling approximately 20,500 acres were surrendered, and the term of remaining leases, along with the related remaining capital commitment were extended to March 31, 2019. Under the amending agreement, the lease term and capital commitment may be further extended to September 30, 2019, should PPR incur at least $37.5 million of the $45.0 million total commitment by March 31, 2019. In the event PPR does not incur the minimum capital expenditures by the end of the given commitment period, the shortfall may be payable to the vendor.

As of December 31, 2017, the Company has incurred a total of $21.3 million towards the total capital commitment of $45.0 million. PPR expects to fulfill the remaining capital commitment through its capital program at the Wheatland area.

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 2017, the Company fully met its commitment related to the December 2016 flow-through share issuance by incurring a total of $4.9 million in qualifying expenditures. Additionally, the Company incurred a total of $0.4 million in 2017 towards the $4.1 million flow-through share commitment related to the March 2017 flow-through share issuance.

Contingencies

In September 2013, LPRI commenced arbitration proceedings under the North American Free Trade Agreement ("NAFTA") against the Government of Canada for actions taken by the Government of Quebec in 2011 to cancel, without compensation, oil and gas mining rights under a portion of the Saint Lawrence River – including an exploration permit covering 33,460 acres previously held by LPR Canada. A 10-day hearing before a NAFTA tribunal was completed in October 2017 with closing arguments heard in November 2017. Although the tribunal is not subject to any particular deadline, the Company anticipates receiving its decision before the end of 2018. There can be no assurance as to the outcome of the proceedings, either with respect to the tribunal's conclusions on the substantive merits of the claim or any determination of compensation thereunder.

In March 2001, a predecessor of PPR Canada acquired interests in certain assets from certain predecessors of Encana Corporation. In 2003, IFP Technologies (Canada) Inc. ("IFP") commenced an action in the Court of Queen's Bench of Alberta against Encana Corporation and certain of its predecessors and affiliates and against certain predecessors of PPR Canada, claiming, among other things, damages for breach of contract and lost opportunity or, alternatively, an accounting of 20% of the net revenue from primary production conducted by PPR Canada's predecessors from the acquired properties. In a decision issued in 2014, the Court of Queen's Bench of Alberta ruled in favour of the defendants and dismissed IFP's claim. IFP subsequently appealed the trial decision to the Court of Appeal of Alberta. In May 2017, the Court of Appeal allowed the appeal and held that IFP has a 20% working interest in the acquired properties. The Court remitted the calculation of net revenue to the Court of Queen's Bench for determination. In August 2017, the defendants applied to the Supreme Court of Canada for leave to appeal the Court of Appeal decision. A decision on the leave application is pending. Although the final outcome of this case remains uncertain in light of the ongoing appeal proceedings and calculation issues left unresolved by the Court of Appeal decision, on the available facts the Company does not expect the ultimate disposition of the matter to have a material effect on its business.

Off Balance Sheet Transactions

There were no off balance sheet transactions entered into during the period, nor are there any outstanding as of the date of this MD&A.

Supplemental Information

Financial – Quarterly extracted information

($000)	**2017 Q4**	2017 Q3	2017 Q2	2017 Q1	2016 Q4	2016 Q3	2016 Q2	2016 Q1
Oil and natural gas revenue	**20,510**	17,611	21,682	19,208	17,060	9,334	9,151	7,203
Royalties	**(2,171)**	(2,164)	(3,009)	(3,029)	(2,270)	(1,050)	(924)	(649)
Unrealized (loss) gain on derivatives	**(6,960)**	(2,586)	4,471	5,858	(7,231)	(1,936)	(10,959)	852
Realized gain on derivatives	**851**	2,222	1,150	703	1,362	2,257	2,539	3,585
Revenue net of realized and unrealized gains (losses) on derivative instruments	**12,230**	15,083	24,294	22,740	8,921	8,605	(193)	10,991
Net earnings (loss)	**(44,145)**	(11,985)	1,066	7,262	(8,782)	(11,588)	(43,223)	3,197
Per share – basic (1)	**(0.38)**	(0.10)	0.01	0.07	(0.09)	(0.12)	(0.44)	0.03
Per share – diluted (2)	**(0.38)**	(0.10)	0.01	0.07	(0.09)	(0.12)	(0.44)	0.03
Adjusted funds from operations (3)	**5,545**	4,536	7,060	5,934	7,107	1,810	3,252	1,090
Per share – basic (4)	**0.05**	0.04	0.06	0.06	0.07	0.02	0.03	0.01
Per share – diluted (5)	**0.05**	0.04	0.06	0.06	0.07	0.02	0.03	0.01

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 has fluctuated primarily due to changes in production and movement in commodity prices. The Company's production has varied due to its 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 gains on derivatives, even though significant swings in unrealized gains/losses on derivatives occurred. 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.

Fourth quarter 2017 oil and natural gas revenue increased from the prior quarter due to higher realized prices and a higher liquids ratio partially offset by lower production volumes. The fourth quarter 2017 net loss of $44.1 million was attributable to non-cash items including $30.8 million of impairment losses, $7.0 million of unrealized losses on derivative instruments, $8.8 million of depletion and depreciation expense and $3.7 million of E&E expense.

Third quarter 2017 oil and natural gas revenue was below the peak that occurred in the second quarter of 2017 due to 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 a record compared to the previous six quarters due to the Company generating its highest production volumes which included a full quarter of production from the Red Earth Acquisition and incremental volumes from the Arrangement with Arsenal. The quarter also had the highest blended realized prices due to strengthening commodity prices, as well as a higher liquids weighting in the quarter compared to the previous six quarters and relative to the quarter immediately following. 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 higher production volumes which included production from the Arrangement with Arsenal and ten days of production from the Red Earth Acquisition, as well as stronger crude oil prices compared to 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 stemming from significant production increases, coupled with the recovery of commodity prices over 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 recorded a net loss of $43.2 million 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.

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.

Annual Selected Financial and Operational Information

($000s except per unit amounts)	**2017**	2016	2015
Financial			
Oil and natural gas revenue	**79,011**	42,748	39,335
Net loss	**(47,802)**	(60,396)	(59,894)
Per share – basic & diluted[1]	**(0.42)**	(0.62)	(0.61)
Adjusted Funds from operations[2]	**23,075**	13,259	26,382
Per share – basic & diluted[3]	**0.20**	0.14	0.27
Net capital expenditures (dispositions)[4]	**64,198**	34,875	24,627
Corporate acquisitions of P&D assets	**50,500**	67,065	–
Total assets	**263,507**	247,835	198,905
Total liabilities	**201,339**	145,249	272,967
Long-term debt	**55,760**	15,047	–
Preferred shares liability	**—**	—	166,171
Preferred shares – conversion liability	**—**	—	26,450
Weighted average shares outstanding			
Basic & diluted[5]	**113,350**	97,868	97,409
Operating			
Production Volumes			
Crude oil (bbls/d)	**3,178**	2,012	1,820
Natural gas (Mcf/d)	**12,537**	9,253	4,577
Natural gas liquids (bbls/d)	**202**	126	69
Total (boe/d)	**5,470**	3,680	2,652
% Liquids	**62%**	58%	71%
Average Realized Prices			
Crude oil ($/bbl)	**56.01**	46.75	51.24
Natural gas ($/Mcf)	**2.47**	2.21	3.01
Natural gas liquids ($/bbl)	**37.08**	17.91	10.76
Total ($/boe)	**39.57**	31.74	40.64
Operating Netback ($/boe)[6]			
Realized price	**39.57**	31.74	40.64
Royalties	**(5.20)**	(3.63)	(2.26)
Operating costs	**(19.36)**	(17.39)	(16.49)
Operating netback	**15.01**	10.72	21.89
Realized gains on derivative instruments	**2.47**	7.23	17.34
Operating netback, after realized gains on derivative instruments	**17.48**	17.95	39.23

1,3,5 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.

2,6 Adjusted funds from operations and Operating Netback are non-IFRS measures and are defined below under "Other Advisories".

4 Net capital expenditures (disposition) include expenditures on E&E assets.

In 2015 and 2016 the Company focused capital expenditure on its drilling program in the Wheatland area. The Wheatland drilling program coupled with the Arsenal acquisition resulted in increased production and revenue in 2016 compared to 2015 despite a decrease in realized crude oil and natural gas prices.

In March 2017, the Company acquired oil-weighted producing properties in the Greater Red Earth area and in October 2017 the Company disposed of non-core natural gas-weighted properties. These changes, coupled with the September 2016 Arsenal acquisition and ongoing capital programs, increased production, revenue and liquids-weighting in 2017 compared to 2016. Stronger realized prices in the year relative to 2016 also contributed to increased revenue.

Internal Control over Financial Reporting and Officer Certifications

Internal control over financial reporting is a process designed to provide reasonable assurance that all of the Company's 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 National Instrument 52-109. The control framework used by PPR's officers 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"). Based on their evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's internal controls over financial reporting were effective as of December 31, 2017. There have been no changes in the Company's internal controls over financial reporting during the period from January 1, 2017 to December 31, 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 2017 Annual Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). There were no new or amended accounting standards or interpretations adopted during the year ended December 31, 2017.

The following new or amended accounting standards and pronouncements issued are applicable to PPR in future periods:

- 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 has reviewed its revenue streams and underlying contracts with customers and has completed its documentation of such contracts. PPR will adopt IFRS 15 using the modified retrospective approach and has concluded that the adoption will not have material impact on the consolidated financial statements. 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. The Company will adopt

IFRS 9 on January 1, 2018. The Company and has concluded that the 'expected loss' impairment model will not have a material impact on its consolidated financial statements. The Company does not currently apply hedge accounting to its derivative financial instruments and will not apply hedge accounting upon initial adoption of IFRS 9; and

- In January 2016, 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.

Critical Accounting Estimates

The preparation of financial statements in conformity with IFRS requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, revenues and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

- PPR's oil and gas assets are grouped into cash generating units ("CGUs"). A CGU is the lowest level of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs requires significant judgement and interpretations with respect to the integration between assets, geological formation, geographical proximity, the existence of common sales points and shared infrastructures and the way in which management monitors its operations. The recoverability of the PPR's oil and gas assets is assessed at the CGU level, and therefore, the determination of a CGU could have a significant impact on impairment losses or impairment reversals;

- Reserve engineering is an inherently complex and subjective process of estimating underground accumulations of petroleum and natural gas. The process relies on interpretations of available geological, geophysical, engineering, economic and production data. The accuracy of a reserves estimate is a function of the quality and quantity of available data, the interpretation of that data, the accuracy of various economic assumptions and the judgement of those preparing the estimate. Because these estimates depend on many assumptions, all of which may differ from actual results, reserves estimates and estimates of future net revenue may be different from the sales volumes ultimately recovered and net revenues actually realized. Changes in market conditions, regulatory matters and the results of subsequent drilling, testing and production may require revisions to the original estimates. Estimates of reserves impact: (i) the assessment of whether or not a new well has found economically recoverable reserves; (ii) depletion rates; (iii) the determination of net recoverable amount of oil and gas properties for impairment assessment and measurement, and (iv) the determination of reserve lives which affect the timing of decommissioning activities, all of which could have a material impact on earnings and financial positions;

- Recoverable amounts calculated for impairment testing are based on estimates of future commodity prices, expected volumes, quantity of reserves and discount rates as well as future development costs and operating costs. These calculations require the use of estimates and assumptions, which by their nature, are subject to measurement uncertainty. In addition, judgement is exercised by management as to whether there have been indicators of impairment or of impairment reversal. Indicators of impairment or impairment reversal may include, but are not limited to a change in: market value of assets, estimate of future prices and costs, a change in estimated quantity of reserves and appropriate discount rates;

- Business combinations are accounted for using the acquisition method of accounting where the acquired assets, liabilities and consideration issued were all fair valued. The determination of fair value requires the use of assumptions and estimates related to future events. The valuation of property and equipment includes key assumptions and estimates related to oil and gas reserves acquired, forecasted commodity prices, expected production volumes, future development costs, operating costs and discount rates. The valuation of exploration and evaluation assets includes key assumptions and estimates related to recent transactions on similar assets considering geographic location and risk profile. The valuation of the decommissioning liabilities and other liabilities includes estimates related to the timing and amount of anticipated cash outflows as well as for inflation rates and discount rates. As PPR common shares were issued in exchange for AEI's common shares, PPR common shares were fair valued with reference to PPR's enterprise value, which in turn was determined by fair valuing PPR's underlying assets and liabilities. Key assumptions used to fair value PPR's assets and liabilities were similar to those mentioned above. In addition, PPR's enterprise value was calibrated against trading metrics of recent market transactions for reasonableness. Changes in assumptions and estimates used in the determination of assets and liabilities acquired and consideration issued could result in changes to the values assigned to the assets, liabilities and goodwill or a bargain purchase gain. This could in turn impact future earnings or loss as a result of changes in the realization of asset value or the settlement of liabilities;

- Amounts recorded for decommissioning liabilities and the related accretion expense require the use of estimates with respect to the amount and timing of decommissioning expenditures, inflation rates and discount rates. Actual costs and cash outflows can differ from estimates because of changes in law and regulations, public expectations, market conditions, discovery and analysis of site conditions and changes in technology. Decommissioning liabilities are recognized in the period when it becomes probable that there will be a future cash outflow;

- Compensation costs recorded pursuant to share-based compensation plans are subject to the estimated fair values of the awards on the grant date and the estimated number of units that will ultimately vest. The Company uses the Black-Scholes option pricing model to estimate the fair value of options, which requires the Company to determine the most appropriate inputs including the expected life of the options, volatility, forfeiture rates and future dividends, which by nature, are subject to measurement uncertainty. The determination of the fair value of performance share units requires the estimation of the performance multiplier from 0 to 2 on the grant date;

- Derivative risk management contracts are valued using valuation techniques with market observable inputs. The most frequently applied valuation techniques include forward pricing and swap models, using present value calculations. The models incorporate various inputs including the credit quality of counterparties, foreign exchange spot and forward rates, and forward rate curves of the underlying commodity. Changes in any of these assumptions would impact fair value of the risk management contracts and as a result, future net income and other comprehensive income;

- Tax interpretations, regulations and legislation in the various jurisdictions in which the Company operates are subject to change. The Company is also subject to income tax audits and reassessments which may change its provision for income taxes. Therefore, the determination of income taxes is by nature complex, and requires making certain estimates and assumptions. PPR recognizes net deferred tax benefit related to deferred tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of deferred tax assets requires the Company to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in each jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Company to realize the net deferred tax assets recorded at the reporting date could be impacted;

- The determination of fair value requires judgement and is based on market information, where available and appropriate. Fair value is best evidenced by an independent quoted market price for the same asset or liability in an active market. However, quoted market prices and active markets do not always exist. In those instances, fair valuation techniques are used. The Company applies judgement in determining the most appropriate inputs and the weighting ascribed to each such input as well as its selection of valuation methodologies. The calculation of fair value is based on market conditions as at each reporting date, and may not be reflective of ultimate realizable value;

- Contingencies will only be resolved when one or more future events occur or fail to occur. The assessment of contingencies inherently involves the exercise of significant judgment and estimates of the outcome of future events; and

- Amounts recorded for capitalized general and administrative cost that is related to directly attributed supporting functions and activity to post license exploration and evaluation assets and to development and producing CGU properties requires the use of estimates and judgements and is by its nature subject to measurement uncertainty.

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 below. Additional risks are provided in the "Risk Factors" section of the 2017 Annual Information Form filed on SEDAR at www.sedar.com.

Risks Associated with Commodity Prices

- PPR's operational results and financial condition, and therefore the amount of capital expenditures, are dependent on the prices received for crude oil and natural gas production. Decreasing crude oil and natural gas prices and/or widening of oil price differentials will affect the Company's cash flows, impact its level of capital expenditures and may result in the shut-in of certain producing properties. Longer-term adverse forward pricing outlook could also result in write-down of the Company's carrying values of its oil and gas assets.

- The Revolving Facility has a reserves-based borrowing capacity. Decreases in future commodity prices may negatively impact the borrowing capacity and restrict PPR's liquidity.

- PPR may manage the risk associated with changes in commodity prices by entering into crude oil or natural gas price derivative contracts. If PPR engages in activities to manage its commodity price exposure, it may forego the benefits it would otherwise experience if commodity prices were to increase. In addition, activities related to commodity derivative contracts could expose the Company to losses. To the extent that PPR engages in risk management activities related to commodity prices, it would be subject to the credit risks associated with the counterparties with which it contracts.

Risks Associated with Operations

- The markets for crude oil and natural gas produced in Western Canada are dependent upon available capacity to refine crude oil and process natural gas as well as pipeline or other methods to transport the products to consumers. Pipeline capacity and natural gas liquids fractionation capacity in Alberta have not kept pace with the drilling of liquids-rich gas properties in some areas of the province which may limit production periodically.

- Exploration and development activities may not yield anticipated production, and the associated cost outlay may not be recovered. In addition, the costs and expenses of drilling, completing and operating wells are often uncertain.

- Continuing production from a property is largely dependent upon the ability of the operator of that property. A portion of PPR's production is either operated by third parties or dependent on third-party infrastructure and PPR has limited ability to influence costs on partner-operated properties. To the extent the operator fails to perform their duties properly, PPR's operating income from such properties may be reduced.

- Exploration and development activities are dependent on the availability of drilling, completion and related equipment in the particular areas where the activities are conducted. Demand for limited equipment or access restrictions may negatively impact the availability of such equipment to PPR and delay exploration and development activities.

- The operations of oil and gas properties involves a number of operating and natural hazards which may result in health and safety incidents, environmental damage and other unexpected and/or dangerous conditions.

- The operations of oil and gas properties are subject to environmental regulation pursuant to local, provincial and federal legislation. Changes in these regulations could have a material adverse effect on operating and capital costs. A breach of such legislation may result in the imposition of fines as well as higher operating standards that may increase costs. Public support for climate change action has grown in recent years. Governments in Canada and globally have responded to these shifting societal attitudes by adopting ambitious emissions reduction targets and supporting legislation. Existing and future laws and regulations may impose significant compliance costs or liabilities on failure to comply with requirements.

- PPR's corporate environment, health and safety program has a number of specific policies and practices to minimize the risk of safety hazards and environmental incidents. It also includes an emergency response program should an incident occur. If areas of higher risk are identified, PPR will undertake to analyze and recommend changes to reduce the risk including replacement of specific infrastructure. In addition to the above, PPR maintains business interruption insurance, commercial general liability insurance as well as specific environmental liability insurance, in amounts consistent with industry standards. Although PPR carries industry standard property and liability insurance on its properties, losses associated with potential incidents could potentially exceed insurance coverage limits.

Risks Associated with Reserve Estimates

- The reservoir and recovery information in reserve reports prepared by independent reserve evaluators are estimates and actual production and recovery rates may vary from the estimates and the variations may be significant. The reserves estimation process is inherently complex and subjective. The process relies on interpretations of available geological, geophysical, engineering, economic and production data. The accuracy of a reserves estimate is a function of the quality and quantity of available data, the interpretation of that data, the accuracy of various economic assumptions and the judgement of those preparing the estimate. Reserves data impacts not only PPR's financial statements, but also business decisions such as those pertaining to merger and acquisitions, and the assessment of capital projects for development and budgeting. Uncertainties around reserves estimates could have a profound impact on PPR's financial position, operating performance and strategic plans.

Risks Associated with Capital Resources

- Absent capital reinvestment or acquisition, PPR's reserves and production levels from petroleum and natural gas properties will decline over time as a result of natural declines. As a result, cash generated from operating these properties may decline. A decrease in reserves levels will also negatively impact the borrowing base under outstanding credit facilities.

- PPR is required to comply with covenants under outstanding debt agreements. In the event the Company does not comply with the covenants, its access to capital may be restricted. Any additional indebtedness brings the Company closer to its financial covenant limits, which increases the possibility of adverse changes in revenues, expenses, assets or liabilities resulting in non-compliance with financial covenants. Any such future non-compliance could result in adverse action by the lenders, including the imposition of limits on further borrowing.

- There have been high levels of price and volume volatility of publicly-traded securities in the last couple of years, particularly in the oil and natural gas exploration and development industry. Fluctuations in prices have not necessarily been related to the operating performance, underlying asset values or prospect of such companies. Market fluctuations may hinder the Company's ability to raise equity.

- To the extent that external sources of capital become limited or unavailable or available on unfavourable terms, PPR's ability to make capital investments, meet its capital commitments, and maintain or expand existing assets and reserves may be impaired and PPR's assets, liabilities, business, financial condition, and results of operations may be materially or adversely affected as a result.

- Fluctuations in interest rates could result in increases in the amount PPR pays to service future debt. World oil prices are quoted in US dollars and the price received by Canadian producers is therefore affected by the Canadian/US dollar exchange rate. A material increase in the value of the Canadian dollar may negatively impact PPR's net production revenue.

- PPR is exposed to exchange rate risk from its US dollar denominated long-term debt. Material adverse changes to the Canadian dollar and US dollar exchange rate could negatively impact PPR's cash flow related to interest and principal payments.

- Although the Company monitors the credit worthiness of third parties with which it contracts, there can be no assurance that the Company will not experience a loss for nonperformance by any counterparty with whom it has a commercial relationship. Such events may result in material adverse consequences to the business of the Company.

Risks Associated with Acquisitions

- Acquisitions of oil and gas properties or companies are based in large part on engineering, environmental and economic assessments made by the acquirer, independent engineers and consultants. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of oil and natural gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the Company's control. All such assessments involve a measure of geological, engineering, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated.

- Although select title and environmental reviews are conducted prior to any purchase of resource assets, such reviews cannot guarantee that any unforeseen defects in the chain of title will not arise to defeat the Company's title to certain assets or that environmental defects, liabilities or deficiencies do not exist or are greater than anticipated. Such deficiencies or defects could adversely affect the value of the assets and the Company's securities.

- There may be liabilities that the Company failed to discover or was unable to quantify in its due diligence review conducted prior to the execution of an acquisition, and which could have a material adverse effect on the Company's business, financial condition or future prospects.

- Achieving the benefits of an acquisition depends in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as the Company's ability to realize the anticipated growth opportunities and synergies from integrating the assets into its existing portfolio of properties. The integration of the assets requires the dedication of substantial management effort, time and resources, which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the disruption of ongoing business, customer and employee relationships that may adversely affect its ability to achieve the anticipated benefits of the acquisition.

General Business Risks

- The operations of PPR are conducted under permits issued by the federal and provincial governments and these permits must be renewed periodically. The federal and provincial governments may make operating requirements more stringent, which may require additional spending.

- Provincial programs, including royalty regimes and environmental regulations, related to the oil and gas industry may change in a manner that adversely impacts the Company. Future amendments to any of these programs could result in reduced cash flow and operating results.

- The use of fracture stimulations has been ongoing safely in an environmentally responsible manner in Western Canada for decades. With the increase in the use of fracture stimulations in horizontal wells, there is increased communication between the oil and natural gas industry and a wider variety of stakeholders regarding the responsible use of this technology. This increased attention to fracture stimulations may result in increased regulation or changes of law, which may make the conduct of PPR’s business more expensive or prevent the Company from conducting its business as it currently does.

- The operation of oil and gas properties requires physical access for people and equipment on a regular basis, which could be affected by weather, accidents, government regulations or third-party actions.

- Skilled labor is necessary to run operations (both those employed directly by PPR and by the Company’s contractors) and there is a risk that it may have difficulty sourcing skilled labor which could lead to increased operating and capital costs.

- The loss of a member of PPR's senior management team and/or key technical operations employee could result in a disruption to the Company's operations.

- Income tax laws, other laws or government incentive programs relating to the oil and gas industry, may in the future be changed or interpreted in a manner that affects PPR or its stakeholders.

- The Company has become increasingly dependent on the availability, capacity, reliability and security of its information technology (IT) systems and infrastructure. Should access to these systems be significantly interrupted, the operations of the Company could be disrupted.

Forward-Looking Statements

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

Forward-looking statements 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 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 statements are reasonable, but PPR can give no assurance that they will prove to be correct. Readers are cautioned that these forward-looking statements 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 statements, 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 statements. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak 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 statements, 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 statements 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, the warrant liability 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 and the warrant liability are excluded as they are non-monetary liabilities.

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

($000s)	**December 31, 2017**	December 31, 2016
Current assets	**19,588**	17,539
Less current derivative instrument assets	**895**	—
Current assets excluding current derivatives instruments	**18,693**	17,539
Current liabilities	**28,594**	28,120
Less flow-through share premium	**(711)**	(390)
Less current derivative instrument liabilities	**(4,156)**	(2,311)
Less current portion of decommissioning liability	**(2,300)**	(3,500)
Less warrant liability	**(533)**	
Current assets excluding current derivatives instruments and current portion of decommissioning liabilities	**20,894**	21,919
Working capital (deficit)	**(2,201)**	(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 (loss) and gain, 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 December 31,		Year Ended December 31,	
($000s)	**2017**	2016	**2017**	2016
Cash flow from operating activities	**5,646**	3,623	**16,621**	8,145
Changes in non-cash working capital	**149**	1,289	**501**	(2,539)
Funds from Operations	**5,795**	4,912	**17,122**	5,606
Other	**(534)**	23	**(258)**	433
Settlement of decommissioning liabilities	**233**	1,657	**5,136**	4,540
Restructuring costs	**—**	—	**—**	392
Transaction costs	**51**	515	**1,075**	2,288
Adjusted Funds from Operations	**5,545**	7,107	**23,075**	13,259

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 Revolving Facility and Subordinated Notes (and previously under the Amended Credit Facility). "Adjusted EBITDAX" corresponds to defined terms in the Company's Revolving 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 credit facility, Adjusted EBITDAX is determined using financial information from the most recent 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 December 31,		Year Ended December 31,	
($000s)	**2017**	2016	**2017**	2016
Net loss before income tax	**(44,232)**	(8,796)	**(48,272)**	(60,410)
Add (deduct):				
Interest	**1,561**	230	**3,028**	730
Depletion and depreciation	**8,814**	7,409	**34,875**	21,344
Exploration and evaluation expense	**3,711**	9	**4,877**	58
EBITDAX	**(30,146)**	(1,148)	**(5,492)**	(38,278)
Unrealized (gain) loss on derivative instruments	**6,960**	7,231	**(783)**	19,274
Impairment loss	**30,777**	(54)	**34,177**	26,723
Accretion	**556**	451	**2,132**	12,389
Loss (gain) on foreign exchange	**(963)**	215	**(1,621)**	(9,510)
Reorganization costs[1]	**—**	—	**—**	392
Share-based compensation	**164**	177	**687**	366
Loss (gain) on sale of properties	**(314)**	—	**(853)**	73
Gain on business combination	**—**	—	**(3,893)**	—
Gain on warrant liability	**(46)**		**(46)**	
Transaction costs	**51**	515	**1,075**	2,288
Pro-forma impact of acquisition	**—**	—	**2,394**	3,206
Adjusted EBITDAX	**7,039**	7,387	**27,777**	16,923

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