Prairie Provident Resources Inc.

Management's Discussion and Analysis
For the Three and Nine Months Ended September 30, 2018

Dated: November 7, 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" refers to Prairie Provident Resources Inc., as parent corporation, together with its wholly-owned subsidiaries, Prairie Provident Resources Canada Ltd., Lone Pine Resources Inc., Lone Pine Resources (Holdings) Inc., Arsenal Energy USA Inc. and Arsenal Energy Holding Ltd. The following MD&A provides management's analysis of the Company's results of operations, financial position and outlook as at and for the three and nine months ended September 30, 2018. This MD&A is dated November 7, 2018 and should be read in conjunction with the unaudited condensed interim consolidated financial statements for the three and six months ended June 30, 2018 (the "Interim Financial Statements"), the audited consolidated financial statements of PPR as at and for the year ended December 31, 2017 (the "2017 Annual Financial Statements") and the 2017 annual MD&A (the "Annual MD&A") dated March 28, 2018. 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 September 30,		Nine Months Ended September 30,	
($000s except per unit amounts)	2018	2017	2018	2017
Financial				
Oil and natural gas revenue	27,810	17,611	71,280	58,501
Net loss	(2,627)	(11,985)	(29,433)	(3,657)
Per share – basic & diluted	(0.02)	(0.10)	(0.25)	(0.03)
Adjusted Funds from Operations[1]	6,112	4,536	14,786	17,530
Per share – basic & diluted	0.05	0.04	0.13	0.16
Capital expenditures and acquisitions (net of proceeds from dispositions)	109	4,794	19,815	57,947
Production Volumes				
Crude oil (bbls/d)	4,044	3,185	3,552	3,160
Natural gas (Mcf/d)	9,607	12,799	9,056	13,661
Natural gas liquids (bbls/d)	131	188	120	235
Total (boe/d)	5,776	5,506	5,181	5,672
% Liquids	72%	61%	71%	60%
Average Realized Prices				
Crude oil ($/bbl)	69.83	50.63	67.84	53.93
Natural gas ($/Mcf)	1.35	1.84	1.53	2.62
Natural gas liquids ($/bbl)	52.61	34.98	52.66	34.28
Total ($/boe)	52.33	34.77	50.40	37.78
Operating Netback ($/boe)[2]				
Realized price	52.33	34.77	50.40	37.78
Royalties	(9.04)	(4.27)	(7.89)	(5.30)
Operating costs	(18.81)	(20.94)	(19.47)	(18.95)
Operating netback	24.48	9.56	23.04	13.53
Realized losses on derivative instruments	(6.77)	4.39	(5.48)	2.63
Operating netback, after realized gains on derivative instruments	17.71	13.95	17.56	16.16

Year-to-date 2018 highlights include:

- On September 13, 2018, PPR and Marquee Energy Ltd. ("Marquee") entered into a definitive agreement to effect a business combination (the "Arrangement") whereby Marquee shareholders will be issued 0.0886 PPR common shares for each Marquee common share. The Arrangement is expected to close around November 20, 2018 and is subject to approval by Marquee shareholders, regulatory and court approvals and satisfaction of certain closing conditions. The business combination is expected to enhance the Company's size and competitive position through economies of scale, operating synergies and increased capital investment efficiency. PPR has received a commitment letter from its creditors in respect to the expansion of its credit facilities and contemplates it will provide PPR with senior secured revolving facilities and subordinated senior notes of up US$93.5 million in total. Marquee's existing credit facilities would be repaid in full and terminated concurrent with the credit facility expansion.

- Subsequent to the third quarter of 2018, on October 11, 2018, PPR closed a $5.5 million of equity financing which included the issuance of 3,750,150 flow-through common shares at $0.46 per share and the issuance of 9,590,200 subscription receipts at $0.39 per unit. The proceeds from the sale of the subscription receipts will

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

be held in escrow until the closing of the Arrangement, upon which, the holders of the subscription receipts will automatically receive for each subscription receipt held, one PPR common share and one half-warrant. Each whole warrant will entitle the holder to acquire one common share at a purchase price of $0.50 until October 11, 2020.

- PPR's strategy to focus on oil and natural gas liquid opportunities successfully led to an oil and liquids production weighting of 71% for the first nine months of 2018, up from 60% in the first nine months of 2017. The attractive production mix positioned PPR to benefit from oil price recovery, resulting in a 33% increase in per boe realized price and a 70% improvement in per boe operating netbacks (before realized gains on derivative instruments) to $23.04/boe compared for the first nine months of 2017, or an overall increase in operating netbacks by $11.6 million.

- Production averaged 5,181 boe/day (71% liquids). Excluding the impact from divesting certain non-core gas weighted properties in 2017, production for the nine months ended September 30, 2018 was unchanged from the same period in 2017. Natural declines was 100% replaced by new production from the successful 2018 drilling program which brought on 1,000 boe/d of incremental production for the first nine months of the year.

- Adjusted EBITDAX (before pro-forma adjustments) was $18.7 million, a $0.3 million increase from year-to-date 2017 primarily due to higher operating netbacks, largely offset by a $11.8 million decrease in realized hedging gains. PPR enters into commodity hedges on a portion of its proved developed production (base production). While PPR's new production and unhedged base production benefited fully from the strengthening in oil and NGL benchmark prices in 2018, the Company also realized hedging losses on its existing hedges.

- Adjusted funds from operations were $14.8 million, a decrease of $2.7 million as compared to $17.5 million for the corresponding period in 2017, primarily due to higher realized hedging losses and higher finance costs as a result of higher average outstanding debt during 2018.

- Per boe operating netback before realized hedging gains was $23.04/boe for the first nine months of 2018, an increase of $9.51/boe from the same period in 2017. The increase was primarily due to a $12.62/boe increase in realized prices, partially offset by a $2.59/boe increase in royalties and $0.52/boe increase in operating expenses. The increase in realized prices was due to a higher liquids weighting in our production mix, combined with higher oil and NGL benchmark prices. Higher per boe royalties related to higher prices and substantial production from three new Princess wells that have higher royalty rates than the corporate average. Operating expenses on a per boe basis increased marginally due to averaging fixed costs over lower production and higher per boe costs associated with oil production.

- PPR drilled, completed and brought on production eight new wells for $15.2 million, or $1.9 million per well. Year-to-date capital expenditures totaled $21.8 million which also included expenditures in facilities, pipelines, land and capitalized overhead. In the Princess area, $10.6 million was directed primarily towards the development of five Lithic Glauconite ("Glauc") wells, pipeline construction and a multi-well satellite. The first three wells were on production in the second quarter of 2018, while the final two wells were on production in mid-July and early September of 2018. Three of the Princess Glauc wells (102/13-24-020-11W4 ("Princess-1"), 102/13-26-020-11W4 ("Princess-4') and 103/14-12-019-11W4 ("Princess-5"), collectively "Princess 1, 4 and 5") had average 30-day initial production of 760 boe/d per well, resulting in considerable impact on both the third quarter 2018 and year-to-date 2018 results. In the Wheatland area, $7.2 million was primarily directed towards the development of three Wayne wells, all of which were on production by the end of the second quarter. In the Evi area, $3.2 million was allocated to the continued advancement of the waterflood project. In the first quarter of 2018, PPR acquired synergistic assets in the Princess area for $0.9 million, which included approximately 50 boe/d of production. In the third quarter of 2018, PPR disposed of certain non-core gas weighted properties for cash proceeds of $2.8 million. The disposed properties had production of approximately 60 boe/d and were cash flow neutral. The disposition did not have any impact to PPR's borrowing base.

- Net loss for the first nine months of 2018 was $29.4 million, compared to $3.7 million in the nine months ended September 30, 2017. The $25.7 million increase in net loss was a result of a $2.7 million decrease in adjusted funds from operations and negative variances in certain non-cash items, including a $24.1 million decrease in unrealized gains on derivative instruments.

- During the second quarter of 2018, PPR increased the borrowing base under its Revolving Facility (defined herein) from US$40 million to US$45 million. The expanded borrowing base reflects PPR's increased underlying reserves value and provides additional liquidity and financial flexibility.

- At September 30, 2018, PPR had US$34.5 million of borrowings drawn against the US$45 million Revolving Facility and US$16.7 million of Subordinated Notes (defined herein) plus a working capital deficit of CDN$5.1 million (US$3.9 million equivalent using the September 30, 2018 exchange rate of $1.00 USD to $1.2945 CAD).

Third quarter 2018 highlights include:

- Production averaged 5,776 boe/day (72% liquids) in the third quarter of 2018, a 5% increase compared to the third quarter of 2017, or a 14% increase excluding the impact from divesting certain non-core gas weighted properties in the fourth quarter of 2017 and the third quarter of 2018. The production increase was due to the successful 2018 drilling program which increased third quarter 2018 production by approximately 1,930 boe/d, including 1,500 boe/d from Princess 1, 4 and 5, partially offset by natural declines.

- Adjusted EBITDAX (before pro-forma adjustments) was $7.4 million, a $2.6 million increase from the third quarter of 2017 primarily due to higher operating netbacks, partially offset by a $5.8 million decrease in realized hedging gains.

- Adjusted funds from operations were $6.1 million, a $1.6 million increase as compared to the third quarter of 2017 primarily due to higher adjusted EBITDAX, partially offset by higher finance costs.

- Operating netback before realized hedging gains was $24.48/boe for the third quarter of 2018, an increase of $14.92/boe from the third quarter of 2017. The increase was primarily due to higher realized prices and lower operating costs, partially offset by higher royalties. Increases in realized prices and royalties were primarily due to higher benchmark prices. Lower operating costs were due to lower maintenance expenses.

- Capital expenditures excluding dispositions were $2.9 million, primarily directed to the Princess drilling program.

- Net loss for the third quarter of 2018 was $2.6 million, compared to $12.0 million in the same quarter of 2017. The $9.4 million variance was primarily the result of a certain non-cash items including a decrease of $3.4 million of impairment losses, an increase of $2.9 million in gains on property dispositions and a $0.7 million decrease in unrealized losses on derivative financial instruments.

Outlook

Prairie Provident's business strategy has been built on a balanced approach, utilizing predictable funds flow from our low-decline oil assets to fuel growth developments. Completion of the Arrangement with Marquee will result in the combined enterprise having three core areas (Michichi/Wayne, Princess and Evi) offering light oil exposure and greater capital allocation alternatives over an enlarged asset base, with low based decline rate of 18%, better economies of scale, operational synergies, lower risk development drilling opportunities, a proven water flood program, potentially improved marketplace liquidity and future consolidation prospects. The combined company will operate over 90% of its production and have an average working interest greater than 98% in its core areas. The Arrangement is expected to close around November 20, 2018, after which Prairie Provident will incorporate Marquee's financial results in its consolidated financial statements.

In addition to implementing the Arrangement, PPR remains focused with its exploration and development efforts. In light of $1.7 million of incremental CEE commitments from its recently completed flow-through share issuance, PPR has expanded its fourth quarter exploration program at Evi by one additional light-oil Granite Wash well. A total of four Granite Wash wells will be drilled, which are expected to complete in December 2018. To reduce rig moving costs, Prairie Provident plans to advance its 2019 drilling of two lower-risk Slave Point light-oil development wells in Evi, immediately following the completion of its Granite Wash wells. The Slave Point wells are expected to be brought on production in the first quarter of 2019. As a result of drilling one additional Granite Wash well and advancing Slave Point drilling in 2018, full-year capital expenditures are estimated to be approximately $29 million, a $3 million increase from our original guidance. Prairie Provident maintains its 2018 production guidance of 5,200 to 5,600 boe/d.

Transportation bottlenecks continue stranding Canadian crude oil from global markets, creating deep discounts from global benchmark prices. Softer demand due to recent US refinery turnarounds has intensified the price discounts applied on Canadian crude. The widening differentials towards the end of the third quarter 2018 had a modestly negative impact on the Company's realized pricing for the period. Subsequent to September 30, 2018, differentials have widened further for all oil grades, especially in heavy oil (Western Canadian Select or "WCS"). The industry anticipates Canadian crude prices to gain back some grounds in the first quarter of 2019 as the US refineries are back online and more crude oil gets shipped by rail.

Most of PPR's oil production is in light/medium grade, however, 39% of its crude oil receives prices correlated with WCS due to their proximity to heavy oil sales points. The remaining 61% of oil production receive prices referenced to Edmonton Light Sweet, which are not as heavily discounted as the WCS. Prairie Provident is exploring several options to improve its realized oil prices, including transporting oil to other sales points with lesser oil differentials. The Company expects the widened differentials to negatively impact its Q4 financial results. For each $1/bbl change in Edmonton Light Sweet differential and WCS differential, quarterly funds flow is expected to change by approximately $0.3 million and $0.1 million, respectively. Prairie Provident will continue to monitor Canadian crude oil prices and remain cautious with its capital spending. After completing the fourth quarter capital program that focuses on bringing on Edmonton Light Sweet priced oil, the Company may defer further development until there is more clarity on the oil differentials.

Additional details on the Arrangement, Prairie Provident's 2018 capital program and guidance can be found on the Company's website at www.ppr.ca.

Arrangement Agreement

On September 13, 2018 PPR and Marquee, an oil and natural gas exploration and production company listed on the TSX Venture Exchange entered into a definitive agreement (the "Arrangement Agreement") to effect a business combination by way of a plan of arrangement under the Business Corporations Act (Alberta). Under the Arrangement, Marquee shareholders will receive 0.0886 PPR common shares for each Marquee common share. Marquee has low decline, liquids weighted production of approximately 2,700 boe/d at the time of the news release. Its core assets are located in the Michichi area where Marquee owns a high working interest position in large, proven and delineated light oil play. The business combination is expected to provide PPR with enhanced drilling opportunities, economies of scale and operating synergies with its Wheatland core area. Completion of the Arrangement is subject to various conditions as set out in the Arrangement Agreement, including approval of at least 66⅔% of votes cast of the Marquee shareholders at special meetings scheduled for November 19, 2018, and approval of the Court of Queen's Bench of Alberta pursuant to section 193 of the Business Corporations Act (Alberta).

PPR has received a commitment letter from its creditors in respect to the expansion of its current credit agreements, to be effected concurrently with, and subject to, the closing of the Arrangement. The letter contemplates that expanded debt structure will provide PPR with senior secured revolving facilities of US$65 million (CDN $84 million using the September 30, 2018 exchange rate of $1.00 USD to $1.2945 CAD) and up to US$28.5 million (CDN $36.9 million using the September 30, 2018 exchange rate) subordinated senior notes with a maturity date of October 31, 2021. In conjunction with the anticipated expansion of its existing credit facilities, PPR will issue 6,000,000 warrants to its creditors at a price to be determined at closing. Also concurrent with the expansion of PPR's credit facilities, it is anticipated that Marquee's existing credit facilities will be repaid in full and terminated. PPR will issue $1.5 million equivalent of shares to Marquee's term loan lender for early repayment of the term loan.

Subsequent Event

On October 11, 2018, PPR closed an equity financing comprised of a bought deal financing, which included the exercise of the over-allotment option, and a private placement for total gross proceeds of $5.5 million. The bought deal financing, included the immediate issuance of 3,750,150 PPR flow-through common shares with respect to Canadian Exploration Expenses ("CEE"), as defined in the Income Tax Act, at a price of $0.46 per share and the issuance of 6,810,200 subscription receipts at $0.39 per unit. The private placement included the issuance of 2,780,000 subscription receipts at $0.39 per unit. The proceeds from the subscription receipts issued under both the bought deal financing and private placement will be held in escrow until the closing of the Arrangement with Marquee, upon which, the purchasers of the subscription receipts will automatically receive for each subscription receipt held, one PPR common share and one-half of one common share purchase warrant (each whole warrant, a "Warrant"). Each Warrant will entitle the holder to acquire one common share at an exercise price of $0.50 until October 11, 2020. As such, the closing of the Arrangement will result in the issuance of 9,590,200 common shares and 4,795,100 warrants.

Should the Arrangement not be completed by December 6, 2018, or a later date if consented to in writing by the buyer and seller, the gross proceeds from the subscription receipts issued will be reimbursed on a pro rata basis, along with any interest income earned thereon, to the holders of the subscription receipts.

As prescribed in the Income Tax Act, the Company will have until December 31, 2019 to incur $1.7 million of qualifying CEE costs related to the flow-through common share issuance.

Prior Year 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 "Red Earth Acquisition"). The assets acquired include high quality and low decline oil production which is complementary to PPR's existing operations at Evi in the Peace River Arch area of Northern Alberta and further enhances the Company's size and competitive position in the area. The Greater Red Earth asset includes producing assets with current production of approximately 1,100 boe/d (98% liquids weighting) and approximately 78,000 net acres of undeveloped land. The acquisition was funded through the Company's credit facility 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.

Results of Operations

Production

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	**2018**	2017
Crude oil (bbls/d)	**4,044**	3,185	**3,552**	3,160
Natural gas (Mcf/d)	**9,607**	12,799	**9,056**	13,661
Natural gas liquids (bbls/d)	**131**	188	**120**	235
Total (boe/d)	**5,776**	5,506	**5,181**	5,672
Liquids Weighting	**72%**	61%	**71%**	60%

PPR's production for the three months ended September 30, 2018 increased by 5%, while production for the nine months ended September 30, 2018 decreased by 9% as compared to the corresponding periods in 2017. The Company's conscious effort to focus on oil and natural gas liquids opportunities resulted in the divestitures of 400 boe/d of non-core gas weighted properties in the fourth quarter of 2017 and the development of more liquids-rich prospects. Additional 60 boe/d of non-core gas weighted production was disposed of at the beginning of third quarter of 2018. As a result, oil and liquids weighting increased to 72% and 71% for the three and nine months ended September 30, 2018, compared to 61% and 60% for the same respective periods in 2017.

Excluding the impact of divestitures, average production increased by 14% and decreased by 1% for the three and nine months ended September 30, 2018, respectively. During 2018, PPR executed a successful drilling program comprised of eight wells, all of which were on production by the end of the third quarter, resulting in increased average production in the three and nine months ended September 30, 2018 by 1,930 boe/d and 1,000 boe/d, respectively. During the third quarter of 2018, Princess-4 came on production in mid-July and Princess-5 came on production at the beginning of September. Princess-1 came on production in May. These three Princess wells resulted in increased production of approximately 1,500 boe/d and 680 boe/d during the three and nine months ended September 30, 2018, respectively. The increase in the third quarter of 2018 was the result of the successful 2018 drilling program, as described above, partially offset by natural declines and divested non-core production.

Revenue

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per unit amounts)	**2018**	2017	**2018**	2017
Revenue				
Crude oil	**25,979**	14,835	**65,781**	46,521
Natural gas	**1,197**	2,171	**3,774**	9,781
Natural gas liquids	**634**	605	**1,725**	2,199
Oil and natural gas revenue	**27,810**	17,611	**71,280**	58,501
Average Realized Prices				
Crude oil ($/bbl)	**69.83**	50.63	**67.84**	53.93
Natural gas ($/Mcf)	**1.35**	1.84	**1.53**	2.62
Natural gas liquids ($/bbl)	**52.61**	34.98	**52.66**	34.28
Total ($/boe)	**52.33**	34.77	**50.40**	37.78
Benchmark Prices				
Crude oil - WTI ($/bbl)	**90.84**	60.34	**86.07**	64.61
Crude oil - Edmonton Light Sweet ($/bbl)	**81.69**	56.26	**78.03**	60.38
Natural gas - AECO monthly index-7A ($/Mcf)	**1.35**	2.04	**1.40**	2.58
Natural gas - AECO daily index - 5A ($/Mcf)	**1.19**	1.46	**1.49**	2.31
Exchange rate - US$/CDN$	**0.77**	0.80	**0.78**	0.77

PPR's third quarter 2018 revenue increased by 58% or $10.2 million from the third quarter of 2017. The 75% increase in crude oil revenue incorporates a 38% rise in realized prices and a 27% increase in oil production. The 45% decrease in natural gas revenue was the result of a 27% decrease in realized prices coupled with a 25% decrease in production. A significant portion of the decrease in gas production was due to the sale of non-core gas weighted assets in the fourth quarter of 2017 and third quarter of 2018.

On a year-to-date basis, revenue increased by 22% or $12.8 million, compared to the same period in 2017. The 41% increase in crude oil revenue reflected a 26% increase in realized prices and a 12% rise in production. The 61% decrease in natural gas revenue reflected a 42% drop in realized prices and a 34% production decrease.

The movements in PPR's realized prices correlated with those observed in the benchmark prices. The increases in the overall average realized prices of 51% and 33% for the three and nine months ended September 30, 2018, respectively, incorporated a higher liquids-weighted production mix in 2018 than in 2017.

Royalties

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2018**	2017	**2018**	2017
Royalties	**4,806**	2,164	**11,158**	8,202
Per boe	**9.04**	4.27	**7.89**	5.30
Percentage of revenue	**17.3%**	12.3%	**15.7%**	14.0%

A large portion of PPR's royalties are paid to the Crown, which are based on various sliding scales that are dependent on incentives, production volumes and commodity prices. As oil and NGL prices increased in 2018, compared to 2017, Crown royalty rates also increased. Additionally, the Princess 1, 4 and 5 wells, one of which came on production in the second quarter of 2018 and two of which came on production in the third quarter of 2018, all have flat freehold royalty rates which are above the average royalty rate of the Company. These above factors resulted in the increases in royalties on a percentage of revenue basis in the three and nine months ended September 30, 2018 as compared to the respective periods in 2017.

Commodity Price and Risk Management

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2018**	2017	**2018**	2017
Realized (loss) gain on derivatives	**(3,596)**	2,222	**(7,751)**	4,075
Unrealized (loss) gain on derivatives	**(1,884)**	(2,586)	**(16,399)**	7,743
Total (loss) gain on derivatives	**(5,480)**	(364)	**(24,150)**	11,818

Per boe				
Realized (loss) gain on derivatives	**(6.77)**	4.39	**(5.48)**	2.63
Unrealized (loss) gain on derivatives	**(3.55)**	(5.11)	**(11.59)**	5.00
Total (loss) gain on derivatives	**(10.31)**	(0.72)	**(17.07)**	7.63

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

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 such economic hedges.

As of September 30, 2018, the Company held the following outstanding derivative contracts:

Remaining Term	**Reference**	**Total Daily Volume (bbl)**	**Weighted Average Price**
Crude Oil Swaps			
October 1, 2018 – December 31, 2018	US$ WTI	1,050	$55.50
January 1, 2019 – March 31, 2019	US$ WTI	900	$55.68
April 1, 2019 – May 31, 2019	US$ WTI	250	$52.65
April 1, 2019 – June 30, 2019	US$ WTI	325	$52.75
July 1, 2019 – September 30, 2019	US$ WTI	500	$52.50
October 1, 2019 – December 31, 2019	US$ WTI	450	$52.00
January 1, 2020 – March 31, 2020	US$ WTI	450	$51.50
April 1, 2020 – June 30, 2020	US$ WTI	425	$51.00
July 1, 2020 – September 30, 2020	US$ WTI	400	$50.75
October 1, 2020 – December 31, 2020	US$ WTI	400	$50.50
Crude Oil Sold Call Options			
October 1, 2018 – December 31, 2018	US$ WTI	500	$65.00
January 1, 2019 – December 31, 2019	CDN$ WTI	400	$85.00
January 1, 2020 – December 31, 2020	US$ WTI	400	$60.50
Crude Oil Collars			
October 1, 2018 – December 31, 2018	CDN$ WTI	800	$58.00/67.50
January 1, 2019 – December 31, 2019	US$ WTI	400	$52.50/60.00
January 1, 2019 – December 31, 2019	US$ WTI	275	$50.00/57.00
January 1, 2020 – December 31, 2020	US$ WTI	175	$49.00/54.75

Remaining Term	Reference	Total Daily Volume (GJ)	Weighted Average Price
Natual Gas Swaps			
October 1, 2018 – December 31, 2018	AECO 7A Monthly Index	1,500	$2.76
January 1, 2019 – March 31, 2019	AECO 7A Monthly Index	3,000	$2.73
Natual Gas Sold Call Options			
October 1, 2018 – December 31, 2018	AECO 7A Monthly Index	1,500	2.76

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

Operating Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2018**	2017	**2018**	2017
Lease operating expense	**7,209**	7,560	**20,500**	20,383
Transportation and processing	**1,709**	1,864	**4,398**	5,859
Production and property taxes	**1,076**	1,182	**2,635**	3,096
Total operating expenses	**9,994**	10,606	**27,533**	29,338
Per boe	**18.81**	20.94	**19.47**	18.95

Lease operating expenses for the third quarter of 2018 decreased by $0.4 million from the same period in 2017, despite a 5% increase in production. The decrease was primarily the result of lower maintenance costs. Lease operating expenses for the nine months ended September 30, 2018 increased by $0.1 million or 1% from the same period in 2017. Lease operating costs did not change to the same extent as the production decrease for this period due to the impact of fixed operating costs. Furthermore, the production decrease was due to lower natural gas production which has lower per unit operating costs than oil production.

Transportation and processing expense for the three and nine months ended September 30, 2018 decreased by $0.2 million and $1.5 million, respectively, as compared to the same periods in 2017. The decreases primarily related to lower natural gas production resulting in reduced third-party natural gas processing and transportation costs.

Production and property tax expense for the three and nine months ended September 30, 2018 decreased by $0.1 million and $0.5 million, respectively, as compared to the same periods in 2017. The year-to-date 2018 decrease largely related to a favourable prior period adjustment of $0.6 million recorded in the second quarter of 2018.

Operating expenses on a per boe basis were 10% lower in the third quarter of 2018 and 3% higher in the first nine months of 2018 as compared to the corresponding periods in 2017. The decrease in the third quarter of 2018 is the result of lower maintenance expenses coupled with the dilution of costs on a per boe basis due to the increased production from the Princess 1, 4 and 5 wells. The increase in year-to-date 2018 operating expenses on a per boe basis incorporated PPR's production mix shift to liquids-weighted production that incurs higher per unit operating expense, as well as averaging fixed operating costs over lower average production for the period. The dilution from the Princess 1, 4 and 5 wells had a lesser impact on the 2018 year-to-date results due to the timing of the wells coming on production.

Operating Netback

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ per boe)	**2018**	2017	**2018**	2017
Revenue	**52.33**	34.77	**50.40**	37.78
Royalties	**(9.04)**	(4.27)	**(7.89)**	(5.30)
Operating costs	**(18.81)**	(20.94)	**(19.47)**	(18.95)
Operating netback	**24.48**	9.56	**23.04**	13.53
Realized (losses) gains on derivative instruments	**(6.77)**	4.39	**(5.48)**	2.63
Operating netback, after realized gains on derivative instruments	**17.71**	13.95	**17.56**	16.16

PPR's operating netback after realized hedging gains increased by $3.76/boe and $1.40/boe, respectively, for the three and nine months ended September 30, 2018, compared to the corresponding periods in 2017. Increased realized prices in the 2018 periods were partially offset by higher royalties and realized losses on derivative instruments.

General and Administrative Expenses ("G&A")

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2018**	2017	**2018**	2017
Gross cash G&A expenses	**2,267**	2,714	**7,417**	8,155
Gross share-based compensation expense	**245**	211	**706**	570
Less amounts capitalized	**(342)**	(537)	**(1,417)**	(1,510)
Net G&A expenses	**2,170**	2,388	**6,706**	7,215
Per boe	**4.08**	4.71	**4.74**	4.66

For the three months and nine months ended September 30, 2018, gross cash G&A were $0.4 million and $0.7 million lower than the respective periods in 2017. The decreases primarily related to lower professional fees incurred in 2018 than in 2017.

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. Capitalized G&A varies with the composition and compensation levels of technical departments and their time attributed to capital projects.

Share-based compensation

In the first nine months of 2018, the Company granted 1,922,274 restricted share units ("RSUs") to officers and employees. RSUs vest evenly over a three-year period. As at September 30, 2018, 1,906,974 RSUs were outstanding. In addition, the Company issued 250,865 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 September 30, 2018, there were 455,102 DSUs outstanding.

Previously issued share-based compensation awards included options and performance share units "PSUs". Options vest evenly over a three year period and will expire five years after the grant date. PSUs were granted to certain officers of the company and vest on a date specified per the agreement, no more than three years after the grant date. Each PSU is subject to a performance multiplier ranging from 0 to 2 based on share performance relative to a select group of peers. As of September 30, 2018, there were 471,332 PSUs outstanding and 2,451,261 options with a weighted average strike price of $0.81 per share, of which 1,037,573 were exercisable at a weighted average strike price of $0.84 per share.

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 September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2018**	2017	**2018**	2017
Interest expense	**1,852**	633	**5,214**	1,467
Accretion expenses	**557**	553	**1,689**	1,576
Total finance cost	**2,409**	1,186	**6,903**	3,043
Per boe	**4.53**	2.34	**4.88**	1.97

Interest expense is primarily comprised of interest incurred related to the Company's outstanding borrowings. The increase in interest expense of $1.2 million and $3.7 million for the three and nine months ended September 30, 2018 as compared to the respective periods in 2017 related to increased average borrowings, higher effective interest rates on the Revolving Facility and Senior Notes than the previously outstanding credit facility that was settled on October 31, 2017 and higher amortization of deferred financing fees related to the new financing since October 31, 2017. Of the $1.9 million and $5.2 million of interest expense incurred in the three and nine months ended September 30, 2018, $0.3 million and $1.0 million, respectively, was deferred and will be repaid upon maturity of the Senior Notes (see Subordinated Senior Notes section below). The weighted average effective interest rate for the three and nine months ended September 30, 2018 was 8.8% and 8.8%, respectively (2017 – 3.8% and 3.5% respectively).

Accretion charges are non-cash expenses and primarily relate to the decommissioning liabilities. Accretion remained consistent in three and nine months ended September 30, 2018 as compared to the same periods in 2017.

Gain (Loss) on Foreign Exchange

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2018**	2017	**2018**	2017
Realized gain (loss) on foreign exchange	**3**	214	**(382)**	411
Unrealized gain (loss) on foreign exchange	**1,081**	130	**(1,550)**	247
Gain (loss) on foreign exchange	**1,084**	344	**(1,932)**	658

Foreign exchange (losses) gains incurred in the three and six months ended September 30, 2018 related largely to borrowings denominated in US dollars (see "Capital Resources and Liquidity" section below). There were no US dollar denominated borrowings in the first nine months of 2017.

Exploration and Evaluation Expense

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2018**	2017	**2018**	2017
Exploration and evaluation expense	**46**	1,100	**292**	1,166
Per boe	**0.09**	2.17	**0.21**	0.75

Exploration and evaluation expenses incurred in the third quarter and year-to-date 2018 are comprised of undeveloped land expiries. Third quarter and year-to-date 2017 exploration and evaluation expenses include costs related to a dry exploration well drilled in the third quarter of 2017 in the Wheatland area and undeveloped land expiries. The 2017 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.

Depletion and Depreciation

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2018**	2017	**2018**	2017
Depletion and depreciation	**8,903**	8,636	**24,578**	26,061
Per boe	**16.75**	17.05	**17.38**	16.83

Depletion and depreciation rates are subject to change based on changes in the carrying value of the asset base, changes in future development costs, reserve updates and changes in production by area. The slight increase in the depletion rate for the nine months ended September 30, 2018 from the comparable period in 2017 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, partially offset by decreases in carrying values of the asset base as a result of impairment charges recognized in the fourth quarter of 2017. The slight decrease in the depletion rate for the three months ended September 30, 2018, includes estimated reserve additions from two Princess wells which came on production in the third quarter of 2018.

Impairment Loss

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2018**	2017	**2018**	2017
P&D impairment	**—**	3,400	**—**	3,400
P&D impairment – decommissioning asset	**—**	—	**(162)**	—
Total impairment loss (recovery)	**—**	3,400	**(162)**	3,400

The year-to-date 2018 impairment recovery resulted from changes in estimated decommissioning liabilities of certain assets with zero carrying value.

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

Capital Expenditures[1]

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2018**	2017	**2018**	2017
Drilling and completion	**1,129**	1,635	**12,889**	8,944
Equipment, facilities and pipelines	**1,041**	2,199	**6,423**	5,162
Land	**166**	80	**779**	385
Capitalized overhead and other	**562**	871	**1,673**	1,967
Total expenditures	**2,898**	4,785	**21,764**	16,458
Acquisitions – cash consideration	**—**	—	**887**	41,829
Proceeds from disposals of property	**(2,789)**	9	**(2,836)**	(340)
Total – net	**109**	4,794	**19,815**	57,947

PPR focused its capital activities during the third quarter of 2018 in the Princess area. In the Princess area, PPR completed, equipped and tied-in two gross (2.0 net) wells that were drilled late in the second quarter of 2018, including pipeline construction. Both of these wells came on production in the third quarter of 2018.

PPR's year-to-date capital activities included the drilling, completion, equip and tie-in of five gross (5.0 net) wells in the Princess area and three gross (3.0 net) wells in the Wheatland area, construction of pipelines and a multi-well satellite in Princess and the expansion of the Evi waterflood project with the conversion of three producing wells into injector wells. All of the eight gross (8.0 net) wells drilled in 2018 were on production by the end of the third quarter. Year-to-date capital expenditures also include $0.9 million for the acquisition of oil and natural gas properties and infrastructure in the Princess area in the first quarter of 2018. In the third quarter of 2018, PPR disposed of certain non-core gas weighted properties for cash proceeds of $2.8 million. The disposed properties had production of approximately 60 boe/d and were cash flow neutral. The disposition did not have any impact to PPR's borrowing base.

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

Transaction Costs

Transaction costs incurred in the three and nine months ended September 30, 2018 of $0.8 million and $0.9 million, respectively relate to the Arrangement with Marquee. Transaction costs were comprised primarily of legal fees and professional fees.

Decommissioning Liabilities

The Company's decommissioning liabilities at September 30, 2018 were $107.6 million (December 31, 2017 - $112.8 million) to provide for future remediation, abandonment and reclamation of PPR's oil and gas properties.

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

During the nine months ended September 30, 2018, the Company recognized a decrease of $3.2 million due to changes in estimates, primarily related to a reduction in cost estimates due to the costs of abandonment work performed coming in lower than previously estimated.

Changes in estimates result in a corresponding increase or decrease in the carrying amount of the related assets except for certain assets with a zero carrying value, in which case, the amount is immediately recognized as an impairment charge or recovery.

The Company has estimated the undiscounted total future liabilities of approximately $165.1 million spanning over the next 55 years, based on an inflation rate of 1.7% (December 31, 2017 – $171.5 million). While the provision for decommissioning liabilities is based on management's best estimates of future costs, discount rates, timing and the economic lives of the assets, there is uncertainty regarding the amount and timing of incurring these costs.

Capital Resources and Liquidity

Capital Resources

Working Capital

At September 30, 2018, PPR had a working capital deficit (as defined in "Other Advisories" below) of $5.1 million (December 31, 2017 – $2.2 million). The increase in the working capital deficit was primarily the result of capital expenditures incurred in the first nine months of 2018, as well as transaction costs incurred related the Arrangement with Marquee.

Revolving Facility

On June 21, 2018, PPR amended the borrowing base under its senior secured revolving note facility ("Revolving Facility"). The amended Revolving Facility provides a borrowing base of US$45 million (CDN$58.3 million equivalent using the September 30, 2018 exchange rate of $1.00 USD to $1.2945 CAD), an increase of US$5 million from the original agreement. 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 September 30, 2018, the Company has drawn US$24.5 million (CDN$31.7 million equivalent using the September 30, 2018 exchange rate) of USD denominated notes and CDN$12.9 million of CAD denominated notes under the Revolving Facility.

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 November 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 September 30, 2018, 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 September 30, 2018, $1.6 million of deferred costs related to the Revolving Facility was netted against its carrying value (December 31, 2017 – $2.0 million).

Subordinate Senior Notes

On October 31, 2017, the Company obtained four-year US$16 million (CDN $20.7 million using the exchange rate of $1.00 USD to $1.2945 CAD) subordinated senior notes ("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 that is deferrable. 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. At September 30, 2018, the total deferred payment was US$0.7 million (December 31, 2017 – US$0.1 million). In conjunction with the Senior Notes, the Company issued 2,318,000 warrants with an exercise price of $0.549 per share 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 September 30, 2018 was $0.3 million (December 31, 2017 – $0.5 million).

As at September 30, 2018, $0.8 million of deferred costs related to PPR's Senior Notes was netted against its carrying value (December 31, 2017 – $0.9 million).

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:

Financial Covenant	Revolving Facility Requirement	Senior Note Requirement	As at September 30, 2018
Total Leverage – adjusted Indebtedness to EBITDAX (as defined below) for the four quarters most recently ended	Cannot Exceed 3.5 to 1.0	Cannot Exceed 3.75 to 1.00	2.4 to 1.0
Senior Leverage – senior adjusted indebtedness to EBITDAX (as defined below) for the four quarters most recently ended	Cannot Exceed 3.0 to 1.0	Cannot Exceed 3.25 to 1.0	2.4 to 1.0
Asset Coverage – 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	Cannot be less than 1.3 to 1.0	2.0 to 1.0
Current ratio – consolidated current assets, plus any undrawn capacity under the Revolving Facility, to consolidated liabilities at the end of the quarter[1]	Cannot be less than 1.0 to 1.0	Cannot be less than 0.85 to 1.0	1.4 to 1.0

[1] 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 September 30, 2018.

Shareholders' Equity

At September 30, 2018, PPR had consolidated share capital of $121.5 million (December 31, 2017 – $121.5 million) and had 115.8 million outstanding common shares. In addition, PPR had various long-term incentive awards outstanding, as outlined in the "Share-Based Compensation" section.

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. During the nine months of 2018, the Company purchased and cancelled 57,000 shares under the NCIB at a weighted average cost of $0.43 per share.

Subsequent to September 30, 2018, PPR closed an equity financing for total gross proceeds of $5.5 million (see "Subsequent Events" above). Additionally, the Company purchased and cancelled 85,000 shares under the NCIB at a weighted average cost of $0.35 per share.

As of the date of this MD&A, there were 119.5 million common shares outstanding.

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.

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 within the financial covenants imposed on it under its outstanding debt agreements. Total debt to Adjusted EBITDAX at September 30, 2018 was 2.4 to 1.0 (December 31, 2017 – 2.0 to 1.0), which was well below the financial covenant requirement of 3.0 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.

During the third quarter of 2018, PPR repaid US$3.5 million dollars to its Revolving Facility borrowings using cash flow from operations and cash proceeds from the disposition of certain non-core gas weighted properties that had a neutral impact on cash flow from operating activities. Additionally, during the second quarter of 2018, PPR increased its Revolving Facility borrowing base by US$5 million, enhancing its access to capital resources.

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 and Commitments

Contractual obligations and commitments are outlined in Note 20 of the Annual Financial Statements. There were no significant changes during the first nine months of 2018 except as outlined below.

Wheatland Capital Commitment

Under the Wheatland capital commitment, the Company has committed to capital expenditures of $45 million by March 31, 2019 pursuant to the acquisition of undeveloped land in the Wheatland area.

As of September 30, 2018, the Company has incurred a total of $27.9 million towards the total capital commitment of $45.0 million. 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. 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.

As at September 30, 2018, the Company incurred a total of $1.8 million towards the flow-through share commitment. The Wheatland capital commitment as described above and the flow-through share capital commitment may be fulfilled by the same exploration expenditures.

Supplemental Information

Financial – Quarterly extracted information

($000)	2018 Q3	2018 Q2	2018 Q1	2017 Q4	2017 Q3	2017 Q2	2017 Q1	2016 Q4
Oil and natural gas revenue	27,810	24,187	19,283	20,510	17,611	21,682	19,208	17,060
Royalties	(4,806)	(3,815)	(2,537)	(2,171)	(2,164)	(3,009)	(3,029)	(2,270)
Unrealized (loss) gain on derivatives	(1,884)	(9,316)	(5,199)	(6,960)	(2,586)	4,471	5,858	(7,231)
Realized (loss) gain on derivatives	(3,596)	(2,943)	(1,212)	851	2,222	1,150	703	1,362
Revenue net of realized and unrealized (losses) gains on derivative instruments	17,524	8,113	10,335	12,230	15,083	24,294	22,740	8,921
Net (loss) earnings	(2,627)	(15,064)	(11,742)	(44,145)	(11,985)	1,066	7,262	(8,782)
Per share – basic & diluted	(0.02)	(0.13)	(0.10)	(0.38)	(0.10)	0.01	0.07	(0.09)
Adjusted funds from operations (1)	6,112	4,792	3,882	5,545	4,536	7,060	5,934	7,107
Per share – basic & diluted	0.05	0.04	0.03	0.05	0.04	0.06	0.06	0.07

1 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 and Princess, the acquisition of 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 US denominated borrowings after October 31, 2017.

Third quarter 2018 oil and natural gas revenue increased from the prior quarter due to higher production and higher realized oil prices. Realized losses on derivatives incurred in the third, second and first quarters of 2018 were attributed to the continued strengthening in oil prices, as contrasted with realized gains in the fourth quarter of 2017. The net loss of $2.6 million incurred in the third quarter of 2018 relates to non-cash items including $1.9 million of unrealized losses on derivatives instruments and $8.9 million of depletion and depreciation expense.

Second quarter 2018 oil and natural gas revenue increased from the prior quarter due to higher production and higher realized oil prices. The net loss of $15.1 million incurred in the second quarter of 2018 relates to non-cash items including $9.3 million of unrealized losses on derivatives instruments and $8.3 million of depletion and depreciation expense.

First quarter 2018 oil and natural gas revenue declined from the prior quarter due to lower production, partially offset by increase in realized oil and NGL prices. The first quarter of 2018 net loss of $11.7 million was attributable to non-cash items including $5.2 million of unrealized losses on derivative instruments and $7.4 million of depletion and depreciation expense.

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.

Internal Control over Financial Reporting and Officer Certifications

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

The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal controls over financial reporting as defined in NI 52-109. The control framework PPR's officers used to design and evaluate the Company's internal controls over financial reporting is the Internal Control – Integrated Framework (2013) by The Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). There have been no changes in the Company's internal controls over financial reporting during the period from January 1, 2018 to September 30, 2018 that have materially affected, or are reasonably likely to materially affect the Company's internal controls over financial reporting.

Changes in Accounting Policies

The Interim Financial Statements have been prepared on a basis consistent with the accounting, estimation and valuation policies described in the Annual Financial Statements other than changes in accounting policies effective January 1, 2018 described below related to the adoption of new accounting pronouncements.

Effective January 1, 2018, PPR adopted IFRS 9 – Financial Instruments replacing IAS 39 – Financial Instruments: Recognition and Measurement and IFRS 15 – Revenue from Contracts with Customers, replacing IAS 11 – Construction Contracts, IAS 18 – Revenue and several revenue-related interpretations. The adoption of these standards did not have a material impact on the Company's consolidated financial statements. Further information on the changes to accounting policies can be found in Note 3 to the Interim Financial Statements.

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

- 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. An accounting policy choice can be made whereby 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. The Company will adopt IFRS 16 on January 1, 2019 using the modified retrospective approach and applying certain practical expedients available upon transition. PPR intends to apply a practical expedient that allows the Company to apply a recognition exemption for leases with remaining lease terms of less than 12 months on the transition date. The Company also intends to apply a practical expedient which allows the right-of-use asset recognized on transition to equal the lease liability recorded versus recognizing the carrying amount of the right-of-use asset as if IFRS 16 had been applied since the commencement date of the lease. This practical expedient is available on a lease by lease basis and PPR intends to apply it to leases that are not individually significant. PPR has identified and reviewed the majority of contracts entered into by PPR to date that fall within the scope of the new standard and is in the process of quantifying the impact. Subsequent to the closing of the Arrangement with Marquee, the Company will incorporate contracts previously entered into by Marquee into its assessment. The impact of Marquee's leases has not yet been determined.

Operational and Other Risk Factors

PPR's operations are conducted in the same business environment as most other oil and gas operators and the business risks are very similar. Significant risks are summarized in the Annual MD&A and have remained unchanged during the first nine months of 2018. Additional risks are provided in the "Risk Factors" section of the 2017 Annual Information Form filed on SEDAR at www.sedar.com.

Forward-Looking Information

Certain statements and information in this MD&A may constitute forward-looking 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, including the anticipated financing upon completion of the Arrangement under the terms proposed by PPR’s creditors and accepted by the Company;
- 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, including prospective operating synergies, G&A cost savings, improved economies of scale, risk of drilling opportunities and marketplace liquidity;
- the anticipated timeframe for the closing of mergers 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;
- requisite shareholder support for the Arrangement and the issuance of common shares thereunder by the Company;
- the likelihood of satisfying all conditions to completion of the Arrangement;
- 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)	September 30, 2018	December 31, 2017
Current assets	17,828	19,588
Less current derivative instrument assets	(286)	895
Current assets excluding current derivatives instruments	17,542	18,693
Current liabilities	39,299	28,594
Less flow-through share premium	(447)	(711)
Less current derivative instrument liabilities	(13,587)	(4,156)
Less current portion of decommissioning liability	(2,300)	(2,300)
Less warrant liability	(324)	(533)
Current liabilities excluding current derivatives instruments, current portion of decommissioning liabilities, flow-through share premium and warrant liability	22,641	20,894
Working capital deficit	(5,099)	(2,201)

Operating Netback

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

Adjusted Funds from Operations

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	2018	2017	2018	2017
Cash flow from operating activities	6,508	5,983	13,910	10,975
Changes in non-cash working capital	(1,754)	(2,222)	(1,611)	352
Funds from Operations	4,754	3,761	12,299	11,327
Other	(4)	215	33	276
Settlement of decommissioning liabilities	579	351	1,406	4,903
Restructuring costs	—	—	187	—
Transaction costs	783	209	861	1,024
Adjusted Funds from Operations	6,112	4,536	14,786	17,530

Adjusted EBITDAX

The Company monitors its capital structure and liquidity based on the ratio of Debt to Adjusted EBITDAX as defined below. The ratio provides a measure of the Company's ability to manage its debt levels under current operating conditions. "Debt" refers to the Company's borrowings under its outstanding debt agreements (for the periods prior to October 31, 2017, Amended Credit Facility). "Adjusted EBITDAX" corresponds to defined terms in the Company's debt agreements 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 ("pro-forma adjustments"). As transaction costs related to business combinations 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 long-term debt, Adjusted EBITDAX is determined using financial information from the most recent four consecutive fiscal quarters. Adjusted EBITDAX (before pro-forma adjustments) is determined by subtracting pro-forma adjustments from Adjusted EBITDAX.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2018**	2017	**2018**	2017
Net earnings (loss) before income tax	**(2,722)**	(12,107)	**(29,697)**	(4,040)
Add (deduct):				
Interest	**1,852**	633	**5,214**	1,467
Depletion and depreciation	**8,903**	8,636	**24,578**	26,061
Exploration and evaluation expense	**46**	1,100	**292**	1,166
EBITDAX	**8,079**	(1,738)	**387**	24,654
Unrealized (gain) loss on derivative Instruments	**1,884**	2,586	**16,399**	(7,743)
Impairment loss	**—**	3,400	**(162)**	3,400
Accretion	**557**	553	**1,689**	1,576
Loss (gain) on foreign exchange	**(1,084)**	(344)	**1,932**	(658)
Reorganization costs[1]	**—**	—	**187**	—
Share-based compensation	**190**	195	**553**	523
Loss (gain) on sale of properties	**(2,905)**	9	**(2,952)**	(539)
Loss (gain) on business combination	**—**	—	**—**	(3,893)
Gain on warrant liability	**(70)**	—	**(209)**	—
Transaction costs	**783**	209	**861**	1,024
Pro-forma impact of acquisition	**—**	—	**131**	2,394
Adjusted EBITDAX	**7,434**	4,870	**18,816**	20,738

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