Prairie Provident Resources Inc.

Management's Discussion and Analysis
For the Three Months and Year Ended December 31, 2018

Dated: March 27, 2019

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. This MD&A includes the results of operations of Marquee Energy Ltd. ("Marquee") since November 21, 2018, the closing date of the acquisition. 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, 2018. This MD&A is dated March 27, 2019 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, 2018 (the "2018 Annual Financial Statements"). Additional information relating to PPR, including the Company's December 31, 2018 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,	
($000s except per unit amounts)	**2018**	2017	**2018**	2017
Financial				
Oil and natural gas revenue	**13,542**	20,510	**84,822**	79,011
Net loss	**(3,532)**	(44,145)	**(32,965)**	(47,802)
Per share – basic & diluted	**(0.02)**	(0.38)	**(0.27)**	(0.42)
Adjusted Funds Flow[1]	**(5,346)**	5,312	**8,034**	17,939
Per share – basic & diluted	**(0.04)**	0.05	**0.07**	0.16
Net capital expenditures[2]	**4,661**	6,251	**24,476**	64,198
Production Volumes				
Crude oil (bbls/d)	**4,042**	3,233	**3,676**	3,178
Natural gas (Mcf/d)	**10,523**	9,200	**9,426**	12,537
Natural gas liquids (bbls/d)	**141**	106	**125**	202
Total (boe/d)	**5,937**	4,872	**5,372**	5,470
% Liquids	**70%**	69%	**71%**	62%
Average Realized Prices				
Crude oil ($/bbl)	**30.47**	62.01	**57.47**	56.01
Natural gas ($/Mcf)	**1.74**	1.81	**1.59**	2.47
Natural gas liquids ($/bbl)	**40.70**	54.86	**49.38**	37.08
Total ($/boe)	**24.79**	45.76	**43.26**	39.57
Operating Netback ($/boe)[3]				
Realized price	**24.79**	45.76	**43.26**	39.57
Royalties	**(3.48)**	(4.84)	**(6.66)**	(5.20)
Operating costs	**(19.01)**	(20.78)	**(19.34)**	(19.36)
Operating netback	**2.30**	20.14	**17.26**	15.01
Realized (losses) gains on derivative instruments	**(2.32)**	1.90	**(4.60)**	2.47
Operating netback, after realized gains/losses on derivative instruments	**(0.02)**	22.04	**12.66**	17.48

2018 Corporate Developments

- On November 21, 2018 PPR completed the acquisition of Marquee, an oil and natural gas exploration and production company listed on the TSX Venture Exchange, by way of a plan of arrangement under the Business Corporations Act (Alberta) (the "Arrangement"). Pursuant to the Arrangement, PPR acquired all of the outstanding Marquee common shares on a share exchange basis, with Marquee shareholders receiving an aggregate of 38,608,416 PPR shares based on an exchange ratio of 0.0886 PPR common shares for each Marquee share. 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.

- Concurrent with the closing of the Arrangement, PPR expanded its existing credit agreements through a US$20 million increase in its senior secured revolving note facility (from US$45 million to US$65 million, which was automatically reduced by US$5 million on February 1, 2019) and the issuance of an additional US$12.5 million principal amount of 15% subordinated notes due October 31, 2021. Marquee's previous credit facilities were repaid in full and terminated with funds drawn under the credit facility expansion.

[1,2,3] Adjusted funds flow, net capital expenditures and operating netback are non-IFRS measures and are defined below under "Other Advisories".

- On October 11, 2018, PPR closed a $5.5 million 'bought-deal' 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 were held in escrow until the closing of the Arrangement, upon which, the holders were granted for each subscription receipt held one PPR common shares and one half-warrant. Each whole warrant entitles the holder to acquire one common share at a price of $0.50 until October 11, 2020.

- Subsequent to year-end 2018, PPR's remaining $17.3 million of capital commitment in the Wheatland area was eliminated by mutual agreement of the Company and the lessor for an immaterial cash consideration. A current liability was recorded on the balance sheet as at December 31, 2018 for the cash payable to the lease owner. In conjunction with the full release, PPR did not renew its leases on the undeveloped lands; accordingly, in the fourth quarter of 2018, PPR recognized $5.3 million of E&E impairment.

Annual Operational & Financial Highlights

- PPR's strategy to focus on oil and natural gas liquid opportunities successfully led to an oil and liquids production weighting of 71% for 2018, up from 62% in 2017. The improvement in production mix resulted in a 9% and 15% annual increases in per boe realized price and per boe operating netbacks (before realized gains on derivatives), respectively.

- Annual production averaged 5,372 boe/d (71% liquids), at the midpoint of our 2018 guidance. Excluding the impact from non-core dispositions and shut-in of gas-weighted production in the Wheatland area during the second half of 2018, annual production increased by approximately 300 boe/d from 2017. The year-over-year increase reflected incremental production of 1,120 boe/d from the successful 2018 drilling program and 41 days of production from Marquee, which exceeded natural declines.

- Net loss was $33.0 million in 2018 compared to $47.8 million in 2017. The decrease in net loss was primarily due to non-cash items: a $28.9 million decrease in impairment losses, a $9.8 million increase of in unrealized derivative gains, and a combined $9.5 million decrease in E&E expenses and depletion and depreciation expenses, partially offset by a $6.2 million increase in unrealized losses on foreign exchange, a $3.9 million decrease in gains on a business combination and a $5.7 million increase in loss from disposition. The non-cash variances were further offset by a $13.9 million increase in realized losses on derivatives and a $3.4 million increase in transaction, restructuring and other costs.

- Operating netbacks[1] before realized hedging gains was $17.26/boe, a $2.25/boe improvement from 2017 due to higher realized prices of $3.69/boe, partially offset by $1.46/boe increase in royalty expenses. The year-over-year 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 netbacks before realized hedging gains was $4.00/boe lower than the midpoint of 2018 guidance due to lower than expected Edmonton Light and WCS prices as Canadian crude differentials widened to unprecedented levels in the fourth quarter of 2018, coupled with higher than expected royalties rates.

- Operating netback after realized hedging gains was $12.66/boe for 2018, a decrease of $4.82/boe from 2017. The decrease was driven by $7.07/boe increase in realized losses on derivative instruments.

- In this MD&A, adjusted funds flow[2] has been restated in the current and prior periods to include decommissioning liability settlements that were previously excluded from the calculation to conform to recent direction expressed by Alberta Securities Commission staff regarding funds flow disclosure by oil and gas issuers. The annual 2018 adjusted funds flow (included $2.1 million of settlement of decommissioning

[1,2] Operating netback and adjusted funds flow are non-IFRS measures and are defined below under "Other Advisories".

liabilities) totaled $8.0 million, a $9.9 million decrease over the $17.9 million generated in 2017. The decrease was primarily related to an increase of $13.9 million in realized losses on derivative instruments and a $2.8 million increase in cash interest expense, partially offset by an increase in operating netbacks of $3.9 million and a decrease in decommissioning liability settlements of $3.1 million.

- PPR drilled, completed and brought on production ten gross (10.0 net) new wells for $18.0 million, or $1.8 million per well. Year-to-date capital expenditures included another $11.8 million for Evi waterflood advancement, drilling two Slave Point wells (2.0 net) in Evi which was brought on production in Q1 2019, drilling two exploration wells at Evi that were deemed unsuccessful and abandoned, as well as facilities, pipelines, land and capitalized overhead.

  - In the Princess area, $10.5 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 second half 2018 and year-to-date 2018 results.
  - In the Wheatland area, $7.0 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, $3.3 million was allocated to the continued advancement of the waterflood project and $7.7 million was allocated to the drilling 6 wells (5.9 net). Four Granite Wash wells (3.9 net) were drilled in the fourth quarter of 2018, of which two (2.0 net) came on production late in 2018 and two were deemed unsuccessful. Two Slave Point wells were drilled in the fourth quarter of 2018, and completed and tied in during the first quarter of 2019.
  - Through the 2018 exploration program, the Company's flow-through share commitment (see "Contractual Obligations and Commitments") for 2018 was fulfilled.
  - In the first quarter of 2018, PPR acquired synergistic assets in the Princess area for $1.0 million, which included approximately 50 boe/d of production. In the third and fourth quarter of 2018, PPR disposed of certain non-core gas-weighted properties for $2.8 million. The disposed properties had production of approximately 60 boe/d and were cash flow neutral. During the fourth quarter of 2018, PPR disposed of certain non-core E&E assets for $3.2 million.

- At December 31, 2018, PPR had US$47.9 million of borrowings (CAD$65.4 million equivalent using the December 31, 2018 exchange rate of $1.00 USD to $1.3642 CAD) drawn against the US$65 million Revolving Facility (CAD$88.7 million equivalent using the year-end exchange rate) and US$29.5 million of Subordinated Notes (defined herein) (CAD$40.2 million equivalent using the using the year-end exchange rate) plus a working capital deficit of CDN$16.1 million (US$11.8 million equivalent using the year end exchange rate).

Fourth Quarter 2018 Operational & Financial Highlights

- Average production in the fourth quarter of 2018 was 5,937 boe/d, an increase of 22% from the fourth quarter of 2017. The production increase was due to approximately 1,500 boe/d of incremental production from the successful 2018 drilling program including 1,200 boe/d from Princess 1, 4 and 5, as well as the Arrangement with Marquee which contributed 930 boe/d of production for the quarter. These increases were partially offset by natural declines, shut-in of natural gas-weighted wells in the Wheatland area and non-core dispositions.

- Net loss was $3.5 million, compared to a net loss of $44.1 million in the comparable quarter of 2017. The decrease was primarily due to an increase in unrealized derivative gains by $33.9 million, a decrease in impairment loss by $25.3 million, and a combined $7.2 million decrease in E&E expense and depletion and depreciation expenses, partially offset by an increase in losses on dispositions by $8.1 million, a decrease in operating netbacks after hedging gains/losses by $9.9 million, an increase in foreign exchange loss by $4.7 million and an increase of transaction, restructuring and other costs by $3.4 million.

- Adjusted funds flow was a loss of $5.3 million (which included $0.7 million of decommissioning liability settlement), a $10.7 million decrease from the same period of 2017, primarily due to a decrease of $9.9 million in operating netbacks after hedging loss and higher interest expenses.

- Operating netbacks after realized hedging gains were a loss of $0.02/boe for the fourth quarter of 2018, a decrease of $22.06/boe from the fourth quarter of 2017. Realized prices decreased by $20.97/boe as a result of widening differentials for Canadian crude oil in the quarter, coupled with an increase in realized hedging losses by $4.22/boe.

- Capital expenditures prior to acquisitions or dispositions in the quarter were $7.8 million, primarily directed towards the Evi drilling program

Outlook

On February 25, 2019, Prairie Provident announced its planned 2019 capital budgeted (see February 25, 2019 press release). With continued volatility and uncertainty in Canadian oil and natural gas prices, coupled with PPR's ongoing commitment to enhance financial flexibility, the Company believes it has developed a disciplined and conservative budget that reflects the prevailing commodity price environment and the broader market, while supporting balance sheet strength and flexibility. Full-year 2019 guidance estimates are outlined in the table below.

2019 Financial and Operating Guidance Summary

Production guidance	6,100 -6,500 boe/d
2019 exit production	6,650 boe/d
Liquids weighting	69%
Capital expenditures(1)	$14.2 million
Development capital	$12.3 million
Operating expense	$18.70 – 19.95/boe
General & administrative expense	$3.60 – 3.80/boe
Pricing Assumptions	
Oil (WTI)	US$56.90/bbl
Oil (WTI)	C$75.00/bbl
Oil (WCS)	C$52.60/bbl
Natural gas (AECO)	C$1.90/mcf
Edmonton Light/WTI differential	C$6.80/bbl
WCS differential	C$22.30/bbl
USD/CAD exchange rate	0.76

(1) Previously, capital budget was disclosed at $18.9 million which included expected decommissioning (ARO) expenditures of $4.7 million. ARO expenditures are now excluded from capital expenditure numbers and included in adjusted funds flow to conform to recent direction from Alberta Securities Commission staff regarding funds flow disclosure by oil and gas issuers and permissible adjustments. This is a change in classification and does not change PPR's 2019 expected overall cash flows.

Arrangement Agreement

On November 21, 2018, PPR completed the acquisition of Marquee by way of a plan of arrangement under the Business Corporations Act (Alberta). Pursuant to the Arrangement, PPR acquired all of the outstanding Marquee common shares on a share exchange basis, with Marquee shareholders receiving an aggregate of 38,608,416 PPR shares based on an exchange ratio of 0.0886 PPR share for each Marquee.

The acquisition of Marquee 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 Marquee business and the assets and liabilities assumed were recorded at their fair values. Transaction costs associated with the acquisition were expensed when incurred.

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 acquired Greater Red Earth assets included producing assets with production of approximately 1,100 boe/d (98% liquids weighting) upon the acquisition and approximately 78,000 net acres of undeveloped land. Funding for the acquisition was provided 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 December 31,		Year Ended December 31,	
	2018	2017	**2018**	2017
Crude oil (bbls/d)	**4,042**	3,233	**3,676**	3,178
Natural gas (Mcf/d)	**10,523**	9,200	**9,426**	12,537
Natural gas liquids (bbls/d)	**141**	106	**125**	202
Total (boe/d)	**5,937**	4,872	**5,372**	5,470
Liquids Weighting	**70%**	69%	**71%**	62%

PPR's production for the three months ended December 31, 2018 increased by 22%, while production for the year ended December 31, 2018 decreased by 2% as compared to the corresponding periods in 2017.

Production increase in the fourth quarter of 2018 was partially due to 930 boe/d of incremental production from Marquee. The remaining increase was attributed to PPR's 2018 development program, where a total of ten gross (10.0 net) new wells were brought on production during 2018 including two Evi Granite Wash wells that came on production in late 2018. The 2018 drilling program resulted in an increase in the fourth quarter 2018 production by 1,500 boe/d, including 1,200 boe/d of average production from Princess 1, 4 and 5 wells. Production additions were partially offset by natural declines, the shut-in of natural-gas weighted wells in Wheatland which decreased the fourth quarter production by approximately 210 boe/d and the disposition of approximately 60 boe/d of non-core gas-weighted production at the beginning of the third quarter of 2018.

The minor annual production decline in 2018 as compared to 2017 encompassed the Company's conscious effort to focus on oil and natural gas liquids opportunities resulting in the divestitures of 400 boe/d of non-core gas weighted properties in the fourth quarter of 2017, as well as the 60 boe/d of non-core disposition in 2018 as described above. Additionally, the shut-in Wheatland production decreased annual production by approximately 60 boe/d. These dispositions and shut-ins, coupled with the development of more liquids-rich prospects, resulted in an increase in the oil and liquids weighting to 71% for 2018, compared to 62% for 2017. Excluding the impact from dispositions and shut-ins, annual production increased by approximately 300 boe/d. The Arrangement contributed approximately 235 boe/d of annual production, while the 2018 drilling program added another 1,120 boe/d of which 800 boe/d related to Princess 1, 4 and 5. These production additions exceeded PPR's natural production decline.

Revenue

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per unit amounts)	**2018**	2017	**2018**	2017
Revenue				
Crude oil	**11,331**	18,445	**77,112**	64,966
Natural gas	**1,683**	1,530	**5,457**	11,311
Natural gas liquids	**528**	535	**2,253**	2,734
Oil and natural gas revenue	**13,542**	20,510	**84,822**	79,011
Average Realized Prices				
Crude oil ($/bbl)	**30.47**	62.01	**57.47**	56.01
Natural gas ($/Mcf)	**1.74**	1.81	**1.59**	2.47
Natural gas liquids ($/bbl)	**40.70**	54.86	**49.38**	37.08
Total ($/boe)	**24.79**	45.76	**43.26**	39.57
Benchmark Prices				
Crude oil - WTI ($/bbl)	**77.59**	70.45	**83.93**	66.08
Crude oil - Edmonton Light Sweet ($/bbl)	**42.73**	68.63	**69.13**	62.46
Natural gas - AECO monthly index-7A ($/Mcf)	**1.87**	1.95	**1.51**	2.42
Natural gas - AECO daily index - 5A ($/Mcf)	**1.56**	1.69	**1.51**	2.15
Exchange rate - US$/CDN$	**0.76**	0.79	**0.77**	0.77

PPR's fourth quarter 2018 revenue decreased by 34% or $7.0 million from the fourth quarter of 2017, principally due to the significant drop in oil revenue. While oil production volumes increased by 25%, oil revenue decreased by 39% or $7.1 million due to a 51% reduction in realized oil prices. Benchmark prices for Canadian crude oil were impacted by ongoing transportation constraints, which resulted in Canadian crude benchmark pricing trading at a wider discount to WTI in 2018. Intensified by lower demands due to U.S. refinery outages in the fourth quarter of 2018, the differentials for light and heavy grades of Canadian oil widened significantly. In the fourth quarter of 2018, the WCS heavy differential averaged $42.35/bbl (2017 – $5.45/bbl) and the Edmonton par differential averaged $34.86/bbl (2017 – $1.82/bbl) after averaging $18.29/bbl and $8.04/bbl for the first nine months of 2018, respectively. Production curtailments mandated by the Alberta Government have resulted in a narrowing of the Canadian oil differentials early in 2019.

Fourth quarter 2018 natural gas revenue increased by 10% or $0.2 million, compared to the same quarter in 2017, reflecting a 14% increase in production offset by a 4% decrease in realized natural gas prices. A significant portion of the increase in the fourth quarter 2018 natural gas production was due to the Arrangement which closed on November 21, 2018.

On an annual basis, total revenue increased by 7% or $5.8 million, compared to 2017. The 19% or $12.1 million increase in crude oil revenue reflected a 3% increase in realized oil prices and a 16% rise in oil production. Edmonton Light Sweet averaged $69.13/bbl in 2018 which represented a differential of $14.80/bbl to WTI as compared to a $3.62/bbl differential in 2017. The WCS heavy oil differential averaged $24.35/bbl in 2018, relative to a differential of $5.75/bbl in 2017. Averaged WTI for 2018 increased by $17.85/bbl which muted the effect from the widened differentials and resulted in an insignificant change to PPR's realized oil prices on a year-over-year basis.

The 52% or $5.9 million annual decrease in natural gas revenue reflected a 36% drop in realized natural gas prices and a 25% natural gas production decrease. A significant portion of the decrease in gas production was due to the divestitures of non-core gas-weighted properties and shut-in of certain Wheatland production.

On a per boe basis, the 9% or $3.69/boe increase in averaged realized prices correlated to the overall average realized sales price and a rise in the liquids-weighted production mix to 71% in 2018 compared to 62% in 2017.

Royalties

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2018**	2017	**2018**	2017
Royalties	**1,902**	2,171	**13,060**	10,373
Per boe	**3.48**	4.84	**6.66**	5.20
Percentage of revenue	**14.0%**	10.6%	**15.4%**	13.1%

The Company pays royalties to respective provincial governments and landowners in accordance with the established royalty regime. 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.

On an annual basis, increased oil and NGL prices in 2018 as compared to 2017 resulted in increased Crown royalty rates. Additionally, of the 10 wells that came on production in 2018, 8 have flat freehold royalty rates which are above the average royalty rate of the Company. These factors resulted in increased royalties as a percentage of revenue basis in the year ended December 31, 2018 as compared to the respective period in 2017.

Fourth quarter 2018 royalties decreased by $0.3 million, but remained above the fourth quarter of 2017 on a percentage of revenue basis despite decreases in crude oil and natural gas prices. This was the result of flat royalty rates on new production as discussed above.

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)	**2018**	2017	**2018**	2017
Realized (loss) gain on derivatives	**(1,269)**	851	**(9,020)**	4,926
Unrealized gain (loss) on derivatives	**26,968**	(6,960)	**10,569**	783
Total gain (loss) on derivatives	**25,699**	(6,109)	**1,549**	5,709
Per boe				
Realized (loss) gain on derivatives	**(2.32)**	1.90	**(4.60)**	2.47
Unrealized gain (loss) on derivatives	**49.37**	(15.53)	**5.39**	0.39
Total gain (loss) on derivatives	**47.05**	(13.63)	**0.79**	2.86

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 unrealized gain on derivatives recognized in the fourth quarter and year ended December 31, 2018 was primarily due to the sharp decline in WTI futures pricing at year-end.

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 predominantly in US dollars to maintain such economic hedges.

As of December 31, 2018, the Company held the following outstanding derivative contracts:

Remaining Term	Reference	Total Daily Volume (bbl)	Premium/bbl	Weighted Average Price/bbl
Crude Oil Swaps				
January 1, 2019 - March 31, 2019	US$ WTI	900	—	$55.68
January 1, 2019 - December 31, 2019	CDN$ WTI	150	—	$64.39
April 1, 2019 - June 30, 2019	US$ WTI	325	—	$52.75
April 1, 2019 - May 31, 2019	US$ WTI	250	—	$52.65
July 1, 2019 - September 31, 2019	US$ WTI	500	—	$52.50
October 1, 2019 -December 1, 2019	US$ 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	—	$50.75
October 1, 2020 - December 1, 2020	US$ WTI	400	—	$50.50
Crude Oil Sold Call Options				
January 1, 2019 – December 31, 2019	CDN$ WTI	400	—	$85.00
January 1, 2020 – December 31, 2020	US$ WTI	400	—	$60.50
Crude Oil Put Options				
January 1, 2019 - June 30, 2019	US$ WTI	400	$4.95	$45.00
July 1, 2019 - December 31, 2019	US$ WTI	450	$6.29	$55.00
April 1, 2019 -June 30, 2019	CDN$ WTI	100	$2.75	$73.42
January 1, 2020 - March 31, 2020	CDN$ WTI	400	$3.65	$56.05
April 1, 2020 - June 30, 2020	CDN$ WTI	300	$6.00	$71.30
Crude Oil Collars				
January 1, 2019 – December 31, 2019	US$ 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)	Premium/GJ	Weighted Average Price/GJ
Natural Gas Swaps				
January 1, 2019 - March 31, 2019	AECO 7A Monthly Index	3,000	—	$2.73
July 1, 2019 - December 31, 2019	US$ NYMEX	3,000	—	$3.15
Natural Gas Put Options				
January 1, 2019 - March 31, 2019	AECO 7A Monthly Index	1,700	$0.13	$1.05
April 1, 2019 - June 30, 2019	AECO 7A Monthly Index	1,200	$0.25	$1.11
January 1, 20120 - March 30, 2020	AECO 7A Monthly Index	4,000	$0.15	$1.16
April 1, 2020 - June 30, 2020	AECO 7A Monthly Index	4,600	$0.25	$1.11
Natural Gas Collars				
January 1, 2019 - March 31, 2019	AECO 7A Monthly Index	3,000	—	$2.92/2.40
April 1, 2019 - June 30, 2019	AECO 7A Monthly Index	3,000	—	$2.14/1.90

The following table summarizes commodity derivative transactions entered subsequent to December 31, 2018:

Remaining Term	Reference	Total Daily Volume (bbl)	Premium/bbl	Weighted Average Price/bbl
Crude Oil Swaps				
July 1, 2020 - December 31, 2020	US$ WTI	500	—	$55.00
Crude Oil Sold Put Options				
January 1, 2020 - March 31, 2020	US$ WTI	400	—	$42.50
January 1, 2020 - March 31, 2020	US$ WTI	300	—	$45.00
January 1, 2021 - March 31, 2021	US$ WTI	200	—	$42.50
January 1, 2021 - December 31, 2021	US$ WTI	650	—	$40.00
Crude Oil Collars				
February 1, 2019 – December 31, 2019	US$ WTI	300	—	$50.00/60.00
April 1, 2019 – December 31, 2019	US$ WTI	150	—	$52.50/63.10
January 1, 2020 – March 31, 2020	US$ WTI	400	—	$52.50/65.00
January 1, 2020 – March 31, 2020	US$ WTI	300	—	$55.00/66.15
July 1, 2020 - December 31, 2020	US$ WTI	500	—	$50.00/59.00
January 1, 2021 – March 31, 2021	US$ WTI	200	—	$52.50/65.00
January 1, 2021 – December 31, 2021	US$ WTI	650	—	$50.00/64.25
Crude Oil Differential Swaps				
March 1, 2019 - June 30, 2019	CDN$ WCS - WTI Diff	500		$17.85
March 1, 2019 - June 30, 2019	CDN$ Edmonton Sweet - WTI Diff	1,500		$8.25

Remaining Term	Reference	Total Daily Volume (GJ)	Premium/GJ	Weighted Average Price/GJ
Natural Gas Swaps				
April 1, 2019 - October 31, 2019	US$ NYMEX	1,800	—	$2.70
July 1, 2019 - December 31, 2019	US$ NYMEX	1,420	—	$2.70

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)	**2018**	2017	**2018**	2017
Lease operating expense	**7,789**	7,152	**28,289**	27,535
Transportation and processing	**1,620**	1,392	**6,018**	7,251
Production and property taxes	**973**	768	**3,608**	3,864
Total operating expenses	**10,382**	9,312	**37,915**	38,650
Per boe	**19.01**	20.78	**19.34**	19.36

Although during the fourth quarter 2018 total operating expenses increased by 11% or $1.1 million, operating expenses on a per boe basis were 9% lower for the three months ended December 31, 2018, as compared to the corresponding period in 2017. The decrease in the fourth quarter of 2018 was the result of averaging fixed operating expenses over higher production volumes. For the year ended December 31, 2018, operating costs on a per boe basis remained consistent with 2017.

Lease operating expense for the fourth quarter 2018 increased by $0.6 million or 9%, from the same period in 2017, largely due to a 22% increase in average production. Lease operating expenses for the year ended December 31, 2018 increased by $0.8 million or 3% from the year of 2017, despite a 2% decrease in production. 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 driven by lower natural gas production which has lower per unit operating costs than oil production.

Transportation and processing expense for the three months ended December 31, 2018 increased by $0.2 million compared to the same period in 2017 and decreased by $1.2 million for the year ended December 31, 2018 compared to 2017. The changes in transportation and processing expenses were largely due to the changes in natural gas production for the applicable periods.

Production and property tax expense for the three months and year ended December 31, 2018 increased by $0.2 million and decreased $0.2 million, respectively, as compared to the same periods in 2017. The increase in the fourth quarter of 2018 is largely related to properties acquired under the Arrangement. The year-to-date 2018 decrease largely related to a favorable prior period adjustment of $0.6 million recorded in the second quarter of 2018.

Operating Netback

	Three Months Ended December 31,		Year Ended December 31,	
($ per boe)	**2018**	2017	**2018**	2017
Revenue	**24.79**	45.76	**43.26**	39.57
Royalties	**(3.48)**	(4.84)	**(6.66)**	(5.20)
Operating costs	**(19.01)**	(20.78)	**(19.34)**	(19.36)
Operating netback	**2.30**	20.14	**17.26**	15.01
Realized (losses) gains on derivative instruments	**(2.32)**	1.90	**(4.60)**	2.47
Operating netback, after realized (losses) gains	**(0.02)**	22.04	**12.66**	17.48

on derivative instruments				

PPR's operating netbacks after realized hedging were ($0.02) and $12.66 per boe for the three months and year ended December 31, 2018, respectively, which represents a decrease of $22.06 and $4.82 per boe compared with the same periods of 2017. For the three months ended 2018, the decrease in operating netback was primarily due to a decrease in the total realized sales price of $20.97/boe and an increase in realized losses on derivative instruments of $4.22 per boe from the comparative three-month period of 2017. These were partially offset by a per boe reduction of 28% in royalty costs and a per boe reduction of operating expenses by 9%.

For the year ended December 31, 2018 the decrease in operating netback was primarily due to an increase in realized losses on derivative instruments of $7.07 per boe and an increase in royalties of a $1.46 per boe, compared to December 31, 2018, partially offset by increase in realized prices.

General and Administrative Expenses ("G&A")

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2018**	2017	**2018**	2017
Gross cash G&A expenses	**2,742**	3,374	**10,159**	11,529
Gross share-based compensation expense	**104**	202	**810**	772
Less amounts capitalized	**(388)**	(573)	**(1,805)**	(2,083)
Net G&A expenses	**2,458**	3,003	**9,164**	10,218
Per boe	**4.50**	6.70	**4.67**	5.12

For the three months and year ended December 31, 2018, gross cash G&A were $0.6 million and $1.4 million lower than the respective periods in 2017. The decreases primarily related to cost savings in 2018.

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, the vesting period over which the related expense is recognized and timing and quantity of forfeitures. Capitalized G&A varies with the composition and compensation levels of technical departments and their time attributed to capital projects.

On a per boe basis, net G&A expenses decreased by 33% and 9% for the three months and year ended December 31, 2018 as compared to the respective periods in 2017.

Share-based compensation

During 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 December 31, 2018, 1,635,807 RSUs were outstanding. In addition, the Company issued 431,475 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, 2018, 635,712 DSUs were 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 December 31, 2018, there were 292,070 PSUs outstanding and 2,156,839 options with a weighted average strike price of $0.81 per share, of which 883,181 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 and past practice 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)	**2018**	2017	**2018**	2017
Interest expense	**2,402**	1,561	**7,616**	3,028
Accretion expenses	**674**	556	**2,363**	2,132
Total finance cost	**3,076**	2,117	**9,979**	5,160
Per boe	**5.63**	4.72	**5.09**	2.58

Interest expense is primarily comprised of interest incurred related to the Company's outstanding borrowings. The increase in interest expense of $0.8 million and $4.6 million for the three months and year ended December 31, 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 $2.4 million and $7.6 million of interest expense incurred in the three months and year ended December 31, 2018, $0.4 million and $1.3 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 months and ended December 31, 2018 was 9.7% and 9.0%, respectively (2017 – 7.6% and 4.75% respectively).

Accretion charges are non-cash expenses and primarily relate to the decommissioning liabilities. The slight increases in accretion expenses in the fourth quarter and year ended 2018 primarily relate to additional decommissioning liabilities acquired from the Arrangement on November 21, 2018.

Gain (Loss) on Foreign Exchange

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2018**	2017	**2018**	2017
Realized (loss) gain on foreign exchange	**(592)**	(309)	**(974)**	102
Unrealized (loss) gain on foreign exchange	**(3,160)**	1,272	**(4,710)**	1,519
Gain (loss) on foreign exchange	**(3,752)**	963	**(5,684)**	1,621

Foreign exchange gains (losses) incurred in the three months and year ended December 31, 2018 and December 31, 2017 related largely to borrowings denominated in US dollars (see "Capital Resources and Liquidity" section below).

Exploration and Evaluation Expense ("E&E")

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2018**	2017	**2018**	2017
Exploration and evaluation expense	**252**	3,711	**544**	4,877
Per boe	**0.46**	8.28	**0.28**	2.44

Exploration and evaluation expenses incurred in the fourth quarter and year 2018 were comprised of undeveloped land expiries. Fourth quarter 2017 E&E expenses primarily related to surrendered undeveloped lands. 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 and undeveloped land expiries.

Depletion and Depreciation

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2018**	2017	**2018**	2017
Depletion and depreciation	**5,108**	8,814	**29,686**	34,875
Per boe	**9.35**	19.66	**15.14**	17.47

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 decrease in the depletion rate for the three months and year ended December 31, 2018 from the comparable periods in 2017 reflected the assets and associated reserves acquired through the Arrangement with Marquee, changes in assumptions used in the Company's independent annual reserves evaluation, as well as, a credit of $4.2 million recorded in the fourth quarter of 2018 related to changes in decommissioning liabilities of properties with no carrying value and no previously recorded impairment.

Impairment Loss

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2018**	2017	**2018**	2017
E&E impairment	**5,279**	—	**5,279**	—
E&E impairment – decommissioning asset	**(170)**	(17)	**(170)**	(17)
Total E&E impairment	**5,109**	(17)	**5,109**	(17)
P&D impairment	**—**	30,700	**—**	34,100
P&D impairment – decommissioning asset	**372**	115	**210**	115
Total P&D impairment	**372**	30,815	**210**	34,215
Inventory impairment (recovery)	**—**	(21)	**—**	(21)
Total impairment loss	**5,481**	30,777	**5,319**	34,177

Fourth quarter and annual 2018 E&E impairment of $5.3 million related to undeveloped lands expected to expire in the near term that were not expected to be renewed (see "Capital Commitments" within this MD&A). For the three months and year ended December 31, 2018, PPR also recognized impairment and impairment recovery related to changes in decommissioning liabilities of certain properties that had zero carrying value.

Fourth quarter and annual 2017 P&D impairment primarily related to $30.7 million charge against Wheatland and Princess CGUs that was triggered by continued and prolonged declines in forecasted oil and natural gas prices.

In addition to the factors described above, the 2017 P&D impairment also included $3.4 million 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.

Net Capital Expenditures[1]

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2018**	2017	**2018**	2017
Drilling and completion	**6,456**	2,180	**19,345**	11,124
Equipment, facilities and pipelines	**756**	1,854	**7,179**	7,016
Land	**186**	2,075	**965**	2,460
Capitalized overhead and other	**393**	1,120	**2,066**	3,087
Total capital expenditures	**7,791**	7,229	**29,555**	23,687
Acquisitions – business combination	**116**	54	**1,003**	41,883
Asset dispositions (net of acquisitions)	**(3,246)**	(1,032)	**(6,082)**	(1,372)
Net Capital Expenditures	**4,661**	6,251	**24,476**	64,198

[1] Net capital expenditures are non-IFRS measures and are defined below under "Other Advisories".

PPR focused its capital activities during the fourth quarter of 2018 on the drilling of six gross (5.9 net) wells in the Evi area including four gross (3.9 net) exploratory light-oil Granite Wash locations and two gross (2.0 net) lower-risk Slave Point light-oil development wells. Two of the Granite Wash wells were successful and were completed, tied-in and brought on production in late November and early December, respectively. The two gross (2.0 net) unsuccessful Granite Wash locations were drilled and subsequently abandoned. The two Slave Point wells were completed, tied-in and came on production during the first quarter of 2019. During the fourth quarter of 2018, PPR disposed of certain non-core E&E assets for proceeds of $3.2 million and recorded $7.7 million of loss on disposition.

In addition to the fourth quarter expenditures, 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. Overall, ten gross (10.0 net) of the 14 gross (13.9 net) wells drilled in 2018 were on production by the end of the year, with an additional two gross (2.0 net) coming on production in the first quarter of 2019. Year-to-date capital expenditures also include $1.0 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 $2.9 million. The disposed properties had production of approximately 60 boe/d and were cash flow neutral.

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).

Transaction, Restructuring and Other Costs

Transaction, restructuring and other costs incurred for the three months and year ended December 31, 2018 were $3.4 million and $4.5 million, respectively, of which $1.8 million and $2.7 million related directly to the Arrangement with Marquee. For the three months and year ended December 31, 2017, $0.1 million and $1.1 million were incurred, respectively, for the Red Earth Acquisition and the business combination with Arsenal Energy Inc. Transaction costs were comprised largely of legal and professional fees and severance costs.

Decommissioning Liabilities

PPR's decommissioning liabilities at December 31, 2018 were $148.5 million (December 31, 2017 - $112.8 million) to provide for future remediation, abandonment and reclamation of the Company's oil and natural gas properties. The $35.7 million increase was primarily due to $51.9 million of liabilities assumed from Marquee, including $41.6 million of "day 1" adjustment from revaluating the acquired liabilities using the risk-free rate. The acquired liabilities were initially recognized and measured at fair-valued using the credit-adjusted discount rate of 10%. Partially offsetting the increase was a $3.0 million reduction from higher risk-free rates, settlements of decommissioning obligations totaling $2.1 million and a $9.8 million decrease from changes in cost estimates. Lower cost estimates were substantiated by recent abandonment work performed with actual costs 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 in the income statement.

The Company estimated the undiscounted and inflation-adjusted future liabilities of approximately $263.9 million spanning over the next 52 years, based on an inflation rate of 1.7% (December 31, 2017 – $171.5 million). Of the estimated undiscounted future liabilities, $14.0 million is estimated to be settled over the next five years. 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, 2018, the Company had $486.9 million (December 31, 2017 – $403.6 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 $362.0 million (December 31, 2017 – $179.9 million), scheduled to expire in the years 2019 to 2038.

As of December 31, 2018 and December 31, 2017, 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, 2018, the Company had a working capital deficit (as defined in “Other Advisories” below) of $16.1 million (December 31, 2017 – $2.2 million). Included within the Accounts Payable and Accrued Liabilities balance as of December 31, 2018 was $6.0 million of current liabilities residing in one of PPR’s subsidiaries. PPR expects the settlement of the liabilities will be limited to the subsidiary’s net asset value of approximately $1.3 million. Under IFRS, such liabilities continue to be measured and presented at their face value until they are legally discharged. Excluding the $4.7 million difference between the face value and expected settlement value would reduce the working capital deficit to $11.4 million as of December 31, 2018.

The increase in the working capital deficit from December 31, 2017 was primarily the result of capital expenditures incurred in late 2018, the Arrangement with Marquee which added a working capital deficit of $2.2 million upon closing of the transaction and as well as transaction costs incurred related the Arrangement with Marquee. In addition, weak Canadian crude prices in the fourth quarter of 2018 resulted in lower oil and gas revenue receivables at the end of 2018, compared to 2017.

Revolving Facility

On November 21, 2018, in conjunction with the closing of the Arrangement, PPR amended the borrowing base under its senior secured revolving note facility (“Revolving Facility”) with a maturity date of October 31, 2020. The amended Revolving Facility provided a borrowing base of US$65 million until January 31, 2019 (CDN$88.7 million equivalent using the year-end exchange rate of $1.00 USD to $1.3642 CAD), an increase of US$20 million from the June 21, 2018 amending agreement. After January 31, 2019, the borrowing base was automatically reduced by US$5 million. The US$5 million was provided to bridge short-term liquidity needs from the Arrangement.

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$54 million or US$30 million. As at December 31, 2018, the Company has drawn US$19.0 million (CDN$25.9 million equivalent using the year-end exchange rate) of USD denominated notes and CDN$39.5 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 April 2019.

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, 2018, PPR had outstanding letters of credit of $5.4 million. The letters of credit are issued by a financial institution at which PPR had a $5.5 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, 2018, $2.0 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 November 21, 2018, upon closing of the Arrangement, PPR issued an additional US$12.5 million (CDN $17.1 million using the year-end exchange rate of $1.00 USD to $1.3642 CAD) of subordinated senior notes ("Senior Notes") due October 31, 2021. In addition to the US$16 million Senior Notes issued on October 31, 2017 (CDN $21.8 million using the year-end exchange rate) due October 31, 2021, Senior Notes outstanding as at December 31, 2018 totaled US$28.5 million (CDN $38.9 million using the year-end exchange rate). Senior Notes 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 issued on October 31, 2017, the Company issued 2,318,000 warrants with an exercise price of $0.549 with a five-year term expiring October 31, 2022. Effective November 29, 2018, the exercise price of the 2,318,000 warrants issued on October 31, 2017 were adjusted down to $0.473 from $0.549 pursuant to their terms. Together with the Senior Notes issued on November 21, 2018, the Company issued 6,000,000 warrants with an exercise price of $0.282 expiring on October 31, 2023. The warrants issued under both tranches were classified as financial liabilities due to a cashless exercise provision and are 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, 2018 was $0.8 million.

As at December 31, 2018, $1.2 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 December 31, 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	3.4 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	2.0 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 1.1 to 1.0	Cannot be less than 1.1 to 1.0	1.1 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	1.2 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 December 31, 2018.

The financial impact from depressed oil prices during Q4 2018 is expected to have a lasting effect to the computation of certain financial covenants for 2019. In light of this, the Company has reached an understanding with our lenders and anticipates that the financial covenant requirements will be adjusted by March 31, 2019.

Shareholders' Equity

At December 31, 2018, PPR had consolidated share capital of $136.1 million (2017 – $121.5 million) and had 171.9 million outstanding common shares. In addition, PPR had 2.2 million options (2017 – 2.7 million), 0.3 million PSUs (2017 – 0.5 million) (which will be settled subject to a performance multiplier ranging from 0 to 2), 0.6 million DSUs (2017 – 0.2 million), 8.0 million warrants (2017 – 3.2 million) and 1.6 million RSUs (2017 – nil) outstanding as at December 31, 2018.

On November 29, 2018, the Toronto Stock Exchange ("TSX") accepted for filing 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 5,000,000 common shares during the period from December 4, 2018 to December 3, 2019. The NCIB effectively renews the existing NCIB, which was scheduled to end on November 30, 2018. Shares purchased under the bid will be cancelled. Transactions under the NCIB 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 of the Alberta Exchange Commission.

For the year of 2018, 395,600 shares were purchased and cancelled. Subsequent to December 31, 2018, the Company purchased and cancelled 643,130 shares under the NCIB.

As of the date of this MD&A, there are 171.3 million common shares, 3.5 million RSUs, 4.5 million stock options, 0.3 million PSUs, and 13.1 million outstanding warrants.

Capital Management and Liquidity

PPR's objective when managing capital is to maintain a flexible capital structure and sufficient liquidity to meet its financial obligations and to execute its planned capital expenditure program. The Company considers its capital structure to include shareholders' equity, the available borrowing under outstanding debt agreements, adjusted funds flow and working capital.

The Company monitors its current and forecasted capital structure in response to changes in economic conditions and the risk characteristics of its oil and gas properties. Adjustments are made on an ongoing basis in order to meet its capital management objectives. 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, though there is no certainty that any of these additional sources of capital would be available if required.

In light of continued volatility in benchmark oil prices and Canadian crude oil differentials, coupled with the lack of market support for growth in publicly-traded energy equities, PPR's short-term capital management objective is to fund its capital expenditures necessary for the replacement of production declines using adjusted funds flow. Value-creating activities may be financed with a combination of adjusted funds flow and other sources of capital. 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 flow.

PPR monitors its capital structure using the ratio of total debt to trailing twelve months' Bank Adjusted EBITDAX (as defined in "Other Advisories" below). Total debt to Bank 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 Bank Adjusted EBITDAX at December 31, 2018 was 3.4 to 1.0 (December 31, 2017 – 2.0 to 1.0). The increase in the ratio as at December 31, 2018 incorporated increased borrowings subsequent to the Arrangement with Marquee as well as significant declines in operating netbacks during the fourth quarter of 2018 from widened Canadian crude oil differentials. Management of debt levels is a priority for PPR and its 2019 capital program was designed with this key objective in mind.

Canadian crude oil differentials tightened significantly during the first quarter of 2019 and as such, operating netbacks are expected to improve. PPR's management believes that with the high-quality liquids-rich reserve base, deep development inventory, solid hedging program and steady base cash flows, the Company is well positioned to execute its business strategy.

Contractual Obligations, Commitments and Contingencies

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

	2019	2020	2021	2022	2023	Thereafter	Total
Debt	7,783	72,777	48,728	—	—	—	129,288
Leases – net	4,400	4,860	4,477	2,470	381	—	16,588
Firm transportation agreements	2,636	450	269	44	29	50	3,478
Capital commitments	—	750	—	—	—	—	750
Flow-through share commitment	1,453	—	—	—	—	—	1,453
Other agreements	187	85	27	28	28	234	589
Total	16,459	78,922	53,501	2,542	438	284	152,146

Included in 'Leases – net' are sublease recoveries in the amount of $1.1 million over the contractual period.

The flow-through share commitment relates to flow-through shares issued by PPR in 2018 and will be met by incurring CEE as defined in the *Income Tax Act* and renouncing the related income tax deductions to investors.

The 2020 capital commitment relates to land acquired in 2017 and is comprised of a remaining three-well drilling commitment. The costs included in the schedule above represent estimated drilling costs in the area.

In addition to contractual commitments, the Company has estimated future decommissioning liabilities of $263.9 million on an undiscounted basis, inflated at 1.7%, of which $14.0 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 committed total capital expenditures of $45.0 million pursuant to the acquisition of undeveloped land in the Wheatland area. As of December 31, 2018, PPR has incurred a total of $27.7 million towards the total capital commitment. Subsequent to year-end 2018, the Company and lessor reached agreement to terminate further commitments, thereby eliminating further drilling expenditure obligations for an immaterial cash consideration. A current liability was recorded on the balance sheet as at December 31, 2018 for the cash payable to the lessor. As such, the contractual obligations table above no longer includes any capital commitment related to this lease.

Flow-through Share Commitment

Pursuant to the bought deal financing which closed on October 11, 2018 and the related over-allotment option, the Company issued 3,750,150 flow-through common shares with respect to CEE at $0.46 per share. As defined by the *Income Tax Act*, the Company has until December 31, 2019 to incur $1.8 million of CEE costs related to this flow-through common share issuance. As at December 31, 2018, PPR incurred a total of $0.3 million towards this commitment.

During 2018, the Company fully met its remaining commitment related to the March 16, 2017 flow-through share issuance and related overallotment.

Contingencies

In September 2013, Lone Pine Resources Inc. 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 Lone Pine Resources Canada. A 10-day hearing before a NAFTA tribunal was completed in October 2017 with closing arguments heard in November 2017. The parties continue to await the tribunal's decision. 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 from 2002. The Court remitted the calculation of net revenue to the Court of Queen's Bench for determination. Although the final outcome of this case remains uncertain in light of the calculation issues left unresolved by the Court of Appeal decision and sent back to the Court of Queen's Bench for further determination, 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)	2018 Q4	2018 Q3	2018 Q2	2018 Q1	2017 Q4	2017 Q3	2017 Q2	2017 Q1
Oil and natural gas revenue	**13,542**	27,810	24,187	19,283	20,510	17,611	21,682	19,208
Royalties	**(1,902)**	(4,806)	(3,815)	(2,537)	(2,171)	(2,164)	(3,009)	(3,029)
Unrealized (loss) gain on derivatives	**26,968**	(1,884)	(9,316)	(5,199)	(6,960)	(2,586)	4,471	5,858
Realized gain on derivatives	**(1,269)**	(3,596)	(2,943)	(1,212)	851	2,222	1,150	703
Revenue net of realized and unrealized gains (losses) on derivative instruments	**37,339**	17,524	8,113	10,335	12,230	15,083	24,294	22,740
Net earnings (loss)	**(3,532)**	(2,627)	(15,064)	(11,742)	(44,145)	(11,985)	1,066	7,262
Per share – basic & diluted	**(0.02)**	(0.02)	(0.13)	(0.10)	(0.38)	(0.10)	0.01	0.07
Adjusted funds flow [(1)]	**(5,346)**	6,112	4,792	3,882	5,545	4,536	7,060	5,934
Per share – basic & diluted	**(0.04)**	0.05	0.04	0.03	0.05	0.04	0.06	0.02

1 Adjusted funds flow 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 Arrangement with Marquee, 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. 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. The Company has maintained positive adjusted funds flow in all of the past eight quarters except for the most recent quarter. Negative funds flow from operations in the fourth quarter of 2018 was the result of negative operating netbacks after realized losses on derivatives instruments caused by significant widening in Canadian oil differentials which caused a substantial reduction in realized revenue for the quarter.

Fourth quarter 2018 oil and natural gas revenue decreased significantly from the prior quarter due to lower realized oil and natural gas prices as a result of falling benchmark prices, partially offset by higher production. The net loss of $3.5 million in the quarter was attributable to non-cash items including losses on property dispositions of $7.8 million, impairment losses of $5.5 million and $5.1 million of depletion and depreciation expense.

Third quarter 2018 oil and natural gas revenue increased from the prior quarter due to higher production and higher realized oil prices. Higher production was attributable to the successful 2018 drilling program. Realized losses on derivatives incurred in the third, second and first quarters of 2018 were attributed to the continued strengthening in oil prices. 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 related 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 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 increased from the previous quarters due to the Company generating higher 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 improved blended realized prices due to strengthening commodity prices, as well as a higher liquids weighting in the quarter compared to the previous quarters. 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 included a full quarter of production from Arsenal and ten days of production from the Red Earth Acquisition, coupled with 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.

Annual Selected Financial and Operational Information

($000s except per unit amounts)	**2018**	2017	2016
Financial			
Oil and natural gas revenue	**84,822**	79,011	42,748
Net loss	**(32,965)**	(47,802)	(60,396)
Per share – basic & diluted[1]	**(0.27)**	(0.42)	(0.62)
Adjusted Funds Flow[2]	**8,034**	23,075	13,259
Per share – basic & diluted[3]	**0.07**	0.20	0.14
Net capital expenditures[4]	**24,476**	64,198	34,875
Corporate acquisitions of P&D assets	**55,375**	50,500	67,065
Total assets	**337,733**	263,507	247,835
Total liabilities	**290,682**	201,339	145,249
Long-term debt	**101,144**	55,760	15,047
Weighted average shares outstanding			
Basic & diluted[5]	**122,426**	113,350	97,868
Operating			
Production Volumes			
Crude oil (bbls/d)	**3,676**	3,178	2,012
Natural gas (Mcf/d)	**9,426**	12,537	9,253
Natural gas liquids (bbls/d)	**125**	202	126
Total (boe/d)	**5,372**	5,470	3,680
% Liquids	**71%**	62%	58%
Average Realized Prices			
Crude oil ($/bbl)	**57.47**	56.01	46.75
Natural gas ($/Mcf)	**1.59**	2.47	2.21
Natural gas liquids ($/bbl)	**49.38**	37.08	17.91
Total ($/boe)	**43.26**	39.57	31.74
Operating Netback ($/boe)[6]			
Realized price	**43.26**	39.57	31.74
Royalties	**(6.66)**	(5.20)	(3.63)
Operating costs	**(19.34)**	(19.36)	(17.39)
Operating netback	**17.26**	15.01	10.72
Realized gains on derivative instruments	**(4.60)**	2.47	7.23
Operating netback, after realized gains on derivative instruments	**12.66**	17.48	17.95

[1,3,5] Prior to the closing of an arrangement agreement with Arsenal Energy Ltd. on September 12, 2016 when Lone Pine Resources and Arsenal were brought under a common parent entity, the historical financial statements were prepared on a combined and consolidated basis and as such, it is not possible to measure per share amounts until subsequent to the closing of this transaction. 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 flow and Operating Netback are non-IFRS measures and are defined below under “Other Advisories”.

[4] Adjusted net capital expenditures are non-IFRS measures and are defined below under “Other Advisories”.

Increased revenue during 2018 was primarily the result of increased oil production due to PPR’s successful drilling program coupled with benchmark oil price improvements. Additionally, on November 21, 2018, PPR entered into an Arrangement with Marquee resulting in the acquisition of large, proven and delineated light oil plays. 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 2017 relative to 2016 also contributed to increased revenue.

Disclosure Controls and Procedures

Disclosure controls and procedures ("DC&P") seek to ensure that information to be disclosed by Prairie Provident is accumulated and communicated to management, as appropriate, to allow timely decisions regarding required disclosures. The Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures, as defined by National Instrument 52-109 Certification, to provide reasonable assurance that (i) material information relating to the Company is made known to the Company's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual and interim filings are prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. As at December 31, 2018, the Chief Executive Officer and the Chief Financial Officer evaluated the effectiveness of the design and operation of the Company's DC&P. Based on their evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's DC&P were effective as at December 31, 2018. All control systems by their nature can only provide reasonable, but not absolute, assurance that the objectives of the control system are met.

Internal Control over Financial Reporting

Internal control over financial reporting ("ICFR") 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, ICFR 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 control 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 ICFR is the Internal Control – Integrated Framework (2013) published 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 ICFR was effective as of December 31, 2018. There have been no changes in the Company's ICFR during the period from October 1, 2018 to December 31, 2018 that have materially affected, or are reasonably likely to materially affect, the Company's ICFR.

Limitation on Design

Management has limited the scope of the design of the Company's DC&P and ICFR to exclude the controls, policies and procedures of Marquee, which was acquired by PPR on November 21, 2018. The Marquee operations have been included in the consolidated financial statements of PPR since November 21, 2018. However, PPR and its certifying officers have not had sufficient time to appropriately assess the DC&P and ICFR previously used by Marquee and integrate them with those of PPR. The scope limitation is permitted under National Instrument 52-109, which allows an issuer to limit its design of DC&P and ICFR to exclude the controls, policies and procedures of a business acquired not more than 365 days before the end of the financial period to which the above conclusions relate.

During the year ended December 31, 2018, the Marquee business contributed revenues, net of royalties, of $1.1 million to PPR's consolidated revenues. At December 31, 2018, the consolidated assets of the Company included total assets of $68.5 million attributable to the acquired Marquee business.

Changes in Accounting Policies

The 2018 Annual Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). The Company adopted the following changes in accounting policies effective January 1, 2018 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 of the Annual 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 a right-of-use 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 and leases of low value on the transition date. The payments of these leases will be disclosed in the notes to the financial statements. 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. In addition, any provision for onerous contracts previously recognized will be applied to the associated right-of-use asset recognized upon transition to IFRS 16 on transition date. In these cases, there will be no impairment assessment made under IAS 36 - Impairment of Assets.

The Company is in the process of quantifying the impact of the contracts that falls within the scope of the new standard. The Company expects adjustments for its processing facility lease, office leases and the related subleases and certain vehicle leases; however, the full extent of the impact has not yet been finalized.

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 PPR's oil and gas assets is assessed at the CGU level, and therefore, the determination of a CGU costs 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, (iv) purchase price allocation for business combinations, and (v) 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, asset performance, estimate of future prices, royalties and costs, 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. 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 Black-Scholes option pricing model and forward pricing and swap models. The models incorporate various inputs including the credit quality of counterparties, foreign exchange spot and forward rates, volatilities of commodity prices 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 2018 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.

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, 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)	**December 31, 2018**	December 31, 2017
Current assets	**24,834**	19,588
Less current derivative instrument assets	**(5,768)**	895
Current assets excluding current derivatives instruments	**19,066**	18,693
Current liabilities	**41,047**	28,594
Less flow-through share premium	**(332)**	(711)
Less current derivative instrument liabilities	**—**	(4,156)
Less current portion of decommissioning liability	**(4,700)**	(2,300)
Less warrant liability	**(810)**	(533)
Current assets excluding current derivatives instruments and current portion of decommissioning liabilities	**35,205**	20,894
Working capital (deficit)	**(16,139)**	(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 (loss) and gain, adjusts the operating netback for only realized gains and losses on derivative instruments.

Adjusted Funds Flow

Adjusted Funds Flow is calculated based on cash flow from operating activities before changes in non-cash working capital, transaction costs, restructuring costs, and other non-recurring items. Management believes that such a measure provides an insightful assessment of PPR's operational 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 Flow 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 flow per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of earnings per share.

Note that in this MD&A, PPR has restated current and prior period Adjusted Funds Flow to include decommissioning settlements that were previously excluded from the calculation. This adjustment was made in order to meet regulatory requirements. The revised Adjusted Funds Flow numbers incorporate more seasonal variability into previously disclosed numbers as a significant portion of PPR's decommissioning settlements incurred in the last few years has been in winter access only areas, with considerably higher spend incurred in the winter months.

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

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2018**	2017	**2018**	2017
Cash flow from operating activities	**2,643**	5,646	**16,553**	16,621
Changes in non-cash working capital	**(11,012)**	149	**(12,623)**	501
Other	**(419)**	(534)	**(386)**	(258)
Transaction, restructuring and other costs	**3,442**	51	**4,490**	1,075
Adjusted Funds Flow	**(5,346)**	5,312	**8,034**	17,939

Bank Adjusted EBITDAX

The Company monitors its capital structure and liquidity based on the ratio of Debt to Bank 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 (for the periods prior to October 31, 2017, the "Amended Credit Facility"). "Bank 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. 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 net income. For purposes of calculating covenants under long-term debt, Bank Adjusted EBITDAX is determined using financial information from the most recent four consecutive fiscal quarters.

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

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	2018	2017	2018	2017
Net loss before income tax	(4,020)	(44,232)	(33,717)	(48,272)
Add (deduct):				
Interest	2,402	1,561	7,616	3,028
Depletion and depreciation	5,108	8,814	29,686	34,875
Exploration and evaluation expense	252	3,711	544	4,877
Unrealized (gain) loss on derivative instruments	(26,968)	6,960	(10,569)	(783)
Impairment loss	5,481	30,777	5,319	34,177
Accretion	674	556	2,363	2,132
Loss (gain) on foreign exchange	3,752	(963)	5,684	(1,621)
Share-based compensation	73	164	626	687
Loss (gain) on sale of properties	7,762	(314)	4,810	(853)
Gain on business combination	—	—	—	(3,893)
Gain on warrant liability	(354)	(46)	(563)	(46)
Transaction, reorganization and other costs	3,442	51	4,490	1,075
Pro-forma impact of acquisition	548	—	13,122	2,394
Bank Adjusted EBITDAX	(1,848)	7,039	29,411	27,777

Net Capital Expenditures

Net capital expenditures is a non-IFRS measure commonly used in the oil and gas industry. The measurement assists management and investors to measure PPR's investment in the Company's existing asset base.

Net capital expenditures is calculated by taking total capital expenditures, which is the sum of property and equipment and exploration and evaluation expenditures from the Consolidated Statement of Cash Flows, plus capitalized stock-based compensation, plus acquisitions from business combinations, which is the outflow cash consideration paid to acquire oil and gas properties, less asset dispositions (net of acquisitions), which is the cash proceeds from the disposition of producing properties and undeveloped lands.