Prairie Provident Resources Inc.

Management's Discussion and Analysis
For the Three Months and Year Ended December 31, 2019

Dated: March 26, 2020

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, 2019. This MD&A is dated March 26, 2020 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, 2019 (the "2019 Annual Financial Statements"). Additional information relating to PPR, including the Company's December 31, 2019 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 Summary

	Three Months Ended December 31,		Year Ended December 31,	
($000s except per unit amounts)	**2019**	2018	**2019**	2018
Production Volumes				
Crude oil (bbl/d)	**3,715**	4,042	**3,966**	3,676
Natural gas (Mcf/d)	**11,169**	10,523	**11,635**	9,426
Natural gas liquids (bbl/d)	**149**	141	**166**	125
Total (boe/d)	**5,725**	5,937	**6,071**	5,372
% Liquids	**67 %**	70 %	**68 %**	71 %
Average Realized Prices				
Crude oil ($/bbl)	**59.62**	30.47	**61.30**	57.47
Natural gas ($/Mcf)	**2.21**	1.74	**1.72**	1.59
Natural gas liquids ($/bbl)	**31.08**	40.70	**30.48**	49.38
Total ($/boe)	**43.81**	24.79	**44.18**	43.26
Operating Netback ($/boe)[2]				
Realized price	**43.81**	24.79	**44.18**	43.26
Royalties	**(4.49)**	(3.48)	**(4.55)**	(6.66)
Operating costs	**(21.62)**	(19.01)	**(21.04)**	(19.34)
Operating netback	**17.70**	2.30	**18.59**	17.26
Realized losses on derivatives	**(0.85)**	(2.32)	**(0.98)**	(4.60)
Operating netback, after realized losses on derivatives	**16.85**	(0.02)	**17.61**	12.66

Fourth Quarter 2019 Financial & Operational Highlights

- Production averaged 5,725[1] boe/d (67% liquids) for the fourth quarter of 2019, a 4% decrease from the same period in 2018. Natural declines were largely replaced by new well production and added production from the Arrangement completed in November 2018. The period-over-period decline was primarily due to the shut-in of uneconomic natural gas production.

- The latest Princess well commenced production on December 13, 2019, with average production of 464 boe/d (73% liquids) for the last 19 days of December, contributing 96 boe/d (73% liquids) of incremental production to the quarter.

- Fourth quarter 2019 operating netback[2] before the impact of derivatives was $9.3 million ($17.70/boe), and $8.9 million ($16.85/boe) after realized loss on derivatives, a $8.1 and $8.9 increase from the fourth quarter of 2018 primarily due to higher realized commodity prices.

- Adjusted funds flow ("AFF")[2], excluding $0.1 million of decommissioning settlements, was $4.8 million ($0.03 per basic and diluted share) for the fourth quarter of 2019, a 203% increase from the same quarter in 2018 due to higher production and an improved operating netback after realized losses on derivatives.

- Net loss totaled $12.7 million in the fourth quarter of 2019 compared to a net loss of $3.5 million in the same period last year, primarily driven by non-cash items such as depletion and amortization.

- Net capital expenditures[2] during the fourth quarter of 2019 were $3.1 million, primarily directed to drilling one Lithic Glauconite well and one stratigraphic well in the Princess area.

1 Q4 2019 average production is comprised of 3,436 bbl/d of light/medium oil, 278 bbl/d of heavy oil, 11,049 Mcf/d of conventional natural gas, 120 Mcf/d of coal bed methane and 149 bbl/d of natural gas liquids.
2 Operating netback, AFF and net capital expenditures are non-IFRS measures and are defined below under "Other Advisories".

Annual Financial & Operational Highlights

- For the year ended December 31, 2019, production averaged 6,071 boe/d[1] (weighted 68%), which was 13% or 699 boe/d higher than 2018, reflecting the impact of the Marquee acquisition and PPR's successful 2019 development program. The drilling of a Lithic Glauconite well was deferred from Q4 2019 into 2020 to preserve liquidity and development economics in light of widening WCS differentials in Q3 2019, leading to annual production nominally below 2019 guidance.
- Operating netback[2] was $41.2 million ($18.59/boe) before the impact of derivatives in 2019, and $39.0 million ($17.61/boe) after realized loss on derivatives, a 22% and 57% increase from 2018, respectively. Operating netback in 2019 reflects higher production, improved per boe realized oil and natural gas prices, royalties and realized losses on derivatives, partially offset by increased operating expenses from 2018.
- Adjusted funds flow ("AFF")[2], excluding $3.8 million of decommissioning settlements, was $22.3 million ($0.13 per basic and diluted share) as at December 31, 2019, a 120% increase from the same period in 2018 due to higher production and an improved operating netback.
- Net loss totaled $33.1 million for the year ended December 31, 2019, compared to a net loss of $33.0 million in the same period last year, driven primarily by non-cash items such as depletion and amortization.
- Exited December 31, 2019 with positive working capital[2] of $2.2 million (December 31, 2018 – deficit of $16.1 million), including cash and restricted cash of $7.8 million. The significant improvement in working capital was primarily due to repayment of accounts payable and accrued liabilities with AFFs and long-term debt borrowing, combined with an increase in accrued revenue at higher oil prices.
- As at December 31, 2019, net debt[2] totaled $111.4 million, which was $0.7 million and $5.9 million lower than September 30, 2019 and December 31, 2018, respectively. The decreases reflect PPR's effort to keep net capital expenditures within AFF, combined with the positive impacts of a stronger Canadian dollar on US-denominated debt.
- Net capital expenditures[2] for 2019 totaled $11.9 million, primarily focused in the Evi and Princess areas. In Evi, two gross (2.0 net) Slave Point wells drilled in Q4 2018 came on production in late February 2019. In Princess, the Company drilled and brought two development wells on production, one in June and one in December of 2019, while one stratigraphic well was drilled and abandoned during the fourth quarter of 2019. A 3D seismic program was undertaken in Princess during the year and PPR acquired undeveloped lands and mineral rights in Princess and Wayne.
- At December 31, 2019, PPR had US$57.6 million of borrowings drawn against the US$60.0 million Revolving Facility, comprised of US$30.0 million (CAN$40.5 million equivalent using the exchange rate at the time of borrowing) of CAD-denominated borrowing and US$27.6 million of USD-denominated borrowing (CAN$35.8 million equivalent using the December 31, 2019 exchange rate of $1.00 USD to $1.30 CAD). In addition, US$31.0 million (CAN$40.3 million equivalent using the December 31, 2019 exchange rate) of senior subordinated notes (defined herein) due October 31, 2021 were outstanding at year end, for total borrowings of US$88.6 million (CAN$116.7 million using the December 31, 2019 exchange rate). The increase in borrowings from year-end 2018 was largely used to reduce the working capital deficit.

1 2019 average production is comprised of 3,716 bbl/d of light/medium oil, 251 bbl/d of heavy oil, 11,506 Mcf/d of conventional natural gas, 128 Mcf/d of coal bed methane and 166 bbl/d of natural gas liquids.

2 Operating netback, AFF, Working capital (deficit), net debt and net capital expenditures are non-IFRS measures and are defined below under "Other Advisories".

2019 Corporate Highlights:

- During the fourth quarter of 2019, PPR's lenders confirmed continuation of the borrowing base under the senior secured revolving note facility ("Revolving Facility") at US$60.0 million, extended the maturity date of the Revolving Facility from October 31, 2020 to April 30, 2021, and removed the "term-out" feature so as to keep the facility as a revolving facility for the remainder of the term. Financial covenants are unchanged. The next borrowing base re-determination for the Revolving Facility will be on or about April 30, 2020.

- In the third quarter of 2019 PPR satisfied its remaining $1.8 million of Canadian Exploration Expense ("CEE") expenditure commitment related to its October 11, 2018 flow-through share issuance and related over-allotment.

- On March 29, 2019, the Company'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.

Outlook

In March 2020, the COVID19 pandemic coupled with the price war between Saudi Arabia and Russia resulted in significant downfall in global oil prices. PPR is cautious with its capital spending in light of uncertainties around worldwide energy consumption and supplies and the duration of this turmoil. The Company initiated the drilling of one Michichi well in February and plans to complete the well in late March. After completing the Michichi well, PPR plans to suspend its capital program to preserve future development economics unless oil prices recover in due course. Over 80% of PPR's 2020 forecast base oil production (net of royalties) is hedged, which is expected to help PPR weather through the depressed pricing environment. In addition, PPR is reviewing its 2020 budget, including exploring all avenues to reduce debt, G&A and operating expenses.

Prior Year Arrangement Agreement

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 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.

Results of Operations

Production

	Three Months Ended December 31,		Year Ended December 31,	
	2019	2018	**2019**	2018
Crude oil (bbls/d)	**3,715**	4,042	**3,966**	3,676
Natural gas (Mcf/d)	**11,169**	10,523	**11,635**	9,426
Natural gas liquids (bbls/d)	**149**	141	**166**	125
Total (boe/d)	**5,725**	5,937	**6,071**	5,372
Liquids Weighting	**67 %**	70 %	**68 %**	71 %

Average production for the three months ended December 31, 2019 was 5,725 boe/d (67% liquids), a decrease of 4%, while production for the year ended December 31, 2019 was 6,071 boe/d (68% liquids), an increase of 13%, compared to the corresponding periods in 2018.

Comparing the three months ended December 31, 2019 against the same period in 2018, natural declines were largely replaced by new well production and production from the Marquee acquisition that was completed in November 2018. The 4% period-over-period decline was largely due to the shut-in of uneconomic gas production.

For the year end December 31, 2019, increased production volumes compared to 2018 were driven by PPR's successful 2019 development program and incremental production volumes from the Marquee acquisition, partially offset by cold weather related outages of approximately 400 boe/d during Q1 2019 and the shut-in of 200 boe/d of natural gas-weighted production and natural declines.

In Evi, two gross (2.0 net) Slave Point wells that were drilled in late 2018 were brought on production in late February 2019. Combined production from the two wells averaged 153 boe/d (96% liquids) and 181 boe/d (97% liquids) for the three months and year ended December 31, 2019, respectively. PPR drilled and completed two Lithic Glauconite wells at Princess during 2019. The first well was brought on production on June 18, 2019, and produced on average 235 boe/d (43% liquids) and 168 boe/d (42% liquids) for the three months and year ended December 31, 2019, respectively. The second well, which also marked PPR's seventh successful Lithic Glauconite well in the Princess area in the last two years, was brought on production on December 13, 2019, with production averaging 464 boe/d (73% liquids weighting) for the last 19 days of 2019, contributing 96 boe/d (73% liquids) and 24 boe/d (73% liquids) for the three months and year ended December 31, 2019, respectively.

Revenue

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per unit amounts)	**2019**	2018	**2019**	2018
Revenue				
Crude oil	**20,378**	11,331	**88,732**	77,112
Natural gas	**2,272**	1,683	**7,312**	5,457
Natural gas liquids	**426**	528	**1,847**	2,253
Oil and natural gas revenue	**23,076**	13,542	**97,891**	84,822
Average Realized Prices				
Crude oil ($/bbl)	**59.62**	30.47	**61.30**	57.47
Natural gas ($/Mcf)	**2.21**	1.74	**1.72**	1.59
Natural gas liquids ($/bbl)	**31.08**	40.70	**30.48**	49.38
Total ($/boe)	**43.81**	24.79	**44.18**	43.26
Benchmark Prices				
Crude oil - WTI ($/bbl)	**75.18**	77.59	**75.72**	83.93
Crude oil - Edmonton Light Sweet ($/bbl)	**67.60**	42.73	**68.75**	69.13
Crude oil - WCS ($/bbl)	**54.27**	25.48	**58.42**	49.73
Natural gas - AECO monthly index-7A ($/Mcf)	**2.21**	1.87	**1.58**	1.51
Natural gas - AECO daily index - 5A ($/Mcf)	**2.35**	1.56	**1.71**	1.51
Exchange rate - US$/CDN$	**0.76**	0.76	**0.75**	0.77

PPR's fourth quarter 2019 revenue increased by 70% or $9.5 million from the fourth quarter of 2018, principally due to a significant increase in oil revenue. Crude oil revenue for the fourth quarter of 2019 increased by 80%, compared to the corresponding period in 2018, primarily due to realized crude oil prices rising 96%, partially offset by an 8% decrease in crude oil production volumes. PPR's product prices generally correlate to changes in the benchmark prices. While the average WTI price decreased by 3% or $2.41/bbl from the fourth quarter of 2018, production curtailments mandated by the Alberta Government throughout 2019 resulted in a narrowing of Canadian oil differentials. In the fourth quarter of 2019, the WCS to WTI differential decreased to $20.91bbl (Q4 2018 - $52.11/bbl) and the Edmonton Light Sweet to WTI differential decreased to $7.58/bbl (Q4 2018 - $34.86/bbl). Fourth quarter 2019 natural gas revenue increased by 35% or $0.6 million, compared to the same quarter in 2018, reflecting a 6% increase in production volumes and a 27% increase in realized natural gas prices.

Average realized prices per boe for the fourth quarter of 2019 increased by 77% or $19.02/boe compared to the same period in 2018, correlating to increases in the underlying crude oil and natural gas realized prices, partially offset by a 3 percentage point decrease in the liquids-weighting in PPR's production mix.

On a year-over-year basis, revenue increased by 15% or $13.1 million. The 15% increase in crude oil revenue reflected a 7% rise in realized crude oil prices and an 8% increase in oil production volumes. For the year ended December 31, 2019, the average WTI price decreased by 10% or $8.21/bbl, compared to 2018, which were mitigated by the narrowing of Canadian oil differentials relative to WTI and lower pipeline apportionment charges. For the year ended December 31, 2019, the WCS to WTI differential decreased to $17.30/bbl (2018 - $34.20/bbl) and the Edmonton Light Sweet to WTI differential decreased to $6.97/bbl (2018 - $14.80/bbl). The 34% increase in natural gas revenue reflected a 23% production increase and an 8% increase in realized natural gas prices.

Average realized prices per boe for the year ended December 31, 2019 increased by 2% or $0.92/boe, compared to the same period in 2018, resulting from higher crude oil and natural gas realized prices, partially offset by a decrease in the liquids-weighting from 71% to 68% in 2019.

Royalties

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2019**	2018	**2019**	2018
Royalties	**2,367**	1,902	**10,086**	13,060
Per boe	**4.49**	3.48	**4.55**	6.66
Percentage of revenue	**10.3 %**	14.0 %	**10.3 %**	15.4 %

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.

Fourth quarter 2019 royalties increased by $0.5 million, compared to the corresponding period in 2018, but on a percentage of revenue basis, royalties for the three months ended December 31, 2019 decreased compared to the corresponding period in 2018. The decrease was due to lower production for the Princess and Wheatland areas by 20% and 42%, respectively, despite 77% increase in the average realized price relative to the same period in 2018. Production in the Princess and Wheatland areas is subject to flat freehold royalty rates (range: 15% - 21%), which are higher than the Company's average royalty rate.

The year-to-date decrease in royalties as a percentage of revenue is due to a 50% production decrease in the Wheatland area, full year production from Marquee properties which bear lower royalties burden than the corporate average royalty rate and favorable gas cost allowance deductions.

Commodity Price and Risk Management

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

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2019**	2018	**2019**	2018
Realized loss on derivatives	**(448)**	(1,269)	**(2,169)**	(9,020)
Unrealized (loss) gain on derivatives	**(6,619)**	26,968	**(10,618)**	10,569
Total (loss) gain on derivatives	**(7,067)**	25,699	**(12,787)**	1,549
Per boe				
Realized loss on derivatives	**(0.85)**	(2.32)	**(0.98)**	(4.60)
Unrealized (loss) gain on derivatives	**(12.57)**	49.37	**(4.79)**	5.39
Total (loss) gain on derivatives	**(13.42)**	47.05	**(5.77)**	0.79

Realized losses and gains on derivative risk management contracts represent the cash settlements of outstanding contracts while unrealized gains and losses on derivative risk management reflect changes in the 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 loss on derivatives recognized for the three months and year ended December 31, 2019 is primarily related to a rise in WTI futures pricing at December 31, 2019 relative to the underlying prices of the derivative contracts.

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 at December 31, 2019, 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, 2020 - March 31, 2020	US$ WTI	450		$51.50
January 1, 2020 - June 30, 2020	US$ WTI	800		$55.10
January 1, 2020 - June 30, 2020	US$ WTI	200		$57.00
April 1, 2020 - June 30, 2020	US$ WTI	425		$51.00
April 1, 2020 - June 30, 2020	US$ WTI	600		$57.30
July 1, 2020 - September 30, 2020	US$ WTI	400		$50.75
October 1, 2020 - December 1, 2020	US$ WTI	400		$50.50
July 1, 2020 - December 31, 2020	US$ WTI	500		$55.00
Crude Oil Sold Call Options				
January 1, 2020 – December 31, 2020	US$ WTI	400		$60.50
Crude Oil Put Options				
January 1, 2020 - March 31, 2020	CDN$ WTI	400	$3.65	$56.05
April 1, 2020 - June 30, 2020	CDN$ WTI	300	$6.00	$71.30
Crude Oil Collars				
January 1, 2020 – December 31, 2020	US$ WTI	175		$49.00/54.75
July 1, 2020 - December 31, 2020	US$ WTI	500		$50.00/59.00
Crude Oil Three-way Collars				
January 1, 2020 – March 31, 2020	US$ WTI	400		$42.50/52.50/65.00
January 1, 2020 – March 31, 2020	US$ WTI	300		$45.00/55.00/66.15
January 1, 2021 – March 31, 2021	US$ WTI	200		$45.50/52.50/65.00
January 1, 2021 – December 31, 2021	US$ WTI	650		$40.00/50.00/64.25

Remaining Term	Reference	Total Daily Volume (GJ)	Premium/ GJ	Weighted Average Price/GJ
Natural Gas Put Options				
January 1, 2020 - 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

Subsequent to December 31, 2019 the Company entered into the following commodity derivative contracts:

Remaining Term	Reference	Total Daily Volume (bbl)	Premium/ bbl	Weighted Average Price/bbl
Crude Oil Collars				
July 1, 2020 – December 31, 2020	US$ WTI	700		$50.00/65.00

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)	**2019**	2018	**2019**	2018
Lease operating expense	**8,805**	7,789	**35,716**	28,289
Transportation and processing	**1,085**	1,620	**4,735**	6,018
Production and property taxes	**1,495**	973	**6,175**	3,608
Total operating expenses	**11,385**	10,382	**46,626**	37,915
Per boe	**21.62**	19.01	**21.04**	19.34

During the three months and year ended December 31, 2019, lease operating expenses increased by 13% or $1.0 million and 26% or $7.4 million, respectively, from the corresponding periods in 2018. Lease operating expense for the fourth quarter of 2019 increased from the same period in 2018 due to increased surface lease rentals and insurance premiums. On a year-over-year basis, the increase was primarily the result of higher production volume.

Transportation and processing expenses for the three months and year ended December 31, 2019 increased by 33% or $0.5 million and 21% or $1.3 million, respectively, compared to the same periods in 2018. The increases were primarily due to decreased natural gas production in the Wheatland and Princess areas, resulting in lower third-party natural gas processing and natural gas transportation costs.

Production and property tax expenses for the three months and year ended December 31, 2019 increased by 54% or $0.5 million and 71% or $2.6 million, respectively, compared to the corresponding periods in 2018. The increases primarily related to property taxes on the properties acquired from the Arrangement, freehold mineral taxes associated with new wells in the Princess area and higher administration and orphan levy fees paid to the Alberta Energy Regulator.

On a per boe basis, total operating expense for the three months and year ended December 31, 2019 increased by 14% or $2.61/boe and 9% or $1.70/boe, respectively, compared to the same periods in 2018. The increases were largely due to higher property taxes per boe on properties acquired through the Arrangement, rising fixed operating expenses as mentioned above and higher maintenance costs incurred in the first quarter of 2019 due to extreme cold weather, partially offset by lower third-party transportation and processing fees.

Operating Netback

	Three Months Ended December 31,		Year Ended December 31,	
($ per boe)	**2019**	2018	**2019**	2018
Revenue	**43.81**	24.79	**44.18**	43.26
Royalties	**(4.49)**	(3.48)	**(4.55)**	(6.66)
Operating costs	**(21.62)**	(19.01)	**(21.04)**	(19.34)
Operating netback	**17.70**	2.30	**18.59**	17.26
Realized losses on derivatives	**(0.85)**	(2.32)	**(0.98)**	(4.60)
Operating netback, after realized losses on derivatives	**16.85**	(0.02)	**17.61**	12.66

PPR's operating netback after realized losses on derivatives was $16.85/boe and $17.61/boe for the three months and year ended December 31, 2019, respectively, representing increases of $16.87/boe and $4.95/boe, respectively, compared with the corresponding periods of 2018.

For the three months ended December 31, 2019, the operating netback increase was due to average realized prices rising by $19.02/boe and a decrease in realized losses on derivatives of $1.47/boe, partially offset by increased royalties of $1.01/boe and operating expenses of $2.61/boe, respectively, compared to the corresponding three-month period in 2018.

For the year ended December 31, 2019, the operating netback increase was due to a increase in average realized prices of $0.92/boe, a decrease in realized losses on derivatives of $3.62/boe and a decrease in royalties of $2.11/boe, respectively, partially offset by a $1.70/boe increase in operating expenses, compared to the corresponding three-month period in 2018.

General and Administrative Expenses ("G&A")

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2019**	2018	**2019**	2018
Gross cash G&A expenses	**2,148**	2,742	**9,074**	10,159
Gross share-based compensation expense	**215**	104	**825**	810
Less amounts capitalized	**(388)**	(388)	**(1,622)**	(1,805)
Net G&A expenses	**1,975**	2,458	**8,277**	9,164
Per boe	**3.75**	4.50	**3.74**	4.67

For the three months and year ended December 31, 2019, gross cash G&A decreased by $0.6 million and $1.1 million, or 22% and 11%, respectively, compared to the same periods in 2018 as office lease payments are no longer included in G&A in 2019 after the adoption of IFRS 16.

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. Gross stock-based compensation increased by 107% and 2% for the three months and year ended December 31, 2019, respectively, compared with the same periods in 2018.

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

Finance Costs

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2019**	2018	**2019**	2018
Interest expense	**2,878**	2,049	**11,344**	6,522
Amortization of financing costs	**323**	305	**1,499**	973
Non-cash interest on financing lease	**231**	—	**1,028**	—
Non-cash interest on warrant liabilities	**98**	48	**357**	121
Accretion – decommissioning liabilities	**811**	642	**3,284**	2,238
Accretion – other liabilities	**3**	32	**76**	125
Total finance cost	**4,344**	3,076	**17,588**	9,979
Interest expense per boe	**5.46**	3.75	**5.12**	3.33
Non-cash interest and accretion expense per boe	**2.78**	1.88	**2.82**	1.76

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 $4.8 million for the three months and year ended December 31, 2019, respectively, compared to the corresponding periods in 2018 related to increased average borrowings and higher effective interest rates on the Company's Revolving Facility. PPR assumed Marquee's debt obligations as part of the Arrangement, resulting in higher average debt borrowings in 2019 than in 2018.

Of the $2.9 million and $11.3 million of interest expense incurred in the three months and year ended December 31, 2019, $0.5 million and $2.0 million, respectively, was deferred interest on the Senior Notes which will be repaid upon maturity (see Subordinated Senior Notes section below). The weighted average effective interest rate for the three months and year ended December 31, 2019 were 9.6% and 9.7%, respectively (2018 – 9.7% and 9.1%, respectively).

The Company adopted IFRS 16 using the modified retrospective method whereby the standard is applied retrospectively with the cumulative effect of initially applying the standard recorded to the opening retained earnings as at January 1, 2019 without any restatement to the comparative financial statements. As such, no non-cash interest on financing lease was recognized on lease liabilities for the three months and year ended December 31, 2018 (refer to the 2019 Annual Financial Statements, note 3o).

Accretion – decommissioning liabilities increased by $0.2 million and $1.0 million during the three months and year ended December 31, 2019, respectively, compared to the same periods in 2018, due to additional decommissioning liabilities acquired through the Arrangement.

Gain (Loss) on Foreign Exchange

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2019**	2018	**2019**	2018
Realized gain (loss) on foreign exchange	**102**	(592)	**202**	(974)
Unrealized gain (loss) on foreign exchange	**1,514**	(3,160)	**3,624**	(4,710)
Gain (loss) on foreign exchange	**1,616**	(3,752)	**3,826**	(5,684)

Foreign exchange gains (losses) incurred in the three months and year ended December 31, 2019 related largely to the translation impact on US dollar denominated borrowings (see “Capital Resources and Liquidity” section below).

Exploration and Evaluation ("E&E") Expense

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2019**	2018	**2019**	2018
Exploration and evaluation expense	**460**	252	**996**	544
Per boe	**0.87**	0.46	**0.45**	0.28

E&E expenses are comprised of undeveloped land expiries.

Depletion and Depreciation

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2019**	2018	**2019**	2018
Depletion and depreciation	**9,822**	5,108	**39,826**	29,686
Depreciation on right-of-use assets	**685**	—	**2,743**	—
Total depletion expense	**10,507**	5,108	**42,569**	29,686
Per boe	**19.95**	9.35	**19.21**	15.14

Depletion and depreciation rates are subject to change based on changes in the carrying value of the asset base, changes in future development costs, reserve updates and changes in production by area. The increase in the depletion expenses during 2019 from 2018 reflects the assets and associated reserves acquired through the Arrangement. The higher per unit expenses were due to increased depletion expense over similar average production between the comparable periods.

Depreciation on the right-of-use assets reflects the depreciation charge recognized for the three months and year ended December 31, 2019 after the adoption of IFRS 16 – *Leases*, effective January 1, 2019. The Company adopted IFRS 16 using the modified retrospective method. As such, no depreciation was recognized on right-of-use assets for the three months and year ended December 31, 2018 (refer to the 2019 Annual Financial Statements, note 3o).

Impairment (Recovery) Loss

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2019**	2018	**2019**	2018
E&E impairment	**—**	5,279	**—**	5,279
E&E impairment – decommissioning asset loss (recovery)	**656**	(170)	**656**	(170)
Total E&E impairment	**656**	5,109	**656**	5,109
P&D impairment	**—**	—	**—**	—
P&D impairment – decommissioning asset (recovery)	**(1,092)**	372	**(1,092)**	210
Total P&D impairment	**(1,092)**	372	**(1,092)**	210
Total impairment (recovery) loss	**(436)**	5,481	**(436)**	5,319

The Company's E&E assets were assessed for impairment as at December 31, 2019, and it was concluded that no indicators of impairment were present. However, PPR recognized a non-cash E&E impairment related to changes in estimates used in decommissioning liabilities.

Fourth quarter and year-to-date 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. 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.

At December 31, 2019, the decreases in crude oil and natural gas benchmark prices as compared to December 31, 2018 were considered potential indicators of impairment for the P&D assets. As a result, the Company completed impairment tests on all of its cash generating units ("CGU's") in accordance with IAS 36 and determined that the carrying amounts of the CGUs did not exceed their fair value less costs of sale.

Neither a 4 percentage point increase in the discount rate nor a 4% decrease in the forward price estimates used in the impairment assessments would result in any impairment loss.

In the three months and year ended December 31, 2019, PPR recognized a non-cash P&D impairment recovery of $1.1 million related to changes in estimates used in decommissioning liabilities. During the three months and year ended December 31, 2018, the Company recorded impairment recovery of $0.2 million related to changes in decommissioning liabilities of certain properties having a zero carrying value.

Net Loss

	Three Months Ended December 31,		Year Ended December 31,	
($000s except per share)	**2019**	2018	**2019**	2018
Net loss	**(12,734)**	(3,532)	**(33,079)**	(32,965)
Per share – basic	**(0.07)**	(0.02)	**(0.19)**	(0.27)
Per share – diluted	**(0.07)**	(0.02)	**(0.19)**	(0.27)

Net loss for the fourth quarter of 2019 was $12.7 million, compared to a net loss of $3.5 million in the same quarter of 2018. Although PPR recognized an additional $9.5 million of AFF (excluding decommissioning settlements) in the fourth quarter of 2019 than the same quarter of 2018, net loss increased by $9.2 million due to non-cash items, including a $33.6 million increase in unrealized derivative losses due to changes in the marked-to-market value of open derivative contracts and a $5.4 million increase in depletion, depreciation and amortization, partially offset by a $5.9 million decrease in impairment loss, a $4.7 million increase in unrealized foreign exchange gain and a $7.9 million increase in gain on disposition.

Net loss was $33.1 million for the year ended December 31, 2019, compared to a net loss of $33.0 million in the same period of 2018. The $0.1 million increase in net loss was primarily due to non-cash items, including a $21.2 million increase in unrealized derivative losses due to changes in the marked-to-market value of open derivative contracts and a $12.9 million increase in depletion, depreciation and amortization, partially offset by a $12.2 million increase in AFF (excluding decommissioning settlements), $5.8 million decrease in impairment loss, a $8.3 million increase in unrealized foreign exchange gain, a $5.1 million increase in gain on disposition and a $3.3 million reduction in other liabilities.

Net Capital Expenditures[1,2]

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2019**	2018	**2019**	2018
Drilling and completion	**1,596**	6,456	**5,907**	19,345
Equipment, facilities and pipelines	**693**	756	**1,970**	7,179
Land and seismic	**483**	186	**2,717**	965
Capitalized overhead and other	**519**	393	**1,547**	2,066
Total capital expenditures	**3,291**	7,791	**12,141**	29,555
Acquisitions – business combination	**—**	116	**—**	1,003
Asset dispositions (net of acquisitions)	**(193)**	(3,246)	**(285)**	(6,082)
Net capital expenditures	**3,098**	4,661	**11,856**	24,476

[1] Net capital expenditures include expenditures on E&E assets.
[2] Net capital expenditures are non-IFRS measures and are defined below under "Other Advisories"

Capital expenditures prior to acquisitions or dispositions for the three months and year ended December 31, 2019 were $3.3 million and $12.1 million, respectively. The Company focused its capital activities during the first three months of 2019 in the Evi and Princess areas. In Evi, PPR incurred expenditures of $2.8 million during the first quarter of 2019 related to the completion, equipping and tie-in of two gross (2.0 net) Slave Point wells, both of which came on production in late February 2019. During the second quarter of 2019, one gross (1.0 net) well in southern Princess was drilled and brought on production in mid-June 2019. The Company incurred total capital expenditures of $1.6 million to drill, complete, equip and tie-in this new well. Further, PPR acquired undeveloped lands in the Michichi and Princess areas for $0.4 million and $0.3 million, respectively, and mineral rights in the Wayne area for $0.5 million through the year. During the third quarter of 2019, the Company recompleted one well in the Provost area, undertook facility work at Evi and spent $0.9 million on 3D seismic in the Princess area.

During the fourth quarter of 2019, PPR's most recent well in Princess was completed and brought on production during the latter half of December 2019. The Company incurred total capital expenditures of $2.1 million to drill, complete, equip and tie-in this new well. In the Princess area, the Company acquired undeveloped lands and mineral rights for $0.3 million and one CEE stratigraphic well was drilled and abandoned for total capital expenditures of $0.4 million.

During the fourth quarter of 2018, PPR drilled 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. The two successful Granite Wash wells were completed, tied-in and brought on production in late November and early December 2018, respectively, while the remaining unsuccessful Granite Wash locations were 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 a $7.7 million loss on disposition.

During 2018, PPR drilled, completed, equipped and tied-in five gross (5.0 net) wells in the Princess area and three gross (3.0 net) wells in the Wheatland area, constructed pipelines and a multi-well satellite in Princess and expanded the Evi waterflood project with the conversion of three producing wells into injector wells. Overall in 2018, ten gross (10.0 net) of the 14 gross (13.9 net) wells drilled 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. Full year 2018 capital expenditures also included $1.0 million for the acquisition of oil and natural gas properties and infrastructure in the Princess area in the first quarter of 2018 and the disposition of certain non-core gas weighted properties for cash proceeds of $2.9 million in the third quarter of 2018. The disposed properties had production of approximately 60 boe/d and were cash flow neutral.

Transaction, Restructuring and Other Costs

Transaction, restructuring and other costs incurred for the three months ended December 31, 2019 were a nominal amount and were $0.9 million for the year ended December 31, 2019, primarily related to the Arrangement with Marquee in Q4 2018. For the three months and year ended December 31, 2018, $3.4 million and $4.5 million were incurred, respectively, of which $1.8 million and $2.7 million related directly to the Arrangement with Marquee.

Decommissioning Liabilities

PPR's decommissioning liabilities at December 31, 2019 were $167.8 million (December 31, 2018 - $148.5 million) to provide for future remediation, abandonment and reclamation of PPR's oil and gas properties. The increase of $19.3 million from year-end 2018 was due to $3.3 million of accretion of decommissioning liabilities and changes in estimates of $19.3 million principally related to lower risk-free rates applied as at year-end 2019, partially offset by a decrease in cost estimates related to properties acquired from the Arrangement. The increase was partially offset by settlements of decommissioning obligations of $3.8 million.

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 $266.4 million spanning over the next 52 years, based on an inflation rate of 1.7% (December 31, 2018 – $263.9 million). Of the estimated undiscounted future liabilities, $20.0 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, 2019, the Company had $467.6 million (December 31, 2018 – $496.4 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 $382.8million (December 31, 2018 – $353.9 million), scheduled to expire in the years 2020 to 2039.

As of December 31, 2019 and December 31, 2018, 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 of the likelihood 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, 2019, the Company had positive working capital (as defined in "Other Advisories" below) of $2.2 million (December 31, 2018 – $16.1 million deficit). The improvement in working capital from December 31, 2018 was primarily the result of repaying accounts payable and accrued liabilities with AFFs and long-term debt borrowing, combined with an increase in accrued revenue at higher oil prices.

Revolving Facility

In the fourth quarter of 2019, PPR confirmed continuation of the borrowing base under its senior secured revolving note facility ("Revolving Facility") at US$60.0 million, extended the maturity date of the Revolving Facility from October 31, 2020 to April 30, 2021, and removed the "term out" feature so as to keep the facility as a revolving facility for the remainder of the term. Financial covenants remain unchanged. The next borrowing base re-determination date will be on or about April 30, 2020.

The Revolving Facility provides a borrowing base of US$60.0 million. It is denominated in USD, but accommodates CAD advances up to the lesser of CAN$54 million or US$30 million. As of December 31, 2019, PPR had US$57.6 million (December 31, 2018 – US$49.0 million) of borrowings drawn against the US$60.0 million Revolving Facility, including US$30.0 (CAN$40.5 million equivalent using the exchange rate at the time of borrowing; December 31, 2018 – US$30.0 million or CAN$40.5 million) of CAD denominated borrowing and US$27.6 million (CAN$35.8 million equivalent using the December 31, 2019 exchange rate of $1.00 USD to $1.30 CAD; December 31, 2018 – US$19.0 million or CAN$25.9 million using the December 31, 2018 exchange rate of $1.00USD to $1.36CAD) of USD denominated borrowing. The increase in borrowings from year-end 2018 was largely used to reduce working capital deficit. All notes were issued at par by PPR Canada and are guaranteed by Prairie Provident Resources Inc. and certain of its other subsidiaries and secured by a US$200 million debenture.

The determination of the borrowing base is made by the lenders, in their sole discretion, taking into consideration the estimated value of PPR's oil and natural gas properties in accordance with the lenders' customary practices for oil and gas loans. If a borrowing base deficiency exists because of a re-determination, the lender is required to notify the Company of such shortfall. The Company may repay the shortfall amount by either making one installment within 90 days or six equal consecutive monthly installments beginning within 30 days after the Company's receipt of the borrowing base deficiency notice.

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.

During the fourth quarter of 2019, the note agreement was further amended as such that for the period between December 1, 2019, and March 31, 2020, the Applicable Margin for CDOR and LIBOR advances was set at 500 bps.

As at December 31, 2019, PPR had outstanding letters of credit of $4.9 million. The letters of credit are issued by a financial institution at which PPR posted a 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, 2019, $1.3 million of deferred costs related to the Revolving Facility was netted against its carrying value (December 31, 2018 – $2.0 million).

Subordinate Senior Notes

On October 31, 2017 the Company issued US$16.0 million Senior Notes (CAN$20.8 million using the December 31, 2019 month-end exchange rate of $1.00 USD to $1.30 CAD) due October 31, 2021. In addition, upon closing of the Arrangement on November 21, 2018, PPR issued an additional US$12.5 million (CAN$16.2 million using the December 31, 2019 month-end exchange rate of $1.00 USD to $1.30 CAD) of Senior Notes. Senior Notes outstanding as at December 31, 2019 totaled US$28.5 million (CAN$37.0 million using the December 31, 2019 month end exchange rate of $1.00 USD to $1.30 CAD). 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. As at December 31, 2019, US$2.5 million (CAN$3.3 million using the December 31, 2019 month-end exchange rate of $1.00 USD to $1.30 CAD; December 31, 2018 - US$1.0 million or CAN$1.4 million using the December 31, 2018 month-end exchange rate of $1.00 USD to $1.36 CAD) of interests were deferred and will be repaid upon maturity of the Senior Notes.

In conjunction with the issuances of the Senior Notes, the Company issued a total of 8,318,000 warrants. Concurrent with the issuance of the October 31, 2017 Senior Notes, the Company issued 2,318,000 warrants with an exercise price of $0.549 and 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. Concurrent with the issuance of the November 21, 2018 Senior Notes, the Company issued 6,000,000 warrants with an exercise price of $0.282 expiring on October 31, 2023.

The warrants are 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 valuation model. The value of the warrant liability as at December 31, 2019 was $0.1 million (December 31, 2018 - $0.8 million).

As at December 31, 2019, $0.9 million of deferred costs related to PPR’s Senior Notes was netted against its carrying value (December 31, 2018 – $1.2 million).

Covenants

During the second quarter of 2019, PPR finalized the amending agreement terms with its lender related to its Revolving Facility and Senior Notes, which eased certain financial covenant thresholds and were effective for the quarter ending March 31, 2019 through to the quarter ending December 31, 2019. The threshold easing was intended to accommodate the continuing impact from widened Canadian crude oil price differentials during the fourth quarter of 2018 on the computation of PPR's financial covenants for 2019.

The financial covenants applicable to December 31, 2019 are as follows:

Financial Covenant	**Revolving Facility Requirement**	**Senior Note Requirement**	**As at December 31, 2019**
Total Leverage – adjusted indebtedness to EBITDAX	Cannot Exceed 3.75 to 1.0	Cannot Exceed 4.00 to 1.00	3.6 to 1.0
Senior Leverage – senior adjusted indebtedness to EBITDAX	Cannot Exceed 3.25 to 1.0	Cannot Exceed 3.50 to 1.0	2.3 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 0.9 to 1.0 [1]	Cannot be less than 0.9 to 1.0 [1]	1.1 to 1.0
Current ratio – consolidated current assets, plus any undrawn capacity under the Revolving Facility, to consolidated current liabilities	Cannot be less than 0.85 to 1.0	Cannot be less than 0.85 to 1.0	1.3 to 1.0

1. The Asset Coverage covenant was amended to 0.9x to 1.0 from 1.3x to 1.0 for December 31, 2019.

The Company was in compliance with all covenants as at December 31, 2019.

Shareholders' Equity

At December 31, 2019, PPR had consolidated share capital of $136.0 million (December 31, 2018 – $136.1 million) and had 171.4 million (December 31, 2018 – 171.9 million) outstanding common shares. The Company also had 4.8 million (December 31, 2018 – 8.0 million) warrants outstanding from a bought deal financing and a private placement completed in October 11, 2018. Each warrant entitles the holder to purchase one PPR share at a price of $0.50 until October 11, 2020, subject to adjustment in certain circumstances.

In the first quarter of 2019, the Company granted 2.4 million options to officers and employees. As at December 31, 2019, 3.9 million (December 31, 2018 – 2.2 million) options were outstanding with a weighted average strike price of $0.48 per share, of which 1.3 million were exercisable at a weighted average strike price of $0.82 per share. Options vest evenly over a three-year period and expire five years after the grant date. During the first quarter of 2019, the Company also granted 2.4 million restricted share units ("RSUs") to officers and employees. RSUs vest evenly over a three-year period. As at December 31, 2019, 3.2 million (December 31, 2018 – 1.6 million) RSUs were outstanding. In addition, the Company issued 1.7 million deferred share units ("DSUs") to non-management directors in lieu of cash payments for a portion of their annual retainer during 2019. 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, 2019, 2.3 million (December 31, 2018 – 0.6 million) DSUs were outstanding.

Previously issued share-based compensation awards also included performance share units "PSUs". As at December 31, 2019, no (December 31, 2018 – 0.3 million) PSUs were outstanding. 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.

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. During the three months and year ended December 31, 2019, the Company repurchased and cancelled zero and 0.6 million of common shares under the NCIB. The Company has not renewed the NCIB since December 2019.

As of the date of this MD&A, there are 172.1 million common shares, 2.9 million RSUs, 6.6 million stock options, 2.3 million DSUs and 13.1 million outstanding warrants.

Capital Management, Liquidity and Going Concern

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, AFF 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 or acquiring or disposing of assets, though there is no certainty that any of these additional sources of capital would be available if required.

This MD&A has been prepared in accordance with generally accepted accounting principles applicable to a going concern, which assumes that PPR will be able to realize its assets and discharge its liabilities in the normal course of business.

The oil and natural gas commodity price environment has been extremely volatile and depressed over the last few years. PPR has, to the best of its ability, managed through this low commodity price environment by maintaining an active risk management program and by managing a capital program with cash flows, debt and equity capital. However, the recent downfalls in global oil prices resulted in deterioration in the fair value of its reserves and the Company's projected cash flows over the next 12 months. Such forecasts may change based upon actual revenue received during the year, changes in future oil and natural gas pricing and future business plans.

At December 31, 2019, the amount outstanding on the Revolving Facility aggregated to USD$56.5 million (Note 10). The maximum amount available on lines of credit at December 31, 2019 was USD$60 million. The Company also has Senior Notes of US$31 million which are due on October 31, 2021. The Revolving Facility is subject to semi-annual reviews of the borrowing base, with the next review scheduled to conclude on or around April 30, 2020. The lenders have sole discretion on the determination of the borrowing base, which is based predominately on the amount of the Company's proved developed producing oil and natural gas reserves. The current state of the Canadian energy industry coupled with significant declines in commodity prices since December 31, 2019 have negatively impacted the available amount of credit facilities within the industry. Both the Revolving Facility and Senior Notes have financial covenants as more fully described in Note 10 to the Annual Financial Statements. At forward prices for crude oil being traded in the futures market subsequent to March 5, 2020, management is forecasting a breach in covenants within the next 12 months.

PPR forecasts that it continues to meet its obligations including interest payments, capital spending and abandonment and remediation expenses with its internally generated cash flows and available borrowing capacity. However, there are no assurances that the lenders will maintain the borrowing base at current levels, which may result in a borrowing base shortfall. If the Company cannot repay a borrowing base shortfall, it would represent an event of default under both the Revolving Facility and the Senior Notes. In such case, the lenders have the right to demand immediate repayment of all amounts owed under both facilities.

Due to these factors, there is a material uncertainty that may cast significant doubt on the Company's ability to continue as a going concern. This MD&A does not include adjustments to the recoverability and classification of recorded asset and liabilities and related expenses that might be necessary should the Company be unable to continue as a going concern and therefore be required to realize its assets and liquidate its liabilities and commitments in other than the normal course of business at amounts different from those in the accompanying consolidated financial statements. Such adjustments could be material.

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, 2019 was 3.6 to 1.0 (December 31, 2018 – 3.4 to 1.0). Management of debt levels is a priority for PPR and the Company's 2019 capital program was designed with this key objective in mind.

Contractual Obligations, Commitments and Contingencies

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

	2020	2021	2022	2023	2024	Thereafter	Total
Debt	9,447	127,757	—	—	—	—	137,204
Leases - variable	1,117	909	76	—	—	—	2,102
Firm transportation agreements	1,459	368	190	96	30	30	2,173
Other agreements	176	88	42	43	29	217	595
Total	12,199	129,122	308	139	59	247	142,074

Contractual obligations and commitments are outlined in Note 24 of the Annual Financial Statements.

The most significant change from December 31, 2018 relates to the removal of lease commitments which are now recorded as lease liabilities on the balance sheet (see Note 4 to the Annual Financial Statements). In 2019, the Company fully met its $1.8 million of CEE costs commitments related to the October 11, 2018 flow-through share issuance and related over allotment (see capital commitments below). In addition to contractual commitments, the Company has estimated future decommissioning liabilities of $266.4 million on an undiscounted basis, inflated at 1.7%, of which $20.0 million is estimated to be incurred over the next five years.

Capital Commitments

Lease Acquisition Capital Commitment

On March 29, 2019, the Company'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.

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 had until December 31, 2019 to incur $1.8 million of CEE costs related to this flow-through common share issuance.

As at December 31, 2019, PPR had fully met its CEE costs commitment.

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 except per unit amounts)	2019 Q4	2019 Q3	2019 Q2	2019 Q1	2018 Q4	2018 Q3	2018 Q2	2018 Q1
Production Volumes								
Crude oil (bbl/d)	3,715	4,029	4,230	3,892	4,042	4,044	3,513	3,089
Natural gas (Mcf/d)	11,169	12,092	11,709	11,568	10,523	9,607	9,175	8,373
Natural gas liquids (bbl/d)	149	169	204	142	141	131	104	124
Total (boe/d)	5,725	6,214	6,386	5,962	5,937	5,776	5,146	4,609
% Liquids	67 %	68 %	69 %	68 %	70 %	72 %	70 %	70 %
Financial								
Oil and natural gas revenue	23,076	24,589	27,331	22,895	13,542	27,810	24,187	19,283
Royalties	(2,367)	(2,770)	(3,148)	(1,801)	(1,902)	(4,806)	(3,815)	(2,537)
Unrealized (loss) gain on derivatives	(6,619)	5,194	5,316	(14,509)	26,968	(1,884)	(9,316)	(5,199)
Realized (loss) gain on derivatives	(448)	(167)	(1,427)	(127)	(1,269)	(3,596)	(2,943)	(1,212)
Revenue net of realized and unrealized (losses) gains on derivatives	13,642	26,846	28,072	6,458	37,339	17,524	8,113	10,335
Net earnings (loss)	(12,734)	(2,320)	3,235	(21,260)	(3,532)	(2,627)	(15,064)	(11,742)
Per share – basic & diluted	(0.07)	(0.01)	0.02	(0.12)	(0.02)	(0.02)	(0.13)	(0.10)
AFF [(1)]	4,684	6,196	6,321	1,248	(5,346)	5,533	4,625	3,222
Per share – basic & diluted	0.03	0.04	0.04	0.01	(0.04)	0.05	0.04	0.03
AFF - excluding decommissioning settlements [(1)]	4,810	6,570	6,626	4,244	(4,691)	6,112	4,792	3,882
Per share – basic & diluted	0.03	0.04	0.04	0.02	(0.03)	0.05	0.04	0.03

[1] AFF 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 its core areas, the Arrangement with Marquee and natural declines. Movements in oil and natural gas revenue attributable to fluctuations in commodity prices were partially offset by realized gains/losses on derivatives. Significant swings in unrealized gains/losses on derivatives occurred due to fluctuations in forwarded prices at each period end. With the exception of the second quarter of 2019, 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, accretion expense and foreign exchange losses related to the US dollar denominated borrowings. The Company has maintained positive AFF in all the quarters, with the exception of the fourth quarter of 2018. Negative AFF in the fourth quarter of 2018 was the result of significant widening in Canadian oil differentials which resulted in a substantial reduction in realized revenue.

Fourth quarter 2019 oil and natural gas revenue decreased from the prior quarter primarily due to lower production volumes, partially offset by higher realized average realized prices per boe. Though the Company realized $4.8 million of AFF (before decommissioning settlements of $0.1 million), a net loss of $12.7 million was recorded in the fourth quarter of 2019 due to non-cash items including an unrealized loss on derivatives of $6.6 million, $2.0 million non-cash finance costs and $10.5 million of depletion and depreciation expense, partially offset by a $1.5 million unrealized foreign exchange gain and an impairment recovery of $0.4 million.

Third quarter 2019 oil and natural gas revenue decreased from the prior quarter primarily due to lower realized oil and natural gas prices as a result of falling benchmark prices. Though the Company realized $6.6 million of AFF (before decommissioning settlements of $0.4 million), a net loss of $2.3 million was recorded in the third quarter of 2019 due to non-cash items including a $1.0 million unrealized foreign exchange loss, $2.1 million non-cash finance costs and $10.9 million of depletion and depreciation expense, partially offset by an unrealized gain on derivatives of $5.2 million.

Second quarter 2019 oil and natural gas revenue increased from the prior quarter primarily due to a full quarter of production from the Arrangement, the Company's successful drilling program and a rise in crude oil prices. Realized losses on derivatives incurred in the second quarter of 2019 was attributed to the strengthening in oil prices. Net earnings of $3.2 million in the second quarter of 2019 was attributable to AFF of $6.6 million (before decommissioning settlements of $0.3 million), partially offset by the aggregate impact from non-cash items including $5.3 million of unrealized gain on derivatives, $1.8 million of unrealized foreign exchange gain, a $3.3 million reduction in other liabilities, $2.1 million of non-cash finance costs and $11.2 million of depletion and depreciation expense.

First quarter 2019 oil and natural gas revenue increased significantly from the prior quarter primarily due to a full quarter of production from the Arrangement and the recovery of crude oil prices. Net loss of $21.3 million in the first quarter of 2019 was largely the result of non-cash items including an unrealized loss on derivatives of $14.5 million and $10.0 million of depletion and depreciation expense.

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 and widened Canadian crude oil differentials, 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 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 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 derivatives and $7.4 million of depletion and depreciation expense.

Annual Selected Financial and Operational Information

($000s except per unit amounts)	2019	2018	2017
Financial			
Oil and natural gas revenue	97,891	84,822	79,011
Net loss	(33,079)	(32,965)	(47,802)
Per share - basic & diluted	(0.19)	(0.27)	(0.42)
AFF[1]	18,449.00	8,034	17,939
Per share - basic & diluted	0.11	0.07	0.16
AFF - excluding decommissioning settlements[1]	22,250	10,095	23,075
Per share - basic & diluted	0.13	0.08	0.20
Net capital expenditures[1]	11,856	24,476	64,198
Corporate acquisitions of P&D assets	—	55,736	50,500
Total assets	331,525	337,733	264,679
Total liabilities	317,947	290,682	201,339
Long-term debt	113,595	101,144	55,760
Weighted average shares outstanding			
Basic	171,349	122,426	113,350
Diluted	171,349	122,426	113,350
Operating			
Production Volumes			
Crude oil (bbls/d)	3,966	3,676	3,178
Natural gas (Mcf/d)	11,635	9,426	12,537
Natural gas liquids (bbls/d)	166	125	202
Total (boe/d)	6,071	5,372	5,470
% Liquids	68 %	71 %	62 %
Average Realized Prices			
Crude oil ($/bbl)	61.30	57.47	56.01
Natural gas ($/Mcf)	1.72	1.59	2.47
Natural gas liquids ($/bbl)	30.48	49.38	37.08
Total ($/boe)	44.18	43.26	39.57
Operating Netback ($/boe)[1]			
Realized price	44.18	43.26	39.57
Royalties	(4.55)	(6.66)	(5.20)
Operating costs	(21.04)	(19.34)	(19.36)
Operating netback	18.59	17.26	15.01
Realized (losses) gains on derivative instruments	(0.98)	(4.60)	2.47
Operating netback, after realized (losses) gains on derivative	17.61	12.66	17.48

[1] AFF, net capital expenditures and operating netback are non-IFRS measures and are defined below under "Other Advisories".

Revenue increased during 2019 primarily due to a production increase of 699 boe/d or 13% from 2018 as a result of the Marquee acquisition and PPR's successful Q4 2018 – 2019 development program. 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, liquids-weighting in 2017 and stronger realized prices in 2017 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, 2019, 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, 2019. 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 and Officer Certifications

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

The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal controls over financial reporting as defined in NI 52-109. The control framework PPR's officers used to design and evaluate the Company's internal controls over financial reporting is the Internal Control – Integrated Framework (2013) by The Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). There have been no changes in the Company's internal controls over financial reporting during the period from January 1, 2019 to December 31, 2019 that have materially affected or are reasonably likely to materially affect the Company's internal controls over financial reporting.

Limitation on Design

For the financial periods of the Company ending after its acquisition of Marquee Energy Ltd. (Marquee) on November 21, 2018 and prior to October 1, 2019, the Company limited its design of internal control over financial reporting (ICFR) and disclosure controls and procedures (DC&P) to exclude the controls, policies and procedures of Marquee, as permitted under National Instrument 52-109. Such limitation on scope of design no longer applies as at December 31, 2019, and the Company's DC&P and ICFR cover the acquired Marquee business.

Changes in Accounting Policies

The 2019 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, 2019 related to the adoption of new accounting pronouncements.

Effective January 1, 2019, the Company adopted IFRS 16 – *Leases* ("IFRS 16") which replaces IAS 17 – *Leases*. The standard has been applied using the modified retrospective approach and applying certain practical expedients available upon transition. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively. Further information on the changes to accounting policies can be found in Note 4 to the Annual Financial Statements.

The are no new or amended accounting standards and pronouncements issued that are applicable to PPR in future periods.

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 valuation 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 valuation 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;

- 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; and

- Management applies judgment in reviewing each of its contractual arrangements to determine whether the arrangement contains a lease within the scope of IFRS 16. Leases that are recognized are subject to further management judgment and estimation in various areas specific to the arrangement. The Company determines the lease term as the non-cancellable term of the lease, together with any periods covered by an option to extend the lease if it is reasonably certain to be exercised, or any periods covered by an option to terminate the lease, if it is reasonably certain not to be exercised. The Company applies judgment in evaluating whether it is reasonably certain to exercise the option to renew by considering all relevant factors that create an economic incentive for it to exercise the renewal. After the commencement date, the Company reassesses the lease term if there is a significant event or change in circumstances that is within its control and affects its ability to exercise (or not to exercise) the option to renew (e.g., a change in business strategy). Where the rate implicit in a lease is not readily determinable, the discount rate of lease obligations are estimated using a discount rate similar to PPR's company-specific incremental borrowing rate. This rate represents the rate that PPR would incur to obtain the funds necessary to purchase an asset of a similar value, with similar payment terms and security in a similar economic environment.

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 2019 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 the Company.

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, PPR 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 ratio 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

PPR 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 excluding the current portion of derivative instruments, less accounts payable and accrued liabilities. 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 and warrant liabilities are excluded as it is a non-monetary liability. Lease liabilities have historically been excluded as they were not recorded on the balance sheet until the adoption of IFRS 16 – Leases on January 1, 2019.

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

($000s)	December 31, 2019	December 31, 2018
Current assets	20,708	24,834
Less: current derivative instrument assets	(11)	(5,768)
Current assets excluding current derivatives instruments	20,697	19,066
Less: Accounts payable and accrued liabilities	18,479	35,205
Working capital (deficit)	2,218	(16,139)

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 derivatives.

Adjusted Funds Flow ("AFF")

AFF 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. AFF 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. AFF 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, AFF includes decommissioning liability settlements, which were previously excluded from the calculation in accordance with common industry practice, to conform to recent direction expressed by Alberta Securities Commission staff regarding funds flow disclosure by oil and gas issuers. By including the cost of decommissioning liability settlements in AFF, the current calculation results in a correspondingly lower AFF amount than under the previous methodology. With many oil and gas issuers continuing to exclude decommissioning settlements from their own funds flow calculations, the Company emphasizes that its AFF measurement may not be comparable with the calculation of similar measurements used by other companies.

PPR has restated prior period AFF to include decommissioning settlements that were previously excluded from the calculation. The revised AFF 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 AFF under the current and previous methodologies:

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	2019	2018	2019	2018
Cash flow from operating activities	6,150	2,643	4,380	16,553
Changes in non-cash working capital	(1,894)	(11,012)	12,653	(12,623)
Other	448	(419)	528	(386)
Transaction, restructuring and other costs	(20)	3,442	888	4,490
Adjusted funds flow ("AFF")	4,684	(5,346)	18,449	8,034
Decommissioning settlements	126	655	3,801	2,061
AFF - excluding decommissioning settlements	4,810	(4,691)	22,250	10,095

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 (loss) 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 earnings (loss) before income tax:

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2019**	2018	**2019**	2018
Net loss before income tax	**(12,734)**	(4,020)	**(33,392)**	(33,717)
Add (deduct):				
Interest	**3,530**	2,402	**14,228**	7,616
Depletion and depreciation	**9,822**	5,108	**39,826**	29,686
Depreciation on right-of-use assets	**685**	—	**2,743**	—
Exploration and evaluation expense	**460**	252	**996**	544
Unrealized loss (gain) on derivatives	**6,619**	(26,968)	**10,618**	(10,569)
Impairment (recovery) loss	**(436)**	5,481	**(436)**	5,319
Accretion	**814**	674	**3,360**	2,363
Loss (gain) on foreign exchange	**(1,616)**	3,752	**(3,826)**	5,684
Change in other liabilities	**—**	—	**(3,283)**	—
Share – based compensation	**179**	73	**679**	626
Gain (loss) on sale of properties	**(163)**	7,762	**(263)**	4,810
Gain on warrant liability	**(60)**	(354)	**(726)**	(563)
Transaction costs, reorganization and other costs[1]	**(20)**	3,442	**888**	4,490
Pro-forma impact of acquisitions	**—**	548	**—**	13,122
Bank Adjusted EBITDAX	**7,080**	(1,848)	**31,412**	29,411

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

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.

Net Debt

Net debt is a non-IFRS measure, defined as long-term debt plus working capital surplus or deficit. Net debt is a measure commonly used in the oil and gas industry for assessing the liquidity of a company.

The following table provides a calculation of net debt:

($000s)	**December 31, 2019**	December 31, 2018
Working capital (deficit)[1]	**2,218**	(16,139)
Long-term debt	**(113,595)**	(101,144)
Total net debt	**(111,377)**	(117,283)

[1] Working capital (deficit) is a non-IFRS measure and is defined above under "Other Advisories".