Prairie Provident Resources Inc.

Management's Discussion and Analysis
For the Three and Nine Months Ended September 30, 2021

Dated: November 10, 2021

Advisories

In this management's discussion and analysis ("MD&A"), unless otherwise indicated or the context otherwise requires, the terms "we", "us", "our", "PPR", "Prairie Provident" and "the Company" refers to Prairie Provident Resources Inc., as parent corporation, together with its wholly-owned subsidiaries, Prairie Provident Resources Canada Ltd., Lone Pine Resources Inc., Lone Pine Resources (Holdings) Inc., Arsenal Energy USA Inc. and Arsenal Energy Holding Ltd.

The following MD&A provides management's analysis of the Company's results of operations, financial position and outlook as at and for the three and nine months ended September 30, 2021. This MD&A is dated November 10, 2021 and should be read in conjunction with the unaudited condensed interim consolidated financial statements for the three and nine months ended September 30, 2021 (the "Interim Financial Statements"), the audited consolidated financial statements of PPR as at and for the year ended December 31, 2020 (the "2020 Annual Financial Statements") and the 2020 annual MD&A (the "Annual MD&A"). Additional information relating to PPR, including the Company's December 31, 2020 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 September 30,		Nine Months Ended September 30,	
($000s except per unit amounts)	**2021**	2020	**2021**	2020
Production Volumes				
Light & medium crude oil (bbl/d)	**2,261**	2,730	**2,408**	2,963
Heavy crude oil (bbl/d)	**384**	200	**228**	225
Conventional natural gas (Mcf/d)	**8,986**	8,704	**8,783**	9,411
Natural gas liquids (bbl/d)	**131**	135	**133**	134
Total (boe/d)	**4,273**	4,516	**4,234**	4,891
% Liquids	**65%**	68%	**65%**	68%
Average Realized Prices				
Light & medium crude oil ($/bbl)	**76.12**	43.84	**69.06**	35.95
Heavy crude oil ($/bbl)	**71.78**	42.12	**66.18**	34.00
Conventional natural gas ($/Mcf)	**3.69**	2.26	**3.32**	2.09
Natural gas liquids ($/bbl)	**59.16**	24.96	**51.70**	22.47
Total ($/boe)	**56.30**	33.47	**51.35**	27.99
Operating Netback ($/boe)[1]				
Realized price	**56.30**	33.47	**51.35**	27.99
Royalties	**(6.89)**	(3.38)	**(5.41)**	(2.78)
Operating costs	**(25.69)**	(21.79)	**(25.15)**	(20.80)
Operating netback	**23.72**	8.30	**20.79**	4.41
Realized (losses) gains on derivatives	**(5.79)**	6.85	**(4.85)**	9.65
Operating netback, after realized (losses) gains on derivatives	**17.93**	15.15	**15.94**	14.06

Third Quarter 2021 Financial & Operating Highlights

- Production averaged 4,273 boe/d (65% liquids) in the third quarter of 2021, a 5% or 243 boe/d decrease from the same period in 2020, primarily driven by natural declines from the prior year, partially offset by production from our successful 2021 drilling program. Of the third quarter 2021 two-well drilling program, one Princess well commenced production in mid-September 2021 while the other came on production at the beginning of October 2021 with IP30 rates of of approximately 190[(2)] boe/d and 220[(3)] boe/d, respectively. These two wells are currently producing at 385[(4)] boe/d in total. Due to the on-stream timing of these two new drills, their impact on third quarter 2021 production was minimal. Year-to-date 2021 drilling activity also included two Princess wells that came on production in April and May 2021, contributing approximately 420[(5)] boe/d of incremental production in the third quarter of 2021.

- PPR commenced drilling of one additional well in the Princess area in mid-October 2021 following the strong results of the initial four wells drilled in the year, with expected on-stream timing before the end of 2021. Average production is expected to increase throughout the remainder of 2021 as we add production from our 2021 capital program (see "Net Capital Expenditures" section for further information).

- Operating netback[1] before the impact of realized losses on derivatives was $9.3 million ($23.72/boe) for the third quarter of 2021, reflecting an increase of $5.9 million or 170% from the same period in 2020. On a per boe basis, operating netback before and after realized losses on derivatives increased by $15.42/boe and $2.78/boe, respectively, primarily due to higher realized prices, partially offset by higher realized losses on derivatives. Q3 2021 operating expenses included higher seasonal electricity and fuel costs as a result of extreme hot weather as well as increased direct operating costs due to inflation.

- Net loss totaled $9.9 million in the third quarter of 2021, a $1.6 million increase compared to Q3 2020. The increase in net loss was driven primarily by a $3.7 million increase in unrealized foreign exchange loss and an $1.0 million increase in loss on warrant liability, partially offset by an increase of $0.9 million in adjusted funds flow[1] excluding decommissioning settlements and a decrease of $1.0 million in unrealized derivative losses due to changes in the marked-to-market value of open derivative contracts.

- Adjusted funds flow ("AFF")[1], excluding $0.5 million of decommissioning settlements, was $4.8 million ($0.04 per basic and diluted share) for the third quarter of 2021, a $0.5 million or 12% increase from the second quarter of 2021 reflecting improved netbacks. Compared against the same quarter in 2020, AFF excluding decommissioning settlements increased by $0.9 million primarily due to an improved netbacks and lower cash interest expenses. The positive effect on AFF of further improved commodity pricing was partially offset by realized losses on required derivative contracts arising from mandatory hedge positions pursuant to credit facility covenants entered into when the pricing environment was volatile. Approximately 55% of our fourth quarter 2021 forecast production is hedged with 3-way collars capped at an average ceiling price of WTI US$60.80/bbl.

- Net capital expenditures[1] in the third quarter of 2021 of $4.7 million were directed towards the drill, completion, equip and tie-in of two Princess wells. PPR continues with its disciplined approach towards balance sheet maintenance. For the nine months ended September 30, 2021, PPR incurred $11.3 million of net capital expenditures primarily related to its four gross (4.0 net) well drilling program in the Princess area, largely funded by $11.2 million of AFF[1] (excluding decommissioning settlements).

- Net debt[1] at September 30, 2021 totaled $121.0 million, up $5.0 million from December 31, 2020. The increase was primarily due to lease payments, decommissioning settlements and net capital expenditures in the first nine months of 2021 that exceeded AFF[1]; together with deferred interest recognized on the Company's long-term debt of $1.3 million and unrealized foreign exchange loss of $0.3 million on US dollar denominated debt.

- At September 30, 2021, PPR had US$44.4 million (CAN$58.9 million equivalent) of borrowings drawn against the US$57.7 million Revolving Facility, leaving US$13.3 million (CAN$16.9 million equivalent) of available borrowing capacity. In addition, US$48.0 million of subordinated senior notes ("Senior Notes") (equivalent to CAN$61.2 million) were outstanding at September 30, 2021, for total borrowings of US$92.4 million (CAN$120.1 million equivalent).

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[1] Non-IFRS measure – see below under "Non-IFRS Measures "

[2] Average initial production over a 30-day period commencing September 14, 2021, during which the well produced an average of 111 bbl/d of heavy crude oil and 474 Mcf/d of conventional natural gas from the Ellerslie formation. Readers are cautioned that short-term initial production rates are preliminary in nature and may not be indicative of stabilized on-stream production rates, future product types, long-term well or reservoir performance, or ultimate recovery. Actual future results will differ from those realized during an initial short-term production period, and the difference may be material.

[3] Average initial production over a 30-day period commencing October 2, 2021, during which the well produced an average of 185 bbl/d of heavy crude oil and 222 Mcf/d of conventional natural gas from the Glauconite formation. Readers are cautioned that short-term test rates are preliminary in nature and may not be indicative of stabilized on-stream production rates, future product types, long-term well or reservoir performance, or ultimate recovery. Actual future results will differ from those realized during an initial short-term test period, and the difference may be material.

[4] Comprised of average production of approximately 296 bbl/d of heavy crude oil and 537 Mcf/d of convention natural gas based on field estimates.

[5] Comprised of average production of approximately 232 bbl/d of heavy crude oil and 1,128 Mcf/d of convention natural gas.

Outlook

Following the drilling successes in Princess, we expanded our 2021 drilling program by one additional Glauconite well. As this fifth Princess well is largely funded with the remainder of our capital budget, our total 2021 capital expenditures are forecasted to be materially in line with previous guidance. The Glauconite well is expected to be on production before the end of 2021. While our average 2021 production is forecasted to be slightly below guidance, we expect our exit production to exceed guidance of 4,370 boe/d, providing a head start to our 2022 production volume.

As a result of the activity and capital program completed during 2021, PPR is well positioned for further success in 2022 with predictable funds flow from our low-decline assets and an attractive inventory of drilling locations. Our three core areas offer well-balanced light/medium oil and natural gas exposures, with a relatively low base decline rate of approximately 17%. At the current commodity prices, our drilling inventory provides multiple capital allocation options. We look forward to sharing our 2022 capital budget and operational guidance when they are finalized.

Results of Operations

Production

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	**2021**	2020
Light & medium crude oil (bbl/d)	**2,261**	2,730	**2,408**	2,963
Heavy crude oil (bbl/d)	**384**	200	**228**	225
Conventional natural gas (Mcf/d)	**8,986**	8,704	**8,783**	9,411
Natural gas liquids (bbls/d)	**131**	135	**133**	134
Total (boe/d)	**4,273**	4,516	**4,234**	4,891
Liquids Weighting	**65%**	68%	**65%**	68%

Average production for the three and nine months ended September 30, 2021 was 4,273 boe/d (65% liquids) and 4,234 boe/d (65% liquids), a decrease of 5% and 13%, respectively, compared to the corresponding periods in 2020. Production decreases resulted from natural declines, partially offset by production from our 2021 drilling program. Year-to-date 2021 production was also impacted by temporary downtime related to extreme cold weather in the first quarter of 2021.

Drilling activity in the quarter included two gross (2.0 net) wells drilled in the Princess area, one of which came on production in mid-September 2021, while the other came on production in October 2021. As such, these Princess wells had a minimal impact on production for the three and nine months ended September 30, 2021.

During the first quarter of 2021, PPR drilled two gross (2.0 net) Princess wells, which commenced production in late April and late May 2021, respectively. The 2021 Princess drilling program added incremental production of approximately 420 boe/d and 270 boe/d for the three and nine months ended September 30, 2021, respectively, with a combined average liquids weighting of approximately 55%. Oil production from the new wells is classified as heavy crude oil resulting in an increase in heavy oil production compared to the corresponding periods in 2020.

Revenue

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per unit amounts)	**2021**	2020	**2021**	2020
Revenue				
Light & medium crude oil	**15,834**	11,010	**45,399**	29,185
Heavy crude oil	**2,536**	775	**4,119**	2,098
Conventional natural gas	**3,050**	1,809	**7,964**	5,401
Natural gas liquids	**713**	310	**1,877**	825
Oil and natural gas revenue	**22,133**	13,904	**59,359**	37,509
Average Realized Prices				
Light & medium crude oil ($/bbl)	**76.12**	43.84	**69.06**	35.95
Heavy crude oil ($/bbl)	**71.78**	42.12	**66.18**	34.00
Conventional natural gas ($/Mcf)	**3.69**	2.26	**3.32**	2.09
Natural gas liquids ($/bbl)	**59.16**	24.96	**51.70**	22.47
Total ($/boe)	**56.30**	33.47	**51.35**	27.99
Benchmark Prices				
Crude oil - WTI ($/bbl)	**88.90**	54.52	**81.10**	51.50
Crude oil - Edmonton Light Sweet ($/bbl)	**83.49**	49.04	**75.59**	42.89
Crude oil - WCS ($/bbl)	**71.77**	42.47	**65.45**	32.99
Natural gas - AECO monthly index-7A ($/Mcf)	**3.54**	2.03	**3.11**	1.96
Natural gas - AECO daily index - 5A ($/Mcf)	**3.60**	2.12	**3.27**	1.98
Exchange rate - US$/CDN$	**0.79**	0.75	**0.80**	0.74

PPR's third quarter 2021 revenue increased by 59% or $8.2 million from the third quarter of 2020, primarily due to higher realized crude oil and NGL prices, partially offset by lower production volumes.

Light & medium crude oil revenue for the third quarter of 2021 increased by 44%, compared to the corresponding period in 2020, due to an increase in realized light & medium crude oil prices by 74%, partially offset with a 17% decrease in light & medium crude oil production volumes. Heavy crude oil revenue increased by 227% in the third quarter of 2021, compared to the third quarter of 2020, due to an increase in heavy oil realized prices of 70% coupled with an increase in production volumes of 92% contributed by the 2021 drilling program.

PPR's product prices generally correlate to changes in the benchmark prices. In the third quarter of 2021, the average WTI price increased by 63% or $34.38/bbl and the average Edmonton Light Sweet price increased by 70% or $34.45/bbl, from the average pricing in the third quarter of 2020. During the third quarter of 2021, the WCS to WTI differential widened to $17.13/bbl (Q3 2020 - $12.06/bbl), and the Edmonton Light Sweet to WTI differential narrowed to $5.40/bbl (Q3 2020 - $5.48/bbl).

Third quarter 2021 natural gas revenue increased by 69% or $1.2 million, compared to the same quarter in 2020, reflecting a 63% increase in realized natural gas prices coupled with a 3% increase in production volumes as a result of the successful 2021 drilling program.

Average realized prices per boe for the third quarter of 2021 increased by 68% or $22.83/boe from the same quarter of 2020, due to the increases in the realized prices across all products.

On a year-to-date basis, revenue increased by 58% or $21.9 million, compared to the same period in 2020. The 56% increase in light & medium crude oil revenue reflected a 92% increase in realized light & medium crude oil prices, offset by a 19% decline in light & medium crude oil production volumes. A 96% increase in heavy oil revenue reflected a 95% increase in heavy oil prices and a 1% increase in heavy oil production volumes. For the nine months ended September 30, 2021, the average WTI price and the average Edmonton Light Sweet price increased by 57% or $29.60/bbl and 76% or $32.70/bbl, respectively, compared to the same period of 2020. The WCS to WTI differential narrowed to $15.65/bbl (Q3 2020 - $18.51/bbl), and the Edmonton Light Sweet to WTI differential narrowed to $5.52/bbl (Q3 2020 - $8.61/bbl). The 47% increase in natural gas revenue reflected a 59% increase in realized natural gas prices, partially offset by a 7% production decrease.

Averaged realized prices per boe for the nine months ended September 30, 2021 increased by 83% or $23.36/boe, compared to the same period in 2020, correlating to increases in the realized prices across all products.

Royalties

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2021**	2020	**2021**	2020
Royalties	**2,708**	1,404	**6,257**	3,722
Per boe	**6.89**	3.38	**5.41**	2.78
Percentage of revenue	**12.2%**	10.1%	**10.5%**	9.9%

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 Alberta Crown, which are based on various sliding scales that are dependent on incentives, production volumes and commodity prices.

Third quarter and year-to-date 2021 royalties increased by $1.3 million and $2.5 million, respectively, compared to the corresponding periods in 2020, primarily due to higher commodity prices, partially offset by a decrease in production volumes of 5% and 13%, respectively.

On a percentage of revenue basis, royalties for the three and nine months ended September 30, 2021 increased slightly compared to the corresponding periods in 2020 primarily due to higher average royalty rates as a result of higher commodity prices.

Commodity Price and Risk Management

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2021**	2020	**2021**	2020
Realized (loss) gain on derivatives	**(2,276)**	2,847	**(5,609)**	12,928
Unrealized (loss) gain on derivatives	**(2,904)**	(3,879)	**(14,092)**	8,697
Total (loss) gain on derivatives	**(5,180)**	(1,032)	**(19,701)**	21,625
Per boe				
Realized (loss) gain on derivatives	**(5.79)**	6.85	**(4.85)**	9.65
Unrealized (loss) gain on derivatives	**(7.39)**	(9.33)	**(12.19)**	6.49
Total (loss) gain on derivatives	**(13.18)**	(2.48)	**(17.04)**	16.14

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 contracts 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 and nine ended September 30, 2021 is primarily related to the significant rise in WTI futures prices relative to 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 September 30, 2021, the Company held the following outstanding derivative contracts:

Remaining Term	**Reference**	**Total Daily Volume (bbl)**	**Premium/ bbl**	**Weighted Average Price/ bbl**
Crude Oil Put Spread Options				
January 01, 2023 - March 31, 2023	US$ WTI	1,100	3.50[1]	$40.00/50.00
April 01, 2023 - June 30, 2023	US$ WTI	1,050	3.75[1]	$40.00/50.00
Crude Oil Three-way Collars				
October 01, 2021 - December 31, 2021	US$ WTI	650		$40.00/50.00/64.25
October 01, 2021 - December 31, 2021	US$ WTI	300		$30.00/40.00/55.00
October 01, 2021 - December 31, 2021	US$ WTI	725		$35.00/42.50/60.10
January 01, 2022 - June 30, 2022	US$ WTI	300		$30.00/40.00/58.50
January 01, 2022 - June 30, 2022	US$ WTI	1,150		$35.00/45.00/64.00
July 01, 2022 - December 31, 2022	US$ WTI	1,250		$32.00/42.00/64.00

[1] Deferred premiums, payable upon settlement of the derivative contracts.

Remaining Term	**Reference**	**Total Daily Volume (MMBtu)**	**Weighted Average Price/ MMBtu**
Natural Gas Swaps			
October 01, 2021 - October 31, 2021	US$ AECO	3,500	$2.15
Natural Gas Three-way Collars			
April 01, 2022 - December 31, 2022	US$ NYMEX	3,600	$1.75/2.00/3.32
January 01, 2023 - March 31, 2023	US$ NYMEX	3,300	$2.00/2.50/3.75
Natural Gas Collars			
October 01, 2021 - December 31, 2021	US$ NYMEX	2,100	$2.25/3.90
January 01, 2022 - March 31, 2022	US$ NYMEX	2,350	$2.75/3.90
November 01, 2021 - March 31, 2022	US$ NYMEX	2,200	$2.50/3.99
April 01, 2023 - June 30, 2023	US$ NYMEX	3,000	$2.00/3.80
Natural Gas Basis Swaps			
November 01, 2021 - March 31, 2022	US$ NYMEX/AECO	2,200	($0.67)

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

Operating Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2021**	2020	**2021**	2020
Lease operating expense	**8,175**	7,252	**23,026**	21,896
Transportation and processing	**859**	489	**2,166**	1,738
Production, property and carbon taxes	**1,067**	1,313	**3,882**	4,238
Total operating expenses	**10,101**	9,054	**29,074**	27,872
Per boe	**25.69**	21.79	**25.15**	20.80

During the three and nine months ended September 30, 2021, lease operating expenses increased by 13% or $0.9 million and 5% or $1.1 million, respectively, from the corresponding periods in 2020. The increase in the third quarter of 2021 related to higher fuel and power pricing as a result of above average summer temperatures for portions of the quarter, in addition to cost increases linked to inflation during the period. Year-to-date 2021 lease operating expenses also included higher workover costs compared to the prior year due to the suspension of workovers activities during the first half of 2020 in response to falling commodity prices Additionally, 2021 lease operating expenses were also impacted by higher fuel and power pricing and increased maintenance costs resulting from extreme cold weather in the first quarter of 2021.

Transportation and processing expense for the three and nine months ended September 30, 2021 increased by 76% or $0.4 million and 25% or $0.4 million, respectively, from the corresponding periods in 2020. The increases largely relate to production from the new wells drilled in Princess in 2021.

Production, property and carbon tax expense for the three and nine months ended September 30, 2021 decreased by 19% or $0.2 million and 8% or $0.4 million, respectively, from the comparative periods in 2020. Decreases in production, property and carbon taxes were attributable to projects to remove unused equipment from field locations and to update operating statuses with municipal authorities to reduce the related tax burden, partially offset by increased provincial administration fees levied by the Alberta Energy Regulator in 2021, as compared to 2020 when the Government of Alberta provided COVID-19 relief, and increased federal carbon tax during 2021.

On a per boe basis, total operating expense for the three and nine months ended September 30, 2021 increased by 18% or $3.90/boe and 21% or $4.35/boe, respectively, compared to the same periods in 2020. In addition to the above mentioned factors, the increases also related to distributing fixed operating costs over lower production volumes. Production related to the Princess wells drilled in the third quarter of 2021 had limited impact on the third quarter and first nine months of 2021 due to the on production timing — one well late in the third quarter and the other at the beginning of the fourth quarter. PPR expects per boe operating expenses to decrease in the fourth quarter of 2021 as a result of added production from our 2021 capital program.

Operating Netback

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ per boe)	**2021**	2020	**2021**	2020
Revenue	**56.30**	33.47	**51.35**	27.99
Royalties	**(6.89)**	(3.38)	**(5.41)**	(2.78)
Operating costs	**(25.69)**	(21.79)	**(25.15)**	(20.80)
Operating netback	**23.72**	8.30	**20.79**	4.41
Realized (losses) gains on derivatives	**(5.79)**	6.85	**(4.85)**	9.65
Operating netback, after realized (losses) gains on derivatives	**17.93**	15.15	**15.94**	14.06

PPR's operating netback after realized losses on derivatives was $17.93/boe and $15.94/boe for the three and nine months ended September 30, 2021, which represents an increase of $2.78/boe and $1.88/boe, respectively, compared with the corresponding periods of 2020.

For the three months ended September 30, 2021 the operating netback increase was due to average realized pricing increasing by $22.83/boe, partially offset by a $12.64/boe increase in the realized losses on derivatives, a $3.90/boe increase in operating expenses and a $3.51/boe increase in royalties, compared to the corresponding three-month period in 2020.

For the nine months ended September 30, 2021, the operating netback increase was due to average realized prices rising by $23.36/boe, partially offset by a $14.50/boe increase in the realized losses on derivatives, an increases in operating expenses of $4.35/boe and an increase in royalties of $2.63/boe, compared to the corresponding nine-month period in 2020.

General and Administrative Expenses ("G&A")

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2021**	2020	**2021**	2020
Gross cash G&A expenses	**1,253**	1,241	**4,441**	4,734
Gross share-based compensation (recovery) expense	**(9)**	89	**46**	268
Less amounts capitalized	**(171)**	(2)	**(513)**	(184)
Net G&A expenses	**1,073**	1,328	**3,974**	4,818
Per boe	**2.73**	3.20	**3.44**	3.60

For the three months ended September 30, 2021, gross cash G&A remained consistent, while for the nine months ended September 30, 2021 it decreased by $0.3 million or 6%, compared to the same periods in 2020. On a year-to-date basis, PPR continues to benefit from cost reduction initiatives that were implemented in 2020. Additionally, PPR qualified for $0.2 million (2020 - $0.1 million) and $0.6 million (2020 - $0.3 million) of government grants under the Canadian Emergency Wage Subsidy and Canadian Emergency Rent Subsidy during the three and nine months ended September 30, 2021, respectively.

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 decreased by 110% and 83% for the three and nine months ended September 30, 2021 compared with the same periods in 2020 as a result of forfeitures in 2021.

Capitalized G&A varies with the composition and compensation levels of technical departments and their time attributed to capital projects. Capitalized G&A increased for the three and nine months ended September 30, 2021 by $0.2 million and $0.3 million, respectively, as PPR resumed its capital program in 2021 after nine months of capital suspension in 2020 as a result of global economic conditions.

Finance Costs

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2021**	2020	**2021**	2020
Cash interest expense	**1,165**	1,096	**3,519**	4,084
Deferred interest expense	**458**	2,046	**1,326**	5,327
Non-cash interest on debt (fair valuation and warrant liabilities)	**1,617**	111	**4,640**	316
Amortization of financing costs	**85**	386	**258**	1,104
Non-cash interest on financing lease	**86**	155	**333**	519
Accretion – decommissioning liabilities	**423**	694	**1,267**	2,081
Accretion – other liabilities	**2**	2	**6**	8
Total finance cost	**3,836**	4,490	**11,349**	13,439
Interest expense (defined below) per boe	**4.13**	7.56	**4.19**	7.02
Non-cash interest and accretion expense per boe	**5.63**	3.24	**5.63**	3.01

Deferred interest expense is interest expense which has been added to the principal balance of borrowings outstanding and will be repaid under the terms of principal repayments in accordance to the underlying borrowing agreements. Cash interest expense and deferred interest expense (collectively, "Interest Expense") is primarily comprised of interest incurred related to the Company's outstanding borrowings. The decrease in Interest Expense of $1.5 million and $4.6 million for the three and nine months ended September 30, 2021, as compared to the respective periods in 2020, related to the refinancing transaction that occurred in December 2020 which resulted in an interest holiday on a portion of PPR's Senior Notes until certain conditions are met (see the "Capital Resources" section below for further details) and lower average borrowings under its Revolving Facility during the first half of 2021, compared to the same period in 2020. The refinancing transaction also caused an increase in non-cash interest under the effective interest rate method (see "Subordinate Senior Notes" section).

The weighted average effective interest rate for the three and nine months ended September 30, 2021 was 5.3% and 5.2%, respectively (2020 – 10.3% and 10.4%, respectively).

Accretion on decommissioning liabilities decreased by $0.3 million and $0.8 million during the three and nine months ended September 30, 2021, compared to the same periods in 2020, due to decreases in risk-free discount rates.

Foreign Exchange (Gain) Loss

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2021**	2020	**2021**	2020
Realized (gain) loss on foreign exchange	**(122)**	62	**(201)**	203
Unrealized loss (gain) on foreign exchange	**2,227**	(1,493)	**264**	2,021
Loss (gain) on foreign exchange	**2,105**	(1,431)	**63**	2,224

Foreign exchange losses incurred in the three and nine months ended September 30, 2021 related largely to the translation impact on US dollars denominated borrowings (see "Capital Resources and Liquidity" section below).

Exploration and Evaluation ("E&E") Expense

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2021**	2020	**2021**	2020
Exploration and evaluation expense	**625**	255	**864**	1,811
Per boe	**1.59**	0.61	**0.75**	1.35

Exploration and evaluation expenses are comprised of undeveloped land expiries and surrendered leases.

Depletion and Depreciation

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s, except per boe)	**2021**	2020	**2021**	2020
Depletion and depreciation	**5,821**	6,150	**17,429**	21,650
Depreciation on right-of-use assets	**308**	526	**1,277**	1,652
Total depletion expense	**6,129**	6,676	**18,706**	23,302
Per boe	**15.59**	16.07	**16.18**	17.39

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. Depletion expenses are calculated using depletion rates and production volumes applicable to each depletable asset. On a per boe basis, in the third quarter 2021 depletion expense is relatively consistent with the same quarter in the prior year. The decrease in the depletion expenses and per boe expenses during the nine months ended September 30, 2021, compared to the same periods of 2020 reflects a decrease in the depletable base as a result of P&D impairment recognized in the first quarter of 2020, which was then partially reversed with the recognition of an impairment recovery in the second quarter of 2021 (see "Impairment (Reversal) Loss" section below).

Impairment (Reversal) Loss

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2021**	2020	**2021**	2020
E&E impairment – decommissioning asset loss	**119**	—	**119**	—
Total E&E impairment	**119**	—	**119**	—
P&D impairment (reversal)	**—**	—	**(35,000)**	76,587
P&D impairment – decommissioning asset loss	**601**	—	**601**	—
Total P&D impairment (reversal)	**601**	—	**(34,399)**	76,587
Total impairment loss (reversal)	**720**	**—**	**(34,280)**	**76,587**

Third quarter 2021 E&E and P&D impairment losses related to changes in decommissioning liabilities of certain properties that had zero carrying value. PPR assessed and concluded there were no indicators of impairment or impairment reversal for its E&E and P&D assets as at September 30, 2021.

At June 30, 2021, the significant increase in forecast benchmark commodity prices since the last impairment test at March 31, 2020 was an indicator of impairment reversal for the Company's P&D assets. As a result PPR completed impairment testing on its Evi and Princess cash generating units ("CGUs") and recognized impairment reversals of $23.0 million and $12.0 million in these CGUs, respectively, during the three months ended June 30, 2021.

At March 31, 2020, the significant downturn in crude oil benchmark prices was considered an indicator of impairment for the P&D assets. As a result, the Company completed impairment tests on all of its CGUs and recognized impairment charges totaling $76.6 million related to the Evi, Princess, Provost and Other CGUs.

Net Earnings (Loss)

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s except per share)	**2021**	2020	**2021**	2020
Net (loss) earnings	**(9,922)**	(8,276)	**2,567**	(93,903)
Per share – basic & diluted	**(0.08)**	(0.05)	**0.02**	(0.55)

Net loss for the third quarter of 2021 was $9.9 million, compared to a net loss of $8.3 million in the same period of 2020. The $1.6 million increase in net loss was primarily due to an increase of $3.7 million increase in unrealized foreign exchange loss and an increase in loss on warrant liability by $1.0 million, partially offset by an increase of $0.9 in AFF excluding decommissioning settlements and a decrease of $1.0 million in unrealized derivative losses due to changes in the marked-to-market value of open derivative contracts.

Net earnings were $2.6 million for the first nine months of 2021, compared to a net loss of $93.9 million in the same period of 2020. The $96.5 million increase in net earnings was primarily due to non-cash items including a $110.9 million increase related to an impairment recovery recorded in 2021 versus an impairment loss in 2020 and a $1.8 million decrease in unrealized foreign exchange loss and a $4.6 million decrease in depletion, depreciation and amortization, partially offset by a $22.8 million increase in unrealized loss on open derivative contracts.

Net Capital Expenditures[1,2]

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2021**	2020	**2021**	2020
Drilling and completion	**3,654**	(116)	**8,129**	2,642
Equipment, facilities and pipelines	**887**	18	**2,101**	849
Land and seismic	**29**	33	**380**	150
Capitalized overhead and other	**183**	(4)	**583**	162
Total Capital Expenditures	**4,753**	(69)	**11,193**	3,803
Asset dispositions (net of acquisitions)	**(31)**	(25)	**60**	(184)
Net Capital Expenditures	**4,722**	(94)	**11,253**	3,619

[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 and nine months ended September 30, 2021 were $4.8 million and $11.2 million, respectively. The Company focused its capital activities during the first nine months of 2021 on the Princess area where $9.6 million was incurred to drill, complete, equip and tie-in four gross (4.0 net) development wells, including $4.1 million that was incurred to drill, complete, equip and tie-in two gross (2.0 net) development wells in the third quarter of 2021. The two wells drilled in the third quarter of 2021 came on production in mid-September and early October 2021, respectively. PPR also spent $0.3 million on pipeline construction in the Michichi area in the third quarter of 2021 and $0.3 million on undeveloped land in the Princess area in the first quarter of 2021.

Capital expenditures prior to acquisitions or dispositions for the three and nine months ended September 30, 2020 were $0.1 million and $3.8 million, respectively. The Company focused its capital activities during the first nine months of 2020 on the Michichi area where it incurred $3.1 million for the drilling and completion of one gross (1.0 net) development well, the installation of a water injection facility and the conversion of one well to injection for a pilot waterflood project.

Capitalized overhead increased for the three and nine months ended September 30, 2021 as compared to the same periods in 2020 as the Company's capital program resumed in 2021.

Decommissioning Liabilities

PPR's decommissioning liabilities at September 30, 2021 were $165.3 million (December 31, 2020 - $166.2 million) to provide for future remediation, abandonment and reclamation of PPR's oil and gas properties. The decrease of $0.9 million from year-end 2020 was due to settlements of decommissioning obligations of $0.7 million, funding under government grants for the settlement of decommissioning liabilities of $1.8 million and the net disposal of decommissioning obligations of $0.5 million, partially offset by accretion expense of $1.3 million, changes in estimates of $0.4 million and $0.3 million of liabilities incurred. Government grants were provided by the Government of Alberta under the Site Rehabilitation Program and are recognized as other income and as a reduction in decommissioning liabilities.

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 $252.0 million spanning over the next 55 years, based on an inflation rate of 1.6%. Of the estimated undiscounted future liabilities, $18.0 million is estimated to be settled over the next five years. PPR expects that a portion of this spending will be covered by government grants and has qualified for total gross funding of $6.1 million under the Government of Alberta's Site Rehabilitation Program as of the date of the MD&A. While the provision for decommissioning liabilities is based on management's best estimates of future costs, discount rates, timing and the economic lives of the assets, there is uncertainty regarding the amount and timing of incurring these costs.

Capital Resources and Liquidity

Capital Resources

Working Capital

At September 30, 2021, the Company had working capital deficit (as defined in "Other Advisories" below) of $0.9 million (December 31, 2020 – working capital of $5.3 million). The decrease in working capital from December 31, 2020 resulted from applying excess cash towards repayments against the Revolving Facility of $2.8 million, and higher payables balances for realized derivative instruments and increased capital expenditures, partially offset by a higher accounts receivable balance related to higher commodity prices in September 2021 than in December 2020.

Revolving Facility

On December 21, 2020, PPR renewed and amended its Revolving Facility with a borrowing base of US$57.7 million and extended the maturity date of the Revolving Facility to December 31, 2022. The borrowing base is subject to a reduction to US$53.8 million on December 31, 2021 and to semi-annual redeterminations thereafter, without limiting the lenders' right to require a redetermination at any time. The next borrowing base re-determination date will be around April 2022 based on a year-end 2021 reserves evaluation.

Borrowings under the Revolving Facility are repayable at the Company's election at par plus accrued interest and any applicable breakage costs. Repayments generally will not affect the aggregate commitment or borrowing base under the Revolving Facility, except in certain extraordinary circumstances where a repayment will reduce the borrowing base. The Revolving Facility is denominated in USD, but accommodates CAD advances up to the lesser of CAN$54 million or US$30 million. 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 following table provides a breakdown of borrowings drawn against the US$57.7 million Revolving Facility:

($000s)	September 30, 2021	December 31, 2020
USD Advances (USD $14.0 million (December 31, 2020 - USD $16.0 million))[1]	17,837	20,371
CAD Advances (USD $30.0 million (December 31, 2020 - USD $30.0 million))[2]	40,530	40,530
CAD Deferred Interest (USD $0.4 million (December 31, 2020 - USD $0.5 million)[2]	543	590
Revolving Facility (USD $44.4 million (December 31, 2020 - USD $46.5 million))	58,910	61,491

[1] Converted using the month end exchange rate of $1.00 USD to $1.27 CAD as at September 30, 2021 and $1.00 USD to $1.27 CAD as at December 31, 2020.
[2] Converted using the exchange rate at the time of borrowing of $1.00 USD to $1.35 CAD.

The decrease in borrowings from year-end 2020 was largely due to the net repayment under the Revolving Facility of $2.8 million in the first nine months of 2021. As at September 30, 2021, the Company had US$13.3 million (CAN$16.9 million equivalent) borrowing capacity under the Revolving Facility.

The determination of the borrowing base is made by the lenders, in their sole discretion, taking into consideration the estimated value of PPR's oil and natural gas properties in accordance with the lenders' customary practices for oil and gas loans. 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 for CDOR, CAD prime, LIBOR and USD prime advances are 650 basis points and standby fees on any undrawn borrowing capacity are 87.5 basis points per annum.

As at September 30, 2021, PPR had outstanding letters of credit of $4.2 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 September 30, 2021, $0.4 million of deferred costs related to the Revolving Facility were netted against its carrying value (December 31, 2020 – $0.7 million).

Subordinate Senior Notes

On December 21, 2020, PPR amended its agreements for Senior Notes that were originally issued on October 31, 2017 and November 21, 2018, with total principal outstanding of US$28.5 million and original maturity date of October 31, 2021. Under the amendments, the maturity date was extended to June 30, 2023. The annual interest rate on the notes was reduced from 15% per annum to nil until June 30, 2021, and will thereafter rise to 4% at the earlier of 15 months after closing (March 2022) and the last day of the fiscal quarter for which the Company's trailing 12-month Senior Leverage ratio (as defined in the "Covenants" section below) is 2.5 or less, and to 8% at the earlier of 20 months after closing (August 2022) and the last day of the fiscal quarter for which the Company's trailing 12-month Senior Leverage ratio is 2.0 or less.

Additionally, on December 21, 2020 PPR purchased US$11.4 million of Senior Notes with a maturity date of December 21, 2026 ("Senior Noted due 2026") bearing interest at 12% per annum. Net proceeds from the issuance of Senior Notes due 2026 were applied against borrowings under the Revolving Facility upon issuance.

Interest on Senior Notes is payable quarterly. The Senior Note agreements provide that, until certain criteria are met, including compliance with original financial covenant ratios on the Revolving Facility as at October 31, 2017 (when the facility was first implemented), the absence of any borrowing base deficiency, and a projected ability to meet any scheduled payment obligations under the Revolving Facility for the next 12-month period, PPR may elect to defer all interests due on the Senior Notes. The terms of the Revolving Facility require that the Company make this election and not pay cash interest on the Senior Notes until these criteria are satisfied. PPR will thereafter be permitted to elect to defer up to 4.00% per annum of interest on the Senior Notes. At the date of this MD&A, PPR expects to defer future interest for the respective terms of the Senior Notes.

The following table provides a breakdown of Senior Notes principal and deferred interest balances at the dates presented. The borrowings which are denominated in USD have been converted to CAD using the month-end exchange rate as at the respective dates presented of $1.00 USD to $1.27 CAD as at September 30, 2021 and $1.00 USD to $1.27 CAD as at December 31, 2020.

($000s)	September 30, 2021	December 31, 2020
Senior Notes Issued October 31, 2017		
Principal (US$16.0 million)	20,386	20,371
Deferred interest (US$4.4 million (December 31, 2020 - US$4.4 million))	5,615	5,611
Total Principal and Deferred Interest - October 31, 2017 Senior Notes	26,001	25,982
Senior Notes Issued November 21, 2018		
Principal (US$12.5 million)	15,926	15,915
Deferred interest (US$2.6 million (December 31, 2020 - US$2.6 million))	3,341	3,338
Total Principal and Deferred Interest - November 21, 2018 Senior Notes	19,267	19,253
Senior Notes Issued December 21, 2020		
Principal (US$11.4 million)	14,509	14,500
Deferred interest (US$1.1 million (December 31, 2020 - US$0.04))	1,398	48
Total Principal and Deferred Interest - December 21, 2020 Senior Notes	15,907	14,548
Total Principal and Deferred Interest - Senior Notes	61,175	59,783

In conjunction with the issuance of the Senior Notes due 2026, the Company issued a total of 34,292,360 warrants with an exercise price of $0.0192 per share for an eight-year term expiring on December 21, 2028. Warrants issued concurrent with the Senior Note issuances on October 31, 2017 and November 21, 2018 totaling 8,318,000 warrants were cancelled in full.

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 September 30, 2021 was $3.4 million (December 31, 2020 - $0.7 million).

PPR accounted for amendments to the Senior Notes due 2023 as an extinguishment and as such, the previously recorded liabilities were derecognized and the modified liabilities were recorded at their fair value as at December 21, 2020. In addition, the Senior Notes due 2026 were initially recognized at fair value which was $3.6 million lower than the face value of the notes. The fair value of the Senior Notes was calculated using the present value of expected future cash flows, discounted at 17.5%. Collectively, the modification of Senior Notes due 2023 and recognition of the Senior Notes due 2026 resulted in the recognition of a gain of $15.9 million in the fourth quarter of 2020, net of $1.4 million of financing costs. Under the effective interest method the gain will be amortized by accreting the carrying value of the Senior Notes to their face value with a corresponding non-cash interest charge recognized in the consolidated statement of income (loss) in each reporting period. As a result of this accounting method, the effective interest rate will be at 17.5%, which is much higher than the coupon rates borne by the Senior Notes. The coupon rates dictate the interest expenses that will be settled with cash.

No deferred costs related to PPR's Senior Notes were netted against their carrying value as at September 30, 2021 or December 31, 2020.

Covenants

The note purchase agreement for the Revolving Facility, the Senior Note agreement and related parent and subsidiary guarantees contain various covenants on the part of the Company and its subsidiaries including covenants that place limitations on certain types of activities, including restrictions or requirements with respect to additional debt, liens, asset sales, capital expenditures, hedging activities, investments, dividends and mergers and acquisitions. In addition, capital expenditures and acquisitions are generally limited to consistency with the Company's annual development plan, as created and updated by the Company from time to time and approved by the lenders.

The note purchase agreement for the Revolving Facility and the subordinated Senior Note purchase agreement include the same financial covenants, with 15% less restrictive thresholds under the Senior Note agreements.

The applicable financial covenants thresholds as at September 30, 2021 are as follows:

Financial Covenant	Revolving Facility Requirement	Senior Note Requirement	As at September 30, 2021
Senior Leverage[1]	Cannot exceed 5.45 to 1.00	Cannot exceed 6.27 to 1.00	2.77 to 1.00
Asset Coverage[2]	Cannot be less than 0.37 to 1.00	Cannot be less than 0.31 to 1.00	1.16 to 1.00
Current Ratio[3]	Cannot be less than 1.00 to 1.00	Cannot be less than 0.85 to 1.00	1.88 to 1.00

[1] Under the debt agreements, the Senior Leverage ratio is the ratio of Senior Adjusted Indebtedness (defined herein) to EBITDAX (as defined below in "Other Advisories) for the four quarters most recently ended. Senior adjusted indebtedness is defined as Adjusted Indebtedness (defined herein) less subordinated borrowings. Adjusted Indebtedness is defined as borrowings less outstanding letters of credit for which PPR has issued cash collateral.

[2] Under the debt agreements, the Asset Coverage ratio is the ratio of the net present value of estimated future net revenue from proved reserves (discounted at 10% per annum) adjusted for hedging transactions to Adjusted Indebtedness.

[3] Under the debt agreements, the current ratio is the ratio of consolidated current assets, plus any undrawn capacity under the Revolving Facility, to consolidated current liabilities at the end of any fiscal quarter. Under the agreements, current assets exclude derivative assets while current liabilities exclude the current portion of long-term debt, lease liabilities, decommissioning obligations, derivative liabilities and non-cash liabilities.

The Company was in compliance with all applicable covenants as at September 30, 2021.

Shareholders' Equity

At September 30, 2021, PPR had consolidated share capital of $101.4 million (December 31, 2020 – $136.5 million) and had 128.4 million (December 31, 2020 – 172.3 million) outstanding common shares. In the first quarter of 2021, PPR cancelled 44,711,330 common shares, representing approximately 25.9% of the total number of common shares previously outstanding, that were surrendered by a shareholder to the Company for nominal consideration. The Company had 34.3 million warrants outstanding as at September 30, 2021 (December 31, 2020 – 34.3 million). The outstanding warrants were issued in conjunction with the modification and issuance of Senior Notes on December 21, 2021 and have an exercise price of $0.0192 per share and an eight-year term expiring December 21, 2028.

The table below provides information on our share-based compensation program including grants in the current year and balances outstanding as at the periods presented:

	Options[1]	RSUs	Deferred Share Units ("DSUs")
Units granted during the nine months ended September 30, 2021	**1,000,000**	**1,816,000**	**550,000**
Balance outstanding as at September 30, 2021	**4,361,559**	**2,094,514**	**1,880,268**
Balance outstanding as at December 31, 2020	5,514,877	1,805,021	2,337,081

[1] Outstanding options as at September 30, 2021 had a weighted average strike price of $0.24 per share, of which 2.3 million were exercisable at a weighted average strike price of $0.38 per share.

Options were granted to officers and employees of the Company and vest evenly over a three-year period and expire five years after the grant date. RSUs are granted to officers and employees and vest in three tranches, with the first and second tranches vesting on the first and second anniversary of the grant date, respectively. The third tranche vests on December 15th following the vesting of the second tranche. DSUs are granted to non-management directors of the Company and 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 of the date of this MD&A, there are 128.5 million common shares, 2.0 million RSUs, 4.2 million stock options, 1.9 million DSUs, and 34.3 million outstanding warrants.

Capital Management and Liquidity

PPR's objective when managing capital is to maintain a flexible capital structure and sufficient liquidity to meet its financial obligations and to execute its business plans. The Company considers its capital structure to include shareholders' equity, borrowings under its credit facilities 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.

In light of continued uncertainty in the macroeconomic environment, PPR's short-term capital management objective is to fund its capital expenditures necessary for the replacement of production declines primarily using AFF (as defined in "Other Advisories" below). Value-creating activities may be financed with a combination of AFF and other sources of capital. The Company has determined that its current financial obligations, including current commitments will be adequately funded from the available borrowing capacity, working capital and AFF. Except for the long-term portion of derivative financial instruments, long-term lease liabilities, long-term other liabilities and long-term debt, all of the Company's financial liabilities are due within one year.

PPR monitors its capital structure using the ratio of senior debt to trailing twelve months' Bank Adjusted EBITDAX (as defined in "Other Advisories" below). Senior 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. Senior debt to Bank Adjusted EBITDAX at September 30, 2021 was 2.77 to 1.00 (December 31, 2020 – 3.4 to 1.0), an improvement from December 31, 2020 and significantly lower than the covenant thresholds. Management of debt levels is a priority for PPR and the Company's 2021 capital program was designed with this key objective in mind.

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.

Contractual Obligations and Commitments

For the three and nine months ended September 30, 2021, there was no material change to the Company's commitments or contractual obligations as disclosed in the Annual Financial Statements.

Supplemental Information

Financial – Quarterly extracted information

($000 except per unit amounts)	2021 Q3	2021 Q2	2021 Q1	2020 Q4	2020 Q3	2020 Q2	2020 Q1	2019 Q4
Production Volumes								
Light & medium crude oil (bbl/d)	2,261	2,514	2,453	2,639	2,730	2,996	3,164	3,436
Heavy crude oil (bbl/d)	384	179	117	163	200	183	292	278
Conventional natural gas (Mcf/d)	8,986	9,122	8,233	9,080	8,704	9,351	10,186	11,169
Natural gas liquids (bbl/d)	131	140	129	140	135	141	127	149
Total (boe/d)	4,273	4,354	4,071	4,455	4,516	4,879	5,281	5,725
% Liquids	65 %	65 %	66 %	66 %	68 %	68 %	68 %	67 %
Financial								
Oil and natural gas revenue	22,133	20,259	16,967	14,211	13,904	8,333	15,272	23,076
Royalties	(2,708)	(2,324)	(1,225)	(1,305)	(1,404)	(1,033)	(1,285)	(2,367)
Unrealized (loss) gain on derivatives	(2,904)	(6,884)	(4,304)	(3,917)	(3,879)	(15,029)	27,605	(6,619)
Realized gain (loss) on derivatives	(2,276)	(2,257)	(1,076)	2,313	2,847	8,085	1,996	(448)
Revenue net of realized and unrealized gains (losses) on derivatives	14,245	8,794	10,362	11,302	11,468	356	43,588	13,642
Net earnings (loss)	(9,922)	23,995	(11,506)	3,130	(8,276)	(17,559)	(68,068)	(12,734)
Per share – basic	(0.08)	0.19	(0.07)	0.02	(0.05)	(0.10)	(0.40)	(0.07)
Per share – diluted	(0.08)	0.16	(0.07)	0.02	(0.05)	(0.10)	(0.40)	(0.07)
AFF [(1)]	4,344	4,153	1,979	1,853	3,818	4,570	231	4,684
Per share – basic & diluted	0.03	0.03	0.01	0.01	0.02	0.03	0.00	0.03
AFF excluding decommissioning settlements [(1)]	4,796	4,268	2,104	2,273	3,912	5,221	935	4,810
Per share – basic & diluted	0.04	0.03	0.01	0.01	0.02	0.03	0.01	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 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 forward prices at each period end. With the exception of the second quarter of 2021 and fourth quarter of 2020, the Company incurred net losses due to non-cash expenses, including unrealized derivative losses, impairments to P&D 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.

Third quarter 2021 oil and natural gas revenue increased from the prior quarter mainly due to higher realized prices per boe. Though the Company realized $4.8 million of AFF (before decommissioning settlements of $0.5 million), a net loss of $9.9 million was recorded in the third quarter of 2021 due to non-cash items including $6.1 million of depletion and depreciation expense, $2.9 million unrealized loss on derivatives, $2.2 million of unrealized foreign exchange loss, $2.2 million of non-cash finance costs, $1.0 million of loss on warrant liability and $0.7 million of impairment loss related to changes in decommissioning liabilities of certain properties that had zero carrying value.

Second quarter 2021 oil and natural gas revenue increased from the prior quarter mainly due to higher realized prices per boe coupled with increased production volumes. The Company realized $4.3 million of AFF (before decommissioning settlements of $0.1 million) and $24.0 million of net earnings in the second quarter of 2021 due to non-cash items including $35.0 of impairment reversal related to P&D assets and $1.1 million of unrealized foreign exchange gains, partially offset by a $6.9

million unrealized loss on derivatives, a $2.2 million non-cash finance costs and $6.3 million of depletion and depreciation expense.

First quarter of 2021 oil and natural gas revenue increased from the prior quarter mainly due to higher average realized prices per boe, partially offset by decreased production volumes. Though the Company realized $2.1 million of AFF[1] (before decommissioning settlements of $0.1 million), a net loss of $11.5 million was recorded in the first quarter of 2021 due to non-cash items including $6.3 million of depletion and depreciation expense, losses on derivatives of $4.3 million, $2.1 million non-cash finance costs and $1.4 million loss on warrant liabilities revaluation, partially offset by a $1.0 million unrealized foreign exchange gain.

Fourth quarter 2020 oil and natural gas revenue increased from the prior quarter primarily due to higher average realized prices per boe, partially offset by lower production volumes. Net earnings of $3.1 million in the fourth quarter of 2020 was largely the result of non-cash items including a gain of $15.9 million related to the debt refinancing in December 2020 and unrealized foreign exchange gains of $3.5, partially offset by unrealized losses on derivatives of $3.9 million, non-cash financing costs of $5.5 million, depletion and depreciation expense of $6.8 million and impairment of $1.9 million. The Company realized $2.3 million of AFF[1] (before decommissioning settlements of $0.4 million).

Third quarter 2020 oil and natural gas revenue increased from the prior quarter mainly due to higher realized prices per boe partially offset by decreased production volumes. Though the Company realized $3.9 million of AFF[1] (before decommissioning settlements of $0.1 million), a net loss of $8.3 million was recorded in the third quarter of 2020 due to non-cash items including a $3.9 million unrealized loss on derivatives, a $3.4 million non-cash finance costs and a $6.7 million of depletion and depreciation expense, partially offset by a unrealized foreign exchange gain of $1.5 million.

Second quarter of 2020 oil and natural gas revenue decreased from the prior quarter mainly due to lower realized prices per boe coupled with decreased production volumes. Though the Company realized $5.2 million of AFF[1] (before decommissioning settlements of $0.7 million), a net loss of $17.6 million was recorded in the second quarter of 2020 due to non-cash items including a $15.0 million unrealized loss on derivatives, a $4.1 million non-cash finance costs and a $7.1 million of depletion and depreciation expense, partially offset by a unrealized foreign exchange gain of $3.5 million.

First quarter of 2020 oil and natural gas revenue decreased from the prior quarter mainly due to lower realized prices per boe coupled with decreased production volumes. Though the Company realized $0.9 million of AFF[1] (before decommissioning settlements of $0.7 million), a net loss of $68.1 million was recorded in the first quarter of 2020 due to non-cash items including an asset impairment of $77.3 million, a $7.0 million unrealized foreign exchange loss, a $1.4 million non-cash finance costs and a $9.6 million of depletion and depreciation expense, partially offset by a gain on derivatives of $27.6 million.

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[1] (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 reversal of $0.4 million.

[1] Non-IFRS measure - defined below under "Other Advisories"

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, no matter how well internal controls are designed. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

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, 2021 to September 30, 2021 that have materially affected or are reasonably likely to materially affect the Company's internal controls over financial reporting.

Changes in Accounting Policies

The following new accounting standards and pronouncements were adopted during the three and nine months ended September 30, 2021.

IBOR Reform and its Effects on Financial Reporting - Phase 2
Effective January 1, 2021 PPR adopted the IASB issued *Interest Rate Benchmark Reform - Phase 2* which amended requirements in IFRS 9 *Financial Instruments*, IAS 39 *Financial Instruments: Recognition and Measurement*, IFRS 7 *Financial Instruments: Disclosures*, and IFRS 16 *Leases,* relating to changes in the basis for determining contractual cash flows of financial assets, financial liabilities, and lease liabilities related to benchmark interest rate reform. PPR's Revolving Facility makes reference to LIBOR (for certain USD borrowing) and CDOR (for certain CAD borrowing) rates for certain one-month or three-month advances made under the facility. The terms of the Revolving Facility agreement with PPR's lenders allow for the replacement of these rates with economic equivalents in future periods, should current rates cease publication or prior to the cessation of publication, as a result of benchmark replacement. PPR expects to be able to utilize the practical expedient under IFRS 9 *Financial Instruments* in the future when the replacement of rates occurs and therefore, would not be required to recognize gains or losses on the modification of the Revolving Facility agreement related to changes in the benchmark interest rates.

Operational and Other Risk Factors

PPR’s operations are conducted in the same business environment as most other Canadian oil and gas operators and the business risks are very similar. Significant risks are summarized in the Annual MD&A and in the “Risk Factors” section of the 2020 Annual Information Form filed on SEDAR at www.sedar.com and have remained unchanged during the first nine months of 2021.

Forward-Looking Statements

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

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

- estimates of the Company’s oil and natural gas reserves;
- estimates of the Company’s future oil, natural gas and NGL production, including estimates of any increases or decreases in the Company’s production;
- estimates of future capital expenditures;
- estimates and judgements related to common shares and preferred shares valuations;
- the Company’s future financial condition and results of operations;
- the source of funding for the Company's activities, including development costs;
- the Company’s ability to meet its capital commitment;
- the Company’s future revenues, cash flows and expenses;
- the Company’s access to capital and expectations with respect to liquidity and capital resources;
- the Company’s future business strategy and other plans and objectives for future operations;
- the Company’s future development opportunities and production mix;

- the Company’s outlook on oil, natural gas and NGL prices;
- the anticipated benefits of merger and acquisitions;
- the Company’s ability to incur CEE;
- the amount, nature and timing of future capital expenditures, including future development costs;
- the Company’s ability to access the capital markets to fund capital and other expenditures;
- the Company’s expectations regarding the Company's ability to raise capital and to add reserves and grow production through acquisitions, exploration and development;
- the Company’s assessment of the Company’s counterparty risk and the ability of the Company’s counterparties to perform their future obligations; and
- the impact of federal, provincial, territorial and local political, legislative, regulatory and environmental developments in Canada.

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

- the volatility of oil, natural gas and NGL prices, and the related differentials between realized prices and benchmark prices;
- a continuation of depressed natural gas prices;
- the availability of capital on economic terms to fund the Company’s significant capital expenditures and acquisitions;
- the Company’s ability to obtain adequate financing to pursue other business opportunities;
- the Company's ability to reach an agreement with counterparties to new financing arrangements on terms and conditions that are acceptable to the Company or at least as favorable to the Company than those of the existing credit facilities, or will improve PPR's liquidity profile;
- the Company’s ability to generate sufficient cash flow from operations or obtain adequate financing to fund the Company’s capital expenditures and meet working capital needs;
- the Company’s ability to replace and sustain production;
- a lack of available drilling and production equipment, and related services and labor;
- the Company's ability to successfully integrate the acquired assets;
- increases in costs of drilling, completion and production equipment and related services and labor;
- unsuccessful exploration and development drilling activities;
- regulatory and environmental risks associated with exploration, drilling and production activities;
- declines in the value of the Company’s oil and natural gas properties, resulting in impairments;
- the adverse effects of changes in applicable tax, environmental and other regulatory legislation;
- a deterioration in the demand for the Company’s products;
- the risks and uncertainties inherent in estimating proved oil and natural gas reserves and in projecting future rates of production and the timing of expenditures;
- the risks of conducting exploratory drilling operations in new or emerging plays;
- intense competition with companies with greater access to capital and staffing resources;
- the risks of conducting operations in Canada and the impact of pricing differentials, fluctuations in foreign currency exchange rates and political developments on the financial results of the Company’s operations; and
- the uncertainty related to the pending litigation against us.

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

Other Advisories

Volumetric Conversion

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

Throughout the MD&A, 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 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)	**September 30, 2021**	December 31, 2020
Current assets	**18,581**	20,807
Less: current derivative instrument assets	**—**	(798)
Current assets excluding current derivatives instruments	**18,581**	20,009
Less: Accounts payable and accrued liabilities	**19,491**	14,683
Working capital (deficit)	**(910)**	5,326

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 as oil and gas revenues less royalties less operating costs. Operating netback may be expressed in absolute dollar terms or on a per unit basis. Per unit amounts are determined by dividing the absolute value by gross working interest production. Operating netback after gains or losses on derivative instruments, adjusts the operating netback for only realized gains and losses on derivative instruments.

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 does not and 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.

The following table reconciles cash flow from operating activities to AFF and AFF excluding decommissioning settlements which are seasonal in nature as a significant portion of PPR's decommissioning liabilities are located in winter access only areas:

	Three Months Ended September 30,		Nine Months Ended September 30,	
($000s)	**2021**	2020	**2021**	2020
Cash flow from operating activities	**5,599**	191	**10,986**	6,224
Changes in non-cash working capital	**(1,519)**	3,644	**(823)**	2,272
Other	**(59)**	(11)	**(10)**	16
Transaction, restructuring and other costs	**323**	(6)	**323**	107
AFF under current methodology	**4,344**	3,818	**10,476**	8,619
Decommissioning settlements	**452**	94	**692**	1,449
AFF under previous methodology	**4,796**	3,912	**11,168**	10,068

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 Senior Notes. “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 September 30,		Nine Months Ended September 30,	
($000s)	2021	2020	2021	2020
Net earnings (loss) before income tax	(9,922)	(8,292)	2,581	(93,981)
Add (deduct):				
Interest	3,411	3,794	10,076	11,350
Depletion and depreciation	5,821	6,150	17,429	21,650
Depreciation on right-of-use assets	308	526	1,277	1,652
Exploration and evaluation expense	625	255	864	1,811
Unrealized loss (gain) on derivatives	2,904	3,879	14,092	(8,697)
Impairment (reversal) loss	720	—	(34,280)	76,587
Accretion	425	696	1,273	2,089
(Gain) loss on foreign exchange	2,105	(1,431)	63	2,224
Change in other liabilities	55	(480)	163	(480)
Share – based compensation	(3)	89	55	253
Gain on sale of properties	(163)	(126)	(360)	(203)
Loss (gain) on warrant liability	1,029	—	2,743	(84)
Non-cash other income	(1,799)	—	(1,799)	—
Transaction costs, reorganization and other costs	323	(6)	323	107
Bank Adjusted EBITDAX	5,839	5,054	14,500	14,278

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 borrowings under long-term debt including principal and deferred interest, 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)	September 30, 2021	December 31, 2020
Working capital (deficit)[1]	(910)	5,326
Borrowings outstanding (principal plus deferred interest)	(120,085)	(121,274)
Total net debt	(120,995)	(115,948)

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