Prairie Provident Resources Inc.

Management's Discussion and Analysis
For the Three Months and Year Ended December 31, 2021

Dated: March 29, 2022

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 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, 2021. This MD&A is dated March 29, 2022 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, 2021 (the "2021 Annual Financial Statements"). Additional information relating to PPR, including the Company's December 31, 2021 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-GAAP and other financial 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-GAAP and Other Financial 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,	
	2021	2020	2021	2020
Production Volumes				
Light & medium crude oil (bbl/d)	2,198	2,639	2,355	2,881
Heavy crude oil (bbl/d)	492	163	294	210
Conventional natural gas (Mcf/d)	9,246	9,080	8,900	9,328
Natural gas liquids (bbl/d)	138	140	135	136
Total (boe/d)	4,369	4,455	4,268	4,781
% Liquids	65 %	66 %	65 %	67 %
Average Realized Prices				
Light & medium crude oil ($/bbl)	80.81	45.04	71.83	38.05
Heavy crude oil ($/bbl)	79.98	40.91	72.12	35.26
Conventional natural gas ($/Mcf)	4.89	2.71	3.73	2.25
Natural gas liquids ($/bbl)	74.35	30.98	57.25	24.59
Total ($/boe)	62.36	34.67	54.19	29.56
Operating Netback ($/boe)[1]				
Realized price	62.36	34.67	54.19	29.56
Royalties	(8.32)	(3.18)	(6.16)	(2.87)
Operating costs	(25.18)	(22.93)	(25.16)	(21.30)
Operating netback	28.86	8.56	22.87	5.39
Realized (losses) gains on derivatives	(9.82)	5.64	(6.13)	8.71
Operating netback, after realized (losses) gains on derivatives	19.04	14.20	16.74	14.10

2021 Corporate Highlights:

- During the fourth quarter of 2021, PPR entered into amending agreements with its lender providing for the renewal of its credit facilities including the extension of the maturity date of the Revolving Facility (defined herein) from December 31, 2022 to December 31, 2023. The amendments also provide for added borrowing base certainty during 2022, as there is to be no scheduled redetermination of the borrowing base until after December 31, 2022, when the borrowing base will be reset to US$50.0 million and thereafter be subject to semi-annual redetermination based on year-end and mid-year reserves evaluations during 2023. Additionally, the maturity date of the US$28.5 million aggregate original principal of subordinated senior notes issued in October 2017 and November 2018 (together with deferred interest amounts) was extended from June 30, 2023 to June 30, 2024 ("Senior Notes due 2024"). See "Capital Resources" section below for further information on the debt amendments.

Annual Financial & Operational Highlights

- Commodity prices made significant recoveries in 2021 as restrictions implemented in response to the Covid-19 pandemic were eased and global demand for crude oil and natural gas increased. Meanwhile, global supply of oil and natural gas grew at a more moderate pace due to limited growth capital investment by independent producers and OPEC+ supply management actions. The improved pricing environment resulted in an increase in PPR's oil and natural gas revenue by $32.7 million or 63.2% to $84.4 million in 2021, compared to 2020.

- For the year ended December 31, 2021, production averaged 4,268 boe/d[1] (65% liquids), which was 11% or 513 boe/d lower than 2020, primarily driven by natural declines, partially offset by production from our successful 2021 drilling program, which was comprised of five gross (5.0 net) wells in the Princess area and contributed approximately 415[2] boe/d of incremental production in 2021. 2021 average production was 3% lower than guidance, due to later online timing of certain new wells, offset by drilling one more well than budgeted.

- Operating netback[1] was $35.6 million ($22.87/boe) before the impact of realized losses on derivatives in 2021 or $26.1 million ($16.74/boe) after realized losses on derivatives, a 278% and 6% increase from 2020, respectively. Our mandatory hedge positions pursuant to credit facility covenants resulted in $9.6 million of realized losses in 2021, which partially dampened the 89% and 105% increase in realized light & medium and heavy crude oil prices, respectively, from 2020. 2021 operating expense was $25.16 boe/d, an increase of 18% and 17% compared to 2020 and guidance due to inflation and higher than budgeted workover activities.

- Net earnings totaled $10.4 million for the year ended December 31, 2021, compared to a net loss of $90.8 million from last year, driven primarily by non-cash items, the most significant of which was a $119.2 million increase related to impairment recovery recorded in 2021 versus impairment loss in 2020.

- Adjusted funds flow ("AFF")[1], excluding $3.3 million of decommissioning settlements, was $15.5 million ($0.11 per basic and $0.09 per diluted share) for 2021, a 29% increase from 2020. Primary contributors to the increase were higher operating netbacks and a reduction in cash interest expenses, partially offset by lower production volumes and increased realized hedging losses.

- Net capital expenditures[1] for 2021 totaled $14.7 million, primarily focused in the Princess area where the Company drilled, completed, equipped and tied-in five gross (5.0 net) development wells, all of which were brought on production during the year. Staying in line with its 2021 capital budget, PPR reallocated capital spending and successfully drilled one additional well than planned. 2021 net capital expenditures were fully funded by AFF[1] excluding decommissioning settlements, and included $0.8 million of pre-drill expenses relating to the 2022 capital program.

- PPR actively reduced our decommissioning liabilities in 2021 with the settlements of $5.5 million, of which $2.2 million was covered by government grants under the Government of Alberta Site Rehabilitation Program. PPR continues to increase its focus on environmental stewardship and expects to publish its inaugural Environmental, Social and Governance report on its website (www.ppr.ca) in early April 2022.

- As at December 31, 2021, net debt[1] totaled $124.3 million which increased by $8.4 million from December 31, 2020. The increase was attributed to the aggregate of lease payments, decommissioning settlements and transaction, restructuring and other costs in 2021 in excess of AFF[1] after funding net capital expenditures, as well as the recognition of $1.8 million of deferred interest on the Company's long-term debt.

- At year-end 2021, PPR had US$47.4 million of borrowings drawn against the US$53.8 million Revolving Facility, leaving US$6.4 million (CAN$8.1 million equivalent) of available borrowing capacity. In addition, US$48.4 million of Senior Notes (defined herein; CAN$61.3 million equivalent) were outstanding at December 31, 2021, for total borrowings of US$95.8 million (CAN$124.0 million equivalent).

Fourth Quarter 2021 Financial & Operational Highlights

- Production averaged 4,369 boe/d (65% liquids) for the fourth quarter of 2021, a 2% decrease from the same period in 2020, driven by natural declines and largely offset by production from our successful 2021 drilling program, as described above, which contributed approximately 840[3] boe/d of incremental production in the fourth quarter of 2021.

- Fourth quarter 2021 operating netback[1] before the impact of derivatives was $11.6 million ($28.86/boe), and $7.7 million ($19.04/boe) after realized losses on derivatives, a $8.1 million and $1.8 million increase from the fourth quarter of 2020, respectively. Our hedging program which is required under our credit facility covenants resulted in $3.9 million of realized losses in the fourth quarter of 2021, which diminished the 79% and 96% increases in realized light & medium and heavy crude oil prices, respectively, from the corresponding period in 2020.

- Net capital expenditures[1] for the fourth quarter of 2021 of $3.6 million were directed towards the drill, complete, equip and tie-in of one gross (1.0 net) Princess well and preliminary costs for two gross (2.0 net) wells in the Michichi area that were spudded in January 2022.

- Net earnings totaled $7.9 million in the fourth quarter of 2021 compared to net earnings of $3.1 million in the same period last year, primarily driven by non-cash items such as, impairment recovery versus loss and unrealized gains versus losses on derivative financial instruments, partially offset by decrease in gains on the modification of debt.

- Adjusted funds flow ("AFF")[1], excluding $2.6 million of decommissioning settlements, was $4.3 million ($0.03 per basic and $0.03 diluted share) for the fourth quarter of 2021, a 121% increase from the same quarter in 2020. Primary contributors to the increase were higher operating netbacks due to higher realized prices , partially offset by an increase in realized hedging losses.

1 Operating netback, AFF, working capital (deficit), net debt and net capital expenditures are non-GAAP financial measures and are defined below under "Non-GAAP and Other Financial Measures".
2 Comprised of average production of approximately 258 bbl/d of heavy crude oil and 942 Mcf/d of conventional natural gas.
3 Comprised of average production of approximately 584 bbl/d of heavy crude oil and 1,536 Mcf/d of conventional natural gas.

Outlook

On February 22, 2022, PPR announced its planned 2022 capital budgeted (see press release at www.ppr.ca).

As commodity prices continue gaining momentum, PPR's 2022 development plan builds on 2021 successful drilling programs and waterflood results in its core assets. A combination of short cycle drilling opportunities and low-cost waterflood investment in 2022 underpins PPR's strategy of increasing shareholder value by focusing on long-term sustainable cash flow generation and reserves accretion. PPR expects to fully fund budgeted 2022 capital expenditures and decommissioning settlements from cash from operating activities. PPR may utilize borrowing capacity under the Revolving Facility for liquidity from time to time to temporarily fund operations during periods should expenditures exceed cash from operating activities

Full-year 2022 guidance estimates are outlined in the table below.

2022 BUDGET AND GUIDANCE SUMMARY (1)	
Production guidance	4,350 – 4,600 boe/d
Liquids weighting (2)	65 – 69%
Capital expenditures (excluding decommissioning settlements and capitalized G&A)	$18 million
Operating expense	$20.50 - 22.50/boe
Operating netback (3)	$27.04 - 31.21/boe
2022 year-end long-term debt (net of cash collateralized for letters of credit)	$121 - 124 million
Financial Assumptions	
Oil (WTI)	US$70.00/bbl
Oil (WCS)	US$16.02/bbl
Natural gas (AECO)	C$3.90/Mcf
Edmonton Light/WTI differential	US$5.27
USD/CAD foreign exchange	0.79

(1) See "Forward-looking statements" below.
(2) Based on forecasted 2022 production of 2,000 bbl/d of light and medium crude oil, 725 bbl/d of heavy crude oil, 125 bbl/d of natural gas liquids and 9,000 Mcf/d of conventional natural gas.
(3) Operating netback is a non-GAAP financial measure and is defined below under "Non-GAAP and Other Financial Measures".

Results of Operations

Production

	Three Months Ended December 31,		Year Ended December 31,	
	2021	2020	**2021**	2020
Light & medium crude oil (bbl/d)	**2,198**	2,639	**2,355**	2,881
Heavy crude oil (bbl/d)	**492**	163	**294**	210
Conventional natural gas (Mcf/d)	**9,246**	9,080	**8,900**	9,328
Natural gas liquids (bbl/d)	**138**	140	**135**	136
Total (boe/d)	**4,369**	4,455	**4,268**	4,781
Liquids Weighting	**65 %**	66 %	**65 %**	67 %

Average production for the three months and year ended December 31, 2021 was 4,369 boe/d (65% liquids) and 4,268 boe/d (65% liquids), a decrease of 2% and 11%, 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 fourth quarter included one gross (1.0 net) well in the Princess area which came on production on December 1, 2021. PPR drilled an additional four gross (4.0 net) wells in the Princess area during the first nine months of 2021, one of which commenced production at the beginning of October 2021. The 2021 drilling program resulted in incremental production during the three months and year ended December 31, 2021 of approximately 840 boe/d and 415 boe/d, respectively. Oil production from the wells drilled in 2021 is classified as heavy crude oil, resulting in an increase in heavy crude oil production from the corresponding periods in 2020.

Revenue

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per unit amounts)	**2021**	2020	**2021**	2020
Revenue				
Light & medium crude oil	**16,341**	10,934	**61,740**	40,119
Heavy crude oil	**3,620**	612	**7,739**	2,710
Natural gas	**4,159**	2,266	**12,123**	7,667
Natural gas liquids	**944**	399	**2,821**	1,224
Oil and natural gas revenue	**25,064**	14,211	**84,423**	51,720
Average Realized Prices				
Light & medium crude oil ($/bbl)	**80.81**	45.04	**71.83**	38.05
Heavy crude oil ($/bbl)	**79.98**	40.91	**72.12**	35.26
Conventional natural gas ($/Mcf)	**4.89**	2.71	**3.73**	2.25
Natural gas liquids ($/bbl)	**74.35**	30.98	**57.25**	24.59
Total ($/boe)	**62.36**	34.67	**54.19**	29.56
Benchmark Prices				
Crude oil - WTI ($/bbl)	**97.18**	55.50	**85.15**	52.51
Crude oil - Edmonton Light Sweet ($/bbl)	**92.92**	49.84	**79.96**	44.63
Crude oil - WCS ($/bbl)	**78.68**	43.44	**68.78**	35.62
Natural gas - AECO monthly index-7A ($/Mcf)	**4.93**	2.62	**3.57**	2.12
Natural gas - AECO daily index - 5A ($/Mcf)	**4.66**	2.50	**3.62**	2.11
Exchange rate - US$/CDN$	**0.79**	0.77	**0.80**	0.75

PPR's fourth quarter 2021 revenue increased by 76% or $10.9 million from the fourth quarter of 2020, principally due to significant increases in crude oil and natural gas prices, partially offset by lower production volumes.

Light & medium crude oil revenue for the fourth quarter of 2021 increased by 49% or $5.4 million, compared to the corresponding period in 2020, primarily due to realized light & medium crude oil prices increasing by 79%, partially offset by a 17% decrease in light & medium crude oil production volumes. Heavy crude oil revenue increased by 492%, or $3.0 million in the fourth quarter of 2021 compared to the fourth quarter of 2020 due to an increase in heavy oil realized prices of 96%, coupled with an increase in heavy oil production volumes of 202%, contributed by the 2021 drilling program.

PPR's product prices generally correlate to changes in the benchmark prices. For the fourth quarter of 2021, the average WTI price increased by 75% or $41.68/bbl and the average Edmonton Light Sweet price increased by 86% or $43.08/bbl. In the fourth quarter of 2021, the WCS to WTI differential widened to $18.50/bbl (Q4 2020 - $12.06/bbl) and the Edmonton Light Sweet to WTI differential narrowed to $4.26/bbl (Q4 2020 - $5.66/bbl).

Fourth quarter 2021 conventional natural gas revenue increased by 84% or $1.9 million compared to the same quarter in 2020, reflecting an 80% increase in realized natural gas prices coupled with a 2% increase in production volumes.

Average realized prices per boe for the fourth quarter of 2021 increased by 80% or $27.69/boe compared to the same period in 2020, correlating to increases in the underlying realized prices across all products.

On a year-over-year basis, revenue increased by 63% or $32.7 million. The 54% increase in light & medium crude oil revenue reflected an 89% increase in realized light & medium crude oil prices and an 18% decrease in light & medium crude oil production volumes. The 186% or $5.0 million increase in heavy crude oil revenue reflected a 105% improvement in realized heavy crude oil prices and a 40% increase in heavy crude oil production volumes. For the year ended December 31, 2021, the average WTI price increased by 62% or $32.64/bbl, compared to 2020. For the year ended December 31, 2021, the WCS to WTI differential narrowed to $16.37/bbl (2020 - $16.89/bbl) and the Edmonton Light Sweet to WTI differential narrowed to $5.19/bbl (2020 - $7.88/bbl).

The 58% or $4.5 million increase in conventional natural gas revenue reflected a 66% increase in realized conventional natural gas prices, partially offset by a 5% production decrease.

Average realized prices per boe for the year ended December 31, 2021 increased by 83% or $24.63/boe, compared to the same period in 2020, correlating to increases in the realized prices across all products.

Royalties

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2021**	2020	**2021**	2020
Royalties	**3,346**	1,305	**9,603**	5,027
Per boe	**8.32**	3.18	**6.16**	2.87
Percentage of revenue	**13.3 %**	9.2 %	**11.4 %**	9.7 %

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 and annual 2021 royalties increased by $2.0 million and $4.6 million, respectively, compared to the corresponding periods in 2020 primarily due to higher commodity prices, partially offset by production volume decreases of 2% and 11%, respectively.

On a percentage of revenue basis, royalties for the three months and year ended December 31, 2021 increased compared to the corresponding periods in 2020 due to higher average royalty rates linked to higher realized 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. In addition, PPR's credit facilities require the Company to maintain certain level of hedges on a rolling 24 month basis. 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)	**2021**	2020	**2021**	2020
Realized (loss) gain on derivatives	**(3,947)**	2,313	**(9,556)**	15,241
Unrealized gain (loss) on derivatives	**3,990**	(3,917)	**(10,102)**	4,780
Total gain (loss) on derivatives	**43**	(1,604)	**(19,658)**	20,021
Per boe				
Realized (loss) gain on derivatives	**(9.82)**	5.64	**(6.13)**	8.71
Unrealized gain (loss) on derivatives	**9.93**	(9.55)	**(6.49)**	2.73
Total gain (loss) on derivatives	**0.11**	(3.91)	**(12.62)**	11.44

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 gain on derivatives recognized for the three months ended December 31, 2021 is primarily related to losses becoming realized in the quarter.

The unrealized loss on derivatives recognized for the year ended December 31, 2021 is primarily due to a significant increase in WTI futures pricing as at December 31, 2021, compared to December 31, 2020.

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, 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 (No Ceiling)				
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)	$40.00/50.00
Crude Oil Three-way Collars				
January 01, 2022 - June 30, 2022	US$ 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 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	$2.00/2.50/3.75
Natural Gas Collars			
January 01, 2022 - March 31, 2022	US$ NYMEX	2,350	$2.75/3.90
January 01, 2022 - March 31, 2022	US$ NYMEX	2,200	$2.50/3.99
April 01, 2023 - June 30, 2023	US$ NYMEX	3,000	$2.00/3.80
Natural Gas Basis Swaps			
January 01, 2022 - March 31, 2022	US$ NYMEX/AECO	2,200	($0.67)

Subsequent to December 31, 2021 the Company entered into the following commodity derivative contracts:

Remaining Term	Reference	Total Daily Volume (bbl)	Premium/ bbl	Weighted Average Price/ bbl
Crude Oil Three-way Collars				
July 01, 2023 - December 31, 2023	US$ WTI	500		$55.00/65.00/105.00
Crude Oil Put Spread Options (No Ceiling)				
July 01, 2023 - December 31, 2023	US$ WTI	600	4.20(1)	$55.00/65.00

(1) Deferred premiums, payable upon settlement of the derivative contracts.

Remaining Term	Reference	Total Daily Volume (MMBtu)	Weighted Average Price/ MMBtu
Natural Gas Three-way Collars			
July 01, 2023 - December 31, 2023	US$ NYMEX	1,700	$2.25/2.75/4.65
July 01, 2023 - December 31, 2023	US$ NYMEX	1,700	$2.25/2.75/4.90

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)	**2021**	2020	**2021**	2020
Lease operating expense	**7,475**	6,992	**29,041**	27,144
Transportation and processing	**1,054**	1,306	**4,680**	4,788
Production, property and carbon taxes	**1,591**	1,101	**5,473**	5,339
Total operating expenses	**10,120**	9,399	**39,194**	37,271
Per boe	**25.18**	22.93	**25.16**	21.30

During the three months and year ended December 31, 2021, lease operating expenses increased by 7% or $0.5 million and 7% or $1.9 million, respectively, from the corresponding periods in 2020 largely as a result of cost increases linked to inflation and the rebound of commodity prices in 2021. Increased commodity prices are also linked to higher fuel and power costs incurred by the Company in 2021 as compared to 2020. Additionally, year-to-date lease operating expenses also included higher workover costs compared to the prior year due to the suspension of workover activities in the first half of 2020 in response to falling commodity prices and increased maintenance costs resulting from extreme cold weather in the first quarter of 2021.

Transportation and processing expenses for the three months and year ended December 31, 2021 decreased by 19% or $0.3 million and 2% or $0.1 million, respectively, compared to the same periods in 2020, primarily due to lower production volume during 2021.

Production, property and carbon tax expenses for the three months and year ended December 31, 2021 increased by 45% or $0.5 million and 3% or $0.1 million, respectively, compared to the corresponding periods in 2020. The increases were the result of higher federal carbon tax in 2021, and higher provincial administration fees levied by the Alberta Energy Regulator in 2021 due to Covid-19 relief provided in 2020, partially offset by decreases in property taxes attributable to projects to remove unused equipment from field locations and to update operating statuses with municipal authorities to reduce the related tax burden.

On a per boe basis, total operating expense for the three months and year ended December 31, 2021 increased by 10% or $2.25/boe and 18% or $3.86/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.

Operating Netback[1]

	Three Months Ended December 31,		Year Ended December 31,	
($ per boe)	**2021**	2020	**2021**	2020
Revenue	**62.36**	34.67	**54.19**	29.56
Royalties	**(8.32)**	(3.18)	**(6.16)**	(2.87)
Operating expenses	**(25.18)**	(22.93)	**(25.16)**	(21.30)
Operating netback	**28.86**	8.56	**22.87**	5.39
Realized (losses) gains on derivatives	**(9.82)**	5.64	**(6.13)**	8.71
Operating netback, after realized (losses) gains on derivatives	**19.04**	14.20	**16.74**	14.10

[1] Operating Netback is a non-GAAP financial measures and is defined below under "Non-GAAP and Other Financial Measures".

PPR's operating netback after realized gains on derivatives was $19.04/boe and $16.74/boe for the three months and year ended December 31, 2021, respectively, representing increases of $4.84/boe and $2.64/boe, respectively, compared with the corresponding periods of 2020.

For the three months ended December 31, 2021, the operating netback increase was due to average realized prices increasing by $27.69/boe, partially offset by a $15.46/boe increase in realized losses on derivatives, an increase in royalties of $5.14/boe and increased operating expenses of $2.25/boe, as compared to the corresponding three-month period in 2020.

For the year ended December 31, 2021, the operating netback increase was due to average realized prices increasing by $24.63/boe, partially offset by a $14.84/boe increase in realized losses on derivatives, an increase in operating expenses of $3.86/boe and an increase in royalties of $3.29/boe, as compared to 2020.

General and Administrative Expenses ("G&A")

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2021**	2020	**2021**	2020
Gross cash G&A expenses	**2,041**	953	**6,482**	5,687
Gross share-based compensation (recovery) expense	**14**	(28)	**60**	240
Less amounts capitalized	**(254)**	(1)	**(767)**	(185)
Net G&A expenses	**1,801**	924	**5,775**	5,742
Per boe	**4.48**	2.25	**3.71**	3.28

For the three months and year ended December 31, 2021, gross cash G&A increased by $1.1 million and $0.8 million, respectively, compared to the same periods in 2020. The fourth quarter increase is largely due to a reduction in Canadian Employee Wage Subsidy ("CEWS") grants PPR qualified for in the fourth quarter of 2021 to $0.1 million from $0.5 million in the fourth quarter of 2020. Additionally, PPR incurred higher professional services fees and salaries and benefit costs in the fourth quarter of 2021 as compared to the fourth quarter of 2020 as a result of increased corporate activity levels and the reinstatement of employee salaries and benefits which were reduced in 2020 due to economic conditions as a result of the global pandemic.

On a year-to-date basis, gross cash G&A was $6.5 million, $0.5 million lower than guidance. Compared to 2020, the increase in gross cash G&A was partially due to a $0.4 million decline in the CEWS grants where PPR qualified for $0.6 million in 2021 versus $0.9 million in 2020. Also contributing to the year-to-date increase in gross cash G&A expenses was an increase in costs in 2021 of $0.5 million related to the arbitration proceedings under the North American Free Trade Agreement ("NAFTA") against the Government of Canada (see the "Legal Proceedings" section of the 2021 Annual Information Form).

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 150% and 75% for the three months and year ended December 31, 2021, respectively, compared with the same periods in 2020. Fourth quarter 2020 gross share-based compensation expense was a recovery as a result of forfeitures in the period.

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 months and year ended December 31, 2021 by $0.3 million and $0.6 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 December 31,		Year Ended December 31,	
($000s, except per boe)	**2021**	2020	**2021**	2020
Cash interest expense	**1,489**	1,198	**5,008**	5,282
Deferred interest expense	**472**	1,866	**1,798**	7,193
Non-cash interest on debt modification and warrant liabilities	**1,691**	261	**6,331**	577
Amortization of financing costs	**110**	395	**368**	1,499
Non-cash interest on leases	**81**	139	**414**	658
Accretion – decommissioning liabilities	**596**	695	**1,863**	2,776
Accretion – other liabilities	**2**	2	**8**	10
Total finance cost	**4,441**	4,556	**15,790**	17,995
Interest expense per boe	**4.88**	7.48	**4.37**	7.13
Non-cash interest and accretion expense per boe	**6.17**	3.64	**5.77**	3.15

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 $1.1 million and $5.7 million for the three months and year ended December 31, 2021, respectively, compared to the corresponding 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 the Revolving Facility during 2021, compared to 2020. The refinancing transaction also caused an increase in non-cash interest under the effective interest rate method (see "Subordinated Senior Notes" section).

The weighted average effective interest rates for the three months and year ended December 31, 2021 were 5.3% and 7.0% respectively (2020 – 9.9% and 10.3%, respectively).

Accretion on decommissioning liabilities decreased by $0.1 million and $0.9 million during the three months and year ended December 31, 2021, respectively, compared to the same periods in 2020, due to lower risk-free discount rates applied during 2021 than the risk-free discount rates applied during 2020.

(Gain) Loss on Foreign Exchange

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2021**	2020	**2021**	2020
Realized loss (gain) on foreign exchange	**74**	(116)	**(127)**	87
Unrealized loss (gain) on foreign exchange	**13**	(3,533)	**277**	(1,512)
Loss (gain) on foreign exchange	**87**	(3,649)	**150**	(1,425)

Foreign exchange (gains) losses incurred in the three months and year ended December 31, 2021 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)	**2021**	2020	**2021**	2020
Exploration and evaluation expense	**385**	2,372	**1,249**	4,183
Per boe	**0.96**	5.79	**0.80**	2.39

E&E expenses are comprised of undeveloped land expiries and surrendered leases.

Depletion and Depreciation

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2021**	2020	**2021**	2020
Depletion and depreciation	**5,664**	6,237	**23,093**	27,887
Depreciation on right-of-use assets	**361**	518	**1,638**	2,170
Total depletion expense	**6,025**	6,755	**24,731**	30,057
Per boe	**14.99**	16.48	**15.88**	17.18

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 decrease in the depletion expenses during 2021 from 2020 reflects lower production volumes and a decrease in depletable base as a result of the P&D impairment recognized in the first quarter of 2020, which was partially reversed with the recognition of an impairment recovery in the second quarter of 2021 (see "Impairment Loss (Recovery)" section below).

Impairment Loss (Recovery)

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2021**	2020	**2021**	2020
E&E impairment	**—**	486	**—**	486
E&E impairment – decommissioning asset (recovery) loss	**1,392**	(343)	**1,511**	(343)
Total E&E impairment	**1,392**	143	**1,511**	143
P&D impairment	**—**	—	**(35,000)**	76,587
P&D impairment – decommissioning asset (recovery) loss	**(7,851)**	1,729	**(7,250)**	1,729
Total P&D impairment (recovery) loss	**(7,851)**	1,729	**(42,250)**	78,316
Total impairment (recovery) loss	**(6,459)**	1,872	**(40,739)**	78,459

Fourth quarter 2021 E&E and P&D impairment loss/recovery 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 December 31, 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.

Fourth quarter and annual 2020 E&E and P&D impairment losses/recoveries related to changes in decommissioning liabilities of certain properties that had zero carrying value and undeveloped land expected to expire in the near term that were not expected to be renewed.

Net Earnings (Loss)

	Three Months Ended December 31,		Year Ended December 31,	
($000s except per share)	**2021**	2020	**2021**	2020
Net earnings (loss)	**7,851**	3,130	**10,418**	(90,773)
Per share – basic	**0.06**	0.02	**0.08**	(0.53)
Per share – diluted	**0.05**	0.02	**0.06**	(0.53)

Net earnings for the fourth quarter of 2021 were $7.9 million, compared to a net earnings of $3.1 million in the same quarter of 2020. The $4.7 million increase in net earnings incorporated a $2.4 million increase in AFF (excluding decommissioning settlements) in the fourth quarter of 2021 compared to the same quarter of 2020, as well as the impact of non-cash items, including a $8.3 million increase in impairment recovery, a $7.9 million decrease in unrealized derivative losses due to changes in the marked-to-market value of derivative contracts, a $2.0 million decrease in exploration and evaluation expenses, a $1.8 million decrease in changes in other liabilities and a $0.7 million decrease in depletion, depreciation and amortization, partially offset by a $12.4 million decrease in gains recognized related to debt modification transactions, and a $3.5 million decrease in unrealized foreign exchange gain.

Net earnings were $10.4 million for the year ended December 31, 2021, compared to a net loss of $90.8 million in the same period of 2020. The $101.2 million increase in net earnings was primarily due to non-cash items, including a $119.2 million increase in impairment recovery, a $5.3 million decrease in depletion, depreciation and amortization, and a $2.9 million decrease in exploration and evaluation expense, partially offset by a $14.9 million increase in unrealized derivative losses due to changes in the marked-to-market value of derivative contracts, a $12.4 million decrease in gains recognized related to debt modification transactions, and a $3.2 million increase in losses on warrant liabilities. In addition to the non-cash items, there was a $3.5 million increase in AFF (excluding decommissioning settlements).

Net Capital Expenditures[1,2]

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2021**	2020	**2021**	2020
Drilling and completion	**2,768**	76	**10,897**	2,718
Equipment, facilities and pipelines	**419**	43	**2,520**	892
Land and seismic	**76**	121	**456**	271
Capitalized overhead and other	**306**	1	**889**	163
Total capital expenditures	**3,569**	241	**14,762**	4,044
Asset dispositions (net of acquisitions)	**(116)**	(65)	**(56)**	(249)
Net capital expenditures	**3,453**	176	**14,706**	3,795

[1] Net capital expenditures include expenditures on E&E assets.
[2] Net capital expenditures are non-GAAP financial measures and are defined below under "Non-GAAP and Other Financial Measures".

Capital expenditures prior to acquisitions or dispositions for the three months and year ended December 31, 2021 were $3.6 million and $14.8 million, respectively. During 2021, the Company focused its capital activities on the Princess area where it incurred $12.1 million to drill, complete, equip and tie-in five gross (5.0 net) development wells, including $2.2 million that was incurred to drill, complete, equip and tie-in one gross (1.0 net) well in the fourth quarter of 2021. The fourth quarter Princess well came on production on December 1, 2021. Additionally in the fourth quarter of 2021 PPR incurred $0.8 million related to preliminary drilling costs including the purchase of casing for two gross (2.0 net) wells in the Michichi area that were spudded in January 2022. 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 months and year ended December 31, 2020 were $0.2 million and $4.0 million, respectively. During 2020, the Company focused its capital activities 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. Water injection for the pilot waterflood project commenced in May 2020. Minor capital expenditure in 2020 included recompletions in the Evi and Provost areas and the purchase of undeveloped land in the Princess area.

Decommissioning Liabilities

PPR's decommissioning liabilities at December 31, 2021 were $146.3 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 $19.9 million from year-end 2020 was primarily due to changes in estimates of $16.2 million, settlements of $3.3 million, and funding under government grants for the settlement of decommissioning liabilities of $2.2 million, partially offset by $1.9 million of accretion recorded in 2021. 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 reduction in decommissioning liabilities recorded in 2021 due to changes in estimates were largely the result of higher risk-free discount rates applied as at year-end 2021 and reductions in cost estimates supported by actual cost savings realized on decommissioning activities that were carried out during the year, partially offset by the impact of higher inflation rate incorproated in 2021.

The Company estimated the undiscounted and inflation-adjusted future liabilities of approximately $245.9 million (December 31, 2020 – $221.2 million) spanning over the next 55 years, based on an inflation rate of 1.6% (December 31, 2020 – 1.1%). The increase reflects the impact from the higher inflation rate applied at year-end 2021. Of the estimated undiscounted future liabilities, $18.0 million is estimated to be settled over the next five years. Funding received from under the government sponsored Site Rehabilitation Program may increase estimated settlements 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, 2021, the Company had $508.9 million (December 31, 2020 – $474.8 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 $354.2 million (December 31, 2020 – $383.1 million), scheduled to expire in the years 2022 to 2041.

As at December 31, 2021 and December 31, 2020, the Company did not recognize any deferred tax assets in excess of taxable temporary differences 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, 2021, the Company had working capital deficit (as defined in "Other Advisories" below) of $0.4 million (December 31, 2020 – working capital of $5.3 million). The decrease in working capital from December 31, 2020 was the result of higher accounts payable and accrued liabilities balances from increased capital expenditures and operating expenses and higher realized derivatives losses, partially offset by higher accounts receivable and inventory balances due to higher oil prices at December 31, 2021.

Revolving Facility

On December 29, 2021, PPR renewed and amended its Revolving Facility where the maturity date of the Revolving Facility was extended from December 31, 2022 to December 31, 2023. As of December 31, 2021, the borrowing base was US$53.8 million (December 31, 2020 — US$57.7 million). The 2021 amendments also provided for added borrowing base certainty during 2022, as there is no scheduled redetermination. The borrowing base is subject to a reduction to US$50.0 million on December 31, 2022 and to semi-annual redeterminations thereafter, without limiting the lenders' right to require a redetermination at any time. The next scheduled borrowing base re-determination is in Spring 2023 based on the year-end 2022 reserves evaluation.

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.

The following table provides a breakdown of borrowings drawn against the US$53.8 million Revolving Facility:

($000s)	December 31, 2021	December 31, 2020
USD Advances (USD $17.0 million (December 31, 2020 - USD $16.0 million))[1]	21,553	20,371
CAD Advances (USD $30.0 million (December 31, 2020 - USD $30.0 million))[2]	40,530	40,530
CAD Deferred Interest (US$0.4 million (December 31, 2020 - USD $0.5 million)[2]	541	590
Revolving Facility (USD $47.4 million (December 31, 2020 - USD $46.5 million))	62,624	61,491

[1] Converted using the month end exchange rate of $1.00 USD to $1.27 CAD as at December 31, 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.

As at December 31, 2021, the Company had US$6.4 million (CAN$8.1 million equivalent) borrowing capacity under the Revolving Facility.

Amounts borrowed under the Revolving Facility can be drawn in the form of USD or CAD advances bearing interest based on reference bank lending rates in effect from time to time, plus an applicable margin. Applicable margins per annum are 650 basis points until December 31, 2022, and then 950 basis points thereafter, and standby fees on any undrawn borrowing capacity are 87.5 basis points per annum.

Under the Revolving Facility, PPR can make further draws under the Revolving Facility on or before the maturity date, subject at all times to the then-applicable commitment amount. 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.

As at December 31, 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 deposits as collateral. The related deposits are 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, 2021, $0.4 million of deferred costs related to the Revolving Facility was netted against its carrying value (December 31, 2020 – $0.7 million).

Subordinated Senior Notes

On December 29, 2021, 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. Under the amendments, the maturity date was extended from June 30, 2023 to June 30, 2024. Under a previous amendment to the Senior Notes due 2024 on December 21, 2020, the annual interest rate 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 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. PPR did not incur any interest expense on the Senior Notes due 2024 during 2021 and expects the interest rate to increase to 4% on March 21, 2022 per the terms of the agreements.

Additionally, on December 21, 2020 PPR issued US$11.4 million (CAN$14.4 million using the December 31, 2021 month-end exchange rate of $1.00 USD to $1.27 CAD) of senior notes with a maturity date of December 21, 2026 ("Senior Notes due 2026", together with "Senior Notes due 2024" are herein referred to as "Senior Notes")) 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 so long as any indebtedness remains outstanding under the Revolving Facility, 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. 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 December 31, 2021 and $1.00 USD to $1.27 CAD as at December 31, 2020.

($000s)	**December 31, 2021**	December 31, 2020
Senior Notes Issued October 31, 2017		
Principal (US$16.0 million)	**20,285**	20,371
Deferred interest (US$4.4 million (December 31, 2020 - US$4.4 million))	**5,587**	5,611
Total Principal and Deferred Interest - October 31, 2017 Senior Notes	**25,872**	25,982
Senior Notes Issued November 21, 2018		
Principal (US$12.5 million)	**15,848**	15,915
Deferred interest (US$2.6 million (December 31, 2020 - US$2.6 million))	**3,324**	3,338
Total Principal and Deferred Interest - November 21, 2018 Senior Notes	**19,172**	19,253
Senior Notes Issued December 21, 2020		
Principal (US$11.39 million)	**14,438**	14,500
Deferred interest (US$1.5 million (December 31, 2020 - US$0.04))	**1,866**	48
Total Principal and Deferred Interest - December 21, 2020 Senior Notes	**16,304**	14,548
Total Principal and Deferred Interest - Senior Notes	**61,348**	59,783

In conjunction with the December 21, 2020 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 original issuances on October 31, 2017 and November 21, 2018 totaling 2,318,000 warrants with an exercise price of $0.549 expiring October 31, 2022 and 6,000,000 warrants with an exercise price of $0.282 expiring on October 31, 2023, respectively, 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 December 31, 2021 was $4.1 million (December 31, 2020 - $0.7 million).

PPR accounted for the December 29, 2021 amendments to the Senior Notes due 2024 as a modification, resulting in the recognition of a loss on revaluation of the liability in the fourth quarter of 2021 of $3.5 million.

PPR accounted for December 21, 2020 amendments to the Senior Notes due 2024 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 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 2024 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. The gain was net of $1.4 million of financing costs.

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

Covenants

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

The applicable financial covenants thresholds as at December 31, 2021 are as follows:

Financial Covenant	Revolving Facility Requirement	Senior Note Requirement	As at December 31, 2021
Senior Leverage[1]	Cannot exceed 5.87 to 1.00	Cannot exceed 6.75 to 1.00	2.86 to 1.00
Asset Coverage[2]	Cannot be less than 0.34 to 1.00	Cannot be less than 0.29 to 1.00	1.12 to 1.00
Current Ratio[3]	Cannot be less than 1.00 to 1.00	Cannot be less than 0.85 to 1.00	1.43 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.

Future thresholds for financial covenants vary by quarter and are as follows:

Financial Covenant	Revolving Facility Requirement	Senior Note Requirement
Senior Leverage	Cannot exceed between 3.00 and 6.36 to 1.00	Cannot exceed between 3.00 and 7.31 to 1.00
Asset Coverage	Cannot be less than between 0.34 and 0.87 to 1.00	Cannot be less than between 0.29 and 0.78 to 1.00
Current Ratio	Cannot be less than between 0.90 and 1.00 to 1.00	Cannot be less than between 0.77 and 0.85 to 1.00

The Company was in compliance with all applicable covenants as at December 31, 2021.

Shareholders' Equity

At December 31, 2021, PPR had consolidated share capital of $101.4 million (December 31, 2020 – $136.5 million) and had 128.7 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 December 31, 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 year ended December 31, 2021	**1,000,000**	**1,816,000**	**550,000**
Balance outstanding as at December 31, 2021	**3,401,015**	**1,474,263**	**1,880,268**
Balance outstanding as at December 31, 2020	5,514,877	1,805,021	2,337,081

[1] Outstanding options as at December 31, 2021 had a weighted average strike price of $0.24 per share, of which 1.7 million were exercisable at a weighted average strike price of $0.39 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 128.9 million common shares, 1.4 million RSUs, 2.4 million stock options, 1.9 million DSUs and 34.3 million warrants outstanding.

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.

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.

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 December 31, 2021 was 2.86 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 2022 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:

	2022	2023	2024	2025	2026	Thereafter	Total
Debt (interest and principal)	4,753	69,257	53,068	—	29,361	—	156,439
Leases - variable	292	142	—	—	—	—	434
Firm transportation agreements	261	145	58	50	—	—	514
Other agreements	288	126	57	53	31	250	805
Total	5,594	69,670	53,183	103	29,392	250	158,192

Contractual obligations and commitments are outlined in Note 22 of the Annual Financial Statements. The table above excludes contractual obligations for lease payments which are recorded as lease liabilities on the consolidated statement of financial position in accordance with IFRS 16 (see Note 10 of the Annual Financial Statements for information about lease liabilities).

In addition to contractual commitments, the Company has estimated future decommissioning liabilities of $245.9 million on an undiscounted basis, inflated at 1.6%, of which $18.0 million is estimated to be incurred over the next five years.

Contingencies

PPR is involved in litigation and claims arising in the normal course of operations. Such claims are not expected to have a material impact on the Company's results of operations or cash flows.

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)	2021 Q4	2021 Q3	2021 Q2	2021 Q1	2020 Q4	2020 Q3	2020 Q2	2020 Q1
Production Volumes								
Light & medium crude oil (bbl/d)	2,198	2,261	2,514	2,453	2,639	2,730	2,996	3,164
Heavy crude oil (bbl/d)	492	384	179	117	163	200	183	292
Conventional natural gas (Mcf/d)	9,246	8,986	9,122	8,233	9,080	8,704	9,351	10,186
Natural gas liquids (bbl/d)	138	131	140	129	140	135	141	127
Total (boe/d)	4,369	4,273	4,354	4,071	4,455	4,516	4,879	5,281
% Liquids	65 %	65 %	65 %	66 %	66 %	68 %	68 %	68 %
Financial								
Oil and natural gas revenue	25,064	22,133	20,259	16,967	14,211	13,904	8,333	15,272
Royalties	(3,346)	(2,708)	(2,324)	(1,225)	(1,305)	(1,404)	(1,033)	(1,285)
Unrealized (loss) gain on derivatives	3,990	(2,904)	(6,884)	(4,304)	(3,917)	(3,879)	(15,029)	27,605
Realized (loss) gain on derivatives	(3,947)	(2,276)	(2,257)	(1,076)	2,313	2,847	8,085	1,996
Revenue net of realized and unrealized (losses) gains on derivatives	21,761	14,245	8,794	10,362	11,302	11,468	356	43,588
Net earnings (loss)	7,851	(9,922)	23,995	(11,506)	3,130	(8,276)	(17,559)	(68,068)
Per share – basic	0.06	(0.08)	0.19	(0.07)	0.02	(0.05)	(0.10)	(0.40)
Per share – diluted	0.05	(0.08)	0.16	(0.07)	0.02	(0.05)	(0.10)	(0.40)
AFF [1]	1,718	4,344	4,153	1,979	1,853	3,818	4,570	231
Per share – basic	0.01	0.03	0.03	0.01	0.01	0.02	0.03	0.00
Per share – diluted	0.01	0.03	0.03	0.01	0.01	0.02	0.03	0.00
AFF - excluding decommissioning settlements [1]	4,302	4,796	4,268	2,104	1,946	3,912	5,221	935
Per share – basic	0.03	0.04	0.03	0.01	0.01	0.02	0.03	0.01
Per share – diluted	0.03	0.04	0.03	0.01	0.01	0.02	0.03	0.01

[1] AFF is a non-GAAP measure and is defined below under "Non-GAAP and Other Financial Measures".

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 fourth quarter of 2021, 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.

Fourth quarter 2021 oil and natural gas revenue was the highest among the past eight quarters due to improved average realized prices per boe. Net earnings of $7.9 million in the fourth quarter of 2021 were largely the result of non-cash items including impairment recovery of $6.5 million related to changes in decommissioning liabilities of certain properties that had a zero carrying value, unrealized gains on derivatives of $4.0 million, and a gain of $3.5 million related to the debt refinancing in December 2021, partially offset by depletion and depreciation expense of $6.0 million and non-cash financing costs of $2.5 million. The Company realized $4.3 million of AFF (excluding decommissioning settlements of $2.6 million).

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.

Annual Selected Financial and Operational Information

($000s except per unit amounts)	2021	2020	2019
Financial			
Oil and natural gas revenue	84,423	51,720	97,891
Net earnings (loss)	10,418	(90,773)	(33,079)
Per share - basic	0.08	(0.53)	(0.19)
Per share - diluted	0.06	(0.53)	(0.19)
AFF[1]	12,194	10,472	18,449
Per share - basic	0.09	0.06	0.11
Per share - diluted	0.07	0.06	0.11
AFF - excluding decommissioning settlements[1]	15,470	12,014	22,250
Per share - basic & diluted	0.11	0.07	0.13
Per share - diluted	0.09	0.07	0.13
Net capital expenditures[1]	14,706	3,795	11,856
Total assets	232,963	220,316	331,525
Total liabilities	299,523	297,226	317,947
Long-term debt	109,355	103,071	113,595
Weighted average shares outstanding			
Basic	136,944	172,013	171,349
Diluted	165,529	172,013	171,349
Operating			
Production Volumes			
Light & medium crude oil (bbls/d)	2,355	2,881	3,716
Heavy crude oil (bbl/d)	294	210	251
Conventional natural gas (Mcf/d)	8,900	9,328	11,635
Natural gas liquids (bbls/d)	135	136	166
Total (boe/d)	4,268	4,781	6,071
% Liquids	65 %	67 %	68 %
Average Realized Prices			
Light & medium crude oil ($/bbl)	71.83	38.05	61.83
Heavy crude oil ($/bbl)	72.12	35.26	53.33
Conventional natural gas ($/Mcf)	3.73	2.25	1.72
Natural gas liquids ($/bbl)	57.25	24.59	30.48
Total ($/boe)	54.19	29.56	44.18
Operating Netback ($/boe)[1]			
Realized price	54.19	29.56	44.18
Royalties	(6.16)	(2.87)	(4.55)
Operating costs	(25.16)	(21.30)	(21.04)
Operating netback	22.87	5.39	18.59
Realized (losses) gains on derivative instruments	(6.13)	8.71	(0.98)
Operating netback, after realized (losses) gains on derivative instruments	16.74	14.10	17.61

[1] AFF, net capital expenditures and operating netback are non-GAAP measures and are defined below under "Non-GAAP and Other Financial Measures".

Revenue increased during 2021 primarily due to substantial increases in benchmark prices, partially offset by a decrease in production of 513 boe/d or 11% from 2020 due to natural declines, partially offset by the 2021 drilling program. Revenue decreased during 2020 primarily due to substantial decreases in benchmark prices coupled with a decrease in production of 1,290 boe/d or 21% from 2019 as a result of the suspension of PPR's capital program in response to market conditions.

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, 2021, 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, 2021. All control systems by their nature can only provide reasonable, but not absolute, assurance that the objectives of the control system are met.

Internal Control over Financial Reporting

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

The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal control over financial reporting as defined in National Instrument 52-109. The control framework used by PPR's officers to design and evaluate the Company's ICFR is the Internal Control – Integrated Framework (2013) published by The Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on their evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's ICFR was effective as of December 31, 2021. There have been no changes in the Company's ICFR during the period from January 1, 2021 to December 31, 2021 that have materially affected, or are reasonably likely to materially affect, the Company's ICFR.

Internal control systems, no matter how well designed, have inherent limitations. 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.

Changes in Accounting Policies

The 2021 Annual Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

The following new or amended accounting standards and pronouncements were adopted during the year ended December 31, 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.

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

Amendments to IAS 1 Presentation of Financial Statements
In January 2020, the IASB issued amendments to IAS 1 Presentation of Financial Statements, that specifies the requirements for the classification of debt and other liabilities as either current or non-current. The amended is effective on January 1, 2023. The Company plans to adopt this standard on January 1, 2023 and is in the process of determining the potential impact of this amendment on the consolidated financial statements.

Critical Accounting Estimates

The preparation of financial statements in conformity with IFRS requires management to make judgments, 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.

- The COVID-19 pandemic is an evolving situation that will continue to have widespread implications for our business environment, operations and financial condition. The potential impact of the COVID-19 pandemic has been considered by Management in making judgments, estimates and assumptions used in the preparation of the Consolidated Financial Statements, but the inherent risks and uncertainties resulting from the pandemic may result in material changes to such judgments, estimates and assumptions in future periods as additional information becomes available.

- 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 costs could have a significant impact on impairment losses or impairment reversals;

- Reserves 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, royalties, 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;

- 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;

- 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, 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 judgments and is by its nature subject to measurement uncertainty;

- 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; and

- Management applies judgement in reviewing modifications of financial liabilities to determine if the modifications are considered substantial under the requirements of IFRS 9, including the consideration of qualitative and quantitative factors. The classification of a modification as non-substantial or substantial impacts the accounting treatment for the financial liability as to the implementation of modification accounting or extinguishment accounting and as such, may have material implications on the financial statements.

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 2021 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. Additionally, the impact of climate change results in physical risks as extreme variability of weather patterns could result is the damage of physical assets, significant downtime or other operational disputions.

- 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.

Impact of the COVID-19 Pandemic

- The course of the COVID-19 pandemic remains highly uncertain. The extent to which the COVID-19 pandemic impacts PPR's future operations and financial performance are currently unknown and are dependent on a number of unpredictable factors outside of the knowledge and control of Management, including the duration and severity of the pandemic, the impact of the pandemic on economic growth, inflation, supply chains, commodity prices and financial and capital markets and governmental responses and restrictions. These uncertainties may continue to persist beyond the point where the outbreak of the COVID-19 virus has subsided. PPR continues to monitor the effect of the COVID-19 pandemic on its supply chain and the availability and cost of materials and third-party services. To date, the Company has not experienced a material interruption in supplies or services related to the pandemic, but has begun to observe emerging inflationary pressures that have the potential to impact future operating and capital costs. Commodity prices and economic conditions, including the potential for supply chain disruptions and inflation, remain, in part, dependent on the course of the COVID-19 pandemic and the response thereto.

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 judgments 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-GAAP and Other Financial 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. Non-GAAP and other financial measures are provided as supplementary information by which readers may wish to consider the Company's performance but should not be relied upon for comparative or investment purposes. Readers must not consider non-GAAP and other financial measures in isolation or as a substitute for analysis of the Company's financial results as reported under IFRS. Non-GAAP and other financial measures may include non-GAAP measures, non-GAAP ratios, capital management measures, supplementary measures and total of segment measures. The non-GAAP and other financial measures used in this report are summarized as follows:

Working Capital

Working capital (deficit) is a non-GAAP financial measure, calculated as current assets excluding the current portion of derivative instruments, less accounts payable and accrued liabilities and corresponds with the terms defined under the Company's debt agreements for the calculation of the Current Ratio covenant (see "*Capital Resources and Liquidity - Covenants*" section above). In addition to measuring covenant compliance, this measure is used to assist management and investors in understanding liquidity at a specific point in time.

The following table provides a calculation of Working Capital:

($000s)	**December 31, 2021**	December 31, 2020
Current assets	**19,603**	20,807
Less: current derivative instrument assets	**—**	(798)
Current assets excluding current derivatives instruments	**19,603**	20,009
Less: Accounts payable and accrued liabilities	**19,970**	14,683
Working capital (deficit)	**(367)**	5,326

Operating Netback

Operating netback is a non-GAAP financial measure commonly used in the oil and gas industry, which the Company believes is a useful measure to assist management and investors to evaluate 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). Operating netback, after realized gains (losses) on derivatives, adjusts the operating netback for only realized portion of gains and losses on derivatives. Operating netback may be expressed in absolute dollar terms or on a per boe basis. Per boe amounts are determined by dividing the absolute value by gross working interest production. Operating netback per boe and operating netback, after realized gains (losses) on derivatives per boe are non-GAAP financial ratios.

The following table provides a calculation of Operating Netback:

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2021**	2020	**2021**	2020
Oil and natural gas revenue	**25,064**	14,211	**84,423**	51,720
Royalties	**(3,346)**	(1,305)	**(9,603)**	(5,027)
Operating expenses	**(10,120)**	(9,399)	**(39,194)**	(37,271)
Operating netback	**11,598**	3,507	**35,626**	9,422
Realized (losses) gains on derivatives	**(3,947)**	2,313	**(9,556)**	15,241
Operating netback, after realized (losses) gains on derivatives	**7,651**	5,820	**26,070**	24,663

Adjusted Funds Flow ("AFF")

AFF is a non-GAAP financial measure calculated based on cash flow from operating activities before changes in non-cash working capital, transaction costs, restructuring costs and other non-recurring items. The Company believes that AFF provides a useful measure of PPR's operational performance on a continuing basis by eliminating certain non-cash charges and charges that are non-recurring or discretionary. Management utilizes the measure to assess PPR's ability to finance 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. AFF per share is a non-GAAP ratio.

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 December 31,		Year Ended December 31,	
($000s)	**2021**	2020	**2021**	2020
Cash flow from operating activities	**(1,305)**	3,958	**9,681**	10,182
Changes in non-cash working capital	**2,324**	(493)	**1,501**	1,779
Other	**(46)**	(1,743)	**(56)**	(1,727)
Transaction, restructuring and other costs	**745**	131	**1,068**	238
Adjusted funds flow ("AFF")	**1,718**	1,853	**12,194**	10,472
Decommissioning settlements	**2,584**	93	**3,276**	1,542
AFF - excluding decommissioning settlements	**4,302**	1,946	**15,470**	12,014

Bank Adjusted EBITDAX

The Company monitors its capital structure and liquidity based on the ratio of Debt to Bank Adjusted EBITDAX, which is a capital management measure, 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 December 31,		Year Ended December 31,	
($000s)	**2021**	2020	**2021**	2020
Net earnings (loss) before income tax	**7,851**	3,130	**10,432**	(90,851)
Add (deduct):				
Interest	**3,843**	3,859	**13,919**	15,209
Depletion and depreciation	**5,664**	6,237	**23,093**	27,887
Depreciation on right-of-use assets	**361**	518	**1,638**	2,170
Exploration and evaluation expense	**385**	2,372	**1,249**	4,183
Unrealized loss (gain) on derivatives	**(3,990)**	3,917	**10,102**	(4,780)
Impairment (recovery) loss	**(6,459)**	1,872	**(40,739)**	78,459
Accretion	**598**	697	**1,871**	2,786
Gain on foreign exchange	**87**	(3,649)	**150**	(1,425)
Change in other liabilities	**56**	1,841	**219**	1,361
Modification of financial liabilities	**(3,456)**	(15,874)	**(3,456)**	(15,874)
Share – based compensation	**15**	(28)	**70**	225
Gain on sale of properties	**(116)**	(172)	**(476)**	(375)
Loss on warrant liability	**686**	344	**3,429**	260
Non-cash other income	**(405)**	—	**(2,204)**	—
Transaction costs, reorganization and other costs[1]	**745**	131	**1,068**	238
Pro-forma impact of acquisitions	**—**	—	**—**	—
Bank Adjusted EBITDAX	**5,865**	5,195	**20,365**	19,473

Net Capital Expenditures

Net capital expenditures is a non-GAAP financial measure commonly used in the oil and gas industry, which the Company believes is a useful measure to assist management and investors to assess PPR's investment in its existing asset base. Net capital expenditures is calculated by taking total capital expenditures, which is the sum of property and equipment expenditures 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.

The following table provides a calculation of Net Capital Expenditures:

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2021**	2020	**2021**	2020
Exploration and evaluation expenditures	**76**	121	**456**	271
Property and equipment expenditures	**3,493**	120	**14,316**	3,758
Capitalized stock-based compensation	**—**	—	**(10)**	15
Asset disposition (net of acquisition)	**(116)**	(65)	**(56)**	(249)
Net capital expenditures	**3,453**	176	**14,706**	3,795

Net Debt

Net debt is a non-GAAP financial 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)	**December 31, 2021**	December 31, 2020
Working capital[1]	**(367)**	5,326
Borrowings outstanding (principal plus deferred interest)	**(123,972)**	(121,274)
Total net debt	**(124,339)**	(115,948)

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