PetroShale

Calgary • Denver

Management's Discussion and Analysis & Consolidated Financial Statements

As at and for the three months and years ended December 31, 2021 and 2020

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Management's Discussion and Analysis

This Management's Discussion and Analysis (the "MD&A") has been prepared by management and was reviewed and approved by the Board of Directors of PetroShale Inc. ("PetroShale" or the "Company") on March 14, 2022. This MD&A should be read in conjunction with the Company's audited consolidated financial statements as at December 31, 2021 and 2020 and for the years then ended. The reader should be aware that the operating results discussed below may not be indicative of future performance.

The financial data presented below has been prepared in accordance with International Financial Reporting Standards ("IFRS"), unless otherwise indicated.

Frequently Used Terms:

Term	**Description**
Bbl(s)	Barrel(s)
Boe	Barrel(s) of oil equivalent
Bbls/d	Barrels per day
Boepd	Barrels of oil equivalent per day
HH	Henry Hub, reference price paid in US$ for natural gas deliveries
Mcf	Thousand cubic feet
Mmbtu	Million British Thermal Units
Mmbtu/d	Million British Thermal Units per day
NGLs	Natural gas liquids
WTI	West Texas Intermediate, reference price paid in US$ for crude oil of standard grade

Barrel of Oil Equivalent Advisory

Where amounts are expressed on a Boe basis, natural gas volumes have been converted to Boe using a ratio of 6,000 cubic feet of natural gas to one barrel of oil (6 Mcf:1 Bbl). This Boe conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. The value ratio between the commodities, based on the price of crude oil compared to natural gas, could be significantly different from the energy equivalency of 6 Mcf: 1 Bbl, and therefore utilizing this conversion ratio may be misleading as an indication of value.

Presentation of Volumes

The Company's reserves have been categorized as Tight Oil, Shale Gas, and Natural Gas Liquids pursuant to National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). Production volumes and per Boe calculations are presented on a company working interest basis, before royalty interests, unless otherwise stated.

Functional and Presentation Currency

Amounts in this MD&A are in Canadian dollars, unless otherwise stated, which is the Company's presentation currency. Transactions of the Company's US subsidiary are recorded in US dollars, as this is the primary economic environment in which this subsidiary operates. The US subsidiary has a US dollar functional currency. In translating the financial results from US dollars to Canadian dollars, the Company uses the following method: assets and liabilities are translated at the exchange rate in effect as at the date of the consolidated balance sheet; revenues and expenses are translated at the rate effective at the time of the transaction or the average rate for the period; and changes in shareholders' equity are translated at the rate effective at the time of the transaction. Unrealized gains and losses resulting from the translation to the Canadian dollar presentation currency are included in other comprehensive income.

Non-GAAP and Other Financial Measures

Throughout this MD&A and in other materials disclosed by the Company, PetroShale uses certain measures to analyze historical financial performance, financial position and cash flow. These non-GAAP and other financial measures are not defined by IFRS and therefore may not be comparable to performance measures presented by others. These non-GAAP and other financial measures should not be considered to be more meaningful than GAAP measures which are defined by IFRS, such as cash flow used in investing activities, net income (loss), cash flow from operating activities, petroleum and natural gas revenue and total liabilities, as indicators of the Company's performance.

Non-GAAP Financial Measures

Capital Expenditures

PetroShale uses capital expenditures to measure its investments in capital compared to the Company's annual capital budget. The most directly comparable GAAP measure to capital expenditures is cash flow used in investing activities. The reconciliation between cash flow used in investing activities, as defined by IFRS, and capital expenditures, as defined herein, is as follows:

	Three months ended December 31,		**Year ended December 31,**	
($ thousands)	**2021**	**2020**	**2021**	**2020**
Cash flow used in investing activities	23,361	11,619	52,036	91,430
Change in non-cash working capital	6,568	(8,876)	10,992	(56,256)
Capitalized share-based compensation	44	27	179	127
Decommissioning obligation	338	(659)	1,517	(32)
Capital expenditures	**30,311**	**2,111**	**64,724**	**35,269**

Capital Expenditures, Net

PetroShale uses capital expenditures, net to measure its investments in capital compared to the Company's annual capital budget. The most directly comparable GAAP measure to capital expenditures, net is additions to property, plant and equipment in the cash flow used in investing activities. The reconciliation between additions to property, plant and equipment, as defined by IFRS, and capital expenditures, net, as defined herein, is as follows:

	Three months ended December 31,		**Year ended December 31,**	
($ thousands)	**2021**	**2020**	**2021**	**2020**
Additions to property, plant and equipment	29,929	2,743	63,028	35,197
Proceeds from sale of other assets	-	-	-	(23)
Capital expenditures, net	**29,929**	**2,743**	**63,028**	**35,174**

Adjusted Earnings before Interest, Taxes, Depreciation and Amortization ("EBITDA")

PetroShale uses adjusted EBITDA, which represents cash provided by operating activities prior to changes in non-cash working capital, to measure the Company's ability to generate funds to service its debt and other obligations and to fund its operations, without the impact of changes in non-cash working capital which can vary based solely on timing of settlement of accounts receivable and accounts payable. The reconciliation between cash flow from operating activities, as defined by IFRS, and adjusted EBITDA, as defined herein, is as follows:

	Three months ended December 31,		**Year ended December 31,**	
($ thousands)	**2021**	**2020**	**2021**	**2020**
Cash flow provided by operating activities	17,449	13,326	72,230	69,991
Change in non-cash working capital	4,960	1,878	3,350	(11,265)
Adjusted EBITDA	**22,409**	**15,204**	**75,580**	**58,726**

Operating Netback and Operating Netback Prior to Hedging

Operating netback represents petroleum and natural gas revenue, plus or minus any realized gain or loss on financial derivatives, less royalties, lease operating costs, workover expense, production taxes, and transportation expense. Operating netback prior to hedging represents operating netback prior to any realized gain or loss on financial derivatives. PetroShale believes that in addition to net income (loss) and cash flow provided by operating activities, operating netback and operating netback prior to hedging are useful supplemental measures as they assist in the determination of the Company's operating performance, leverage, and liquidity. Operating netback is commonly used by investors to assess performance of oil and gas properties and the possible impact of future commodity price changes on energy producers.

The table below discloses the Company's operating netback and operating netback prior to hedging, including the reconciliation to its most closely comparable GAAP measure, petroleum and natural gas revenue.

	Three months ended December 31,		Year ended December 31,	
($ thousands)	**2021**	**2020**	**2021**	**2020**
Petroleum and natural gas revenue	72,883	37,268	229,340	143,506
Royalties	(13,785)	(6,704)	(42,699)	(26,255)
Lease operating costs	(7,677)	(4,244)	(24,787)	(21,703)
Workover expenses	(320)	(871)	(3,775)	(3,552)
Production taxes	(5,393)	(2,844)	(16,992)	(11,650)
Transportation expense	(1,824)	(2,739)	(7,361)	(11,473)
Operating netback prior to hedging	**43,884**	**19,866**	**133,726**	**68,873**
Realized loss on financial derivatives	(20,036)	(3,070)	(52,694)	(4,727)
Operating netback	**23,848**	**16,796**	**81,032**	**64,146**

Net Debt

Net debt represents total liabilities, excluding decommissioning obligation, lease liability and financial derivative liability, less current assets, excluding financial derivative assets. PetroShale believes net debt is a key measure to assess the Company's liquidity position at a point in time. Net debt is not a standardized measure and may not be comparable with similar measures for other entities. The reconciliation between total liabilities, as defined by IFRS, and net debt, as defined herein, is as follows:

($ thousands)	**As at December 31, 2021**	**As at December 31, 2020**
Total liabilities	261,047	365,177
Decommissioning obligation	(7,971)	(6,250)
Financial derivative liability	(15,544)	(10,020)
Lease liability	(1,125)	(1,617)
Total current assets	(40,340)	(20,384)
Net Debt	**196,067**	**326,906**

Non-GAAP Financial Ratios

Operating Netback per Boe and Operating Netback Prior to Hedging per Boe

The Company calculates operating netback per Boe as operating netback divided by average daily production. Operating netback prior to hedging per Boe is calculated as operating netback prior to hedging divided by average daily production. Operating netback and operating netback prior to hedging are non-GAAP financial measures. PetroShale believes that operating netback per Boe and operating netback prior to hedging per Boe are key industry performance measures of operational efficiency and are common measures within the oil and gas industry.

Supplementary Financial Measures

In this MD&A, the Company uses the following supplementary financial measures, which have the following meaning.

"Average realized NGLs price" (per Bbl) is comprised of NGLs commodity sales from production, as determined in accordance with IFRS, divided by the Company's NGLs production, expressed in US$ or CAD$, as applicable.

"Average realized shale gas price" (per Mcf) is comprised of shale gas commodity sales from production, as determined in accordance with IFRS, divided by the Company's shale gas production, expressed in US$ or CAD$, as applicable.

"Average realized tight oil price" (per Bbl) is comprised of tight oil commodity sales from production, as determined in accordance with IFRS, divided by the Company's tight oil production, expressed in US$ or CAD$, as applicable.

"Depreciation and depletion expenses per BOE" is comprised of the Company's depreciation and depletion expenses, as determined in accordance with IFRS, divided by the Company's total production (on a BOE basis).

"Impairment (impairment recovery) per BOE" is comprised of the Company's impairment, or impairment recover for the period, as the case may be, as determined in accordance with IFRS, divided by the Company's total production (on a BOE basis).

"Lease operating costs per BOE" is comprised of the Company's lease operating costs, as determined in accordance with IFRS, divided by the Company's total production (on a BOE basis).

"Net G&A expenses per BOE" is comprised of the Company's gross G&A expenses, as determined in accordance with IFRS, less capitalized G&A and overhead recovery, as determined in accordance with IFRS, divided by the Company's total production (on a BOE basis).

"Petroleum and natural gas revenue, per BOE" is comprised of petroleum and natural gas revenue, as determined in accordance with IFRS, divided by the Company's total production (on a BOE basis).

"Petroleum and natural gas revenue, net, per BOE" is comprised of petroleum and natural gas revenue, net of royalties, as determined in accordance with IFRS, divided by the Company's total production (on a BOE basis).

"Production taxes per BOE" is comprised of the Company's production taxes, as determined in accordance with IFRS, divided by the Company's total production (on a BOE basis).

"Realized loss on financial derivatives, per BOE" is comprised of the Company's realized loss on financial derivatives, as determined in accordance with IFRS, divided by the Company's total production (on a BOE basis).

"Royalties per BOE" is comprised of royalties, as determined in accordance with IFRS, divided by the Company's total production (on a BOE basis).

"Royalties as a percentage of revenue" is comprised of royalties, as determined in accordance with IFRS, divided by petroleum and natural gas revenue as determined in accordance with IFRS.

"Total operating expenses per BOE" is comprised of the Company's total operating expenses, as determined in accordance with IFRS, divided by the Company's total production (on a BOE basis).

"Transportation expenses per BOE" is comprised of the Company's transportation expenses, as determined in accordance with IFRS, divided by the Company's total production (on a BOE basis).

"Workover expenses per BOE" is comprised of the Company's workover expenses, as determined in accordance with IFRS, divided by the Company's total production (on a BOE basis).

Forward Looking Statements

This MD&A contains forward looking statements and forward-looking information (collectively, "forward looking statements") within the meaning of applicable Canadian securities laws. The use of any of the words "expect," "anticipate," "continue," "estimate," "objective," "ongoing," "may," "will," "project," "should," "believe," "plans," "intends," "strategy," and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this MD&A contains forward-looking information and statements pertaining to the following: Management's assessment of future plans and operations, the Company's plans, focus and strategy, estimated annual average production range for 2022, 2022 annual capital expenditures and expectation that such expenditures will result in additional production in early 2022, capital expenditures will be funded substantially within operation cash flow for 2022, expectation that the Company will significantly enhance free cash flow in 2022, timing of hedges to expire, the Company's derivative instruments, the terms thereof and the anticipated benefits, anticipated timing to complete wells, the term out and maturity dates of the senior credit facility, methods the Company will use to monitor cash flow and terms of contractual obligations and other commercial commitments.

The forward-looking information and statements included in this MD&A are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: risks associated with oil and gas development, exploitation, production, marketing and transportation of oil, natural gas, and natural gas liquids, loss of markets, determinations by OPEC and other countries as to production levels, volatility of commodity prices, currency fluctuations, inability to transport or process natural gas at economic rates or at all, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services at reasonable costs or at all, unforeseen challenges or circumstances in drilling, equipping and completing wells leading to higher capital costs than anticipated, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions or drilling operations, risks associated with PetroShale's non-operated status on some of its properties, risks associated with the availability of transportation of the Company's production through pipeline and other systems; risks associated with pricing and costs inflation; production delays resulting from an inability to obtain required regulatory approvals or services, unfavorable weather, or the tie-in of associated natural gas production and an inability to access sufficient capital from internal and external sources.

The Company's actual results may differ materially from those expressed in, or implied by, the forward-looking statements. Forward looking statements or information is based on several factors and assumptions which have been used to develop such statements and information, but which may prove to be incorrect. Although PetroShale believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward looking statements because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document and other documents filed by the Company, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic, regulatory and political environment in which PetroShale operates; the impact (and the duration thereof) that the COVID-19 pandemic will have on (i) the demand for tight oil, shale gas and NGLs, (ii) our supply chain, including our ability to obtain the equipment and services we require, and (iii) our ability to produce, transport and/or sell our tight oil, shale gas and NGLs; the ability of the Company to obtain and retain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the Company and the operators of its non-operated properties to operate in the field in a safe, efficient, compliant and effective manner; PetroShale's ability to obtain financing on acceptable terms or at all; changes in the Company's credit facilities including changes to borrowing base and maturity dates; receipt of regulatory approvals; field production rates and decline rates; the ability of the Company, and the operators of its non-operated properties, to tie-in associated natural gas production in an economic manner, or at all; the ability to manage lease operating and transportation costs; the ability to replace and expand oil and natural gas reserves through acquisition, development or exploration; the ability to convert non-producing proved and undeveloped or probable oil and natural gas reserves to producing reserves; the timing and costs of pipeline, storage and facility construction and expansion; the ability of the Company to secure adequate transportation for commodity production; future petroleum and natural gas prices; differentials between benchmark commodity prices and those received by the Company for its production in the field; currency exchange and interest and inflation rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company operates; PetroShale's ability to successfully drill, complete and commence production at commercial rates from its operated wells; and PetroShale's ability, or those of the operators of its non-operated properties, to successfully market its petroleum and natural gas products. Readers are cautioned that the foregoing list of factors is not exhaustive.

Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the System for Electronic Document Analysis and Retrieval ("SEDAR") website (www.sedar.com) or at the Company's website (www.petroshaleinc.com). Furthermore, the forward looking statements contained in this document are made as at the date of this document and the Company does not undertake any obligation to update publicly or to revise any of the included forward looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Financial and Operational Highlights

	Three months ended December 31,		Year ended December 31,	
	2021	2020	2021	2020
Financial *($ thousands, except share amounts)*				
Petroleum and natural gas revenue	72,883	37,268	229,340	143,506
Cash flow provided by operating activities	17,449	13,326	72,230	69,991
Net income (loss)	25,065	(12,417)	(828)	(61,985)
Per share income (loss) – basic and diluted	0.05	(0.07)	-	(0.33)
Adjusted EBITDA (1)	22,409	15,204	75,580	58,726
Capital expenditures, net (1)	29,929	2,743	63,028	35,174
Net debt (1)			196,067	326,906
Number of common shares outstanding:				
Shares outstanding, end of period	523,387,831	188,528,453	523,387,831	188,528,453
Weighted average – basic	521,800,232	188,459,513	431,950,365	188,240,502
Weighted average - diluted	532,490,737	196,003,279	442,640,870	195,784,268
Operating				
Number of days	92	92	365	366
Daily production: (2)				
Tight oil (Bbls)	7,342	7,814	6,930	8,836
Shale gas (Mcf)	11,615	12,772	11,226	11,870
Natural gas liquids (Bbls)	1,628	2,262	1,747	2,113
Barrels of oil equivalent	10,906	12,205	10,548	12,928
Average realized price:				
Tight oil ($/Bbl)	94.72	52.25	83.16	45.69
Shale gas ($/Mcf)	4.71	(0.10)	2.15	(0.71)
Natural gas liquids ($/Bbl)	25.81	(0.85)	16.00	(1.55)
Operating netback ($ per Boe): (3)				
Petroleum and natural gas revenue	72.64	33.19	59.57	30.33
Royalties	(13.74)	(5.97)	(11.09)	(5.55)
Realized loss on financial derivatives	(19.97)	(2.73)	(13.69)	(1.00)
Lease operating costs	(7.65)	(3.78)	(6.44)	(4.59)
Workover expense	(0.32)	(0.78)	(0.98)	(0.75)
Production taxes	(5.37)	(2.53)	(4.41)	(2.46)
Transportation expense	(1.82)	(2.44)	(1.91)	(2.42)
Operating netback (1)	23.77	14.96	21.05	13.56
Operating netback prior to hedging (1)	43.74	17.69	34.74	14.56

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section "Non-GAAP and Other Financial Measures contained within this MD&A."

(2) The Company's reserves have been categorized as Tight Oil, Shale Gas, and Natural Gas Liquids pursuant to National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities ("NI 51-101").

(3) Non-GAAP ratio that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Includes a non-GAAP financial measure component of operating netback. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this MD&A for an explanation of composition.

Management's Discussion and Analysis

Description of Business

PetroShale Inc. ("PetroShale" or the "Company") is an independent oil company focused on the acquisition, development, and production of oil-weighted assets in the Bakken and Three Forks formations in the Williston Basin area of North Dakota. The Company's common shares are listed on the TSX Venture Exchange under the "PSH" ticker symbol.

The Company has corporate offices located at Suite 1800, 350 - 7th Avenue SW, Calgary, Alberta T2P 3N9 and at 303 E. 17th Avenue, Suite 940, Denver, CO 80203.

Recent Developments

In the fourth quarter of 2021, the Company recognized production from four gross (3.50 net) wells newly completed operated wells. All four of these recently completed wells were spud in the third quarter of 2021, with no new wells drilled and completed during the quarter.

The Company recorded an operating netback before hedging losses of $43.74 and $34.74 per Boe, respectively, in the three months and year ended December 31, 2021 ($17.69 and $14.56 per Boe, respectively, for the three months and year ended December 31, 2020). During the three months and year ended December 31, 2021, the Company realized hedge losses of $20.0 million and $52.7 million, respectively, resulting in operating netbacks of $23.77 and $21.05 per Boe, respectively, for the three months and year ended December 31, 2021 ($14.96 and $13.56 per Boe, respectively, for the three months and year ended December 31, 2020). With the majority of the current hedges rolling off at the end of the year, assuming similar benchmark commodity prices, management anticipates a smaller realized hedging loss, in absolute dollar terms and on a per Boe basis, and a consequent increase in cash flows from operations in 2022.

As a result of the volatile economic environment and severe downturn in crude oil and natural gas prices in early 2020, as well as the unprecedented impact of the COVID-19 pandemic, the Company completed a process to optimize the capital structure, reduce debt, increase financial flexibility, and position PetroShale for long-term success. On April 8, 2021, the Company completed a series of agreements (the "Recapitalization Agreements") with its largest common shareholder, Mr. M. Bruce Chernoff (the Company's Executive Chairman and a director), a company of which Mr. Chernoff is a significant shareholder ("ChernoffCo"), and FR XIII PetroShale Holdings L.P. ("First Reserve" or the "Investor"), the former sole owner of the Company's wholly owned subsidiary's preferred shares, initiated a rights offering to its shareholders and reached an agreement in principle in respect of the Company's credit facility with the Company's bank lending syndicate, collectively, to fundamentally improve PetroShale's capital structure. Via this process, the Company raised $30.0 million of equity and eliminated the preferred share obligation further reducing debt by $102.8 million. Refer to the "Liquidity and Capital Resources" section later in this MD&A and Note 10 to the Company's consolidated financial statements for further information.

For the calendar year 2022, the Company expects to incur capital expenditures of $58.0 million and to achieve annual average production between 10,500 Boepd and 11,000 Boepd.

New Management Team, Board Appointment, Private Placements and Proposed Name Change

New Management Team and Board Appointment

On January 13, 2022, the Company announced the appointment of a new management team (the "New Management Team"), led by Brett Herman as President & Chief Executive Officer, Jason Skehar as Chief Operating Officer, Marvin Tang as Vice President, Finance & Chief Financial Officer, Sandy Brown as Vice President, Geosciences, Kristine Lavergne as Vice President, Engineering, and Shane Manchester as Vice President, Operations. In addition, the Company announced the appointment of Dale O. Shwed to the Board of Directors. On February 22, 2022, the Company announced the appointment of Anthony Baldwin as Vice President, Business Development.

Private Placements

In connection with the appointment of the New Management Team, on February 2, 2022, the Company closed a non-brokered private placement of units of PetroShale (the "Units") with the New Management Team, among others, for gross proceeds of $9.5 million (the "Non-Brokered Private Placement") and a brokered private placement of common shares of PetroShale for gross proceeds of $45.0 million (the "Brokered Private Placement", and combined with the Non-Brokered Private Placement, the "Private Placements").

Pursuant to the Non-Brokered Private Placement, PetroShale issued 23,750,000 Units at a price of $0.40 per Unit for total proceeds of $9.5 million. Each Unit is comprised of one common share of PetroShale ("Common Share") and one warrant ("Warrant") entitling the holder to purchase one Common Share at a price of $0.475 per Common Share for a period of five years from the issuance date. The Warrants will vest and become exercisable as to one-third upon the 20-day volume weighted average trading price of the Common Shares (the "Trading Price") equaling or exceeding $0.67 per Common Share, an additional one-third upon the Trading Price equaling or exceeding $0.83 per Common Share and the final one-third upon the Trading Price equaling or exceeding $0.95 per Common Share.

Pursuant to the Brokered Private Placement, the Company issued 112,500,000 Common Shares at a price of $0.40 per Common Share for gross proceeds of $45.0 million. Through the Private Placements, PetroShale raised total gross proceeds of $54.5 million which was used to reduce debt and for general corporate purposes, positioning the Company to execute on a disciplined corporate strategy.

The Company's two largest shareholders, FR XIII PetroShale Holdings L.P. and M Bruce Chernoff, waived their respective rights to participate in the Private Placements in order to maintain their ownership positions and did not acquire any Common Shares as part of the Company's Private Placements.

Proposed Name Change

On January 13, 2022, the Company announced it intends to ask the shareholders of PetroShale to approve the change of the Company's name to Lucero Energy Corp. at the next annual general meeting of shareholders.

Results of Operations

Production

	Three months ended December 31,			Year ended December 31,		
	2021	2020	% change	2021	2020	% change
Tight oil (Bbls per day)	7,342	7,814	(6.0)	6,930	8,836	(21.6)
Shale gas (Mcf per day)	11,615	12,772	(9.1)	11,226	11,870	(5.4)
Natural gas liquids (Bbls per day)	1,628	2,262	(28.0)	1,747	2,113	(17.3)
Total (Boe per day)	10,906	12,205	(10.6)	10,548	12,928	(18.4)
Liquids percentage of total	82.2	82.6	(0.4)	82.3	84.7	(2.9)

Total production during the three months and year ended December 31, 2021 decreased 11% and 18%, respectively, compared to the three months and year ended December 31, 2020 (the "Corresponding Periods"). Total production for the three months and year ended December 31, 2021 decreased compared to the Corresponding Periods due to natural declines as a result of reduced capital spending in the latter half of 2020 and the first half of 2021 while the Company sought to preserve financial liquidity.

Pricing

	Three months ended December 31,			Year ended December 31,		
	2021	2020	% change	2021	2020	% change
Average Benchmark Prices (US$)						
Crude oil – WTI (per Bbl)	77.36	42.59	81.6	67.96	39.38	72.6
Natural gas – HH spot (per Mmbtu)	4.77	2.53	88.5	3.91	2.04	91.7
Average Differential (US$)						
Crude oil (per Bbl)	(2.21)	(2.48)	(10.9)	(1.63)	(5.63)	(71.0)
Natural gas (per Mcf) (1)	(1.03)	(2.61)	(60.5)	(2.20)	(2.56)	(14.1)
Average Realized Prices (US$)						
Tight oil (per Bbl)	75.15	40.11	87.4	66.33	33.75	96.5
Shale gas (per Mcf)	3.74	(0.08)	4,775.0	1.71	(0.52)	428.8
Natural gas liquids (per Bbl)	20.47	(0.65)	3,249.2	12.76	(1.15)	1,209.6
Average Realized Prices (CAD$)						
Tight oil (per Bbl)	94.72	52.25	81.3	83.16	45.69	82.0
Shale gas (per Mcf)	4.71	(0.10)	4,810.0	2.15	(0.71)	402.8
Natural gas liquids (per Bbl)	25.81	(0.85)	3,136.5	16.00	(1.55)	1,132.3

(1) Includes conversion from Mmbtu to Mcf.

After a steep decline in the first half of 2020, benchmark commodity prices rebounded through the second half of 2020 and significantly increased throughout 2021. The Company's average basis differential for crude oil has significantly improved during the three months and year ended December 31, 2021 after widening throughout the majority of 2020, contributing to a significant improvement in realized tight oil prices.

Henry Hub benchmark natural gas prices increased considerably during 2021 when compared to 2020 with significant improvements realized in the second half of 2021, resulting in higher realized shale gas prices. NGL prices reflected the improvement in oil prices.

Revenues and Royalties

	Three months ended December 31,			**Year ended December 31,**		
($ thousands except where noted)	**2021**	**2020**	**% change**	**2021**	**2020**	**% change**
Petroleum and natural gas revenue	72,883	37,268	95.6	229,340	143,506	59.8
Less: royalties	(13,785)	(6,704)	105.6	(42,699)	(26,255)	62.6
Petroleum and natural gas revenue, net	59,098	30,564	93.4	186,641	117,251	59.2
Royalties as a percentage of revenue	18.9%	18.0%	5.1	18.6%	18.3%	1.8
Per Boe amounts:						
Petroleum and natural gas revenue	72.64	33.19	118.8	59.57	30.33	96.4
Less: royalties	(13.74)	(5.97)	130.2	(11.09)	(5.55)	99.8
Petroleum and natural gas revenue, net	58.90	27.22	116.4	48.48	24.78	95.6

Revenues in the three months and year ended December 31, 2021 increased 96% and 60%, respectively, compared to the Corresponding Periods. The increases were primarily due to increased realized commodity prices.

The Company's royalty rate as a percentage of revenues for the three months and year ended December 31, 2021 remained consistent, compared to the Corresponding Periods.

Realized and Unrealized Gain (Loss) on Financial Derivatives

	Three months ended December 31,			**Year ended December 31,**		
($ thousands except where noted)	**2021**	**2020**	**% change**	**2021**	**2020**	**% change**
Realized loss on financial derivatives	(20,036)	(3,070)	552.6	(52,694)	(4,727)	1,014.7
Unrealized gain (loss) on financial derivatives	17,273	(6,849)	(352.2)	(5,216)	(10,386)	(49.8)
Realized loss on financial derivatives per Boe	(19.97)	(2.73)	631.5	(13.69)	(1.00)	1,269.0

In the year ended December 31, 2020, during the uncertain economic environment related to the COVID-19 pandemic, the Company entered into various financial derivatives to reinforce its capital structure. As crude oil prices subsequently recovered, the Company realized losses on its financial derivatives throughout the year ended December 31, 2021. Refer to the Financial Derivatives and Hedging Activities table below for further details.

Operating Expense

	Three months ended December 31,			Year ended December 31,		
($ thousands except where noted)	**2021**	**2020**	**% change**	**2021**	**2020**	**% change**
Lease operating costs	7,677	4,244	80.9	24,787	21,703	14.2
Workover expense	320	871	(63.3)	3,775	3,552	6.3
Production taxes	5,393	2,844	89.6	16,992	11,650	45.9
Total operating expense	13,390	7,959	68.2	45,554	36,905	23.4
Per Boe amounts:						
Lease operating costs	7.65	3.78	102.4	6.44	4.59	40.3
Workover expense	0.32	0.78	(59.0)	0.98	0.75	30.7
Production taxes	5.37	2.53	112.3	4.41	2.46	79.3
Total operating expense	13.34	7.09	88.2	11.83	7.80	51.7
Production taxes – % of net revenue	9.1%	9.3%	(2.2)	9.1%	9.9%	(8.1)

Lease operating costs

Lease operating costs increased on both a dollar and per Boe basis, for the three months and year ended December 31, 2021, compared to the Corresponding Periods. The increases were primarily due to increased variable costs as a result of the global economic recovery and ongoing production optimization efforts.

Workover expense

Workover expense, by its nature, will vary from period to period depending on the level of workover activity and may not be consistent with production levels. With the improved commodity pricing environment in 2021, workover expense increased during the year ended December 31, 2021 compared to the prior year on a dollar and per Boe basis, as the Company performed workovers to optimize and return operated wells to production. For the three months ended December 31, 2021 compared to the three months ended December 31, 2020, workover expense decreased as the majority of the wells were returned to production in the first half of 2021.

Production taxes

North Dakota assesses a 5% oil severance tax and a 5% oil extraction tax on the gross value of after-royalty volumes produced at the wellhead, with certain defined exemptions. Absolute production taxes and production taxes per Boe are higher than the comparable prior year periods primarily due to improved pricing and are consistent with the changes in the Company's average realized prices as discussed in the Pricing section above.

Transportation expense

	Three months ended December 31,			Year ended December 31,		
($ thousands except where noted)	**2021**	**2020**	**% change**	**2021**	**2020**	**% change**
Transportation expense	1,824	2,739	(33.4)	7,361	11,473	(35.8)
Transportation expense per Boe	1.82	2.44	(25.4)	1.91	2.42	(21.1)

Transportation costs associated with the Company's petroleum production are netted against the related revenue if they are incurred following the transfer of control to the entity which has purchased the commodity. If transportation costs are incurred prior to the sale of the production, such costs are reflected separately as an expense in the consolidated statement of operations and comprehensive loss. Transportation costs were lower in the three months and year ended December 31, 2021 compared to the Corresponding Periods due to lower average oil transportation rates as well as lower production in 2021.

Operating Netback

($ per Boe)	Three months ended December 31, 2021	2020	% change	Year ended December 31, 2021	2020	% change
Petroleum and natural gas revenue	72.64	33.19	118.8	59.57	30.33	96.4
Royalties	(13.74)	(5.97)	130.2	(11.09)	(5.55)	99.8
Realized (loss) gain on financial derivatives	(19.97)	(2.73)	631.5	(13.69)	(1.00)	1,269.0
Lease operating costs	(7.65)	(3.78)	102.4	(6.44)	(4.59)	40.3
Workover expense	(0.32)	(0.78)	(59.0)	(0.98)	(0.75)	30.7
Production taxes	(5.37)	(2.53)	112.3	(4.41)	(2.46)	79.3
Transportation expense	(1.82)	(2.44)	(25.4)	(1.91)	(2.42)	(21.1)
Operating netback (1)	23.77	14.96	58.9	21.05	13.56	55.2
Operating netback prior to hedging (1)	43.74	17.69	147.3	34.74	14.56	138.6

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section "Non-GAAP and Other Financial Measures contained within this MD&A".

General and Administrative ("G&A") Expense

($ thousands except where noted)	Three months ended December 31, 2021	2020	% change	Year ended December 31, 2021	2020	% change
Gross G&A expense	2,309	1,830	26.2	7,709	6,686	15.3
Capitalized G&A	(382)	(104)	267.3	(1,172)	(610)	92.1
Overhead recovery	(488)	(134)	264.2	(1,086)	(675)	60.9
Net G&A expense	1,439	1,592	(9.6)	5,451	5,401	0.9
Net G&A expense per Boe	1.43	1.42	0.7	1.42	1.14	24.6

Net G&A costs for the three months ended December 31, 2021 remained consistent compared to the Corresponding Period. This was largely the result of higher gross G&A, offset by increased overhead recoveries as the Company increased its production from operated wells in the period, and increased capitalized G&A as a result of increased capital activity. Net G&A per Boe for the year ended December 31, 2021 increased compared to the prior year largely due to the decrease in production volumes.

Depreciation and Depletion Expense

($ thousands except where noted)	Three months ended December 31, 2021	2020	% change	Year ended December 31, 2021	2020	% change
Depreciation and depletion expense	11,880	13,930	(14.7)	46,207	66,128	(30.1)
Depreciation and depletion expense per Boe	11.84	12.41	(4.6)	12.00	13.98	(14.2)

Depreciation and depletion expense, on an absolute dollar and per Boe basis, decreased during the three months and year ended December 31, 2021, compared to the Corresponding Periods. The decreases on a dollar basis are primarily due to reduced production volumes in the three months and year ended December 31, 2021, compared to the Corresponding Periods. The decreases on a per Boe basis are primarily due to a lower depletable base in the three months and year ended December 31, 2021, compared to the Corresponding Periods.

Impairment and Impairment Recovery

	Three months ended December 31,			Year ended December 31,		
($ thousands except where noted)	**2021**	**2020**	**% change**	**2021**	**2020**	**% change**
Impairment (impairment recovery)	-	-	-	(19,324)	24,000	(180.5)
Impairment (impairment recovery) per Boe	-	-	-	(5.02)	5.07	(199.0)

The Company evaluates its developed and producing ("D&P") assets for impairment indicators that may suggest the carrying value of these assets may not be recoverable. If such impairment indicators exist, impairment is determined by comparing the carrying amount of D&P assets to the greater of the assets value in use or its estimated fair value less selling costs. If the carrying amount is in excess of the estimated recoverable value, the Company will record an impairment expense related to the D&P assets. Alternatively, impairment losses may be reversed in future periods if the estimated recoverable amount of the D&P assets exceed the carrying value. The impairment recovery is limited to a maximum of the previously recognized impairment expense, net of any depletion that would have occurred if not for the impairment.

Determining the estimated cash flows associated with the Company's proved plus probable reserves is an inherently complex process involving the exercise of professional judgment and the use of significant estimates, including future commodity prices, differentials, discount rates, production volumes, royalties, operating costs, and future capital expenditures.

During the quarter ended March 31, 2020, the significant decline in oil prices was deemed an indicator of impairment and, as a result, the Company performed an impairment test using its December 31, 2019 reserve report adjusted internally for activity during the three-month period ended March 31, 2020. Based on the results of this impairment test, the Company recognized an impairment charge of $24.0 million for the three months ending March 31, 2020 on the Company's D&P assets.

During the second quarter of 2021, management identified indicators of impairment recovery. After evaluating the carrying amount of D&P assets versus the estimated recoverable value, the Company recognized an impairment recovery of $19.3 million, primarily due to the increase in forecast benchmark commodity prices at June 30, 2021. The Company's impairment recovery reflects the full prior year impairment net of the related depletion expense impact.

At December 31, 2021, there were no indicators of impairment.

Finance Expense

	Three months ended December 31,			Year ended December 31,		
($ thousands)	**2021**	**2020**	**% change**	**2021**	**2020**	**% change**
Preferred share dividends	-	3,180	(100.0)	4,171	11,792	(64.6)
Senior credit facility interest	2,447	2,680	(8.7)	10,838	10,081	7.6
Preferred share accretion, net	-	675	(100.0)	683	2,744	(75.1)
Decommissioning obligation accretion	119	25	376.0	208	135	54.1
Operating lease and other	19	28	(28.6)	92	693	(86.9)
Total finance expense	**2,585**	**6,588**	**(60.8)**	**15,992**	**25,445**	**(37.2)**

Finance expense reflects costs primarily associated with the Company's senior credit facility and the preferred shares. The preferred shares, which were exchanged for common shares in April 2021, had been reflected as a financial liability in the statement of financial position for accounting purposes. In both the three months and year ended December 31, 2021, finance expense was lower compared to the Corresponding Periods, reflecting the exchange of the preferred shares, slightly offset by higher effective interest rates on the senior credit facility borrowings.

Share-based Compensation

	Three months ended December 31,			Year ended December 31,		
($ thousands)	**2021**	**2020**	**% change**	**2021**	**2020**	**% change**
Gross share-based compensation	195	281	(30.2)	1,096	1,049	4.5
Capitalized share-based compensation	(44)	(27)	63.0	(179)	(127)	40.9
Net share-based compensation	**151**	**254**	**(40.2)**	**917**	**922**	**(0.5)**

The Company has granted restricted share bonus awards and performance share bonus awards (collectively, the "Share Bonus Awards") to certain directors, officers, and employees. Share Bonus Awards granted according to the plan vest over three years from the date of grant and expire before the end of the third year from the date of grant. Restricted share bonus awards vest pro rata, typically over a three-year period. Performance share bonus awards vest ratably over a three-year period, and their value is based on achievement of certain performance hurdles and are subject to a multiplier between 0 and 2.0 times based on the Company's performance against specified key performance indicators. The Share Bonus Awards may be settled by the Company, in its sole discretion, in cash and/or common shares of the Company. The estimated fair value of the Share Bonus Awards is determined based on the current market value of the Company's common shares at the dates of grant and considering anticipated forfeiture rates. For purposes of valuing performance share bonus awards, the Company assumes a performance share bonus award multiplier of 1.0 times. A charge to income is reflected as share-based compensation expense in the consolidated statement of operations and comprehensive loss over the vesting period with a corresponding increase to contributed surplus in the consolidated statement of financial position.

Foreign Currency Gain (Loss) and Translation Adjustment

	Three months ended December 31,		Year ended December 31,	
	2021	**2020**	**2021**	**2020**
Foreign currency translation rates –CAD$/US$:				
Average period exchange rate	1.2605	1.3027	1.2537	1.3408
Ending period exchange rate	1.2637	1.2725	1.2637	1.2725

The Company's consolidated financial statements are reported in Canadian dollars, which is the Company's presentation currency. Transactions of the Company's US subsidiary are recorded in US dollars, its functional currency, as this is the primary economic environment in which the subsidiary operates. The assets, liabilities, and results of operations of the Company's US subsidiary are translated to Canadian dollars in the consolidated financial statements according to the Company's foreign currency translation policy, with any corresponding gain or loss reflected as a currency translation adjustment in other comprehensive income. The Company experienced a currency translation loss of $0.9 million and a currency translation gain of $0.2 million, respectively, for the three months and year ended December 31, 2021 (Corresponding Periods: loss of $7.4 million and $0.6 million, respectively), due to a recent strengthening of the Canadian dollar to US dollar.

Liquidity and Capital Resources

Summary

The Company's capital resources consist primarily of cash flow provided by operating activities, cash and cash equivalents and availability under the senior credit facility. The Company is dependent on cash on hand, operating cash flows and equity and/or debt issuances to finance capital expenditures and property acquisitions. Borrowings are managed in relation to credit capacity and ability to generate future operating cash flows to service such debt.

The Company continuously monitors production, commodity prices and/or resulting cash flows. Should the outlook for future cash flow forecasts reflect a significantly negative trend, the Company is capable of managing its cash flows by not consenting to participate in additional drilling proposed by the operators of its non-operated properties, by reducing its drilling and completion activity on its operated properties and by entering into commodity price hedge contracts. The Company considers its current and future financial capacity and liquidity before proceeding with additional wells on its operated lands.

During the second quarter of 2021, the Company utilized gross proceeds from the Recapitalization Agreements and free cash flow to reduce the amount drawn under the senior credit facility by approximately US$24.4 million. Free cash flow was used to further reduce the senior credit facility balance by US$6.8 million during the year ended December 31, 2021. The senior credit facility balance is US$143.2 million excluding unamortized debt issuance costs at December 31, 2021 (US$174.4 million at December 31, 2020), or US$142.9 million net of available cash (US$172.2 million at December 31, 2020). The available borrowing base of the senior credit facility was most recently reaffirmed in March 2021 at US$177.5 million and the next borrowing base redetermination is scheduled for May 2022. The Company has no other debt obligations.

Cash Flow provided by Operating Activities

Cash flow provided by operating activities depends on several factors including commodity prices, royalty rates, production volumes, operating expenses, transportation expenses, and production taxes, which generate adjusted EBITDA, as well as the impact of changes in non-cash working capital. During the three months and year ended December 31, 2021, cash flow provided by operating activities was $17.4 million and $72.2 million, respectively, compared to $13.3 million and $70.0 million, respectively, compared to the Corresponding Periods. Cash flow provided by operating activities increased mainly due to larger adjusted EBITDA in 2021. During the three months and year ended December 31, 2021, adjusted EBITDA increased by $7.2 million and $16.9 million, respectively, compared to the Corresponding Periods. The increases are primarily due to significant improvements in commodity prices.

Financial Derivatives and Hedging Activities

The Company's results of operations and cash flow provided by operating activities are impacted by changes in market prices for crude oil, natural gas and NGLs. The Company will, from time to time, enter into various derivative instruments to mitigate a portion of its exposure to adverse market changes in commodity prices. These derivative instruments allow the Company to predict with greater certainty the total revenue it will receive, provide stability to the Company's operating cash flows for capital spending planning purposes, and protect development and acquisition economics.

As at December 31, 2021, the Company had various oil and natural gas price derivative contracts outstanding. The tables below represent the weighted average price for each contract type by fiscal quarter for oil and natural gas derivative contracts, respectively:

Oil Contract Type (WTI)	Quarter	Volume (Bbls/d)	Swap (US$)	Sold Put (US$)	Bought Put (US$)	Sold Call (US$)
Costless collars						
	Q1 2022	2,500	-	-	48.10	63.29
	Q2 2022	2,750	-	-	48.73	62.72
	Q3 2022	1,500	-	-	50.83	65.32
	Q4 2022	1,500	-	-	50.83	65.32
Fixed price swaps						
	Q1 2022	1,118	56.85	-	-	-
	Q2 2022	833	58.63	-	-	-
	Q3 2022	417	62.78	-	-	-
	Q4 2022	317	62.78	-	-	-

Natural Gas Contract Type (Henry Hub)	Quarter	Volume (MMbtu/d)	Swap (US$)	Sold Put (US$)	Bought Put (US$)	Sold Call (US$)
Fixed price swaps						
	Q1 2022	2,000	3.43	-	-	-
	Q2 2022	2,000	3.43	-	-	-
	Q3 2022	2,000	3.43	-	-	-

Capital Expenditures

	Three months ended December 31,			Year ended December 31,		
($ thousands)	**2021**	**2020**	**% change**	**2021**	**2020**	**% change**
Drilling, completion, and facilities	29,929	2,743	991.1	62,994	35,175	79.1
Other, net	-	-	-	34	(1)	(3,500.0)
	29,929	2,743	991.1	63,028	35,174	79.2
Non-cash:						
Capitalized share-based compensation	44	27	63.0	179	127	40.9
Decommissioning obligation	338	(659)	(151.3)	1,517	(32)	(4,840.6)
Total capital expenditures [(1)]	**30,311**	**2,111**	**1,335.9**	**64,724**	**35,269**	**83.5**

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section "Non-GAAP and Other Financial Measures contained within this MD&A".

Capital expenditures, consisting of capitalized development activity for the three months and year ended December 31, 2021, were funded from operating cash flows. For the past year, the Company has cautiously invested in capital expenditures to maintain production while exploiting existing opportunities via DUCs and new drills. Capital expenditures in 2021 include the 23 gross wells drilled (5.08 net). During the fourth quarter of 2021, the Company completed and brought on production from four gross operated (3.50 net) wells. Additionally, during the fourth quarter of 2021, the Company participated in the drilling of eight gross non-operated (0.05 net) wells, which are expected to be completed in early 2022.

Senior Credit Facility

The Company maintains a senior revolving credit facility which is referred to as the senior credit facility in the consolidated statement of financial position. The borrowing capacity was reaffirmed at US$177.5 million in March 2021 by the lending syndicate. The term out date was also extended to June 25, 2022, at which point, the facility can be further extended at the option of the lenders or converted to a one-year term loan expiring on the one year anniversary of the term out date. The amount of the facility is subject to a borrowing base test performed periodically based primarily on producing oil and natural gas reserves and using commodity prices estimated by the lender as well as other factors. The next borrowing base redetermination is scheduled for May 2022. If a decrease in the borrowing base is determined by the senior lenders in the future, it could potentially result in a reduction to the credit facility, which may require a repayment to the lenders.

The credit facility is subject to certain non-financial covenants and the Company is in compliance with all covenants under the senior credit facility as at December 31, 2021. The credit facility has no financial covenants.

As at March 14, 2022, the net amount drawn under the Senior Credit Facility was US$96.7 million representing US$105.8 million of borrowings under the Senior Credit Facility and US$9.1 million of cash on hand.

Preferred Shares

The Company elected to pay its preferred share dividends due in May, August, and November of 2020 in-kind as a means of preserving liquidity. The Company also elected to pay its dividend due in February 2021 and accruing through March 2021 in-kind. The Company paid cash dividends for the period of April 1 through April 8, 2021. The preferred shares were converted to common shares in association with the Recapitalization Agreements in April 2021. Refer also to Note 11 in the Company's consolidated financial statements.

Share Capital

	As at March 14,		As at December 31,
	2022	2021	2020
Weighted average common shares outstanding:			
Basic		431,950,383	188,240,502
Diluted		442,640,888	195,784,268
Outstanding securities:			
Common shares	659,637,831	523,387,831	188,528,453
Preferred shares, convertible	-	-	75,000
Stock options	-	-	550,000
Restricted share bonus awards	3,856,674	2,297,872	3,301,027
Performance share bonus awards	13,909,860	7,803,086	4,242,740
Warrants	23,750,000	-	-

On completion of the transactions pursuant to the Recapitalization Agreements in April 2021, the preferred shares were exchanged for common shares and the voting rights associated with the preferred shares were cancelled.

The Company was previously authorized by the TSX Venture Exchange to commence in a normal course issuer bid ("NCIB"). During the quarter ended March 31, 2020, the Company purchased and cancelled 3,851,500 shares at an average price of $0.48 per common share for a total repurchase cost of $1.9 million under the NCIB. The NCIB expired on February 8, 2021 and was not renewed.

Contractual Obligations, Commitments and Off-Balance Sheet Arrangements

Contractual Obligations and Other Commercial Commitments

The following is a summary of the Company's contractual obligations and commitments as at December 31, 2021:

($ thousands)	2022	2023	2024	2025	2026	Contractual Cash Flow
Accounts payable and accrued liabilities	56,014	-	-	-	-	56,014
Lease liability	345	238	260	282	-	1,125
Senior credit facility, including interest	8,331	184,976	-	-	-	193,307

Off-Balance Sheet Arrangements

The Company is not involved with any contractual arrangement under which a non-consolidated entity may have an obligation under certain guarantee contracts, a retained or contingent interest in assets transferred to a non-consolidated entity or similar arrangement that serves as credit, liquidity, or market risk support by the Company to that entity for such assets. PetroShale has no obligation under financial instruments or a variable interest in a non-consolidated entity that provides financing, liquidity, market risk or credit risk support to the Company.

Letters of Credit

The Company has two outstanding letters of credit. A US$158,000 letter of credit was issued in the third quarter of 2021 for the Office of Natural Resources Revenue. A second letter is in favor of the energy regulator in North Dakota in the amount of US$75,000. As security, the Company has set aside an equivalent amount in cash at the financial institution that issued the letter of credit. In addition, the Company has advanced funds to other regulatory agencies of US$160,000 as security in order to operate in North Dakota.

Selected Financial Data

($ thousands except per share amounts)	2021	2020	As at December 31, 2019
Petroleum and natural gas revenue, net of royalties	186,641	117,251	132,781
Total assets	558,035	502,877	598,828
Total non-current liabilities	189,144	326,358	288,140
Cash flow provided by operating activities	72,230	69,991	78,536
Net income (loss)	(828)	(61,985)	15,327
Net income (loss) per share:			
Basic and Diluted	-	(0.33)	0.08

Summary of Quarterly Results

($ thousands except where noted)	Dec 31 2021	Sep 30 2021	Jun 30 2021	Mar 31 2021	Dec 31 2020	Sep 30 2020	Jun 30 2020	Mar 31 2020
Petroleum and natural gas revenue, net of royalties	59,098	55,530	36,561	35,452	30,564	26,949	19,820	39,918
Adjusted EBITDA [(1)]	22,409	24,254	13,851	15,066	15,204	10,217	8,278	25,027
Cash flow provided by operating activities	17,449	23,884	15,005	15,893	13,326	1,491	16,336	38,837
Net income (loss)	25,065	14,954	3,578	(44,424)	(12,417)	(9,134)	(23,169)	(17,266)
Net income (loss) per share:								
Basic and Diluted	0.05	0.03	0.01	(0.24)	(0.07)	(0.05)	(0.12)	(0.09)

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section "Non-GAAP and Other Financial Measures contained within this MD&A".

Revenues in the fourth quarter of 2021 increased 6.4% over the third quarter of 2021 due primarily to an increase in realized oil prices, somewhat offset by a decrease in production volumes. Net income also improved in the fourth quarter of 2021 mainly as a result of pricing increases. Cash flow provided by operating activities decreased in the fourth quarter 2021 versus the prior quarter due to decreased volumes and increased realized hedging losses, offset by improved realized pricing.

Revenues in the third quarter of 2021 increased 51.9% over the second quarter of 2021 due primarily to a 26.5% increase in production volumes and increased commodity pricing. Adjusted EBITDA and net income also improved in the third quarter of 2021 mainly as a result of production and pricing increases. Cash flow provided by operating activities increased in the third quarter 2021 versus the prior quarter due to improved volumes and pricing.

Revenues in the second quarter of 2021 remained consistent with the prior period as improved pricing was partially offset by a minor production decrease. Cash flow from operating activities and adjusted EBITDA were negatively impacted by the realized loss on financial derivatives, increased operating costs, and increased production taxes.

In the first quarter of 2021, revenues and cash flow from operating activities increased versus the prior quarter primarily as a result of improved pricing while Adjusted EBITDA remained relatively consistent due to the offsetting impacts of a higher operating netback and lower production.

Revenues, Adjusted EBITDA, and cash flow from operating activities increased during the fourth quarter of 2020 versus the prior quarter primarily as a result of improved pricing.

During the third quarter of 2020, revenues increased versus the previous quarter due the stabilization of oil prices. As a result, Adjusted EBITDA improved, and the net loss decreased versus the prior quarter. Cash flow declined due to changes in non-cash working capital.

Revenues declined in the second quarter of 2020 versus the first quarter due to a significant decline in oil prices, which contributed to a reduction in Adjusted EBITDA and cash flows and also resulted in a significant net loss.

Critical Accounting Estimates

The timely preparation of the consolidated financial statements in accordance with IFRS requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the consolidated financial statements and the reported amounts of revenue and expenses during the period. Actual results may differ from these estimates.

Critical judgments that have the most significant effect on the amounts recognized in the consolidated financial statements include the following:

Reserve Estimates

The estimation of recoverable quantities of proved and probable oil and natural gas reserves is an inherently complex process and involves the exercise of professional judgment. Estimates are based on projected future rates of production, estimated commodity prices and differentials, estimated production and transportation costs, engineering data and the timing and amount of future expenditures, all of which are subject to uncertainty. The Company's reserve estimates are evaluated by independent professional engineers and are determined in accordance with Canadian practices and specifically in accordance with National Instrument 51-101, *Standards of Disclosures for Oil and Gas Activities,* and the Canadian Oil and Gas Evaluation Handbook.

Reserve adjustments are made annually based on actual volumes produced, the results from capital expenditure programs, revisions to previous estimates, new discoveries and acquisitions and dispositions made during the year. Changes in reserve estimates can affect the impairment of assets, including the recovery of previously recorded impairment, the estimation of decommissioning obligations, and the amounts reported for depletion and depreciation of property, plant, and equipment.

Impairment

Each quarter, management reviews indicators of impairment (and indicators of impairment recovery as applicable) including internal and external sources of information including changes to reserve estimates, drilling results, performance of its oil and gas producing assets and changes in commodity prices. Significant judgment is involved when assessing such indicators of impairment (and indicators of impairment reversal) and if indicators do exist, to prepare estimates of value in use and fair value less selling costs. Related estimates include assumptions as to appropriate discount factors and future commodity prices.

Decommissioning Obligation

The Company estimates the decommissioning obligations for oil and gas wells and their associated production facilities and pipelines. In most instances, removal of assets and remediation occurs many years into the future. Amounts recorded for the decommissioning obligations and related accretion expense require assumptions regarding removal date, future environmental legislation, the extent of reclamation activities required, the engineering methodology for estimating cost, inflation estimates, future removal technologies, and the estimate of the discount rates used to determine the present value of these cash flows.

Business Combinations

In a business combination, management makes estimates of the fair value of assets acquired and liabilities assumed which includes assessing the value of oil and gas properties based upon estimation of recoverable quantities of proved and probable reserves being acquired.

Share-Based Compensation

The Company's estimate of share-based compensation expense associated with stock option grants and the value of warrants issued is dependent upon estimates of expected volatility of the Company's share price and anticipated forfeiture rates of the related securities. The Company's estimate of share-based compensation expense associated with share bonus awards is dependent on an estimate of anticipated forfeiture rates of such securities.

Deferred Income Taxes

The calculation of deferred income taxes is based on a number of assumptions, including estimating the future periods in which temporary differences, tax losses and other tax credits will reverse, the use of substantively enacted tax rates at the balance sheet date and the likelihood of deferred tax assets being realized.

Derivatives

The Company's estimate of the fair value of derivative financial instruments is dependent upon estimated forward commodity prices and the volatility in those prices.

Preferred Shares

The Company's estimate of the preferred share obligation and preferred share equity component of its previously outstanding preferred shares was dependent on an estimate of the rate of interest which would be incurred by the Company on a similar debt obligation without a conversion feature.

Business Conditions and Risks

The Company's business is inherently risky and there is no assurance that hydrocarbon reserves will be discovered and economically produced. Financial risks associated with the petroleum industry include fluctuations in commodity prices, interest rates, currency exchange rates, and the ability to access debt and/or equity financing at a reasonable cost, or at all. Operational risks include the performance of the Company's properties, safety and performance risks associated with drilling and well completion activities, competition for land and services, environmental factors, reservoir performance uncertainties, a complex regulatory environment, other safety concerns, and reliance on the operators of a portion of the Company's properties. When acquiring land, the Company uses technical and industry knowledge to evaluate potential hydrocarbon plays in order to pay what it believes are economically sound prices that will benefit PetroShale's shareholders. The Company's focus is on areas where the prospects are understood by management. There is risk that the Company may not realize the anticipated benefits of acquired properties or future development thereof.

The Company minimizes operational risks by hiring experienced management and engaging experienced service providers on our operated properties and by participating with well-established operators of our non-operated properties. On our non-operated properties, we have limited ability to exercise influence over, and control the risks associated with, operations of these properties. The failure of an operator of the Company's non-operated properties to adequately perform operations, an operator's breach of the applicable agreements or regulations or an operator's failure to act in ways that are in the Company's best interests could reduce production and revenues or could create a liability for the Company due to the operator's failure to properly maintain wells and facilities or to adhere to applicable safety and environmental standards. With respect to properties that the Company does not operate:

- The operator could refuse to initiate exploration or development projects
- If the Company proceeded with any of those projects the operator has refused to initiate, PetroShale may not receive any funding from the operator with respect to that project and thus bear all the capital risk
- The operator may initiate exploration or development projects on a different schedule than the Company would prefer, possibly resulting in lease expirations
- The operator may propose greater capital expenditures, or proceed on a different schedule than the Company anticipated, including expenditures to drill more wells or build more facilities than the Company has funds for, which may mean that the Company cannot participate in those projects or participate in a substantial amount of the revenues from those projects
- The operator may not have adequate expertise or resources to perform operations efficiently

Any of these events, and the resulting activities, could significantly and adversely affect anticipated exploration and development activities conducted on its properties which the Company does not operate, and the results of those activities.

PetroShale's focus is on areas and geological formations in which the prospects are understood by management. Technological tools are extensively used to increase the probability of success and reduce risk.

PetroShale relies on appropriate sources of funding to support the various stages of the Company's business strategy. There is no guarantee that external sources of financing will be available in the future, on favorable terms or at all. The various sources of funding include:

- Internally generated cash flow from operations
- New common or preferred equity, if available on acceptable terms which may be utilized to fund acquisitions, to expand capital programs when appropriate and to repay any outstanding debt
- Debt, in the form of traditional oil and gas borrowing base bank facilities, and/or subordinated debt which typically has a higher cost than bank debt
- Disposition of non-core assets

The Company is exposed to commodity price and market risk for our principal products of tight oil, shale gas, and natural gas liquids. Commodity prices are influenced by a wide variety of factors, most of which are beyond PetroShale's control. In addition, the Company is exposed to fluctuations in the differentials between market price benchmarks and what is received in our geographic area of operation for our production. To manage this risk, the Company may enter financial derivative contracts for hedging purposes. These derivative contracts may relate to crude oil and natural gas prices, as well as foreign exchange and interest rates. When considering if derivative contracts are warranted, the Company may also, from time to time, enter fixed physical contracts to hedge the realized prices from its production. The Company monitors the cost and associated benefit of these instruments and contracts as well as any debt levels and utilization rates on debt lines. Although the Company's intent in entering such derivative contracts is to manage its exposure to fluctuations in commodity prices, such contracts may limit the Company's ability to fully realize the benefits of higher market prices.

Risk of cost inflation subjects the Company to potential erosion of product netbacks and returns from well drilling and completion activities. For example, increasing costs of crude oil and natural gas production equipment and services can inflate operating costs and/or drilling and well completion expenditures. In addition, increasing prices for undeveloped land can inflate costs of both asset and corporate acquisitions.

The supply of service and production equipment at competitive prices is critical to the ability to add reserves at a reasonable cost and produce them in an economic and timely fashion. In periods of increased activity, these services and supplies can become difficult to obtain. The Company and the operators of its non-operated properties attempt to mitigate this risk by developing long-term relationships with suppliers and contractors.

Demand for crude oil, NGLs and natural gas produced by the Company exists within Canada and the United States; however, crude oil prices are affected by worldwide supply and demand fundamentals while natural gas prices are currently primarily affected by factors restricted to the North American market. Demand for natural gas liquids is influenced mainly by the demand for petrochemicals in North American and offshore markets.

PetroShale mitigates the above-mentioned risks as follows:

- PetroShale and the operators of certain of our properties attempt to explore for and produce oil that is high quality (light, sweet), mitigating the Company's exposure to adverse quality differentials
- Natural gas production will generally be connected to established pipeline infrastructure or other local uses for the natural gas may be found
- Financial derivative instruments or fixed price physical contracts may be used where appropriate to manage commodity price volatility

The Company is exposed to operational risks in terms of engaging service suppliers and drilling contractors, the normal oilfield risks of dangerous operations and the potential for discharge of hazardous substances into the environment, arranging for marketing of the Company's tight oil and shale gas production, as well as financing the costs of completing wells and recovering a share of those costs from our non-operating partners. The Company has and will continue to engage appropriate resources to ensure these risks are managed to the extent possible.

PetroShale owns leases from individual mineral owners (Fee Leases), the State of North Dakota acting by and through the Board of University and School Lands (State Leases), individual native owners with approval from the Secretary of the Interior of the Bureau of Indian Affairs (Allotted or BIA Leases), and the Bureau of Land Management (Federal Leases). PetroShale adheres to the National Environmental Policy Act in its operations and is under the regulatory authority of the North Dakota Industrial Commission, the Bureau of Indian Affairs (BIA), the Bureau of Land Management and the Department of the Interior's Office of Natural Resources Revenue. The Allotted Leases are held in trust by the United States for the benefit of individual native owners and are subject to restrictions against alienation or encumbrance without approval of the Secretary of the Interior. All the Company's Allotted Leases are located within the boundaries of the Fort Berthold Indian Reservation (FBIR) which makes the Company subject to unique regulations that are not applicable to lands outside the FBIR. The Company mitigates regulatory risk by maintaining good relationships with the BIA and staying abreast of current regulations. PetroShale's ability to execute projects and realize the benefits therefrom is subject to factors beyond our control, including changes to regulations promulgated by any of the above entities.

PetroShale owns interests in certain tight oil and shale gas leases beneath the Missouri River in North Dakota. In late 2013, the North Dakota Supreme Court upheld that the State of North Dakota owns the mineral rights under the navigable portions of the Missouri River up to the delineated high-water mark. PetroShale had purchased interests in certain leases which were negatively impacted by the decision, although not material to PetroShale in aggregate. There is ongoing litigation as to the proper delineation of the high-water mark which could further impact PetroShale's interest in these leases, positively or negatively.

Environmental Risks

General Risks

Oil and gas exploration and production can involve environmental risks such as litigation, physical and regulatory risks. Physical risks include the pollution of the environment, climate change and destruction of natural habitat, as well as safety risks such as personal injury. The Company works hard to identify the potential environmental impacts of its new projects in the planning stage and during operations. The Company conducts its operations with exacting standards in order to protect the environment, its employees and consultants, and the general public. The Company maintains current insurance coverage for comprehensive and general liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect current corporate requirements, as well as industry standards and government regulations. If the Company becomes subject to environmental liabilities without such insurance, the payment of such liabilities could reduce or eliminate its available funds or could exceed the funds the Company has available and result in financial distress.

Climate Change Risks

Our exploration and production facilities and other operations and activities emit greenhouse gasses ("GHG") which may require us to comply with US federal and/or state GHG emissions legislation. Climate change policy is evolving at regional, national, and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change or mitigate our effects. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Some of our significant facilities may ultimately be subject to future regional, and/or US federal climate change regulations to manage GHG emissions. In addition, climate change has been linked to long-term shifts in climate patterns and extreme weather conditions both of which pose the risk of causing operational difficulties. The Company has undertaken several initiatives, including continuous flaring reduction initiatives, transporting crude oil by pipeline rather than by truck, and connecting natural gas to pipeline connections to reduce GHG emissions from its operations. Climate change and related regulation and public response to such items may negatively impact demand for oil, natural gas and NGLs in the future, and could reduce market prices for our commodities.

Additional Risk Information

Additional information regarding risks including, but not limited to, business risks is available in the Company's Annual Information Form, a copy of which may be accessed through SEDAR website (www.sedar.com).

COVID-19 Impacts and Oil Pipeline Egress

In March 2020, a pandemic was declared by the World Health Organization due to the COVID-19 virus outbreak. Responses to the spread of COVID-19 resulted in a significant disruption to business operations and a significant increase in economic uncertainty. As a result, crude oil prices drastically declined due to a reduction in oil demand associated with the pandemic, combined with oversupply issues and disputes amongst major oil producing countries. Other economic impacts of the virus have included volatility in oil and gas asset prices, marked fluctuation in currency exchange rates, and a decline in long-term interest rates. More recently, economic activity has improved, commodity prices have increased, vaccines have been approved and a phased rollout has commenced throughout most developed countries.

While the duration and full impact of the COVID-19 pandemic is not yet known, effects of COVID-19 may also include disruptions to production operations, limited access to materials and services, increased employee absenteeism from illness, and temporary closures of the Company's facilities. The extent to which the Company's operational and financial results are affected by COVID-19 will depend on various factors and consequences beyond its control such as the duration and scope of the pandemic; additional actions taken by business and government in response to the pandemic, and the speed and effectiveness of responses to combat the virus. Additionally, COVID-19 and its effect on local and global economic conditions stemming from the pandemic could also aggravate the other risk factors identified in this MD&A, the extent of which is not yet known.

During 2020, large-scale travel bans, stay-at-home orders, border closures and similar protective measures enacted by federal, foreign, state, and local governments to slow the spread of COVID-19 contributed to a significant deterioration in domestic and global demand for crude oil, and to a lesser extent, natural gas. Compounding the impact of COVID-19, the oil production output alliance between Russia, Saudi Arabia and other oil producing nations ("OPEC+") broke down in March 2020 as members were unable to reach agreement over how much to restrict production in order to stabilize crude oil prices. As a result, Saudi Arabia and Russia each initiated efforts to increase production, further driving down oil prices and increasing the global oversupply of crude oil. The excess supply of crude oil and demand imbalance resulted in the WTI crude oil price, the benchmark price for most of the Company's crude production, declining from US$57.53/Bbl in January 2020 to US$17.08/Bbl in April 2020. OPEC+ subsequently reached an agreement in April 2020 which included significant production cuts extending through April 2022. Crude oil prices responded accordingly recovering to US$71.69/Bbl in December 2021, with recent spot pricing in excess of US$90.00/Bbl. Despite recent re-balancing of supply and demand for crude, uncertainties exist around the pace of increase in future economic activity, future actions of OPEC+, and the potential lifting of sanctions against Iran (a major oil producer) and hostilities in the Ukraine involving Russia (another major oil producer), among other factors. As a result, crude oil prices could continue to be volatile and it is uncertain when business operations, including those the Company participates in, will return to conditions that existed prior to COVID-19.

The majority of crude oil currently sold in North Dakota is transported through the Dakota Access Pipeline (DAPL) to the US Gulf Coast. A short section of the DAPL crosses underneath Lake Oahe in South Dakota. In July 2020, a United States District Court Judge made a ruling that the US Army Corps of Engineers (USACE), which had provided a crossing permit under the lake, failed to prepare an environmental impact statement (EIS) for this particular easement. The United States District Court Judge ordered the DAPL to be shut down and emptied of oil while the USACE prepared the necessary environmental analysis. Energy Transfer, which owns the DAPL, and the USACE, appealed the decision to the DC Circuit Court of Appeals (DCCOA). The DCCOA reversed the order to suspend operations and empty the pipeline but upheld the vacatur of the easement under Lake Oahe. A decision by the DCCOA in January 2021 allowed DAPL to remain operational while the USACE prepares the EIS. USACE recently revised the estimated timeline for completion of the EIS from spring to fall of 2022; the agency intends to allow the pipeline to continue transporting crude in the interim. Both the State of North Dakota and the MHA Nation have issued statements and legal petitions in support of DAPL's continued operations. On September 22, 2021, the United States District Court Judge issued an order dismissing all outstanding counts in the case including the requirement that USACE file periodic status updates to the court on the progress of the EIS. The USACE will continue to provide monthly updates to the public and stakeholders on their environmental review, as required under the National Environmental Policy Act (NEPA). The Plaintiffs may still challenge the forthcoming EIS and/or Record of Decision (ROD) but must be done under separate legal action. Energy Transfer completed a proposed expansion of the DAPL in August 2021; the line now has the ability to flow approximately 750,000 barrels per day, an increased from 500,000 barrels per day. On September 20, 2021, Energy Transfer petitioned the DCCOA's finding to the US Supreme Court (SCOTUS). On February 22, 2022, the SCOTUS upheld the lower court's decision; as such, the Energy Transfer & USACE will continue preparation and publication of the EIS, as planned. In the event the DAPL would be required to shut down, management believes there is currently adequate excess rail capacity and alternative pipeline capacity to transport existing and projected production from the basin. Transporting crude oil by rail is more expensive than transportation through the DAPL and may lead to a decrease in realized crude oil prices if such an event occurs.

Additional Information

Additional information can be obtained by contacting the Company at PetroShale Inc., Suite 1800, 350 - 7th Avenue SW, Calgary, Alberta T2P 3N9 or by email at info@petroshaleinc.com. Additional information is also available on www.sedar.com or www.petroshaleinc.com.

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INDEPENDENT AUDITORS' REPORT

To the Shareholders of PetroShale Inc.

Opinion

We have audited the consolidated financial statements of PetroShale Inc. (the Entity), which comprise:

- the consolidated statements of financial position as at December 31, 2021 and December 31, 2020
- the consolidated statements of operations and comprehensive loss for the years then ended
- the consolidated statements of changes in shareholders' equity for the years then ended
- the consolidated statements of cash flows for the years then ended
- and notes to the consolidated financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Entity as at December 31, 2021 and December 31, 2020, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "***Auditors' Responsibilities for the Audit of the Financial Statements***" section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Other Information

Management is responsible for the other information. Other information comprises the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commission.

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions as at the date of this auditors' report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditors' report.

We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS as issued by the IASB, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.
- Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

The engagement partner on the audit resulting in this auditors' report is Murray Suey.

KPMG LLP

Chartered Professional Accountants

Calgary, Canada

March 14, 2022

Consolidated Statements of Financial Position

($ thousands)	**Note**	**As at December 31, 2021**	**As at December 31, 2020**
Assets			
Current assets			
Cash and cash equivalents		340	2,830
Accounts receivable	5	39,617	17,232
Prepaid expenses and deposits		383	322
Total current assets		40,340	20,384
Restricted cash	17	298	300
Right of use assets	6	1,006	1,529
Property, plant and equipment, net	7	516,391	480,664
Total assets		**558,035**	**502,877**
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	8	56,014	28,327
Financial derivative liability	19	15,544	10,020
Lease liability	6	345	472
Total current liabilities		71,903	38,819
Senior credit facility	9	180,393	221,915
Preferred share obligation	11	-	97,048
Lease liability	6	780	1,145
Decommissioning obligation	10	7,971	6,250
Total liabilities		**261,047**	**365,177**
Shareholders' equity			
Common shares	12	366,730	198,925
Preferred share equity component	11	-	7,510
Contributed surplus	12	6,596	6,968
Accumulated deficit		(75,499)	(74,671)
Accumulated other comprehensive loss		(839)	(1,032)
Total shareholders' equity		**296,988**	**137,700**
Total liabilities and shareholders' equity		**558,035**	**502,877**

Commitments	17
Key Management Personnel Compensation	18
Subsequent events	21

See accompanying notes to the consolidated financial statements

Approved by the Board of Directors

(Signed) "Brett Herman"	(Signed) "David Rain"
CEO, Director	Director

Consolidated Statements of Operations and Comprehensive Loss

		Year ended December 31,	
($ thousands, except per share amounts)	**Note**	**2021**	**2020**
Revenue			
Petroleum and natural gas	13	229,340	143,506
Less: Royalties		(42,699)	(26,255)
Petroleum and natural gas, net of royalties		186,641	117,251
Realized loss on financial derivatives	19	(52,694)	(4,727)
Unrealized loss on financial derivatives	19	(5,216)	(10,386)
Total revenue		**128,731**	**102,138**
Expenses			
Operating		45,555	36,905
Transportation	13	7,361	11,473
General and administrative		5,451	5,401
Depreciation and depletion	6,7	46,207	66,128
Impairment (impairment recovery)	7	(19,324)	24,000
Finance expense	15	15,992	25,445
Share-based compensation	12	917	922
Loss on modification of preferred shares	11	27,400	-
Total expenses		**129,559**	**170,274**
Loss before income taxes		(828)	(68,136)
Deferred income tax recovery		-	(6,151)
Net loss		**(828)**	**(61,985)**
Currency translation adjustment		193	(588)
Comprehensive loss		**(635)**	**(62,573)**
Net loss per share:			
Basic and diluted	14	-	(0.33)

See accompanying notes to the consolidated financial statements

Consolidated Statements of Changes in Shareholders' Equity

($ thousands, except share amounts)	**Voting Common Shares**	**Share Capital**	**Preferred Share Equity Component**	**Contributed Surplus**	**Accumulated Deficit**	**Accumulated Other Comprehensive Income (Loss)**	**Shareholders' Equity**
December 31, 2019	**191,185,628**	**200,630**	**7,510**	**6,191**	**(12,686)**	**(444)**	**201,201**
Purchase of common shares for cancellation	(3,865,000)	(1,859)	-	-	-	-	(1,859)
Settlement of share bonus awards	1,207,825	154	-	(272)	-	-	(118)
Share-based compensation, gross	-	-	-	1,049	-	-	1,049
Net loss	-	-	-	-	(61,985)	-	(61,985)
Other comprehensive loss	-	-	-	-	-	(588)	(588)
December 31, 2020	**188,528,453**	**198,925**	**7,510**	**6,968**	**(74,671)**	**(1,032)**	**137,700**
December 31, 2020	**188,528,453**	**198,925**	**7,510**	**6,968**	**(74,671)**	**(1,032)**	**137,700**
Settlement of share bonus awards	2,383,580	833	-	(1,468)	-	-	(635)
Settlement of stock options	200,000	39	-	-	-	-	39
Share-based compensation, gross	-	-	-	1,096	-	-	1,096
Loss on modification of preferred shares	-	-	27,400	-	-	-	27,400
Recapitalization Agreements – Conversion of Preferred Shares	182,275,798	136,933	(34,910)	-	-	-	102,023
Recapitalization Agreements – Rights Offering	29,252,965	5,900	-	-	-	-	5,900
Recapitalization Agreements – Private Placements	120,747,035	24,100	-	-	-	-	24,100
Net loss	-	-	-	-	(828)	-	(828)
Other comprehensive income	-	-	-	-	-	193	193
December 31, 2021	**523,387,831**	**366,730**	-	**6,596**	**(75,499)**	**(839)**	**296,988**

See accompanying notes to the consolidated financial statements

Consolidated Statements of Cash Flows

		Year ended December 31,	
($ thousands)	**Note**	**2021**	**2020**
Operating activities			
Net loss		(828)	(61,985)
Operating items not affecting cash:			
Depreciation and depletion	6,7	46,207	66,128
Impairment (impairment recovery)	7	(19,324)	24,000
Loss on modification of preferred shares	11	27,400	-
Gain on sale of other assets		-	(19)
Deferred income tax recovery		-	(6,151)
Unrealized loss on financial derivatives	19	5,216	10,386
Share-based compensation	12	917	922
Finance expense	15	15,992	25,445
Change in non-cash working capital	20	(3,350)	11,265
Cash flow provided by operating activities		**72,230**	**69,991**
Investing activities			
Additions to property, plant, and equipment	7	(63,028)	(35,197)
Proceeds from sale of other assets		-	23
Change in non-cash working capital	20	10,992	(56,256)
Cash flow used in investing activities		**(52,036)**	**(91,430)**
Financing Activities			
Proceeds from (repayments to) senior credit facility, net	9	(38,536)	39,520
Debt issuance costs		(569)	-
Payment of interest and preferred dividends	20	(11,188)	(14,031)
Payment of lease liabilities	6	(568)	(479)
Proceeds from Recapitalization Agreements	9,12	29,271	-
Settlement of share bonus awards	12	(635)	(118)
Proceeds from exercise of stock options	12	39	-
Purchase of common shares for cancellation	12	-	(1,859)
Cash flow provided by (used in) financing activities		**(22,186)**	**23,033**
Change in cash and cash equivalents		(1,992)	1,594
Effect of foreign exchange rate changes		(498)	629
Cash and cash equivalents, beginning of year		2,830	607
Cash and cash equivalents, end of year		340	2,830

See accompanying notes to the consolidated financial statements

Note 1. Description of Business

PetroShale Inc. (the "Company") is an independent oil company focused on the acquisition, development, and production of oil-weighted assets in the Bakken and Three Forks formations in the Williston Basin area of North Dakota. The Company's common shares are listed on the TSX Venture Exchange under the "PSH" ticker symbol. The Company has corporate offices located at Suite 1800, 350 - 7th Avenue SW, Calgary, Alberta T2P 3N9 and at 303 E. 17th Avenue, Suite 940, Denver, CO 80203.

In early March 2020, the World Health Organization declared the COVID-19 coronavirus outbreak to be a pandemic. Responses to the spread of COVID-19 have resulted in significant disruption to business operations and a significant increase in economic uncertainty, with more volatile commodity prices and currency exchange rates, and a decline in long-term interest rates. These events have resulted in a challenging economic climate in which it is difficult to reliably estimate the length or severity of these developments and their financial impact. The results of the potential economic downturn and any potential resulting direct and indirect impact to the Company has been considered in management's estimates reflected in these financial statements and as described herein; however, there could be a further prospective material impact in future periods.

Note 2. Basis of Presentation

Basis of Measurement and Statement of Compliance

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") applicable to the preparation of financial statements. The Company's accounting policies have been applied consistently for all periods presented in these consolidated financial statements.

These consolidated financial statements were approved for issuance by the Board of Directors on March 14, 2022.

Principles of Consolidation

The consolidated financial statements include the accounts of PetroShale Inc. and its wholly owned subsidiary, PetroShale (US), Inc. The Company's accounts reflect the proportionate share of the assets, liabilities, revenues, expenses, and cash flows from the Company's oil and gas activities that are conducted jointly with third parties. In preparing the consolidated financial statements, all intercompany transactions have been eliminated.

Functional and Presentation Currency

The Company's consolidated financial statements are reported in Canadian dollars, which is the Company's presentation currency. Transactions of the Company's US subsidiary are recorded in US dollars, as this is the primary economic environment in which this subsidiary operates. The US subsidiary has a US dollar functional currency. In translating the financial results from US dollars to Canadian dollars, the Company uses the following method: assets and liabilities are translated at the exchange rate in effect as at the date of the consolidated balance sheet; revenues and expenses are translated at the rate effective at the time of the transaction or the average rate for the period; and changes in shareholders' equity are translated at the rate effective at the time of the transaction. Unrealized gains and losses resulting from the translation to the Canadian dollar presentation currency are included in other comprehensive income.

Transactions of the US subsidiary that are denominated in a currency other than the US dollar are translated to the US dollar using the following method: monetary assets and liabilities are translated at the exchange rate in effect at the date of the consolidated statement of financial position; non-monetary assets and liabilities are translated at the exchange rate on the date such assets or liabilities are assumed; and revenues and expenses are translated at the average rate for the period. Realized gains and losses resulting therefrom are reflected in the consolidated statement of operations as foreign exchange gain or loss.

Use of Estimates, Judgments and Assumptions

The timely preparation of the consolidated financial statements in accordance with IFRS requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the consolidated financial statements and the reported amounts of revenue and expenses during the period. Actual results may differ from these estimates, judgments, and assumptions.

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 on a prospective basis. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change in the consolidated financial statements. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained, and as the Company's operating environment changes, including considerations related to environmental regulations.

Critical judgments that have the most significant effect on the amounts recognized in the consolidated financial statements include the following:

Identification of cash generating units

The Company's assets are aggregated into cash generating units for the purpose of calculating impairment. The aggregation of assets into a cash generating unit ("CGU" or "CGUs") is based on an assessment of the unit's ability to generate independent cash inflows. The determination of individual CGUs is based on management's judgment regarding shared infrastructure, geographical proximity, petroleum type and similar exposure to market risk and materiality. The Company currently has one CGU.

Impairment of property, plant and equipment

Judgments are required to assess when impairment, or impairment reversal, indicators exist and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of tight oil and shale gas reserves, production rates, future oil and natural gas prices, future costs, discount rates, market value of undeveloped land and other relevant assumptions.

Deferred income taxes

Judgments are made by management to determine the likelihood of whether deferred income tax assets at the end of the reporting period will be realized from future taxable earnings.

Key Sources of Estimation Uncertainty

The Company faces uncertainties related to future environmental laws and climate-related regulations, which could affect the Company's financial position and future earnings. A number of variables and assumptions used to determine the estimated recoverable amounts of the Company's oil and gas assets could be impacted. The unpredictable nature, timing and extent of climate-related initiatives presents various risks and uncertainties, including to management's judgements, estimates and assumptions that affect the application of accounting policies. Significant estimates and judgments made by management in the preparation of these consolidated financial statements are outlined below.

The following are key estimates and assumptions made by management affecting the measurement of balances and transactions in the consolidated financial statements:

Reserve estimates

The estimation of recoverable quantities of proved and probable tight oil and shale gas reserves is an inherently complex process and involves the exercise of professional judgment. Estimates are based on projected future rates of production, estimated commodity prices and differentials, estimated production and transportation costs, engineering data and the timing and amount of future expenditures, all of which are subject to uncertainty. The Company's reserve estimates are evaluated by independent professional engineers and are determined in accordance with Canadian practices and specifically in accordance with National Instrument 51-101, Standards of Disclosures for Oil and Gas Activities, and the Canadian Oil and Gas Evaluation Handbook.

Reserve adjustments are made annually based on actual volumes produced, the results from capital expenditure programs, revisions to previous estimates, new discoveries and acquisitions and dispositions made during the year. Changes in reserve estimates can affect the impairment of assets, including the reversal of previously recorded impairment, the estimation of decommissioning obligations, the economic feasibility of exploration and evaluation assets and the amounts reported for depletion and depreciation of property, plant and equipment.

Decommissioning obligation

The Company estimates the decommissioning obligations for oil and gas wells and their associated production facilities and pipelines. In most instances, removal of assets and remediation occurs many years into the future. Amounts recorded for the decommissioning obligations and related accretion expense require assumptions regarding removal date, future environmental legislation, the extent of reclamation activities required, the engineering methodology for estimating cost, inflation estimates, future removal technologies, and the estimate of the liability specific discount rates to determine the present value of these cash flows.

Business combinations

In a business combination, management makes estimates of the fair value of assets acquired and liabilities assumed which includes assessing the value of oil and gas properties based upon estimation of recoverable quantities of proved and probable reserves being acquired.

Share-based compensation

The Company's estimate of share-based compensation expense associated with stock option grants and the value of warrants issued is dependent upon estimates of expected volatility of the Company's share price and anticipated forfeiture rates of the related securities. The Company's estimate of share-based compensation expense associated with share bonus awards is dependent on an estimate of anticipated forfeiture rates of such securities.

Deferred income taxes

The calculation of deferred income taxes is based on a number of assumptions, including estimating the future periods in which temporary differences, tax losses and other tax credits will reverse, the use of substantively enacted tax rates at the balance sheet date and the likelihood of deferred tax assets being realized.

Derivatives

The Company's estimate of the fair value of derivative financial instruments is dependent upon estimated forward commodity prices and the volatility in those prices.

Preferred shares

The Company's estimate of the preferred share obligation and preferred share equity component of its formerly outstanding preferred shares is dependent on an estimate of the rate of interest which would be incurred by the Company on a similar debt obligation without a conversion feature.

Note 3. Summary of Significant Accounting Policies

Business Combinations

The purchase method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of assets given, equity instruments issued, and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of an acquisition over the fair value of the identifiable assets acquired net of liabilities assumed is recorded as goodwill. If the cost of an acquisition is less than the fair value of the net assets of the business acquired, the difference is recognized in the consolidated statement of operations and comprehensive income.

Revenue Recognition

Revenues associated with the production and sale of petroleum products owned by the Company are recognized at the point in which control of the products is transferred to the buyer, which may be when the production enters that party's pipeline or processing facility. Processing or transportation costs associated with petroleum production are netted against the related revenue if they are incurred following the transfer of control to the entity who has purchased the commodity. If transportation or processing costs are incurred prior to the sale of the relevant commodity, such costs are reflected separately as an expense in the consolidated statement of operations.

In addition, the Company is required to evaluate its arrangements with its joint venture partners to determine if the Company acts as the principal or as an agent in respect of the sale of the partners' interest in production. In making this evaluation, management considers whether the Company obtains control of the product delivered, which is indicated by the Company having the primary responsibility for the delivery of the products, its ability to establish prices or assumption of inventory risk. In the Company's case, it is acting in the capacity of an agent rather than as a principal in commodity sales transactions on its operated properties, and so revenue is recognized on a Company net basis.

Cash and Cash Equivalents

The Company considers investments in all highly liquid instruments with original maturities of three months or less at the date of purchase to be cash equivalents. The Company maintains cash in accounts that may not be federally insured beyond certain limits; however, the Company has not experienced any losses in such accounts and believes there is no exposure to any significant credit risk.

Leased Assets

At inception of a contract, the Company assesses whether a contract is, or contains a lease based on whether the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

The Company recognizes a right-of-use asset and a lease obligation at the lease commencement date. The right-of-use asset is initially measured based on the initial amount of the lease obligation adjusted for any lease payments made at or before the commencement date. The assets are depreciated over the lease term using the straight-line method as this most closely reflects the expected pattern of consumption of future economic benefits.

The lease obligation is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the Company's incremental borrowing rate. Lease components are included in the present value calculation of lease payments, with non-lease components expensed as incurred. Variable lease payments that do not depend on an index or rate are not included in the measurement of the lease obligation. The lease obligation is subsequently measured at amortized cost using the effective interest rate method.

Property, Plant and Equipment ("PP&E")

The Company has two categories of PP&E: Developed and Producing assets ("D&P assets) and Other PP&E assets. D&P assets include capital costs (i) related to drilling projects where the drilling location is already determined to hold proved and probable reserves, (ii) incurred to improve an already technically feasible and commercially viable well, and (iii) related to facilities and equipment projects. Other PP&E includes furniture, fixtures, leasehold improvements, software, and office equipment. For presentation purposes, both D&P assets and Other PP&E are included in the PP&E category on the consolidated statement of financial position.

Recognition and measurement
PP&E is measured at cost less accumulated depreciation and depletion and accumulated impairment losses. For the purposes of determining depreciation and depletion, when significant parts of PP&E have different useful lives, they are accounted for separately so that depreciation and depletion rates appropriately reflect useful lives.

Gains and losses on disposal of PP&E, including property swaps and farm-outs of oil and gas interests, are determined by comparing the proceeds from disposal with the carrying amount of the PP&E sold, and are recognized on a net basis in profit or loss.

The net carrying value of D&P assets is depleted using the unit-of-production method by calculating the ratio of production in the period to the related proved and probable reserves. Proved and probable reserves are expressed on a barrels of oil equivalent ("Boe") basis where natural gas volumes are converted to Boe using a ratio of 6,000 cubic feet of natural gas to one barrel of oil. The net carrying value to be depleted includes an estimate of future development costs required to bring any related non-producing or undeveloped reserves into production, which may include the costs of drilling and completing wells. These estimates are reviewed at least annually by independent engineers in conjunction with their evaluation of the Company's proved and probable reserves.

Depreciation for substantially all other property, plant and equipment is provided using the straight-line method based on the estimated useful lives of assets less any estimated residual value. The useful lives of assets are estimated based upon the period the asset is expected to be available for use by the Company. Residual values are based upon the estimated amount that would be obtained on disposal; net of any costs associated with the disposal. Other property, plant and equipment held under finance leases are depreciated over the shorter of the lease term and the estimated useful life of the asset.

Depreciation and depletion rates for all capitalized costs associated with the Company's activities are reviewed at least annually, or when events or conditions occur that impact capitalized costs, reserves, and estimated service lives.

Capitalized overhead
The Company capitalizes to D&P assets certain directly attributable general and administrative costs, including share-based compensation, associated with employees and consultants involved in acquiring licenses or other approvals and drilling, completion, and construction activities on the Company's operated lands.

Impairment
For the purposes of impairment testing, assets are grouped into the smallest group of assets that generate independent cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets.

Impairment testing of PP&E is performed as facts and circumstances suggest by comparing the carrying amount of D&P assets to their recoverable amount. The recoverable amount is the greater of (i) the assets' value in use, and (ii) its fair value less selling costs. In assessing value in use for D&P assets, the estimated future cash flows from the production of proved and probable reserves are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

Impairment losses recognized in prior periods are assessed at each reporting date to evaluate if those losses have decreased or no longer exist. If those impairment losses have decreased or no longer exist (recovered), they are reversed accordingly. Previously recognized impairment losses may be recovered in future reporting periods due to changes in estimates used to determine the recoverable amount. An impairment loss recovery is recorded only to the extent that the PP&E carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized. Impairment losses and recoveries are recorded in the consolidated statement of operations and comprehensive income.

Subsequent costs
Subsequent costs are capital costs incurred to improve an existing D&P asset (such as a well) that is technically feasible and commercially viable. These costs are capitalized as D&P assets only if they increase the future economic benefits of the asset. All other expenditures are expensed in the consolidated statement of operations and comprehensive income as incurred. These improvement costs include costs of further developing proved and probable reserves or enhancing production. The costs of routine maintenance of D&P assets are recognized in the consolidated statement of operations and comprehensive income as incurred. The carrying value of any replaced or sold component is derecognized.

Decommissioning Obligation

An obligation is recognized if, as a result of a past event, the Company has a future legal or constructive obligation resulting from the retirement and reclamation of tangible long-lived assets and this obligation can be reliably estimated. The obligation is measured at the present value of management's best estimate of the expected expenditures required to settle this obligation and is recorded in the period the related assets are put into use with a corresponding increase to the carrying amount of the related assets. This increase in capitalized costs is depleted and depreciated on a basis consistent with the underlying assets. Subsequent changes in the estimated fair value of the obligation are capitalized and depleted over the remaining useful life of the underlying asset.

The obligation is carried in the consolidated statement of financial position at its discounted present value and is accreted over time for the change in its present value. The obligation is discounted at a rate that reflects a current market assessment of the time value of money and the risks specific to the obligation. Accretion of the obligation is included in finance expense in the consolidated statement of operations.

Income Taxes

Current income taxes are measured at the amount expected to be payable on taxable income for the period, using tax rates enacted or substantively enacted at the end of the reporting period.

The Company follows the asset and liability method of accounting for deferred income taxes. Under this method, deferred income taxes are recognized based on the expected future tax consequences of differences between the carrying amount of statement of financial position items and their corresponding tax basis, using the enacted and substantively enacted income tax rates for the years in which the differences are expected to reverse.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

Share-based Compensation

The Company uses the fair value method to recognize the cost associated with stock options granted to employees, directors, and other service providers. The fair value of the stock options granted is measured using the Black-Scholes option pricing model. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest. Under the fair value method, the Company recognizes estimated compensation expense related to stock options over the vesting period of the options granted, with the related credit being charged to contributed surplus. Fair value is measured at the grant date and each vesting tranche is recognized using the graded vesting method over the period during which the options vest. At each reporting date, the amount recognized as an expense is adjusted to reflect the actual number of share options that are expected to vest. Upon exercise of any stock options, amounts previously credited to contributed surplus are reversed and credited to share capital.

Share-based awards to employees, directors and other service providers are measured at the market share price as at the date of grant. A forfeiture rate is estimated on the grant date and the related compensation expense is recognized over the vesting period of the share bonus awards, using the graded vesting method, with the related credit being charged to contributed surplus.

Earnings Per Share

Basic earnings per common share are calculated by dividing the net earnings for the period by the weighted average number of common shares outstanding in each respective period. Diluted earnings per common share reflect the maximum possible dilution from other securities, if dilutive.

Financial Instruments

Non-derivative financial instruments

These comprise cash and cash equivalents including bank overdrafts, restricted cash, accounts receivable, accounts payable and accrued liabilities, and the senior credit facility. Non-derivative financial instruments are recognized initially at fair value plus any directly attributable transaction costs. Subsequent to initial recognition, non-derivative financial instruments are measured as described below.

- Cash and cash equivalents in the consolidated statement of financial position comprise cash at banks and on hand and short-term deposits with an original maturity of three months or less. For the purpose of the consolidated statement of cash flows, cash and cash equivalents consist of cash and cash equivalents defined above, net of outstanding bank overdrafts. These balances are reflected at cost.

- Restricted cash in the consolidated statement of financial position consists of bank deposits held in escrow related to bonding obligations. These balances are reflected at cost plus accrued interest.

- Other non-derivative financial instruments, such as the senior credit facility, accounts receivable, and accounts payable and accrued liabilities, are measured at amortized cost using the effective interest method, less any impairment losses.

Derivative financial instruments
The Company may enter into certain financial derivative contracts in order to manage its exposure to market risks from fluctuations in commodity prices, interest rates and foreign exchange rates. These instruments are not used for trading or speculative purposes. The Company will not designate its financial derivative contracts as effective accounting hedges, and thus will not apply hedge accounting, even though the Company considers all commodities contracts to be economic hedges. As a result, all financial derivative contracts will be classified as fair value through profit or loss and recorded in the consolidated statement of financial position at fair value with changes in fair value recognized in net income. Related transaction costs such as trading commissions will be recognized in the consolidated statement of operations when incurred.

Forward physical delivery and sales contracts of crude oil and natural gas products are entered into in the normal course of business and therefore not recorded at fair value in the consolidated statement of financial position. These physical delivery contracts are not considered to be derivative financial instruments or hedges. Settlements on these physical delivery contracts are recognized in petroleum and natural gas revenue in the consolidated statement of operations.

Share Capital

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares, warrants and stock options are recognized as a reduction from equity, net of any tax effects.

Preferred Share Compound Financial Instrument

Preferred shares which included both an equity conversion feature and a redemption obligation on the part of the Company are considered a compound financial instrument for accounting purposes. Such an instrument requires the Company to value each of the liability and equity residual components of the instrument and present them separately on the consolidated statement of financial position. The Company determines the fair value of the liability component by discounting contractual dividend and redemption payments over the term of the preferred shares at the rate of interest that would apply to a similar financial instrument without a conversion option. The liability component is presented as "preferred share obligation" under non-current liabilities on the consolidated statement of financial position and the equity residual component is presented as "preferred share equity component" under shareholders' equity on the consolidated statement of financial position. Related transaction and issuance costs reduce the carrying amounts of each of the liability and equity residual components on a pro rata basis. The liability component is accreted to the redemption amount of the preferred shares over the term of the preferred shares to maturity, with the related accretion expense included in finance expense on the consolidated statement of operations.

Comprehensive Income

Comprehensive income consists of net earnings and other comprehensive income (loss) ("OCI"). OCI is comprised of the change in the fair value of any derivative instruments accounted for as effective hedges and, the exchange gains and losses arising from the translation of foreign operations with a functional currency that is not Canadian dollars. Amounts included in OCI are shown net of tax. Accumulated OCI is presented in the consolidated statement of financial position under shareholders' equity.

Future Accounting Pronouncements

Amendments to IAS 16 Property, Plant and Equipment
In May 2020, the IASB issued *Property, Plant and Equipment – Proceeds before Intended Use,* which made amendments to IAS 16 *Property, Plant and Equipment*. Effective January 1, 2022, the amendments prohibit a company from deducting from the cost of PP&E amounts received from selling items produced while the company is preparing the asset for its intended use. Instead, a company will recognize such sales proceeds and related cost in profit or loss.

Amendments to IAS 37 Provisions Contingent Liabilities and Contingent Assets

In May 2020, the IASB issued *Onerous Contracts - Cost of Fulfilling a Contract*, which made amendments to IAS 37 *Provisions Contingent Liabilities and Contingent Assets*. Effective January 1, 2022, the amendments specify which costs an entity includes in determining the cost of fulfilling a contract for the purpose of assessing whether the contract is onerous.

Amendments to IAS 1 Presentation of Financial Statements

In January 2020, the IASB issued amendments to IAS 1 *Presentation of Financial Statements*, to clarify its requirements for the presentation of liabilities as current or non-current in the statement of financial position. This change will be effective on January 1, 2023.

Note 4. Determinations of Fair Value

Several of the Company's accounting policies require a determination of fair value for certain assets and liabilities. Fair value for measurement or disclosure purposes is determined on the following basis.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Valuation techniques include the market, income, and cost approaches. The market approach uses information generated by market transactions involving identical or comparable assets or liabilities; the income approach converts estimated future amounts to a present value; and the cost approach is based on the amount that currently would be required to replace an asset.

The Company is required to classify its financial instruments within a hierarchy that prioritizes the inputs to fair market value. The three levels of the fair value hierarchy are:

Level 1 – Unadjusted quoted prices in an active market for identical assets or liabilities

Level 2 – Inputs other than quoted prices that are observable for the asset or liability either directly or indirectly

Level 3 – Inputs that are not based on observable market data

Property, plant and equipment

The fair value of property, plant and equipment recognized in a business combination is based on market value. The market value of PP&E is the estimated amount for which PP&E could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted with knowledge and prudence and without compulsion. The market value of crude oil and natural gas interests included in PP&E is estimated with reference to the discounted future cash flows expected to be derived from crude oil and natural gas production based on internally and externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions.

Cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities

The fair value of cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities, and senior loan are estimated as the present value of related future cash flows, discounted at the market rate of interest at the reporting date. As at December 31, 2021 and 2020, the fair value of cash and cash equivalents, accounts receivable and accounts payable approximated their carrying value due to their short-term maturity.

Derivatives

The Company does not engage in the use of any derivative instruments for speculative purposes. If the Company enters into any contracts for the future delivery of non-financial assets, these are done in accordance with its expected sale requirements. As such, these contracts are not considered to be derivative instruments and have not been recorded at fair value in the consolidated financial statements. As the Company delivers petroleum products in accordance with the terms of these contracts, any associated revenue will be recorded as petroleum and natural gas revenue. The fair value of financial forward contracts and swaps is determined by discounting the difference between the contracted prices and published forward price curves as at the consolidated statement of financial position date, using the remaining underlying amounts and a risk-free interest rate. The fair value of options and costless collars is based on option models that use published information with respect to volatility, prices, and interest rates. The Company classifies its derivative financial instruments as Level 2 in the fair value hierarchy.

Share-based compensation

The fair value of share-based awards is measured using current market value at the related grant date. Measurement inputs include current market value of the Company's shares with consideration of an expected forfeiture rate.

The fair value of employee stock options is measured using a Black-Scholes option pricing model. Measurement inputs include share price on measurement date, exercise price of the option, expected volatility of the underlying share price (based on historical experience), weighted average expected life of the option (based on historical experience and general option holder behavior), expected dividends, forfeiture rate and the risk-free interest rate (based on government bonds).

Senior credit facility and preferred share obligation

The fair value of the Senior Credit Facility approximates the carrying value as it bears a floating rate of interest and the margin charged by the lenders is indicative of current credit spreads.

Note 5. Accounts Receivable

($ thousands)	**As at December 31, 2021**	**As at December 31, 2020**
Accounts receivable – petroleum and natural gas	31,951	15,386
Accounts receivable – joint interest billing and other	7,666	1,846
Total	**39,617**	**17,232**

Note 6. Right of Use Assets and Lease Liability

The Company's right of use assets and lease liability relate to a lease for its Denver office space as well as a lease for a field compressor.

Right of Use Assets

($ thousands)	
January 1, 2020	**445**
Additions	1,901
De-recognition	(242)
Depreciation	(502)
Effect of foreign currency rate changes	(73)
December 31, 2020	**1,529**
Depreciation	(509)
Effect of foreign currency rate changes	(14)
December 31, 2021	**1,006**

Lease Liability

($ thousands)	
January 1, 2020	**453**
Additions	1,901
De-recognition	(247)
Payments	(479)
Lease interest expense	65
Effect of foreign currency rate changes	(76)
December 31, 2020	**1,617**
Payments	(568)
Lease interest expense	90
Effect of foreign currency rate changes	(14)
December 31, 2021	**1,125**

Note 7. Property, Plant and Equipment

($ thousands)	**Developed and Producing**	**Other**	**Total**
December 31, 2019	**543,222**	**142**	**543,364**
Additions	35,175	(1)	35,174
Capitalized share-based compensation	127	-	127
Decommissioning obligation	(32)	-	(32)
Impairment	(24,000)	-	(24,000)
Depreciation and depletion	(65,504)	(122)	(65,626)
Effect of foreign currency rate changes	(8,344)	1	(8,343)
December 31, 2020	**480,644**	**20**	**480,664**
Additions, net	62,994	34	63,028
Capitalized share-based compensation	179	-	179
Decommissioning obligation	1,517	-	1,517
Impairment recovery	19,324	-	19,324
Depreciation and depletion	(45,671)	(27)	(45,698)
Effect of foreign currency rate changes	(2,623)	-	(2,623)
December 31, 2021	**516,364**	**27**	**516,391**

Depreciation, Depletion, and Future Development Costs

For the years ended December 31, 2021 and 2020, PetroShale recorded $45.7 million and $65.5 million, respectively, of depreciation and depletion expense on its developed and producing ("D&P") assets, which reflected an estimated US$256.6 million and US$304.8 million, respectively, of future development costs associated with proved plus probable reserves.

Impairment

Determining the estimated cash flows associated with the Company's proved plus probable reserves is an inherently complex process involving the exercise of professional judgment and the use of significant estimates, including future commodity prices, differentials, discount rates, production volumes, royalties, operating costs, and future capital expenditures. In future periods, previous impairments may be reversed up to the original carrying value less any associated depreciation and depletion if the estimated recoverable amounts of the D&P assets exceed their carrying amount.

During the first quarter of 2020, PetroShale recognized an impairment charge of $24.0 million on the Company's D&P assets. The impairment was attributable to declines in current and forecasted crude prices as a result of the rapid and severe deterioration of economic activity related to COVID-19, combined with a price war fueled by Russia and Saudi Arabia. The recoverable amount of $568.2 million at March 31, 2020 was estimated based on a value in use methodology using the estimated discounted cash flows from proved plus probable reserves discounted at a rate of 14% per annum. Commodity prices were based on market prices at March 31, 2020 and benchmarked against the forward price curve and pricing forecasts prepared by external firms. The pricing forecast used in determining the future cash flows associated with the Company's D&P assets in connection with the impairment determination in the first quarter of 2020 ranged from US$24.17 per Bbl to US$61.81 per Bbl in future periods.

At June 30, 2021, the increase and more recent stability in forecast benchmark commodity prices, as well as improvement in Company valuation, since the last impairment test at March 31, 2020, were deemed to be indicators of impairment recovery. As a result, the Company prepared an impairment recovery test to ascertain the present value of the future cash flows expected to be derived from the D&P assets at June 30, 2021. A recoverable amount of approximately $850.0 million was estimated based on a value in use methodology calculating the estimated discounted cash flows from proved plus probable reserves discounted at a rate of 15% per annum. Commodity prices were based on market prices at June 30, 2021 and were assessed against the forward price curve and pricing forecasts prepared by external firms. As the estimated recoverable amount exceeded the carrying amount of the D&P assets, the maximum available impairment recovery of $19.3 million was recognized in net income.

There are no indicators of impairment at December 31, 2021.

Capitalized Overhead

During the year ended December 31, 2021, the Company capitalized $1.2 million of general and administrative costs and $0.2 million of share-based compensation costs directly attributable to acquisition and development activities of certain of its personnel in relation to the Company's operated properties ($0.6 million and $0.1 million, respectively, for the year ended December 31, 2020).

Note 8. Accounts Payable and Accrued Liabilities

($ thousands)	**As at December 31, 2021**	**As at December 31, 2020**
Trade payables	21,548	8,579
Accrued liabilities	13,928	8,902
Revenue payable	20,538	10,846
Total	**56,014**	**28,327**

Note 9. Senior Credit Facility

The Company's reserves-based revolving credit facility of US$177.5 million is comprised of a US$167.5 million syndicated facility and a US$10.0 million non-syndicated operating facility (together, the "Senior Credit Facility"). As at December 31, 2021, the net amount drawn under the Senior Credit Facility was US$142.9 million representing US$143.2 million of borrowings under the Senior Credit Facility and US$0.3 million of cash on hand. Advances under the Senior Credit Facility are available by way of direct advances, bankers' acceptances, and standby letters of credit. Direct advances bear interest at the prime rate, US base rate or LIBOR rate, as elected by the Company, plus a margin ranging from 2.0% to 6.5%, which is dependent on the Company's Senior Debt to EBITDA ratio. EBITDA, as defined in the Senior Credit Facility agreement and used for determining the Senior Debt to EBITDA ratio, may be different from Adjusted EBITDA referred to in the Company's other disclosures, including Management's Discussion & Analysis. The Senior Credit Facility is secured by a fixed and floating charge debenture on substantially all the Company's assets.

On April 8, 2021, the Company completed a series of agreements (the "Recapitalization Agreements") with its largest common shareholder, Mr. M. Bruce Chernoff (the Company's Executive Chairman and a director), a company of which Mr. M. Bruce Chernoff is a significant shareholder ("ChernoffCo"), and FR XIII PetroShale Holdings L.P. ("First Reserve" or the "Investor"), the former sole owner of the Company's wholly owned subsidiary's preferred shares, and reached an agreement in principle in respect of the Company's credit facility with the Company's bank lending syndicate. Collectively, these agreements fundamentally improved PetroShale's capital structure. The net cash proceeds were applied to the Senior Credit Facility balance. Refer to Note 12 for more discussion of the Recapitalization Agreements.

The Senior Credit Facility borrowing base is subject to redetermination on a periodic basis, based primarily on producing oil and gas reserves, as estimated by the Company's independent third-party engineer, and using commodity prices established by the lender as well as other factors. As part of the Recapitalization Agreements, the lenders to the Senior Credit Facility reaffirmed the borrowing base at US$177.5 million and extended the term out date to June 25, 2022, at which point, the facility can be extended at the option of the lenders or converted to a one-year term loan expiring one year from the term out date. The Company was in compliance with terms of the Senior Credit Facility at December 31, 2021. For the year ended December 31, 2021, the effective interest rate on the outstanding borrowings under the Senior Credit Facility was 5.6% (4.5% for the year ended December 31, 2020).

Note 10. Decommissioning Obligation

($ thousands)	**Year ended December 31, 2021**	**Year ended December 31, 2020**
Beginning of year	6,250	6,313
Obligations incurred	601	20
Obligations settled	(120)	-
Change in estimated future cash flows	1,036	(52)
Accretion	208	135
Effect of foreign currency rate changes	(4)	(166)
End of year	7,971	6,250

The Company's decommissioning obligation consists of remediation obligations resulting from its ownership interests in petroleum and natural gas assets. The total obligation is estimated based on the Company's net working interest in wells and related facilities, estimated costs to return these sites to their original condition, costs to plug and abandon wells and the estimated timing of the costs to be incurred in future years.

The Company has estimated the net present value of its total decommissioning provision to be $8.0 million at December 31, 2021 ($6.3 million at December 31, 2020) based on a total undiscounted and uninflated liability of $7.1 million ($7.0 million at December 31, 2020). Management estimates that these payments are expected to be made over the next 50 years in accordance with estimates prepared by independent engineers. As at December 31, 2021, a risk-free interest rate of 1.9% (1.7% at December 31, 2020) and an inflation rate of 2.3% (1.4% at December 31, 2020) were used to calculate the present value of the decommissioning obligation.

Note 11. Preferred Shares

($ thousands, except share amounts)	Number of Shares	Liability Component	Equity Component
December 31, 2019	**75,000**	**87,380**	**7,510**
Paid in-kind dividends	-	8,850	-
Accretion	-	2,744	-
Effect of foreign currency rate changes	-	(1,926)	-
December 31, 2020	**75,000**	**97,048**	**7,510**
Paid in-kind dividends	-	6,290	-
Accretion	-	683	-
Loss on modification of preferred shares	-	-	27,400
Conversion of preferred shares to common shares	(75,000)	(102,752)	(34,910)
Effect of foreign currency rate changes	-	(1,269)	-
December 31, 2021	**-**	**-**	**-**

In January 2018, the Company's wholly owned subsidiary (the "Subsidiary Issuer") issued 75,000 preferred shares to First Reserve (the "Investor") at a price of US$1,000 per share for gross proceeds of US$75 million. The preferred shares had a maturity date of January 25, 2023, which could be extended at the option of the Investor by one year. The preferred shares entitled the Investor to a cumulative annual dividend of 9.0% per annum, payable quarterly. The preferred share agreement allowed the Company to elect to pay-in-kind two quarterly dividend payments per twelve-month period subject to a cumulative limit of six quarterly dividend payments over the term of the preferred shares and only following the first anniversary of the issuance date. In September 2020, the preferred share agreement was modified to remove the limitation on the number of paid-in-kind elections in any twelve-month period. Any paid-in-kind dividend payments accrue at a rate of 12.0% per annum and are added to the issuance amount of the preferred shares to determine the redemption obligation at maturity or the amount which may be exchanged for common shares at the option of the Investor. The Company elected to pay its preferred share dividends due in May 2020, August 2020, November 2020, February 2021, and March 2021 in kind.

The preferred shares were exchangeable at the discretion of the Investor, in whole or in part, into common voting shares of the Company at a price of $2.40 per share and using an exchange rate of C$1.00 = US$0.795, following the first anniversary of the issuance date. Pursuant to the Recapitalization Agreements (see Notes 9 and 12), the Company and the Investor agreed to revise the exchange price from $2.40 per share to $0.60 per share and all preferred shares were exchanged for common shares at the amended exchange price. As a result of the exchange of the preferred shares to common shares, all corresponding preferred share liabilities were reclassified to common share capital, and the preferred share equity component was recategorized to common share capital.

The Company recognized a $27.4 million non-cash loss on modification of preferred shares in the consolidated statements of operations and comprehensive loss for the year ended December 31, 2021. The loss is representative of the difference between the originally prescribed exchange price of $2.40 per share and the subsequently agreed upon exchange price of $0.60 per share, in respect of the number of common shares to be issued on conversion, using a common share valuation as of March 30, 2021.

Note 12. Share Capital

Recapitalization Agreements

On April 8, 2021, the Company concluded the Recapitalization Agreements, which provided for an equity infusion and a recapitalization of the Company as noted in the events highlighted below:

- The Company completed a rights offering (the "Rights Offering") with its current shareholders by issuing to holders of the outstanding common shares of record at the close of business on March 11, 2021 rights to subscribe for additional common shares at $0.20 per share. Upon closing of the Rights Offering on April 8, 2021, PetroShale issued a total of 29,252,965 common shares at a price of $0.20 per share, raising proceeds from the Rights Offering of approximately $5.9 million.
- In lieu of participating in the Rights Offering, ChernoffCo acquired 70,747,035 common shares for aggregate subscription proceeds of $14.1 million via a private placement at $0.20 per common share which closed concurrently with the Rights Offering.
- In lieu of participating in the Rights Offering, First Reserve acquired 50,000,000 common shares for aggregate subscription proceeds of $10.0 million via a private placement at $0.20 per common share concurrently with the Rights Offering.
- All Preferred Shares, held by First Reserve, were exchanged for 182,275,798 common shares at the previously agreed exchange rate of C$1.00 = US$0.795 and a revised price of $0.60 per share. All special voting shares held by First Reserve were cancelled.
- The Company raised a combined $30.0 million of equity via the Rights Offering, the ChernoffCo private placement, and the First Reserve private placement.

As at December 31, 2021, the derecognition of the adjusted carrying value of the preferred share obligation and the equity conversion feature were recorded to shareholders' equity within common shares.

Common Shares

The Company's authorized share capital consists of unlimited voting common shares, unlimited non-voting common shares, and unlimited Class A preferred shares, issuable in series, of which ones series (being the special voting shares) have been authorized for issuance. As at December 31, 2021, the Company had 523,387,831 voting common shares (188,528,453 at December 31, 2020), no non-voting common shares, and no special voting preferred shares outstanding (42,953,105 at December 31, 2020). The special voting preferred shares were issued in conjunction with the preferred shares issued by the Subsidiary Issuer in January 2018 as well as in connection with the Company's election to pay its preferred share dividends in kind (see Note 11). The special voting preferred shares issued to the Investor entitled the Investor to the "as-exchanged" voting rights of the preferred shares but no other redemption or distribution rights and no claims on the Company's assets. The special voting preferred shares were subsequently cancelled, and all preferred shares (see Note 11) were exchanged for 182,275,798 common shares in concurrence with the Recapitalization Agreements.

The following table reflects the Company's outstanding common shares as at December 31, 2021:

($ thousands, except share amounts)	**Common Shares**	**Share Capital**
December 31, 2019	**191,185,628**	**200,630**
Purchase of common shares for cancellation	(3,865,000)	(1,859)
Settlement of restricted share bonus awards	1,207,825	154
December 31, 2020	**188,528,453**	**198,925**
Settlement of restricted and performance share bonus awards	2,383,580	833
Settlement of stock options	200,000	39
Recapitalization agreement	332,275,798	166,933
December 31, 2021	**523,387,831**	**366,730**

The Company was previously authorized by the TSX Venture Exchange to commence in a normal course issuer bid ("NCIB"). During the quarter ended March 31, 2020, the Company purchased and cancelled 3,851,500 shares at an average price of $0.48 per common share for a total repurchase cost of $1.9 million under the NCIB. The NCIB expired on February 8, 2021 and was not renewed.

Stock Options

The following table presents stock option transactions for the years ended December 31, 2021 and December 31, 2020:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (Years)
December 31, 2019	**550,000**	**0.70**	**1.55**
Exercised	-	-	-
December 31, 2020	**550,000**	**0.70**	**0.55**
Granted	200,000	0.20	-
Exercised	(200,000)	0.20	-
Expired	(550,000)	0.70	-
December 31, 2021	-	-	-

Share Bonus Awards

The Company has granted restricted share bonus awards and performance share bonus awards (collectively, the "share bonus awards") to certain directors, officers, and employees. Share bonus awards granted according to the plan vest over three years from the date of grant and expire before the end of the third year from the date of grant. Performance share bonus awards are valued on achievement of certain performance hurdles and are subject to a multiplier between 0 and 2.0 times based on relative performance. The share bonus awards may be settled by the Company, in its sole discretion, in cash and or common shares of the Company. The estimated fair value of the share bonus awards is determined based on the current market value of the Company's common shares at the dates of grant and considering anticipated forfeiture rates. For purposes of valuing performance share bonus awards, the Company assumes a multiplier of 1.0 times. A charge to income is reflected as share-based compensation expense in the consolidated statement of operations and comprehensive loss over the vesting period with a corresponding increase to contributed surplus.

	Restricted Share Bonus Awards	Performance Share Bonus Awards	Total Awards	Estimated Fair Value Price ($)
December 31, 2019	**2,412,968**	**590,200**	**3,003,168**	**1.46**
Granted	3,604,300	4,854,200	8,458,500	0.15
Settled	(2,044,047)	(96,603)	(2,140,650)	0.80
Forfeited and expired	(672,194)	(1,105,057)	(1,777,251)	0.48
December 31, 2020	**3,301,027**	**4,242,740**	**7,543,767**	**0.41**
Granted	1,778,571	5,554,853	7,333,424	0.20
Settled	(2,464,506)	(1,590,748)	(4,055,254)	0.75
Forfeited and expired	(317,220)	(403,759)	(720,979)	0.19
December 31, 2021	**2,297,872**	**7,803,086**	**10,100,958**	**0.14**

Note 13. Revenue

The following reflects our petroleum and natural gas revenue, before royalties:

	Year ended December 31,	
($ thousands)	**2021**	**2020**
Petroleum and natural gas	229,340	143,506

The Company sells its production pursuant to variable-priced contracts. The transaction price is based on the relevant commodity price, adjusted for quality, location, or other factors, whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Commodity prices are based on market indices that are determined on a monthly or daily basis.

The Company has several different commodity sales as well as transportation and processing contracts related to production from its properties. To the extent control of the relevant commodity is transferred to the purchaser prior to transportation or processing fees are incurred, such fees are netted against the relevant revenue in the consolidated statement of operations and comprehensive loss. To the extent control of the relevant commodity is transferred to a purchaser after transportation or processing fees are incurred, such fees are reflected as transportation expense and as operating expense, respectively in the consolidated statement of operations and comprehensive loss.

Note 14. Net Loss per Common Share

	Year ended December 31,	
($ thousands, except share and per share amounts)	**2021**	**2020**
Net loss	(828)	(61,985)
Weighted average common shares outstanding - basic	431,950,365	188,240,502
Weighted average common shares outstanding - diluted	442,640,870	195,784,268
Net loss per share – basic and diluted	-	(0.33)

For purposes of the net loss per share calculation, the share bonus awards, preferred shares, and stock options are not considered dilutive for the years ended December 31, 2021 and December 31, 2020. On April 8, 2021, in association with the Recapitalization Agreements, the preferred shares were exchanged for common shares. See Notes 11 and 12.

Note 15. Finance Expense

	Year ended December 31,	
($ thousands)	**2021**	**2020**
Preferred share dividends	4,171	11,792
Senior credit facility interest	10,838	10,081
Preferred share accretion, net	683	2,744
Decommissioning obligation accretion	208	135
Operating lease and other	92	693
Total finance expense	**15,992**	**25,445**

Note 16. Income Taxes

The components of income tax expense (recovery) are as follows:

	Year ended December 31,	
($ thousands)	**2021**	**2020**
Current tax expense/(recovery)	-	-
Canada	-	-
United States	-	-
Total current tax expense/(recovery)	-	-
Deferred tax expense/(recovery)		
Canada	-	-
United States	-	(6,151)
Total deferred tax expense/(recovery)	-	(6,151)
Total income tax expense/(recovery)	**-**	**(6,151)**

The provision for income taxes recorded in the consolidated financial statements varies from the amount that would be computed by applying the Canadian statutory rate of 24.00% as a result of the following reconciling differences:

	Year ended December 31,	
($ thousands)	**2021**	**2020**
Income/(loss) before taxes		
Canada	(2,929)	(1,765)
United States	2,101	(66,371)
Total income/(loss) before taxes	(828)	(68,136)
Canadian statutory rate	23.00%	24.00%
Expected income tax	(190)	(16,353)
Impact on income taxes resulting from:		
Foreign and statutory rate differences	710	(729)
Non-deductible expenses	1,001	3,079
Impact of rate change and other	(80)	11
Adjustment to preferred shares equity component	(1,670)	-
Disallowed loss on modification of preferred shares	6,325	-
Change in valuation allowance	(6,096)	7,841
Income tax expense/(recovery)	**-**	**(6,151)**

The following tables provide details of the deferred income tax asset (liability):

($ thousands)	**December 31, 2020**	**Recognized in Earnings**	**Recognized in Equity**	**December 31, 2021**
Deferred income tax liabilities				
Property, plant and equipment	(21,854)	(9,968)	(103)	(31,925)
Preferred shares	(1,868)	1,877	(9)	-
Deferred income tax assets				
Net operating losses	23,722	1,333	111	25,167
Stock compensation	-	201	-	201
Accrued bonuses	-	350	-	350
Decommissioning obligation	-	2,007	-	2,007
Other	-	4,200	-	4,200
Total deferred income tax liability	**-**	**-**	**-**	**-**

($ thousands)	**December 31, 2019**	**Recognized in Earnings**	**Recognized in Equity**	**December 31, 2020**
Deferred income tax liabilities				
Property, plant and equipment	(25,944)	4,961	(871)	(21,854)
Preferred shares	(2,531)	749	(86)	(1,868)
Deferred income tax assets				
Net operating losses	19,736	3,322	664	23,722
Stock compensation	663	(663)	-	-
Accrued bonuses	450	(450)	-	-
Decommissioning obligation	1,585	(1,585)	-	-
Other	183	(183)	-	-
Total deferred income tax liability	**(5,858)**	**6,151**	**(293)**	**-**

Deferred tax assets have not been recognized in respect of the following deductible temporary differences:

	As at December 31,	
($ thousands)	**2021**	**2020**
Property, plant and equipment	428	449
Debt issuance costs	763	2,305
Stock compensation	-	554
Accrued bonus	-	1,227
Decommissioning obligation	-	6,251
Non-capital losses/net operating losses	17,496	20,749
Capital losses	1,478	1,478
Other	-	11,650
Total deductible temporary differences	**20,165**	**44,663**

The Company has a non-capital loss balance of $17.5 million for Canadian tax purposes which expires between 2031 and 2041. For US tax purposes, the Company has a net operating loss balance of $100.3 million, $77.4 million of which will expire between 2031 and 2037 and $22.9 million which do not expire. Additionally, the Company has various state net operating losses of approximately $64.9 million which expire between 2022 and 2041. As at December 31, 2021, the Company had recorded a basis of approximately $392.3 million in depletable and depreciable assets for tax purposes.

Note 17. Commitments

The Company has two outstanding letters of credit. A US$158,000 letter of credit was issued in the third quarter of 2021 for the benefit of the Office of Natural Resources Revenue pending completion of audit procedures. A second letter is in favor of the energy regulator in North Dakota in the amount of US$75,000. As security, the Company has set aside an equivalent amount in cash at the financial institution that issued the letter of credit. In addition, the Company has advanced funds to other regulatory agencies in the amount of US$160,000 as security to operate in North Dakota. These funds are held as restricted cash in the consolidated Statements of Financial Position.

Note 18. Key Management Personnel Compensation

Key management personnel include the directors and officers of the Company. Key management personnel compensation is summarized below:

	Years Ended December 31,	
($ thousands)	**2021**	**2020**
Salaries and other short-term benefits	2,150	1,676
Share-based compensation	618	208
Total compensation	**2,768**	**1,884**

Note 19. Financial Instruments and Risk Management

Financial Instruments

The Company's financial instruments include cash and cash equivalents, accounts receivable, restricted cash, accounts payable and accrued liabilities, senior credit facility, financial derivative assets and liabilities, and lease liabilities. Financial derivatives are measured at fair value through profit or loss. The Company's remaining financial instruments are measured at amortized cost. The fair value of cash and cash equivalents, accounts receivable, restricted cash, accounts payable and lease liabilities approximate their carrying amount due to the highly liquid or short-term nature of these instruments. The fair value of the senior credit facility approximates the carrying amount due the floating rate of interest and the margin charged by the lending syndicate being indicative of current spreads.

The following table summarizes the Company's financial instruments that are carried at fair value as a financial derivative liability on the consolidated statements of financial position:

($ thousands)	**As at December 31, 2021**	**As at December 31, 2020**
Fixed price swaps	4,480	-
Three-way Collars	-	10,020
Costless Collars	11,064	-
Total	**15,544**	**10,020**

Derivatives and Hedging Activity

The Company's commodity derivative financial instruments are measured at fair value and are included in the statements of financial position as financial derivative assets or liabilities. Unrealized gains and losses are recorded based on the changes in the fair values of the derivative instruments. Both the unrealized and realized gains and losses resulting from the contract settlement of derivatives are recorded in the statement of operations.

The amount of unrealized loss recognized in the consolidated statement of operations and comprehensive loss related to the Company's derivative financial instruments was $5.2 million for the year ended December 31, 2021 ($10.4 million unrealized loss for the year ended December 31, 2020). As at December 31, 2021, the Company's derivative instruments consisted of the following types of instruments:

Costless Collars: Costless collars consist of a fixed floor price (purchased put option) and a fixed ceiling price (sold call option). If the market price is between the floor and the ceiling, no payments are due from either party. At the time of settlement, if the market price exceeds the ceiling or falls below the floor, we receive the fixed price and pay the market price.

Fixed price swaps: Under a fixed price swap, the Company receives a fixed price and pays a floating market price to the counterparty.

As at December 31, 2021, the Company had various oil and natural gas price derivative contracts outstanding. The tables below represent the weighted average price for each contract type by fiscal quarter for oil and gas derivative contracts, respectively:

Oil Contract Type (WTI)	Quarter	Volume (Bbls/d)	Swap (US$)	Sold Put (US$)	Bought Put (US$)	Sold Call (US$)
Costless collars						
	Q1 2022	2,500	-	-	48.10	63.29
	Q2 2022	2,750	-	-	48.73	62.72
	Q3 2022	1,500	-	-	50.83	65.32
	Q4 2022	1,500	-	-	50.83	65.32
Fixed swaps						
	Q1 2022	1,118	56.85	-	-	-
	Q2 2022	833	58.63	-	-	-
	Q3 2022	417	62.78	-	-	-
	Q4 2022	317	62.78	-	-	-

Natural Gas Contract Type (Henry Hub)	Quarter	Volume (MMbtu/d)	Swap (US$)	Sold Put (US$)	Bought Put (US$)	Sold Call (US$)
Fixed swaps						
	Q1 2022	2,000	3.43	-	-	-
	Q2 2022	2,000	3.43	-	-	-
	Q3 2022	2,000	3.43	-	-	-

Risk Management Activities

Commodity Price Risk

PetroShale may use financial derivative instruments such as swaps, collars, and options to mitigate the impact of commodity price volatility and enhance the predictability of cash flows for a portion of its future oil, gas, and natural gas liquids production. The Company does not enter derivative instruments for speculative purposes. While these instruments mitigate the cash flow risk associated with future decreases in commodity prices, they may also curtail benefits from future increases in commodity prices.

Credit and Contract Risk

Credit and contract risk represent the economic loss that PetroShale would suffer if a counterparty in a transaction fails to meet its obligations in accordance with agreed terms.

Essentially all the Company's accounts receivable is from the production of tight oil and shale gas and joint operations receivables. Sales of tight oil and shale gas production from the Company's operated properties are made to large industry purchasers. Joint operations receivables are from participants in the tight oil and shale gas sector and collection of outstanding balances is dependent on industry factors including commodity price fluctuations. The Company has not experienced any material credit losses on the collection of accounts receivable.

The use of financial derivative instruments also exposes the Company to credit and contract risk. The Company has entered into derivative instruments only with counterparties that are also lenders in the Senior Credit Facility and have been deemed an acceptable credit risk. As the Company's counterparties are participants in Senior Credit Facility, which is secured by substantially all assets of the Company, the Company is not required to post collateral.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meets its financial obligations as they become due. The Company's approach to managing liquidity is to ensure that it will have sufficient liquidity to meet its short-term and long-term financial obligations when due, under both normal and unusual conditions, without incurring unacceptable losses. As at December 31, 2021, the Company had a net working capital deficit (current assets less current liabilities excluding derivatives) of $16.0 million, excluding the current financial derivative liability of $15.5 million. The financial liabilities in the consolidated statement of financial position consist of accounts payable and accrued liabilities, which are all considered due within one year, and the senior credit facility, lease liability, and derivative liability. The Company anticipates it will continue to have adequate liquidity to fund its financial liabilities as they come due. The Company prudently manages liquidity by forecasting of its cash flows from operating activities and its available capacity under its revolving credit facilities. The Company's accounts payable and accrued liabilities balance at December 31, 2021 is approximately $56.0 million (December 31, 2020 - $28.3 million). It is the Company's general practice to pay suppliers within 60 days. In association with the Recapitalization Agreements, the Company's senior lenders reaffirmed the existing borrowing capacity and extended the term out date to June 25, 2022, at which point, the facility can be extended at the option of the lenders or converted to a one-year term loan. In addition, as a result of the Recapitalization Agreements, the Company's preferred shares were converted to common shares of the Company. Refer to Notes 11, 12 and 21 for information relating to liquidity risk.

The following are the contractual maturities of the Company's debt and anticipated timing of settlements of its other financial liabilities at December 31, 2021, including estimated interest:

($ thousands)	**2022**	**2023**	**2024**	**2025**	**2026**	**Contractual Cash Flow**
Accounts payable and accrued liabilities	56,014	-	-	-	-	56,014
Lease liability	345	238	260	282	-	1,125
Senior credit facility, including interest	8,331	184,976	-	-	-	193,307

Interest Rate Risk

PetroShale is exposed to interest rate risk on bank credit facilities to the extent of changes in market interest rates. Based on the Company's floating rate debt position at December 31, 2021, a 1 percent increase or decrease in the interest rate on floating rate debt would amount to an impact on income before tax of $2.0 million for the year ended December 31, 2021.

Capital Management

The Company's objective when managing capital is to maintain a flexible capital structure which will allow it to execute on its capital expenditure program, which includes expenditures on oil and gas activities which may or may not be successful. Therefore, the Company monitors the level of risk incurred in its capital expenditures to balance the proportion of debt and equity in its capital structure.

The Company manages its capital structure and makes adjustments by continually monitoring its business conditions, including: current economic conditions; the risk characteristics of the Company's petroleum and natural gas assets; the depth of its investment opportunities; current and forecasted net debt levels; current and forecasted commodity prices; and other factors that influence realized commodity prices and cash flow from operations such as quality and basis differential, royalties, operation costs and transportation and processing costs. The Company considers its capital structure to include working capital, any debt, preferred shares, and shareholders' equity. The Company monitors capital based on current cash flow from operations compared to forecasted capital and operating requirements.

In order to maintain or adjust the capital structure, the Company will consider: its forecasted cash flow from operations while attempting to finance an acceptable capital expenditure program which may in the future include acquisition opportunities; the current level of credit available from its lenders; the level of credit that may become available from its lenders as a result of petroleum and natural gas reserve growth; the availability of other sources of debt with different characteristics than bank debt; the sale of assets; limiting the size of the capital expenditure program and new equity if available on favorable terms. Access to any bank credit facility is determined by the lenders and is generally based upon the lenders' borrowing base models which are based upon the Company's petroleum and natural gas reserves.

Note 20. Supplemental Cash Flow Disclosures

Changes in non-cash working capital is comprised of the following:

	Year ended December 31,	
(in thousands)	**2021**	**2020**
Source (use) of cash:		
Accounts receivable	(22,385)	36,788
Prepaid expenses and deposits	(61)	(236)
Accounts payable and accrued liabilities	27,687	(80,446)
	5,241	**(43,894)**
Related to operating activities	(3,350)	11,265
Related to investing activities	10,992	(56,256)
Accrued interest and unpaid dividends	(2,379)	(44)
Difference due to foreign exchange	(22)	1,141
	5,241	**(43,894)**
Interest paid	(11,188)	(14,031)

Note 21. Subsequent Events

New Management Team and Board Appointment

On January 13, 2022, the Company announced the appointment of a new management team (the “New Management Team”), led by Brett Herman as President & Chief Executive Officer, Jason Skehar as Chief Operating Officer, Marvin Tang as Vice President, Finance & Chief Financial Officer, Sandy Brown as Vice President, Geosciences, Kristine Lavergne as Vice President, Engineering, and Shane Manchester as Vice President, Operations. In addition, the Company announced the appointment of Dale O. Shwed to the Board of Directors. On February 22, 2022, the Company announced the appointment of Anthony Baldwin as Vice President, Business Development.

Private Placements

In connection with the appointment of the New Management Team, on February 2, 2022, the Company closed a non-brokered private placement of units of PetroShale (the “Units”) with the New Management Team, among others, for gross proceeds of $9.5 million (the “Non-Brokered Private Placement”) and a brokered private placement of common shares of PetroShale for gross proceeds of $45.0 million (the “Brokered Private Placement”, and combined with the Non-Brokered Private Placement, the “Private Placements”).

Pursuant to the Non-Brokered Private Placement, PetroShale issued 23,750,000 Units at a price of $0.40 per Unit for total proceeds of $9.5 million. Each Unit is comprised of one common share of PetroShale ("Common Share") and one warrant

("Warrant") entitling the holder to purchase one Common Share at a price of $0.475 per Common Share for a period of five years from the issuance date. The Warrants will vest and become exercisable as to one-third upon the 20-day volume weighted average trading price of the Common Shares (the "Trading Price") equaling or exceeding $0.67 per Common Share, an additional one-third upon the Trading Price equaling or exceeding $0.83 per Common Share and the final one- third upon the Trading Price equaling or exceeding $0.95 per Common Share.

Pursuant to the Brokered Private Placement, the Company issued 112,500,000 Common Shares at a price of $0.40 per Common Share for gross proceeds of $45.0 million. Through the Private Placements, PetroShale raised total gross proceeds of $54.5 million which was used to reduce debt and for general corporate purposes, positioning the Company to execute on a disciplined corporate strategy.

The Company's two largest shareholders, FR XIII PetroShale Holdings L.P. and M Bruce Chernoff, waived their respective rights to participate in the Private Placements in order to maintain their ownership positions and did not acquire any Common Shares as part of the Company's Private Placements.

Proposed Name Change

On January 13, 2022, the Company announced it intends to ask the shareholders of PetroShale to approve the change of the Company's name to Lucero Energy Corp. at the next annual general meeting of shareholders.