PetroShale

Calgary • Denver

Management's Discussion and Analysis &

Consolidated Financial Statements

As at December 31, 2019 and 2018 and for the three-month periods and years then ended

PetroShale Inc.
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Financial and Operational Highlights

	Three-months ended December 31,		Years ended December 31,	
(all $ amounts are presented in Canadian dollars)	**2019**	**2018**	**2019**	**2018**
Financial (in thousands, except share and per share data)				
Petroleum and natural gas revenue	$ 60,569	$ 26,231	$ 165,258	$ 121,797
Cash provided by operating activities	$ 27,677	$ 19,810	$ 78,536	$ 69,512
Net income	$ 9,608	$ 7,982	$ 15,327	$ 27,056
Per share - diluted	$ 0.05	$ 0.04	$ 0.08	$ 0.16
Adjusted EBITDA(1)	$ 35,566	$ 11,684	$ 91,487	$ 64,937
Capital expenditures	$ 65,587	$ 27,432	$ 236,703	$ 192,723
Net debt(1)			$ 330,029	$ 176,978
Common shares outstanding			191,185,628	191,758,236
Weighted average - basic	191,681,135	191,040,112	191,920,373	170,866,944
Weighted average - diluted	194,684,301	194,482,248	194,395,182	174,391,337
Operating				
Number of days	92	92	365	365
Daily production(2)				
Crude oil (Bbls)	9,613	4,185	6,538	4,134
Natural gas (Mcf)	8,470	5,765	6,716	4,520
Natural gas liquids (Bbls)	1,148	868	1,023	743
Barrels of oil equivalent (Boe)	12,173	6,014	8,680	5,630
Average realized price				
Crude oil ($/Bbl)	$ 68.98	$ 65.20	$ 69.89	$ 79.64
Natural gas ($/Mcf)	$ 2.35	$ 4.18	$ 2.45	$ 3.48
Natural gas liquids ($/Bbl)	$ 12.71	$ 21.71	$ 10.65	$ 24.50
Netback ($ per Boe)(1)				
Petroleum and natural gas revenues	$ 54.08	$ 47.41	$ 52.16	$ 59.27
Royalties	$ (10.43)	$ (9.64)	$ (10.25)	$ (11.73)
Realized loss on financial derivatives	$ -	$ (1.67)	$ -	$ (3.10)
Lease operating costs	$ (3.77)	$ (5.29)	$ (4.16)	$ (3.47)
Workover expense	$ (0.52)	$ (1.56)	$ (1.03)	$ (1.08)
Production taxes	$ (4.21)	$ (3.67)	$ (4.10)	$ (4.57)
Transportation expense	$ (2.35)	$ (1.68)	$ (2.32)	$ (1.35)
Operating netback(1)	$ 32.80	$ 23.90	$ 30.30	$ 33.97
Operating netback prior to hedging(1)	$ 32.80	$ 25.57	$ 30.30	$ 37.07

(1) Non-IFRS measure - see page 5-6 for a reconciliation of adjusted EBITDA and net debt and a description of operating netback and operating net back prior to hedging.

(2) The Company's reserves have been categorized as Tight Oil and Shale Gas pursuant to National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities, ("NI 51-101"). Rather than Tight Oil and Shale Gas, the Company has used the terms "crude oil" and "natural gas", respectively, as it feels such terms are more easily understood by users of these consolidated financial statements and MD&A as well as consistent with disclosures by industry peers.

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 26, 2020. This MD&A should be read in conjunction with PetroShale's audited consolidated financial statements as at December 31, 2019 and 2018 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	Barrel(s)
Boe	Barrel(s) of oil equivalent
Bopd	Barrels of oil per day
Boepd	Barrels of oil equivalent per day
Mboe	Thousand barrels of oil equivalent
Mcf	Thousand cubic feet
Mcfpd	Thousand cubic feet per day
Mmcf	Million cubic feet per pay
Mmcfd	Million cubic feet per day
Mmboe	Million barrels of oil equivalent
NGLs	Natural gas liquids
WTI	West Texas Intermediate, reference price paid in US$ for crude oil of standard grade
HH	Henry Hub, reference price paid in US$ for natural gas deliveries
PV10	Present value, reflecting a 10% discount rate

Barrel of Oil Equivalent

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 current price of crude oil compared to natural gas, is 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

Production volumes and per Boe calculations are presented on a gross 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-IFRS Measurements and Changes in Accounting Policies

This MD&A contains the terms "*operating netback*", "*operating netback prior to hedging*", "*net debt*" and "*adjusted EBITDA*" which are not defined by IFRS and therefore may not be comparable to performance measures presented by others.

Operating netback represents petroleum and natural gas revenue, plus or minus any realized gain or loss on financial derivatives, less royalties, production taxes, lease operating costs, workover expense and transportation expense. The operating netback is then divided by the working interest production volumes to derive the operating netback on a per Boe basis.

Operating netback prior to hedging represents operating netback prior to any realized gain or loss on financial derivatives.

Finding and development costs or "F&D costs" are calculated by dividing the sum of the total capital expenditures for the year exclusive of net acquisition costs and disposition proceeds (in dollars) by the change in reserves within the applicable reserves category exclusive of changes due to acquisitions and dispositions (in Boe).

Finding, development and acquisition costs or "FD&A costs" are calculated by dividing the sum of the total capital expenditures for the year inclusive of net acquisition costs and disposition proceeds (in dollars) by the change in reserves within the applicable reserves category inclusive of changes due to acquisitions and dispositions (in Boe).

Recycle ratio is calculated by dividing operating netback by F&D costs or FD&A costs.

Net debt represents total liabilities, excluding decommissioning obligation, deferred income tax liability, lease liability and financial derivative liability, less current assets.

Adjusted EBITDA represents cash flow from operating activities prior to changes in non-cash working capital.

The Company believes that adjusted EBITDA provides useful information to the reader in that it measures 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. Management believes that in addition to net income (loss) and cash flow from operating activities, operating netback and adjusted EBITDA 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. Investors should be cautioned, however, that these measures should not be construed as an alternative to either net income (loss) or cash flow from operating activities, which are determined in accordance with IFRS, as indicators of the Company's performance.

The reconciliation between cash flow from operating activities, as defined by IFRS, and adjusted EBITDA, as defined herein, is as follows:

	Years ended December 31,	
(in thousands)	2019	2018
Cash flow from operating activities	$ 78,536	$ 69,512
Change in non-cash working capital	$ 12,951	$ (4,575)
Adjusted EBITDA	$ 91,487	$ 64,937

Net debt, as defined above, is calculated as follows:

	As at December 31,	
(in thousands)	2019	2018
Total liabilities	$ 397,627	$ 209,293
Decommissioning obligation	(6,313)	(4,934)
Derivative liability	(261)	-
Deferred tax liability	(5,858)	-
Lease liability	(453)	-
Total current assets	(54,713)	(27,381)
Net debt	$ 330,029	$ 176,978

The calculation of operating netback and operating netback prior to hedging is found elsewhere within this MD&A.

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. Management's assessment of future plans and operations, drilling plans and the timing thereof, plans for the tie-in and completion of wells and the timing thereof, capital expenditures, timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, use of proceeds from any financing, production estimates, expected commodity mix and prices, expectations as to differentials relative to benchmark commodity prices received for our production, reserve estimates, future lease operating, workover and transportation costs, anticipated production taxes, expected royalty rates, anticipated timing and impact of new gas transportation and processing facilities in North Dakota, expected general and administrative expenses, expected interest rates, debt levels, cash flow from operations and the timing of and impact of implementing new accounting policies, estimates regarding its undeveloped land position, expected changes to amounts and terms of available debt financing and estimated future drilling, recompletion or reactivation activities and anticipated impact upon PetroShale's forecasts in respect of production, cash flow and resulting net debt for any periods subsequent to December 31, 2019 may constitute forward looking statements and necessarily involve risks 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, 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, 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 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 capacity 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 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.

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 symbol "PSH".

The Company has corporate offices located at 421 - 7th Avenue SW, Suite 3230, Calgary, Alberta T2P 4K9 and at 303 E. 17th Avenue, Suite 940, Denver, CO 80203.

Recent Events

Oil and Gas Lease Development

During the fourth quarter, the Company spud 2 gross (1.2 net) operated wells in its Jorgenson unit in the South Berthold area. The Company also completed and commenced production on 5 gross (2.9 net) operated wells that were spud in the second and third quarters of 2019 in the South Berthold area. In addition to the activity on operated wells, the Company also had 9 gross (2.2 net) non-operated wells commence production in the fourth quarter in the South Berthold area. Capital expenditures totaled approximately $65.6 million for the quarter, $18.0 million of which represented the acceleration of 2020 budgeted capital activity into the fourth quarter of 2019. As a result, there will be a corresponding reduction to 2020 budgeted capital expenditures (see "Outlook" below).

Petroleum Reserves Update

The Company obtained an updated reserve report, prepared by its independent engineers, Netherland, Sewell & Associates, as at December 31, 2019. As reflected in the table below, the Company achieved increases in nearly every reserve category, reflecting a successful capital and acquisition program during 2019. Proved developed producing reserves increased by 13.2 Mmboe or 107.4% to 25.4 Mmboe (US$398.5 million PV10) while total proved reserves increased by 8.3 Mmboe or 16.8% to 57.5 Mmboe (US$752.9 million PV10). Probable reserves remained consistent with the prior year. Overall, total proved plus probable reserves increased by 7.7 Mmboe or 12.2% to 70.5 Mmboe (US$922.7 million PV10). Finding and development ("F&D") costs and finding, development and acquisition ("FD&A") costs were $19.55 per Boe and $12.71 per Boe, respectively, based on total proved reserves. This resulted in recycle ratios of 1.5x for F&D and 2.4x for FD&A based on total proved reserves.

Gross Company Interest Reserves:

	As at December 31,		As at December 31,	
	2019	2018	2019	2018
	Mboe	Mboe	PV10 (US$MM)(1)	PV10 (US$MM)(1)
Proved developed producing	25,442	12,264	$ 398.5	$ 208.4
Total proved	57,451	49,182	$ 752.9	$ 655.0
Probable	13,016	13,615	$ 169.9	$ 195.6
Total proved plus probable	70,467	62,797	$ 922.7	$ 850.6
Oil percentage of total proved plus probable	76%	76%		

(1) The PV10 values reported in the table above were calculated by Netherland, Sewell & Associates using forecast pricing as at the respective dates in accordance with NI 51-101.

Outlook

The Company participated in 86 gross (8.8 net) wells during the second half of 2019 and into the first quarter of 2020, which have not yet commenced production. Five gross (1.7 net) wells in which we own an interest commenced production in March

2020 and we anticipate an additional 7 gross (1.1 net) wells to initiate production in the second quarter of 2020. The Company also drilled 2 gross (1.2 net) wells in the fourth quarter of 2019 which it plans to leave uncompleted until prices improve.

The rapid and severe deterioration of economic activity related to COVID-19 (Coronavirus), combined with a price war fueled by Russia and Saudi Arabia, led to a global equity market and oil price shock in early March 2020. With meaningful added oil supply expected over the near term, oil prices and energy equities are expected to remain under pressure. However, this is also anticipated to cause a sizeable reduction in industry spending which should lead to lower supply and thus, stronger pricing in the medium term. PetroShale's strategy has always been to create value by controlling cost and managing risk while seeking to expand production and reserves at a measured pace. The Company's sound capital structure, efficient operating track record, and lean overhead means that PetroShale is positioned to weather short-term commodity price impacts and preserve value by shifting capital allocation and deferring completions until the broader pricing environment improves. The Board and management will continue to monitor commodity prices and follow a conservative strategy for capital deployment.

In response to these broader market factors and the Company's successful development program in 2019, PetroShale will focus in 2020 on further streamlining operating costs as well as the implementation of a sustainable plan to reduce drilling, completion and facility construction costs.

PetroShale's Board of Directors previously approved a 2020 capital budget of $70 million, which was designed to generate significant free cash flow. Approximately $18 million of the 2020 capital budget was accelerated into 2019 as the operators of certain of our non-operated properties completed drilling and well completion activities earlier than anticipated. In addition, our expected capital budget has been further reduced as certain of our current non-operated projects have been suspended by the operators. We now anticipate that our 2020 capital expenditures will be approximately $26 million, representing a reduction of approximately 89% relative to 2019.

With this significantly reduced capital spend, we anticipate a modest production decline relative to the second half of 2019, with forecast 2020 annual volumes expected to average between 11,000 and 12,000 Boe/d during 2020. We anticipate generating free cash flow at current oil prices, which will be allocated to debt reduction. The Company faces no debt maturities until June 2021.

Results of Operation

Production

The following table summarizes the Company's daily production volumes for the relevant periods.

	Three-months ended December 31,		Years ended December 31,	
	2019	2018	2019	2018
Crude oil (Bopd)	9,613	4,185	6,538	4,134
Natural gas (Mcfpd)	8,470	5,765	6,716	4,520
Natural gas liquids (Bopd)	1,148	868	1,023	743
Total (Boepd)	12,173	6,014	8,680	5,630
Liquids percentage of total production	88.4%	84.0%	87.1%	86.6%

Total production during the three months and year ended December 31, 2019, increased by 102.4% and 54.1%, respectively, compared to the three months and year ended December 31, 2018 (the "corresponding periods"). These increases were primarily the result of new wells that were brought online during mid to late 2019, slightly offset by the natural decline on the wells that commenced production in 2018. A total of 62 gross (16.3 net) wells had first sales during 2019.

Liquids as a percentage of total production remained consistent during the periods ended December 31, 2019. NGL yields from associated natural gas production averaged 135 Bbls/Mmcf in the fourth quarter relative to 150 Bbls/Mmcf in the comparative period of 2018. NGL yields averaged 152 Bbls/Mmcf and 164 Bbls/Mmcf in the years ended December 31, 2019 and 2018, respectively.

Pricing

	Three-months ended December 31,		Years ended December 31,	
	2019	**2018**	**2019**	**2018**
Average Benchmarks (US$)				
Crude oil - WTI (per bbl)	$ 56.96	$ 58.70	$ 56.74	$ 64.76
Natural gas - HH spot price (per mmbtu)	2.41	3.77	2.56	3.15
Average Differentials (US$)				
Crude oil (per Bbl)	$ (4.70)	$ (9.37)	$ (4.07)	$ (3.28)
Natural gas (per mcf)(2)	(0.63)	(0.61)	(0.71)	(0.46)
Average Realized Prices (US$) (1)				
Crude oil (per Bbl)	$ 52.26	$ 49.33	$ 52.67	$ 61.48
Natural gas (per Mcf)	1.78	3.16	1.85	2.69
Natural gas liquids (per Bbl)	9.63	16.42	8.03	18.91
Average Period Exchange rate - US/Canadian (CAD$)	$ 1.320	$ 1.322	$ 1.327	$ 1.295
Average Realized Prices (CAD$) (1)				
Crude oil (per Bbl)	$ 68.98	$ 65.20	$ 69.89	$ 79.64
Natural gas (per Mcf)	2.35	4.18	2.45	3.48
Natural gas liquids (per Bbl)	12.71	21.71	10.65	24.50

(1) Excluding transportation and processing costs
(2) Includes conversion from mmbtu to mcf

During the three months ending December 31, 2019, benchmark WTI prices decreased by US$1.74 or 2.9% compared to the 2018 period. Realized prices increased by US$2.94 or 6.0% outperforming the decrease in the benchmark price as a result of a significant improvement in the average differential. During the three-month period ending December 31, 2018, several factors, including US refinery shutdowns and competing supply from western Canadian production, resulted in a widening of the basis differential to US$9.38. The crude oil price differential improved in the first quarter of 2019 and has remained relatively steady for the remainder of 2019.

For the year ended December 31, 2019, benchmark WTI prices decreased by US$8.02/Bbl or 12.4% compared to 2018, largely due to continued growth in global crude supplies, particularly the in US Permian basin. Realized prices in 2019 decreased by US$8.83/Bbl or 14.4% which was consistent with the decrease in the benchmark price.

Henry Hub benchmark natural gas prices were lower in both the three-month period and the year ended December 31, 2019, compared to the corresponding periods. Realized natural gas prices in the Bakken remain discounted to Henry Hub benchmark prices reflecting the shortage of takeaway and processing capacity in the area, although the discount improved during 2019. The Company anticipates the differential may improve further given approximately 400 Mmcfd of natural gas transportation and processing capacity that came online at the end of 2019.

Overall NGL average realized prices have remained relatively steady for the year ended December 31, 2019, compared to the prior year period. NGL realized prices declined significantly in the fourth quarter of 2019 reflecting a decrease in benchmark prices at Conway at the time due to an oversupply in the market and the impact of transportation and marketing challenges associated with certain natural gas liquids in the US, particularly in the Williston basin. The Elk Creek pipeline was completed at the end of 2019 and has increased takeaway capacity out of the Williston basin by approximately 240,000 Bopd.

Revenue

	Three-months ended December 31,				Years ended December 31,			
(in thousands except per Boe amounts)		2019		2018		2019		2018
Petroleum and natural gas	$	60,569	$	26,231	$	165,258	$	121,797
Petroleum and natural gas per Boe	$	54.08	$	47.41	$	52.16	$	59.27

Revenues in the three months and year ended December 31, 2019 increased 130.9% and 35.6%, respectively, compared to the corresponding periods. The increases are primarily due to increased production volumes from drilling activities as discussed in the Production section above.

Royalties

	Three-months ended December 31,				Years ended December 31,			
		2019		2018		2019		2018
Royalties (in thousands)	$	11,686	$	5,332	$	32,477	$	24,098
Royalties per Boe	$	10.43	$	9.64	$	10.25	$	11.73
Royalties as a percentage of revenue		19.3%		20.3%		19.7%		19.8%

The Company's royalty rate as a percentage of revenues remained relatively consistent in the three-month period and year ended December 31, 2019 compared to the corresponding periods. Royalties are higher on an absolute dollar basis for the three-month period and year ended December 31, 2019 compared to the corresponding periods due to higher overall production and revenues as discussed above.

Operating Expenses, Production Taxes and Transportation Expense

	Three-months ended December 31,				Years ended December 31,			
(in thousands except per Boe amounts)		2019		2018		2019		2018
Lease operating costs [1]	$	4,234	$	2,823	$	13,198	$	7,140
Workover expense [1]		581		968		3,266		2,218
Production taxes [1]		4,710		2,030		13,001		9,400
Transportation expense		2,635		932		7,340		2,769
Total	$	12,160	$	6,753	$	36,805	$	21,527
Per Boe amounts:								
Lease operating costs	$	3.77	$	5.29	$	4.16	$	3.47
Workover expense		0.52		1.56		1.03		1.08
Production taxes		4.21		3.67		4.10		4.57
Transportation expense		2.35		1.68		2.32		1.35
Total per Boe	$	10.85	$	12.20	$	11.61	$	10.47

[1] Reflected as production and operating expense in the consolidated statement of operations

Lease operating costs

Lease operating costs for the three-month period and the year ended December 31, 2019, increased 50.0% and 84.7%, respectively, over the corresponding periods due primarily to increased well count and production volumes as discussed in the Production section above. Lease operating costs per Boe are relatively consistent for the periods presented except for the three months ended December 31, 2018. Lease operating costs increased during the three months ended December 31, 2018 due to an increased level of repairs and maintenance activity during the period.

Workover expense

Workover expense by its nature can vary from period to period depending on the level of workover activity, which may not be consistent with production levels. For the year ended December 31, 2019, workover expense increased 47.2% over the corresponding period consistent with the increase in our well count. The decline in workover costs for the fourth quarter of 2019 compared to the fourth quarter of 2018 is primarily due to timing of workover activity.

Production taxes

North Dakota assesses a 5% oil severance tax and a 5% oil extraction tax on the gross value of volumes produced at the wellhead, with certain defined exemptions. Production taxes as a percentage of revenue less royalties were consistent with the statutory rate at 9.6% and 9.8%, respectively, for the three months and year ended December 31, 2019 and 9.7% and 9.6% for the corresponding periods. The fluctuations in production taxes per Boe are consistent with the fluctuations in the Company's average realized prices as discussed in the Pricing section above.

Transportation expense

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 who 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. Transportation costs are higher in the three-month period and year ended December 31, 2019, compared to the corresponding periods due to a higher percentage of our production being shipped in pipelines by midstream operators with the transportation costs being reflected as an expense. In the corresponding periods, a higher percentage of the Company's operated production was sold at the wellhead with transportation costs reflected in the net price received from the purchaser.

Operating Netback

	Three-months ended December 31,		Years ended December 31,	
	2019	2018	2019	2018
Netback ($ per Boe)				
Petroleum and natural gas revenues	$ 54.08	$ 47.41	$ 52.16	$ 59.27
Royalties	(10.43)	(9.64)	(10.25)	(11.73)
Realized loss on financial derivatives	-	(1.67)	-	(3.10)
Lease operating costs	(3.77)	(5.29)	(4.16)	(3.47)
Workover expense	(0.52)	(1.56)	(1.03)	(1.08)
Production taxes	(4.21)	(3.67)	(4.10)	(4.57)
Transportation expense	(2.35)	(1.68)	(2.32)	(1.35)
Operating netback	$ 32.80	$ 23.90	$ 30.30	$ 33.97
Operating netback prior to hedging	$ 32.80	$ 25.57	$ 30.30	$ 37.07

The fluctuations in the Company's operating netback during these periods primarily reflect fluctuations in the WTI benchmark crude oil price.

General and Administrative Expense

	Three-months ended December 31,		Years ended December 31,	
(in thousands, except per Boe amounts)	2019	2018	2019	2018
Gross general and administrative expense	$ 2,217	$ 2,103	$ 7,086	$ 6,478
Capitalization of internal development costs	(247)	(286)	(1,050)	(1,113)
Overhead recovery	(813)	(258)	(1,547)	(505)
Net general and administrative expense	$ 1,157	$ 1,559	$ 4,489	$ 4,860
General and administrative expense per Boe	$ 1.03	$ 2.82	$ 1.42	$ 2.36

G&A per Boe declined significantly in 2019 compared to 2018 due to the increase in production volumes experienced in 2019. Gross general and administrative expense ("G&A") increased by $0.6 million or 9.5% for the year ended December 31, 2019, compared to the corresponding period. The increase during the current year is primarily due to increases in full-time employee headcount reflecting the increase in activity level in 2019. However, these increased costs were more than offset by higher overhead recoveries due to increased drilling and completion activities resulting in net G&A expense for the year being $0.4 million or 7.6% below the prior year period.

Depreciation and Depletion Expense

	Three-months ended December 31,		Years ended December 31,	
(in thousands, except per Boe amounts)	2019	2018	2019	2018
Depreciation and depletion	$ 15,814	$ 7,841	$ 46,986	$ 31,036
Depreciation and depletion per Boe	$ 14.12	$ 14.17	$ 14.83	$ 15.10

Depreciation and depletion expense increased during the three-month period and the year ended December 31, 2019, compared to the corresponding periods, due to the increase in production volumes, and the related capital expenditures, experienced during 2019. The per Boe expense is relatively consistent across all periods presented.

Finance Expense

Finance expense reflects costs primarily associated with the Company's senior credit facility and the preferred shares, which were issued in January 2018 and are treated as a financial liability for accounting purposes. Finance expense was higher year over year reflecting higher senior debt levels in 2019 following the Company's significant drilling and acquisition programs during 2018 and 2019.

Impairment

The Company evaluates its developed and producing assets ("D&P") for impairment indicators that may suggest the carrying value of a cash generating unit ("CGU") may not be recoverable. If such impairment indicators exist, any impairment necessary is determined by comparing the carrying amount of the CGU to the greater of the CGU's value in use ("VIU") or its estimated fair value less selling costs. If the carrying amount is in excess of the estimated recoverable value, then the Company will record an impairment expense related to the CGU. During the three months and year ended December 31, 2019, as well as the corresponding periods, the Company determined that no impairment indicators existed. The stabilization in WTI prices in 2019, the overall increases in the Company's reserve volumes, as well as values, as reflected in the December 31, 2019 reserve report, and the October 2019 increase in the borrowing base under the senior credit facility support the Company's determination.

Deferred Income Tax Expense (Recovery)

The Company recorded a deferred income tax expense of $9.2 million for the year ended December 31, 2019, compared to a $5.7 million deferred tax recovery for the year ended December 31, 2018. The main reason for the large recovery in 2018 is the recognition in that period of the previously unrecognized deferred tax assets.

Share-based Compensation

	Three-months ended December 31,		Years ended December 31,	
(in thousands, except per Boe)	2019	2018	2019	2018
Share-based compensation - restricted awards	$ 239	$ 634	$ 1,652	$ 2,431
Share-based compensation - performance awards	26	-	117	-
Stock options	-	5	10	-
Capitalized share-based compensation	(70)	(168)	(404)	(411)
Total share-based compensation	$ 195	$ 471	$ 1,375	$ 2,020
Total share-based compensation per Boe	$ 0.17	$ 0.85	$ 0.43	$ 0.98

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 over time. Performance share bonus awards vest based on achievement of certain performance hurdles and are subject to a multiplier between 0 and 2 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 giving consideration to 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 over the vesting period with a corresponding increase to contributed surplus.

The expense for the three months ended December 31, 2019 of $195,000 is net of $70,000 capitalized to property, plant and equipment compared to $471,000 and $177,000, respectively, for the corresponding period. Share-based compensation expense decreased during the three-month period and the year ended December 31, 2019, compared to the corresponding periods, due to restricted awards forfeited as a result of an employee resignation.

Foreign Currency Gain (Loss) and Translation Adjustment

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 $9.6 million for the year ended December 31, 2019 compared to a gain of $12.0 million in 2018. The loss in 2019 was the result of the strengthening of the Canadian dollar relative to the US dollar from January 1, 2019 (US dollar / Canadian dollar 1.367) to December 31, 2019 (US dollar / Canadian dollar 1.2990) and the fact that the Company's US dollar-denominated assets exceed its liabilities. The gain in 2018 was caused by a weakening of the Canadian dollar relative to the US dollar in the corresponding periods.

Share Capital

	Three-months ended December 31,		Years ended December 31,	
	2019	**2018**	**2019**	**2018**
Weighted average common shares outstanding:				
Basic	191,681,135	191,040,112	191,920,373	170,866,944
Diluted	194,684,301	194,482,248	194,395,182	174,391,337
Outstanding securities at year end:				
Common shares, voting and non-voting			191,185,628	191,758,236
Preferred shares, convertible			75,000	75,000
Stock options			550,000	550,000
Restricted share bonus awards			2,412,968	3,185,000
Performance share bonus awards			590,200	-

The preferred shares issued entitle the investor to voting rights as though the preferred shares were exchanged to common shares, but no other redemption or distribution rights and no claims on the Company's assets.

On February 7, 2019, the Company announced that the TSX Venture Exchange had accepted the Company's intention to commence a normal course issuer bid ("NCIB"). Pursuant to the NCIB, which was renewed in 2020, the Company is permitted to purchase up to 11,785,163 voting common shares of the Company between February 10, 2020 and February 8, 2021. Through December 31, 2019, the Company had purchased and cancelled 690,000 shares at an average price of $0.56 per common share for a total repurchase cost of $0.4 million under its NCIB. In addition, the Company purchased 384,615 common shares from a departing employee during 2019. Subsequent to year end, the Company purchased an additional 3,828,000 common shares pursuant to the NCIB at cost of $1.9 million or $.48/share.

As at March 26, 2020, the Company had 187,380,628 common shares, 75,000 preferred shares, 550,000 stock options, 2,412,968 restricted bonus awards and 590,200 performance awards outstanding.

Capital Expenditures

	Three-months ended December 31,		Years ended December 31,	
(in thousands)	**2019**	**2018**	**2019**	**2018**
Drilling and completion	$ 62,151	$ 27,263	$ 229,512	$ 101,532
Acquisitions, net of dispositions	3,340	-	7,007	91,031
Other	96	169	184	160
	65,587	27,432	236,703	192,723
Non-cash:				
Capitalized stock-based compensation	70	168	404	411
Decommissioning obligation	1,039	-	1,693	2,072
	$ 66,696	$ 27,600	$ 238,800	$ 195,206

During the year ended December 31, 2019, the Company participated in 95 gross (19.3 net) crude oil wells targeting both the Middle Bakken and Three Forks formations. In addition, during 2019, the Company purchased $7.3 million of oil and gas leases in its focus areas in North Dakota. These lease acquisitions represent increased working interests in drilling units, in the majority of which the Company already owned an interest, with associated proved and probable reserves.

For the quarter ended December 31, 2019, capital expenditures totaled approximately $66.7 million, a portion of which represented the acceleration of 2020 budgeted capital activity into the fourth quarter of 2019. The Company has commitments to make additional capital expenditures following the end of the fourth quarter of approximately $45.0 million (US$34.6 million) related to non-operated wells which were partially completed at the end of the quarter, however, several of the projects have been suspended by the operators due to the current commodity price environment such that we now anticipate 2020 capital expenditures to be approximately $26 million.

Liquidity and Capital Resources

Capital expenditures for acquisitions and drilling and completion activities for the year ended December 31, 2019 were funded from borrowings under the Company's senior loan facility, operating cash flows and working capital.

The Company is dependent on cash on hand, operating cash flows and equity and/or debt issuances to finance capital expenditures and property acquisitions. The Company will manage borrowings in relation to our credit capacity and our 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 be impacted in a negative way, the Company is capable of managing its cash flows by not consenting to participate in additional drilling proposed by operators of its non-operated properties, by reducing its drilling and completion activity on its operated properties and by entering into commodity price contracts. The Company will monitor its financial capacity before proceeding with additional wells on its operated lands.

At December 31, 2019, the Company had a net working capital deficit of $54.8 million which is $12.6 million greater than the undrawn capacity of the senior credit facility of $42.2 million. Accounts payable and accrued liabilities consist of amounts relating to capital spending, field operating activities and general and administrative expenses. The Company experienced an increase in operating cash flows during the latter half of 2019 following a significant increase in production and expects to be able to maintain existing production levels within operating cash flows. Management expects to be able to fully meet all current obligations when due with funding provided by a combination of funds flow from operations and available capacity under the senior credit facility.

The Company maintains a senior revolving credit facility which is referred to as the senior loan in the consolidated statement of financial position. The capacity of this facility was US$177.5 million as at December 31, 2019. The maturity date is June 27, 2020, at which point, the facility can be extended at the option of the lenders, or if not extended, the facility would be converted to a non-revolving facility with a term maturing on June 27, 2021. The amount of the facility is subject to a borrowing base test performed on a periodic basis and at least twice annually by the lenders, based primarily on producing oil and natural gas reserves and using commodity prices estimated by the lender as well as other factors. A decrease in the borrowing base determined by the senior lenders in the future could result in a reduction to the credit facility, which may require a repayment to the lenders. In the normal course, the Company's next borrowing base redetermination is due to be completed by May 31, 2020.

The credit facility is subject to certain non-financial covenants and the Company is in compliance with all of the covenants under the senior loan as at December 31, 2019.

As at March 26, 2020, outstanding borrowings under the senior loan were US$165.8 million. The company held cash of US$14.8 million for net borrowings of US$151.0 million. Oil prices have declined significantly in March 2020. The Company's planned capital expenditures have been focused on participation in well completions planned by operators of certain of our non-operated properties. Recently, the operators of some of these properties have suspended further activities and we do not anticipate these capital projects will be re-instated until oil prices recover materially. As a result, we expect our capital expenditures for 2020 will be approximately $26.0 million.

The current challenging economic climate may lead to further adverse changes in cash flows, working capital levels and/or debt balances, which may also have a direct impact on the Company's operating results and financial position. These and other factors may adversely affect the Company's liquidity and the Company's ability to generate income and cash flows in the future. At December 31, 2019, the Company remains in compliance with all terms of our Senior Loan and based on current available information, management expects to comply with all terms during the subsequent 12-month period. However, in light of the current volatility in commodity prices and uncertainty regarding the timing for recovery in such prices, pipeline and transportation capacity constraints, and the effect of the Coronavirus (COVID-19), the preparation of financial forecasts is challenging.

Letter of Credit

The Company has an outstanding letter of credit 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.

Contractual Obligations

The Company is, or will be, obligated to pay various costs associated with operations incurred in the normal course of business. These costs include royalties paid to governments or mineral rights owners, surface lease rentals and decommissioning obligations. These costs are highly dependent on the future operating environment and are subject to changes in commodity prices, ownership, production volumes and government policies.

The following table reflects the contractual maturities of the Company's debt obligations and anticipated timing of the settlement of its other financial liabilities as at December 31, 2019, including estimated interest payments:

(in thousands)	Contractual Cash Flow	2020	2021	2022 & Beyond
Accounts payable and accrued liabilities	$ 108,773	$ 108,773	$ -	$ -
Lease liability	453	453		
Senior loan [1]	201,206	8,411	192,795	-
Preferred share obligation [2]	115,521	8,768	8,768	97,985
Total	$ 425,953	$ 126,405	$ 201,563	$ 97,985

(1) Includes future interest expense at the rate of 4.5% being the rate applicable at December 31, 2019 to the the current maturity date of June 27, 2021.

(2) The amount differs from that presented on the consolidated statement of financial position due, in part, to the unamortized portion of issuance costs (which are offset against the preferred share obligation on the consolidated statement of financial position), the preferred share equity component (which is presented separately under Shareholders' Equity) and finance cost at the coupon rate of 9% per annum. The table reflects the full dividend payment obligation to the maturity date of January 25, 2023. These preferred shares may be converted to common shares at the option of the investor.

Related Party Transactions

Related party transactions are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

In August 2018, the Company's Executive Chairman and the Investor in the Company's preferred shares each purchased 2.7 million common shares pursuant to a private equity offering at a price of $1.85 per share for $5.0 million.

Risk Management – Financial Derivatives

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

As at December 31, 2019, the Company had the following oil price derivatives outstanding:

Remaining Term	Type	Volume	Price	Reference	Market Value Gain (Loss)
					(in thousands)
Jan 1 - June 30, 2020	Three-way Collar	1,000 bbl/d	$45 / $50 / $65	Nymex Calendar Month Average	$ (124)
Jan 1 - June 30, 2020	Three-way Collar	1,000 bbl/d	$45 / $50 / $66	Nymex Calendar Month Average	(75)
Jan 1 - June 30, 2020	Three-way Collar	1,000 bbl/d	$46 / $51 / $66	Nymex Calendar Month Average	(62)
					$ (261)

Summary of Quarterly and Annual Results

	Three month period ended,							
(in thousands, except per share amounts)	12/31/2019	9/30/2019	6/30/2019	3/31/2019	12/31/2018	9/30/2018	6/30/2018	3/31/2018
Petroleum and natural gas revenues, net of royalties	$ 48,883	$ 42,249	$ 24,419	$ 17,230	$ 20,899	$ 31,980	$ 29,246	$ 15,574
Adjusted EBITDA	$ 35,566	$ 29,996	$ 16,344	$ 9,581	$ 11,684	$ 22,018	$ 20,325	$ 10,910
Cash flow provided by (used in) operating activities	$ 27,677	$ 32,275	$ (1,626)	$ 20,210	$ 19,810	$ 20,112	$ 21,734	$ 7,856
Net income (loss)	$ 9,608	$ 4,982	$ 1,733	$ (996)	$ 7,982	$ 10,449	$ 6,274	$ 2,351
Net income (loss) per share:								
Basic	$ 0.05	$ 0.03	$ 0.01	$ -	$ 0.04	$ 0.06	$ 0.04	$ 0.01
Diluted	$ 0.05	$ 0.03	$ 0.01	$ -	$ 0.04	$ 0.06	$ 0.04	$ 0.01

	Years ended December 31,		
(in thousands except per share amounts)	2019	2018	2017
Petroleum and natural gas, net of royalties	$ 132,781	$ 97,699	$ 34,170
Total assets	$ 598,828	$ 404,022	$ 213,249
Total non-current liabilities	$ 288,140	$ 165,244	$ 83,004
Cash provided by operating activities	$ 78,536	$ 69,512	$ 19,270
Net income (loss)	$ 15,327	$ 27,056	$ (3,093)
Net income (loss) per share:			
Basic	$ 0.08	$ 0.16	$ (0.03)
Diluted	$ 0.08	$ 0.16	$ (0.03)

Revenues in the fourth quarter of 2019 increased 15.7% over the third quarter of 2019 due primarily to a 6.9% increase in production volumes. Adjusted EBITDA and net income also improved in the fourth quarter of 2019 mainly as a result of production increases. Cash flow provided by operating activities fell in the fourth quarter due to changes in non-cash working capital.

Revenue in the third quarter of 2019 increased substantially compared to the second quarter of 2019 due to a 93.4% increase in production, partially offset by lower realized commodity prices. The same factors led to significant increases in adjusted EBITDA, cash flow from operating activities and net income.

Revenue in the second quarter of 2019 increased compared to the first quarter due to an 19.6% increase in production volumes and higher realized oil prices. This increase in revenue also resulted in net income in the second quarter of 2019 compared to a net loss in the first quarter of 2019. Cash flow from operations decreased in the second quarter of 2019 compared to the first quarter as a result of an increase in accounts receivable. Revenue in the first quarter of 2019 declined compared to the fourth quarter of 2018 due to lower production volumes as well as lower benchmark commodity prices. Despite a reduction in revenues, cash flow from operations increased due to a large decrease in working capital. Net income moved to a small loss in the first quarter of 2019 following the reduction in revenues and a large deferred tax recovery in the fourth quarter of 2018.

Revenue in the fourth quarter of 2018 declined compared to the third quarter due to lower production volumes and both weaker benchmark commodity prices and wider Bakken oil differentials. Net income decreased over the period as a result of the aforementioned factors. Revenue, cash flow from operations and net income saw significant growth in the second and third quarters of 2018 compared to prior periods due to increased production volumes resulting from the Company's operated drilling program and acquisitions.

The first quarter of 2018 also saw significantly increased production volumes and improved oil pricing which resulted in net income, higher revenue and improved cash flow from operations.

The Company has made several acquisitions and participated in drilling programs which have generally increased production volumes since 2017.

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 reversal of previously recorded impairment, the estimation of decommissioning obligations, and the amounts reported for depletion and depreciation of property, plant and equipment.

Decommissioning Obligation

The Company estimates the decommissioning obligations for oil and natural 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-based 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 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.

Changes to Accounting Policies

IFRS 16 – *Leases*

The Company adopted IFRS 16, *Leases*, on January 1, 2019. IFRS 16 introduces a single lease accounting model for leases which requires a right-of-use asset and lease obligation to be recognized on the balance sheet for contracts that are, or contain, a lease. The Company used the modified retrospective adoption approach to adopt the new standard. The modified retrospective approach does not require restatement of prior period financial information as it applies the standard prospectively.

On initial adoption, the Company elected to recognize right-of-use assets based on the corresponding lease obligation. Right-of-use assets and lease obligations of $0.3 million were recorded as of January 1, 2019, with no impact on retained earnings. When measuring the present value of lease obligations, the Company discounted remaining lease payments using its incremental borrowing rate at January 1, 2019, which was a weighted-average rate of 6.5%. The recognition of the present value of the lease obligations, which were previously classified as operating leases, resulted in increases to assets, liabilities, depreciation and depletion expense and finance costs and decreases to operating costs and general and administrative expense.

The Company has elected to apply practical expedients to not recognize right-of-use assets and lease obligations for short term leases that have a lease term of 12 months or less, and leases of low-value assets.

Business Conditions and Risks

The Company is engaged in the acquisition, exploration, development and production of crude oil and natural gas. 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, 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 in which 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 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 for 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 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 on a different schedule than the Company anticipated, including expenditures to drill more wells or build more facilities on a project 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

Any of these events could significantly and adversely affect anticipated exploration and development activities carried out 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 regularly used to reduce risk and increase the probability of success.

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, 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 crude oil, natural 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 into 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. The Company may also, from time to time, enter into 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 and utilizes these derivatives and contracts when warranted. Although the Company's intent in entering into 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 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, natural gas liquids ("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 crude 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 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 oil and natural 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 of 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 oil and natural 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.

Like most companies of our size, PetroShale has a limited number of accounting and finance personnel, and therefore it is difficult to create strong segregation of duties which is normally a feature of a company's internal control structure. Management mitigates this risk through performance of analytical review procedures on operating and financial results.

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 high 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. Without such insurance, and if the Company becomes subject to environmental liabilities, 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 oil by pipeline rather than by truck, and connecting natural gas to pipeline connections to reduce GHG emissions from its operations

Off Balance Sheet Arrangements

PetroShale 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 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.

Additional Information

Additional information can be obtained by contacting the Company at PetroShale Inc., Suite 3230, 421-7th Avenue SW, Calgary, Alberta T2P 4K9 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 "Company"), which comprise:

– the consolidated statements of financial position as at December 31, 2019 and December 31, 2018

– the consolidated statements of operations and comprehensive income 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 Company as at December 31, 2019 and December 31, 2018, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards ("IFRS").

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 Company 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 Commissions.

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, 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 Company'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 Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company'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 Company'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 Company'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 Company 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 26, 2020

PetroShale
Calgary • Denver

Consolidated Statements of Financial Position

(thousands of Canadian dollars)	Note	As at December 31, 2019	2018
Assets			
Cash and cash equivalents		$ 607	$ 491
Accounts receivable	5	54,020	26,677
Prepaid expenses and deposits		86	213
Total current assets		54,713	27,381
Restricted cash	18	306	273
Deferred income tax asset	17	-	3,305
Right-of-use assets	6	445	-
Property, plant and equipment, net	7,8	543,364	373,063
Total non-current assets		544,115	376,641
Total assets		**$ 598,828**	**$ 404,022**
Liabilities			
Accounts payable and accrued liabilities	9	$ 108,773	$ 44,049
Derivative liability	12	261	-
Lease liability	6	453	-
Total current liabilities		109,487	44,049
Senior loan	11	188,589	71,398
Preferred share obligation	13	87,380	88,912
Decommissioning obligation	10	6,313	4,934
Deferred income tax liability	17	5,858	-
Total non-current liabilities		288,140	165,244
Total liabilities		397,627	209,293
Shareholders' equity			
Common shares	14	200,630	200,651
Preferred share equity component	13	7,510	7,510
Contributed surplus	14	6,191	5,444
Deficit		(12,686)	(28,013)
Accumulated other comprehensive (loss) income		(444)	9,137
Total shareholders' equity		201,201	194,729
Commitments	18		
Subsequent events	25		
Total liabilities and shareholders' equity		**$ 598,828**	**$ 404,022**

See accompanying notes to the consolidated financial statements

Approved by the Board of Directors

(Signed) "Brett Herman"
Director

(Signed) "M. Bruce Chernoff"
Executive Chairman

PetroShale
Calgary • Denver

Consolidated Statements of Operations and Comprehensive Income

(thousands of Canadian dollars, except per share amounts)	Note	Years Ended December 31, 2019	2018
Revenues			
Petroleum and natural gas	15	$ 165,258	$ 121,797
Less: royalties		(32,477)	(24,098)
Petroleum and natural gas, net of royalties		132,781	97,699
Realized loss on financial derivatives	12	-	(6,375)
Unrealized (loss) gain on financial derivatives	12	(266)	3,356
Total revenue		132,515	94,680
Expenses			
Production and operating		29,465	18,758
Transportation	15	7,340	2,769
General and administrative		4,489	4,860
Depreciation and depletion	6,8	46,986	31,036
Finance	22	18,370	13,838
Share-based compensation	14	1,375	2,020
Total expenses		108,025	73,281
Income before income taxes		24,490	21,399
Deferred income tax expense (recovery)	17	9,163	(5,657)
Net income		15,327	27,056
Currency translation adjustment		(9,581)	12,029
Comprehensive income		$ 5,746	$ 39,085
Net income per share:			
Basic	16	$ 0.08	$ 0.16
Diluted	16	$ 0.08	$ 0.16

See accompanying notes to the consolidated financial statements

PetroShale
Calgary • Denver

Consolidated Statements of Changes in Shareholders' Equity

(thousands of Canadian dollars, except share amounts)	Voting Common Shares Shares	Voting Common Shares Amount	Warrants	Preferred Share Equity Component	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income (Loss)	Shareholders' Equity
December 31, 2017	157,137,767	$ 142,379	$ 684	$ -	$ 3,547	$ (55,069)	$ (2,892)	$ 88,649
Issuance of common shares by prospectus, net of issuance costs	24,865,300	42,451	-	-	-	-	-	42,451
Issuance of common shares by private placement, net of issuance costs	6,756,905	12,460	-	-	-	-	-	12,460
Issuance of preferred shares - equity component, net of tax	-	-	-	7,510	-	-	-	7,510
Exercise of warrants to purchase common shares for cash	2,000,000	2,184	(684)	-	-	-	-	1,500
Exercise of options to purchase common shares for cash	998,264	1,177	-	-	(478)	-	-	699
Share-based compensation, gross	-	-	-	-	2,375	-	-	2,375
Net income	-	-	-	-	-	27,056	-	27,056
Other comprehensive income	-	-	-	-	-	-	12,029	12,029
December 31, 2018	191,758,236	200,651	-	7,510	5,444	(28,013)	9,137	194,729
Purchase of common shares for cancellation	(1,074,615)	(596)	-	-	-	-	-	(596)
Settlement of share bonus awards	502,007	574	-	-	(1,031)	-	-	(457)
Share-based compensation, gross	-	-	-	-	1,779	-	-	1,779
Net income	-	-	-	-	-	15,327	-	15,327
Other comprehensive loss	-	-	-	-	-	-	(9,581)	(9,581)
December 31, 2019	**191,185,628**	**$ 200,630**	**$ -**	**$ 7,510**	**$ 6,191**	**$ (12,686)**	**$ (444)**	**$ 201,201**

See accompanying notes to the consolidated financial statements

PetroShale
Calgary • Denver

Consolidated Statements of Cash Flows

(thousands of Canadian dollars)	Note	Years ended December 31, 2019	2018
Operating Activities			
Net income		$ 15,327	$ 27,056
Operating items not affecting cash:			
Depreciation and depletion		46,986	31,036
Deferred income tax expense (recovery)		9,163	(5,657)
Unrealized loss (gain) on financial derivatives		266	(3,356)
Share-based compensation		1,375	2,020
Finance		18,370	13,838
Change in non-cash working capital	23	(12,951)	4,575
Cash provided by operating activities		78,536	69,512
Investing Activities			
Additions to property, plant and equipment		(229,696)	(100,633)
Acquisitions, net		(7,007)	(92,090)
Change in non-cash working capital	23	51,402	(19,982)
Cash used in investing activities		(185,301)	(212,705)
Financing Activities			
Proceeds from senior loan, net	11	123,286	16,492
Proceeds from convertible preferred share issuance, net	13	-	89,990
Proceeds from share issuances, net		-	54,911
Repayment of subordinated loan, net		-	(30,993)
Payment of interest and preferred dividends	23	(15,340)	(9,328)
Payment of lease liabilities		(245)	-
Purchase of common shares for cancellation	14	(383)	-
Settlement of share-based awards	14	(457)	(56)
Proceeds from exercise of warrants		-	1,500
Proceeds from exercise of options		-	699
Cash provided by financing activities		106,861	123,215
Change in cash and cash equivalents		96	(19,978)
Effect of foreign exchange rate changes		20	2,048
Cash and cash equivalents, beginning of year		491	18,421
Cash and cash equivalents, end of year		**$ 607**	**$ 491**

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 symbol "PSH".

The Company has corporate offices located at 421 - 7th Avenue SW, Suite 3230, Calgary, Alberta T2P 4K9 and at 303 E. 17th Avenue, Suite 940, Denver, CO 80203.

Note 2. Basis of Presentation

Basis of Measurement and Statement of Compliance

The consolidated financial statements have been prepared by management on a historical cost basis, with some exceptions as detailed in the summary of significant accounting policies below, in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"). These accounting policies have been applied consistently for all periods presented in these consolidated financial statements, except for the adoption of IFRS 16 – *Leases*, see Note 3.

These consolidated financial statements were approved by the Chair of the Audit Committee and the Executive Chairman on March 26, 2020 having been duly authorized to do so by the Board of Directors.

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.

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

<u>Identification of cash generating units</u>

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.

<u>Impairment of property, plant and equipment</u>

Judgments are required to assess when impairment 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 oil and natural gas reserves, production rates, future oil and natural gas prices, future costs, discount rates, market value of undeveloped land and other relevant assumptions.

<u>Deferred income taxes</u>

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

<u>Reserve Estimates</u>

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 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 natural 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-based 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 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 ("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 natural 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. These groups of assets are called cash generating units ("CGU's").

Impairment testing of PP&E is performed as facts and circumstances suggest by comparing the carrying amount of each CGU to each CGU's recoverable amount. The recoverable amount of a CGU is the greater of (i) its 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 Payments

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-based 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, accounts receivable, accounts payable and loans and borrowings. 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.

- Other non-derivative financial instruments, such as loans and borrowings, accounts receivable and accounts payable, 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 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 include 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

<u>IFRS 3 Business Combinations</u>

In October 2018, the IASB issued amendments to IFRS 3 *Business Combinations*, that seek to clarify whether a transaction results in an asset or a business acquisition. The amendments apply to businesses acquired in annual reporting periods beginning on or after January 1, 2020. Earlier application is permitted. The amendments include an election to use a concentration test. This is a simplified assessment that results in an asset acquisition if substantially all of the fair value of the gross assets is concentrated in a single identifiable asset or a group of similar identifiable assets. If the concentration test is not applied, or the test is failed, then the assessment focuses on the existence of a substantive process. The Company has not early adopted the amendment.

Changes to Accounting Policies

Adoption of IFRS 16 – *Leases*

In January 2016 the IASB issued IFRS 16-*Leases* which replaces IAS 17-*Leases* and IFRIC 4-*Determining Whether an Arrangement Contains a Lease*. The Company adopted the new standard on January 1, 2019 which provides a single recognition and measurement model for lessees to recognize assets and liabilities for contracts that are, or contain, a lease. A contract is, or contains, a lease if 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 ("ROU") and a lease liability at the lease commencement date. The ROU asset is initially measured at cost based on the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date. The assets are depreciated to the earlier of the end of the useful life of the ROU asset or the lease term using the straight-line method as this most closely reflects the expected pattern of consumption of the future economic benefits. PetroShale presents ROU as its own line item on the consolidated statement of financial position. In addition, the ROU is periodically reduced by impairment losses, if any, and adjusted for certain re-measurements of the lease liability.

The lease liability 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. Generally, the Company uses its incremental borrowing rate as the discount rate.

The lease liability is measured at amortized cost using the effective interest method. It is re-measured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is re-measured in this way, a corresponding adjustment is made to the carrying amount of the ROU asset, or is recorded in profit or loss if the carrying amount of the ROU asset has been reduced to zero. Lease payments are applied against the lease obligation, with a portion reflected as interest expense using the effective interest rate method. PetroShale presents the lease liability separately on the consolidated statement of financial position.

PetroShale used the modified retrospective approach in adopting the new standard, which does not require restatement of prior period financial information as it applies the standard prospectively. The effect of initially applying the standard was an $0.3 million increase to ROU assets, with a corresponding lease liability recorded. The ROU asset was measured at the amount equal to the lease liability on January 1, 2019 with no impact on deficit. The lease liability was measured at the present value of the remaining lease payments, discounted using PetroShale's incremental borrowing rate as at January 1, 2019. The weighted average incremental borrowing rate used to determine the lease obligation on adoption was approximately 6.5 percent based on the Company's total cost of debt and preferred share financing.

Reconciliation to Operating Lease Commitments

(in thousands)		
Operating agreements included in commitments at December 31, 2018	$	315
Discounting		(17)
Lease liability recognized due to the adoption of IFRS on January 1, 2019	**$**	**298**

The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, estimates, and assumptions that affect the reported amount of assets, liabilities, income, and expenses. Actual results could differ significantly from these estimates. Key areas where management has made judgments, estimates, and assumptions related to the application of IFRS 16 include the incremental borrowing rate. The incremental borrowing rate is based on judgments including economic environment, term, currency, and the underlying risk inherent to the asset. The carrying balance of the right-of-use asset, lease obligation, and the resulting interest and depletion and depreciation expense, may differ due to changes in the market conditions and lease term.

The Company has elected to apply practical expedients to not recognize right-of-use assets and lease obligations for short term leases that have a lease term of 12 months or less, and leases of low-value assets are not considered material at December 31, 2019.

Note 4. 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 oil and natural gas interests included in PP&E is estimated with reference to the discounted future cash flows expected to be derived from 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, accounts receivable, accounts payable and accrued liabilities

The fair value of cash and cash equivalents, 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, 2019 and 2018, 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 it 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.

Employee stock options

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 loan and preferred share obligation

The fair value of the senior loan 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. The preferred share obligation bears interest at a fixed rate that the Company would expect to pay for similar financing transactions and accordingly the fair value approximates the carrying value.

Employee share bonus awards

The fair value of share bonus 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.

Note 5. Accounts Receivable

	As at December 31,			
(in thousands)		**2019**		**2018**
Accounts receivable - oil and gas sales	$	32,559	$	9,269
Accounts receivable - joint interest billing and other		21,461		17,409
End of year	**$**	**54,020**	**$**	**26,677**

Note 6. Right of Use Assets and Lease Liabilities

The Company's right of use assets and lease liabilities relate to a lease for its Denver office space as well as a lease for a compressor. See Note 3 for more information on IFRS 16 and our accounting policy for leases and right-of-use assets.

Right of Use Assets

	As at December 31,			
(in thousands)		**2019**		**2018**
Beginning of year	$	298	$	-
Additions		415		-
Depreciation		(253)		-
Effect of foreign currency rate changes		(15)		
End of year	**$**	**445**	**$**	**-**

Lease Liabilities

	As at December 31,	
(in thousands)	**2019**	**2018**
Beginning of year	$ 298	$ -
Additions	415	-
Payments	(245)	-
Effect of foreign currency rate changes	(15)	
End of year	**$ 453**	**$ -**

Note 7. Acquisitions

Non-Producing Property Acquisitions

During the years ended December 31, 2019 and 2018, the Company purchased oil and gas leases in its focus areas in North Dakota. These acquisitions represent increased working interests in drilling units with associated proved undeveloped and probable reserves. The consideration for these leases for the years ended December 31, 2019 and 2018 was approximately US$5.4 million ($7.3 million) and US$1.4 million ($1.8 million), respectively. There were no assumptions of liabilities associated with these purchases.

Producing Property Acquisitions

In August 2018, the Company acquired certain leases with associated proved undeveloped and probable reserves and oil and natural gas producing properties. The Company has treated the transaction as a business combination and has accounted for it using the acquisition method to reflect the fair value of the assets acquired and liabilities assumed. The decommissioning obligation assumed was determined using the Company's estimated timing and costs to remediate, reclaim and abandon the related wells and production infrastructure, discounted at a market rate. Results of operations from the assets acquired were included in the consolidated financial statements from the closing date of the transaction. The total purchase price of US$52.0 million was settled with a draw on the Company's senior credit facility and net proceeds from the Equity Offerings (see Note 14).

The aggregate purchase price was allocated as follows:

(in thousands)	
Consideration (US$51,978)	**$ 67,936**
Developed and producing assets	69,313
Decommissioning obligation	(1,377)
Net Assets Acquired at Fair Value	**$ 67,936**

In March 2018, the Company acquired certain leases with associated proved undeveloped and probable reserves and oil and natural gas producing properties. The Company has treated the transaction as a business combination and has accounted for it using the acquisition method to reflect the fair value of the assets acquired and liabilities assumed. The decommissioning obligation assumed was determined using the Company's estimated timing and costs to remediate, reclaim and abandon the related wells and production infrastructure, discounted at a market rate. Results of operations from the assets acquired were included in the consolidated financial statements from the closing date of the transaction. The total purchase price of US$17.9 million was settled with a draw on the Company's senior loan.

The aggregate purchase price was allocated as follows:

(in thousands)		
Consideration (US$17,900)	**$**	**22,668**
Developed and producing assets		22,721
Decommissioning obligation		(53)
Net Assets Acquired at Fair Value	**$**	**22,668**

Note 8. Property, Plant and Equipment

(in thousands)		Developed and Producing		Other		Total
December 31, 2017	$	184,081	$	91	$	184,172
Acquisitions, net of dispositions		91,031		-		91,031
Additions		101,532		160		101,692
Capitalized stock-based compensation		411		-		411
Decommissioning obligation		2,072		-		2,072
Depreciation and depletion		(30,977)		(59)		(31,036)
Effect of foreign currency rate changes		24,702		19		24,721
December 31, 2018	$	372,852	$	211	$	373,063
Acquisitions, net of dispositions		7,007		-		7,007
Additions		229,512		184		229,696
Capitalized stock-based compensation		404		-		404
Decommissioning obligation		1,693		-		1,693
Depreciation and depletion		(46,509)		(224)		(46,733)
Effect of foreign currency rate changes		(21,737)	$	(29)		(21,766)
December 31, 2019	**$**	**543,222**	**$**	**142**	**$**	**543,364**

Depreciation, Depletion, and Future Development Costs

For the years ended December 31, 2019 and 2018, the Company recorded $46.5 million and $31.0 million, respectively, of depreciation and depletion expense on its developed and producing assets, which reflected an estimated US$332.9 million and US$404 million, respectively of future development costs associated with proved plus probable reserves.

Impairment Charges

As at December 31, 2019 and 2018 there were no facts or circumstances which suggested there is a trigger for impairment of the Company's Developed and Producing Assets. Therefore, an impairment test was not required.

Capitalized Overhead

During the year ended December 31, 2019 the Company capitalized $1.1 million of general and administrative costs and $0.4 million of share-based compensation, which are directly attributable to the acquisition and development activities of certain of its personnel in relation to the Company's operated properties ($1.1 million and $0.4 million, respectively, for the year ended December 31, 2018).

Note 9. Accounts Payable and Accrued Liabilities

	As at December 31,	
(in thousands)	**2019**	**2018**
Trade payables	**$ 56,425**	**$ 18,803**
Accrued liabilities	**35,677**	**18,619**
Revenue payable	**16,671**	**6,627**
End of year	**$ 108,773**	**$ 44,049**

Note 10. Decommissioning Obligation

	As at December 31,	
(in thousands)	**2019**	**2018**
Beginning of year	$ 4,934	$ 2,473
Obligations incurred	1,956	570
Obligations acquired	275	1,429
Change in estimated cash flows	(718)	76
Accretion	133	73
Effect of foreign currency rate changes	(267)	313
End of year	**$ 6,313**	**$ 4,934**

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 total undiscounted amount of estimated future cash flows required to settle the obligation as at December 31, 2019 is $13.7 million (December 31, 2018 – $9.7 million) which includes an annual inflation factor of 2.4% (December 31, 2018 – 2.4%) applied to the estimated future costs of decommissioning and assumes that the liabilities are settled over approximately the next 40 years in accordance with estimates prepared by independent engineers. The estimated future cash flows as at December 31, 2019 have been discounted at the risk-free interest rate of 2.6% (December 31, 2018 – 3.1%).

Note 11. Senior Loan

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 "Credit Facility"). As at December 31, 2019, the amount drawn under the Credit Facility was US$145.0 million. Advances under the 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 0.50% to 3.50% which is dependent on the Company's Senior Debt to EBITDA ratio. EBITDA, as defined in the 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 Credit Facility is available on a revolving basis until June 27, 2020, at which point, the Credit Facility can be extended at the option of the lenders, or if not extended, will convert to a term loan maturing on June 27, 2021. The Credit Facility is secured by a fixed and floating charge debenture on substantially all the Company's assets.

The Credit Facility borrowing base is subject to redetermination on a periodic basis and at least twice annually by the lenders, based primarily on producing oil and natural 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. A decrease in the borrowing base could result in the requirement to make a repayment to the lenders within 90 days of the borrowing base redetermination. In the normal course, the Company's next borrowing base redetermination is due to be completed by May 31, 2020.

The Company was in compliance with all terms of the Credit Facility at December 31, 2019. For the year ended December 31, 2019, the effective interest rate on the outstanding borrowings under the Credit Facility was 4.5% (4.6% in 2018).

Note 12. Financial Derivatives and Hedging Activities

The Company may use swaps, collars and options to reduce the effect of commodity price changes on a portion of its future oil, gas, and natural gas liquids production or to manage its exposure to interest and foreign exchange rate fluctuations. The objective of the Company's use of derivative financial instruments is to achieve more predictable cash flows. In an environment of volatile oil and natural gas prices, commodity price derivatives are used to manage the Company's exposure to commodity price risk. While the use of these derivative instruments limits the downside risk of adverse price movements, such use may also limit the Company's ability to benefit from favorable price movements. The Company may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of the Company's existing positions. The Company does not enter into derivative contracts for speculative purposes.

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 use of derivatives involves the risk that the counterparty to such instruments will be unable to meet the financial terms of such contracts. As at December 31, 2019 the Company had the following oil price derivative contracts outstanding:

Remaining Term	Type	Volume	Price	Reference	Market Value Gain (Loss)	
					(in thousands)	
Jan 1 - June 30, 2020	Three-way Collar	1,000 bbl/d	$45 / $50 / $65	Nymex Calendar Month Average	$	(124)
Jan 1 - June 30, 2020	Three-way Collar	1,000 bbl/d	$45 / $50 / $66	Nymex Calendar Month Average		(75)
Jan 1 - June 30, 2020	Three-way Collar	1,000 bbl/d	$46 / $51 / $66	Nymex Calendar Month Average		(62)
					$	(261)

The amount of unrealized loss recognized in the consolidated statement of operations related to the Company's derivative financial instruments was $0.3 million for the year ended December 31, 2019 ($3.4 million unrealized gain -year ended December 31, 2018).

Note 13. Preferred Shares

(in thousands, except share data)	Number of Shares	Liability Component	Equity Component
December 31, 2017	-	$ -	$ -
Issuance of preferred shares	75,000	79,949	10,041
Accretion	-	2,099	-
Effect of foreign currency rate changes	-	6,864	-
Deferred tax liability	-	-	(2,531)
December 31, 2018	75,000	88,912	7,510
Accretion	-	2,568	
Effect of foreign currency rate changes	-	(4,100)	
December 31, 2019	75,000	**$ 87,380**	**$ 7,510**

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 have a maturity date of January 25, 2023, which may be extended at the option of the Investor by one year. The preferred shares entitle the Investor to a cumulative annual dividend of 9.0% per annum, payable quarterly, except that no dividends shall be payable for the extension year, if any. The Company may elect to defer up to 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. Any deferred 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 converted to common shares at the option of the Investor. The preferred shares may be converted by 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. As part of the financing, the Investor also acquired voting preferred shares of the Company which entitle the Investor to the "as-exchanged" voting rights of the preferred shares. The Company may elect to redeem the preferred shares prior to the maturity date, by making a "make-whole" premium payment in addition to the maturity redemption amount otherwise determined. The make-whole premium is 5% of the redemption amount otherwise determined if redemption occurs prior to the third anniversary of the issuance date, 2.5% if made after the third anniversary date but before the fourth anniversary date and is nil if made after the fourth anniversary. The Company's ability to exercise this early redemption right is conditional on the Company's common shares having a certain minimum price and minimum amount of trading liquidity in the thirty days preceding the optional redemption date.

The preferred shares are a compound financial instrument for accounting purposes and the Company has separately accounted for the liability component and the equity residual component in accordance with its accounting policy described in Note 3.

Note 14. Share Capital

Common Shares

The Company's authorized share capital includes unlimited Class A preferred shares with rights and privileges to be determined by the Board of Directors prior to issuance, unlimited non-voting common shares, convertible into voting common shares on a 1 for 1 basis, and unlimited voting common shares. As at December 31, 2019, the Company had 191,185,628 voting common shares (191,758,236 at December 31, 2018), no non-voting common shares and 39,308,176 special voting preferred shares (39,308,176 at December 31, 2018) outstanding. The special voting preferred shares were issued in conjunction with the preferred shares issued by the Subsidiary Issuer in January 2018 (see Note 13). The special voting preferred shares issued to the Investor entitle 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 following table reflects the Company's outstanding common shares as at December 31, 2019:

(in thousands, except share data)	Shares		Share Capital
December 31, 2017	157,137,767	$	142,379
Issuance of common shares by prospectus, net of issuance costs	24,865,300		42,451
Issuance of common shares by private placement, net of issuance costs	6,756,905		12,460
Exercise of warrants to purchase common shares for cash	2,000,000		2,184
Exercise of options to purchase common shares for cash	998,264		1,177
December 31, 2018	191,758,236		200,651
Purchase of common shares for cancellation	(1,074,615)		(596)
Settlement of restricted share bonus awards	502,007		574
December 31, 2019	**191,185,628**	**$**	**200,630**

On August 14, 2018, the Company closed a $46.0 million subscription receipt prospectus financing through a syndicate of underwriters (the "Public Offering") at a price of $1.85 per share. The result of this transaction was the issuance of 24.9 million common shares for net proceeds of $42.5 million.

The Company also completed a separate private placement of subscription receipts, which closed at the same time and at the same price per share as the Public Offering, resulting in the issuance of 6.8 million common shares for net proceeds of $12.5 million (the "Private Offering", and together with the Public Offering, the "Equity Offerings"). The Company's Executive Chairman and the Investor in the Company's preferred shares each purchased 2.7 million common shares pursuant to the Private Offering at a price of $1.85 per share for $5.0 million.

In February 2019, the Company announced that the TSX Venture Exchange had accepted the Company's intention to commence a normal course issuer bid ("NCIB"). Through December 31, 2019, the Company had purchased and cancelled 690,000 shares at an average price of $0.56 per common share for a total repurchase cost of $0.4 million under its NCIB. In addition, the Company purchased 384,615 common shares from a departing employee during 2019. The NCIB was renewed subsequent to year end as discussed in Note 25.

Stock Options

The following table presents stock option transactions for the years ended December 31, 2019 and December 31, 2018:

(in thousands, except share data)	Number of Options		Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (Years)
December 31, 2017	1,548,264	$	0.70	2.13
Exercised	(998,264)		(0.70)	(1.28)
December 31, 2018	550,000		0.70	2.55
Exercised	-		-	-
December 31, 2019	**550,000**	**$**	**0.70**	**1.55**

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. Restricted share bonus awards vest over time. Performance share bonus awards vest based on achievement of certain performance hurdles and are subject to a multiplier between 0 and 2 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 giving consideration to 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 over the vesting period with a corresponding increase to contributed surplus.

(in thousands)	**Restricted Share Bonus Awards**	**Performance Share Bonus Awards**	**Total Awards**	**Estimated Fair Value Price**
December 31, 2017	2,625,000	-	2,625,000	$ 1.80
Granted	710,000	-	710,000	1.58
Settled	(41,667)	-	(41,667)	(1.80)
Forfeited and expired	(108,333)	-	(108,333)	(1.80)
December 31, 2018	3,185,000	-	3,185,000	1.75
Granted	1,731,300	1,090,200	2,821,500	0.75
Settled	(903,332)	-	(903,332)	(1.82)
Forfeited and expired	(1,600,000)	(500,000)	(2,100,000)	(0.80)
December 31, 2019	**2,412,968**	**590,200**	**3,003,168**	**$ 1.46**

Note 15. Revenue

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

	Years ended December 31,	
(in thousands)	**2019**	**2018**
Petroleum and natural gas	$ 165,258	$ 121,797

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. 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.

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.

Note 16. Net Income per Common Share

		Years ended December 31,		
(in thousands, except for share and per share data)		**2019**		**2018**
Net income	$	15,327	$	27,056
Weighted average common shares outstanding - basic		191,920,373		170,866,944
Weighted average common shares outstanding - diluted		194,395,182		174,391,337
Net income per share - basic	**$**	**0.08**	**$**	**0.16**
Net income per share - diluted	**$**	**0.08**	**$**	**0.16**

The Subsidiary Issuer has issued 75,000 preferred shares which are convertible, at the Investor's option, to 39,308,176 common shares of the Company at a fixed price of $2.40 per share, subject to certain conditions. See Note 13. The preferred shares are not currently considered dilutive.

Note 17. Income Taxes

Tax Expense

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

		Years ended December 31,		
(in thousands)		**2019**		**2018**
Current income tax expense (recovery)				
Canada	$	-	$	-
United States		-		-
Total current income tax expense (recovery)		-		-
Deferred income tax expense (recovery)				
Canada		-		-
United States		9,163		(5,657)
Total deferred income tax expense (recovery)		9,163		(5,657)
Total income tax expense (recovery)	$	9,163	$	(5,657)

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 26.50% as a result of the following:

						Years ended December 31,		
(in thousands, except income tax rate)		**Canada**		**United States**		**2019**		**2018**
Net income (loss) before income taxes	$	(2,065)	$	26,555	$	24,490	$	21,399
Income tax rate		26.50%		26.50%		26.50%		26.50%
Expected income tax		(547)		7,037		6,490		5,671
Foreign and statutory rate differences		-		(371)		(371)		(440)
Non-deductible expenses		368		2,410		2,778		2,755
Impact of rate change and other		304		87		391		(280)
Change in valuation allowance		(125)		-		(125)		(13,363)
	$	-	$	9,163	$	9,163	$	(5,657)

Deferred income tax asset (liability)

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

(in thousands)	January 1, 2019	Recognized in earnings	Recognized in Equity	December 31, 2019
Deferred income tax liabilities				
Property, plant and equipment	$ (16,786)	$ (9,158)	$ -	$ (25,944)
Preferred shares	(2,531)	-	-	(2,531)
Deferred income tax assets			-	
Net operating losses	20,777	(1,041)	-	19,736
Stock compensation	274	389	-	663
Accrued bonus	323	127	-	450
Decomissioning obligation	1,244	341	-	1,585
Other	4	179	-	183
	$ 3,305	$ (9,163)	$ -	$ (5,858)

(in thousands)	January 1, 2018	Recognized in earnings	Recognized in Equity	December 31, 2018
Deferred income tax liabilities				
Property, plant and equipment	$ (7,729)	$ (9,057)	$ -	$ (16,786)
Preferred shares	-	-	(2,531)	(2,531)
Deferred income tax assets				
Net operating losses	7,729	13,048	-	20,777
Stock compensation	-	274	-	274
Accrued bonus	-	323	-	323
Decomissioning obligation	-	1,244	-	1,244
Other	-	4	-	4
	$ -	$ 5,836	$ (2,531)	$ 3,305

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

	As at December 31,	
(in thousands)	**2019**	**2018**
Property, plant and equipment	$ 478	$ 473
Debt issuance costs	3,895	5,480
Non-capital losses - Canada (expires 2031 to 2039)	11,464	6,824
Capital losses	1,478	1,478
	$ 17,315	$ 14,255

Note 18. Commitments

The Company has an outstanding letter of credit in favor of an 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 in order to operate in North Dakota.

Note 19. Related Party Transactions

Share capital issuance

The Company's Executive Chairman and the Investor in the Company's preferred shares each purchased 2.7 million common shares pursuant to the Private Offering at a price of $1.85 per share for $5.0 million. See Note 14.

Compensation of key management personnel

Key management personnel include the Interim Chief Executive Officer (CEO) of the Company, the former Chief Executive Officer of the Company (who resigned in October 2019), the Chief Financial Officer (CFO) and the directors and other officers of the Company.

	Years ended December 31,			
(in thousands)		2019		2018
Salaries and other short-term benefits	$	2,649	$	2,132
Share-based compensation		1,295		2,137
Total compensation	**$**	**3,944**	**$**	**4,269**

Note 20. Risk Management

Overview

The Company's activities expose it to a variety of financial risks such as credit risk, liquidity risk and market risk that arise as a result of its exploration, development, production and financing activities.

This note presents information about the Company's exposure to each of the above risks, the Company's objectives, policies and processes for measuring and managing risk and the Company's management of capital. Further quantitative disclosures are included throughout these consolidated financial statements.

The Board of Directors oversees management's establishment and execution of the Company's risk management framework. Management has implemented and monitors compliance with risk management policies. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls and to monitor risks and market conditions.

Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations.

The carrying amount of the Company's cash and cash equivalents and accounts receivable and the positive fair value of financial derivatives represent the maximum credit exposure.

With respect to accounts receivable, the Company's exposure to credit risk is influenced mainly by the individual characteristics of each customer.

To the extent the Company's oil and natural gas operations are conducted on a non-operated basis, its accounts receivable mainly reflect joint operations receivables from the operators of those properties. In relation to the Company's operated properties, the Company is exposed to collection risks on the sale of its oil and gas production and collection of well costs incurred on behalf of its working interest partners. The Company attempts to mitigate the risk from joint operations receivables by working with large reputable industry participants. However, the receivables are from participants in the petroleum and natural gas sector and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. Further risk exists with joint venture partners as disagreements occasionally arise, increasing the risk of non-collection. Sales of oil and natural gas production from our operated properties are made to large industry purchasers.

The Company does not typically obtain collateral from joint venture partners and believes that operators of its non-operated properties, who are responsible for marketing the production from those properties, do not typically obtain collateral from petroleum and natural gas marketers they may utilize. However, the Company mitigates this risk by working with large reputable operators.

With respect to its operated assets, the Company does not anticipate any default on collection of accounts receivable as it transacts with credit-worthy customers. As such, a provision for doubtful accounts has not been recorded as at December 31, 2019 or December 31, 2018.

Essentially all of the Company's accounts receivable are from the production of petroleum and natural gas and joint venture receivables. As at December 31, 2019 there are receivables of $0.6 million that are greater than 90 days outstanding, however, all material amounts have been collected subsequent to year end.

Should the value of the Company's financial derivative instruments have a positive value, the Company is exposed to that amount should the counterparty to such instruments default.

Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting its financial obligations as they come due. At December 31, 2019, the Company had a net working capital deficit of $54.8 million which is $12.6 million greater than the undrawn capacity of the senior credit facility of $42.2 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 loan and preferred share obligation. The Company anticipates it will continue to have adequate liquidity to fund its financial liabilities as they come due. The Company forecasts its cash flows from operating activities as well as obligations related to capital spending and settlement of accounts payable in relation to available liquidity from its revolving credit facilities. The Company's accounts payable and accrued liabilities balance at December 31, 2019 is approximately $108.8 million (December 31, 2018 - $44.0 million). It is the Company's general practice to pay suppliers within 60 days. As at December 31, 2019, substantially all of the accounts payable balances were less than 90 days old.

The Company anticipates its senior loan facility will either be renewed for a further twelve months, following the senior lender's review expected to be completed by May 2020, or converted to a term facility maturing on June 27, 2021. A decrease in the borrowing base could result in the requirement to make a repayment to the lenders within 90 days of the borrowing base redetermination.

The Company's preferred shares may either be converted, at the option of the Investor, to common shares of the Company, or subject to redemption on January 25, 2023, which date may be extended at the option of the Investor by one year.

The Company has reflected a derivative liability of $0.3 million in the consolidated financial statements at December 31, 2019 (nil at December 31, 2018). Depending on market prices at the time, the Company may need to pay the counterparty to such contracts a monthly amount which reflects the positive difference between the market WTI price and the upper price band of the related collars. The Company will fund such liabilities from proceeds of its oil production which will be sold in the market at prices reflecting such higher WTI prices.

The following are the contractual maturities of the Company's debt and preferred share obligations and anticipated timing of settlements of its other financial liabilities as at December 31, 2019, including estimated interest and dividend payments:

(in thousands)		Contractual Cash Flow		2020		2021		2022 & Beyond
Accounts payable and accrued liabilities	$	108,773	$	108,773	$	-	$	-
Lease liability		453		453				
Senior loan [1]		201,206		8,411		192,795		-
Preferred share obligation [2]		115,521		8,768		8,768		97,985
Total	$	425,953	$	126,405	$	201,563	$	97,985

(1) Includes future interest expense at the rate of 4.5% being the rate applicable at December 31, 2019 to the the current maturity date of June 27, 2021.

(2) The amount differs from that presented on the consolidated statement of financial position due, in part, to the unamortized portion of issuance costs (which are offset against the preferred share obligation on the consolidated statement of financial position), the preferred share equity component (which is presented separately under Shareholders' Equity) and finance cost at the coupon rate of 9% per annum. The table reflects the full dividend payment obligation to the maturity date of January 25, 2023. These preferred shares may be converted to common shares at the option of the investor.

The current challenging economic climate may lead to adverse changes in cash flows, working capital levels and/or debt balances, which may also have a direct impact on the Company's operating results and financial position. These and other factors may adversely affect the Company's liquidity and the Company's ability to generate income and cash flows in the future. At December 31, 2019, the Company remains in compliance with all terms of our Senior Loan and based on current available information, management expects to comply with all terms during the subsequent 12-month period. However, in light of the current volatility in commodity prices and uncertainty regarding the timing for recovery in such prices, pipeline and transportation capacity constraints, and the effect of the Coronavirus (COVID-19), the preparation of financial forecasts is challenging.

As at March 26, 2020, outstanding borrowings under the senior loan were US$165.8 million. The company held cash of US$14.8 million for net borrowings of US$151.0 million.

Market risk

Market risk is the risk that changes in market prices relating to currency, commodity prices and interest rates will affect the Company's net earnings, future cash flows, the value of financial instruments, or the fair value of its assets and liabilities. The objective of market risk management is to manage and control market risk exposure within acceptable parameters.

Although the Company does not generally sell or transact in foreign currencies, its US subsidiary conducts its operations primarily in US dollars. Our US operations are directly exposed to fluctuations in the US dollar when translated to our Canadian dollar denominated consolidated financial statements. Our oil and gas revenues are positively impacted when the Canadian dollar weakens relative to the US dollar. However, our capital spending, transportation and operating costs, and interest expense on US dollar denominated debt are negatively impacted with a weak Canadian dollar. Furthermore, exchange rate fluctuations can affect the fair value and cash flow from derivative contracts. For the years ended December 31, 2019 and December 31, 2018, the Company did not enter into any foreign currency derivative contracts.

Commodity prices for crude oil, natural gas liquids and natural gas are also impacted by political events, meteorological conditions and changes in supply and demand. The Company may enter into commodity derivative contracts that provide downside price protection in order to provide some stability of cash flows for capital spending and planning purposes. The Company's risk management activities are conducted pursuant to its risk management policies approved by the Board of Directors.

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in interest rates. The Company's interest rate risk arises from its floating rate senior loan. For the years ended December 31, 2019 and 2018, the Company did not enter into any interest rate derivative contracts. The impact of a 1% increase in the interest rate associated with the senior loan would have increased interest expense and therefore decreased net income by approximately $1.0 million and $0.6 million for years ended December 31, 2019 and 2018, respectively.

21. 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 funds 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 funds 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 funds 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. The Company's share capital is not subject to external restrictions. 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 22. Finance Expense

The following represents our finance expense:

		Years ended December 31,		
(in thousands)		**2019**		**2018**
Senior loan interest	$	5,923	$	3,379
Preferred share dividends		8,959		8,179
Preferred share accretion		2,568		2,099
Decommissioning obligation accretion		133		73
Operating lease interest		20		-
Other finance costs		767		108
Total finance expense	**$**	**18,370**	**$**	**13,838**

Note 23. Supplemental Cash Flow Disclosures

	Years ended December 31,	
(in thousands)	2019	2018
Source / (use) of cash:		
Accounts receivable	$ (27,343)	$ (16,499)
Prepaid expenses and deposits	94	40
Accounts payable and accrued liabilities	64,725	5,602
	37,476	(10,857)
Related to operating activities	(12,951)	4,575
Related to investing activities	51,402	(19,982)
Accrued and unpaid dividends on preferred shares	328	2,231
Accrued purchase of common shares	213	
Difference due to foreign exchange	(1,516)	2,319
	$ 37,476	$ (10,857)
Interest and preferred dividends paid	$ 15,340	$ 9,328
Income taxes paid	nil	nil

Note 24. Segment Disclosures

	Years ended December 31,	
(in thousands)	2019	2018
Revenue, net of royalties		
United States	$ 132,716	$ 97,632
Canada	65	67
	$ 132,781	$ 97,699
Net income (loss)		
United States	$ 17,392	$ 29,752
Canada	(2,065)	(2,696)
	$ 15,327	$ 27,056

	As at December 31,	
(in thousands)	2019	2018
Property, plant and equipment		
United States	$ 542,821	$ 372,493
Canada	543	570
	$ 543,364	$ 373,063

Note 25. Subsequent Events

In February 2020, the Company renewed its normal course issuer bid ("NCIB") pursuant to which the Company may purchase for cancellation, from time to time, up to maximum of 11,785,163 common shares, which at the time of the renewal of the NCIB, represented 10% of our "public float" of common shares. The NCIB renewed on February 10, 2020 and will terminate on February 10, 2021 or such earlier time as the NCIB is completed or terminated. Subsequent to year end, the Company purchased an additional 3,828,000 common shares pursuant to the NCIB at cost of $1.9 million or $.48/share.

In March 2020, the Company executed fixed price financial derivative contracts for 2,500 bbls/d of crude oil for the period of April 1, 2020 through June 30, 2020, at a weighted average price of US$27.09/bbl, a 1,000 bbls/d of which can be extended at the option of the broker to July 1, 2020 through September 30, 2020 at US$28.76/bbl. Additionally, the Company sold a call option for 500 bbls/d at US$40.00/bbl for the period of July 1, 2020 through September 30, 2020, the proceeds of which were used to enhance the price received under the April 1, 2020 – June 30, 2020 fixed price swaps.

PetroShale's Board of Directors previously approved a 2020 capital budget of $70 million, which was designed to generate significant free cash flow. Approximately $18 million of the 2020 capital budget was accelerated into 2019 as the operators of certain of the Company's non-operated properties completed drilling and well completion activities earlier than anticipated. In addition, the Company's expected capital budget has been further reduced as certain current non-operated projects have been suspended by the operators. The Company now anticipates that 2020 capital expenditures will be approximately $26 million, representing a reduction of approximately 89% relative to 2019.