PetroShale
Calgary • Denver

Management's Discussion & Analysis

As at March 31, 2019
and for the three months ended March 31, 2019 and 2018

MANAGEMENT'S DISCUSSION & ANALYSIS

The following Management's Discussion and Analysis (the "MD&A") has been prepared by management and reviewed and approved by the Board of Directors of PetroShale Inc. ("PetroShale" or the "Company") on May 23, 2019. This MD&A reports on the consolidated financial position and the consolidated results of operations of PetroShale for the three month periods ended March 31, 2019 and 2018 and should be read in conjunction with PetroShale's consolidated interim financial statements as at and for the three months ended March 31, 2019 and the consolidated financial statements for the year ended December 31, 2018. The reader should be aware that historical results are not necessarily 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
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 and Currency

Production volumes and per Boe calculations are presented on a gross working interest basis, before royalty interests, unless otherwise stated. PetroShale's reporting and measurement currency is the Canadian dollar. Amounts in this MD&A are in Canadian dollars unless otherwise stated. The functional currency of PetroShale's US subsidiary is the US dollar, and the US subsidiary's results and balance sheet are translated to Canadian dollars, for purposes of consolidation in PetroShale's financial statements, in accordance with the Company's foreign currency translation accounting policy.

Non-IFRS Measurements and Changes in Accounting Policies

The 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 revenue, plus or minus any realized gain or loss on financial derivatives less royalties, production taxes, operating costs 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. Net debt represents total liabilities, excluding any decommissioning obligation, lease liabilities 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 adjusted EBITDA and cash flow from operating activities can be found later within this MD&A.

Please note the Company adopted IFRS 16 effective January 1, 2019 with no retrospective effect, which provides a single recognition and measurement model for lessees to recognize assets and liabilities for contracts that are, or contain, a lease. This new accounting policy is described in Note 2 to the consolidated interim financial statements and in New and Future Accounting Pronouncements later in this MD&A.

MANAGEMENT'S DISCUSSION & ANALYSIS

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 operating and transportation costs, 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 and cash flow for the year ended December 31, 2019 and the resulting fiscal year end net debt 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 and natural gas, 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, 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 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 a number of 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 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 proven 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 well(s); and PetroShale's ability, or those of the operators of its non-operated properties, to successfully market its petroleum and natural gas products. Readers are cautioned that the foregoing list of factors is not exhaustive.

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

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(all $ amounts are presented in Canadian dollars)	Three months ended March 31, 2019	Three months ended March 31, 2018
FINANCIAL *(in thousands, except per share and share data)*		
Petroleum and natural gas revenue	$ 21,326	$ 19,273
Cash flow from operating activities	$ 20,210	$ 7,856
Net income (loss)	$ (996)	$ 2,351
Per share - diluted	$ (0.00)	$ 0.01
Adjusted EBITDA [1]	$ 9,581	$ 10,910
Capital expenditures	$ 46,615	$ 53,692
Net debt[1]	$ 213,904	$ 126,818
Common shares outstanding		
Weighted average - basic	191,758,236	157,605,212
Weighted average - diluted	191,758,236	162,832,577
OPERATING		
Number of Days	90	90
Daily production[2]		
Crude oil (Bbls)	3,584	2,779
Natural gas (Mcf)	4,892	1,669
NGLs (Bbls)	636	258
Barrels of oil equivalent (Boe)	5,036	3,315
Average realized price		
Crude oil ($/Bbl)	$ 64.10	$ 74.02
Natural gas ($/Mcf)	$ 0.73	$ 1.76
NGLs ($/Bbl)	$ 5.69	$ 21.30
Netback per Boe ($) [1]		
Revenue	$ 47.06	$ 64.59
Royalties	$ (9.04)	$ (12.40)
Realized loss on derivatives	$ -	$ (3.67)
Operating costs	$ (8.71)	$ (4.15)
Production taxes	$ (3.55)	$ (5.01)
Transportation expense	$ (1.90)	$ (0.94)
Operating netback[1]	$ 23.86	$ 38.42
Operating netback prior to hedging[1]	$ 23.86	$ 42.09

(1) Non-IFRS measure - See pages 2-3 and the tables under "Non-IFRS Measures" at the end of this MD&A for a reconcilliation of adjusted EBITDA and net debt.

(2) Our oil and natural gas reserves have been categorized as Tight Oil and Shale Gas pursuant to National Instrument 51-101 and the required disclosure included in our Annual Information Form. We have used the terms "crude oil" and "natural gas" here and throughout this MD&A as we feel they are easily understood by users and consistent with disclosure of our peers.

MANAGEMENT'S DISCUSSION & ANALYSIS

DESCRIPTION OF BUSINESS

PetroShale Inc. (the "Company") is an oil company engaged in the acquisition, development and production of oil-weighted assets in the North Dakota Bakken/Three Forks.

FIRST QUARTER 2019 RECENT EVENTS

Oil and Gas Lease Development

The first quarter of 2019 was active as the Company invested $44.6 million for drilling, completions, pads, facilities and artificial lift in our South Berthold and Antelope areas that included drilling six (5.4 net) wells and fracing two (1.5) net wells. PetroShale also successfully acquired land and working interests within our core South Berthold area for approximately $2.0 million, further strengthening our existing portfolio of high-quality assets in the heart of the North Dakota Bakken / Three Forks play.

Oil Prices and Netbacks

Global oil prices decreased in the first quarter, with WTI averaging US$54.85 per barrel compared to US$62.91 in the corresponding period of 2018. Additionally, operating costs per Boe for the quarter increased due to workover activity. This resulted in a reduction in our operating netback to $23.86 per Boe during the first quarter compared to $42.09 per Boe ($38.42 per Boe with hedging) in the corresponding period of 2018. Oil prices decreased near the end of 2018 to below US$50 but have improved over the course of the first quarter of 2019 with March WTI averaging US$58.17 per barrel. The Bakken differential has also improved in the first quarter of 2019 compared to the fourth quarter of 2018 and we anticipate further improvements in our operating netback as a result of both stronger WTI oil prices and Bakken differentials.

OUTLOOK AND SIGNIFICANT EVENTS

2019 Outlook

The Company has been active in 2019 with a continuous one operated rig drilling program and plans to participate in various non-operated wells throughout the year. During the second quarter of 2019 we plan to finish drilling four gross (2.3 net) wells and commence drilling three gross (1.5 net) wells. We finished fracing three gross (2.9 net) wells in May 2019 and will commence fracing operations on two gross (2.0 net) wells. All of these wells are expected to be on-line and producing through facilities at various times over the next six months.

RESULTS OF OPERATIONS

Note: All $ amounts reflected throughout this management's discussion and analysis are in Canadian dollars, unless stated otherwise, consistent with the presentation of the Company's consolidated interim financial statements. All production volumes and per Boe amounts are on a working interest (gross of royalty) basis unless otherwise stated.

Production

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

	Three months ended March 31,	
	2019	2018
Crude oil (Bbls per day)	3,584	2,779
Natural gas (Mcf per day)	4,892	1,669
NGLs (Bbls per day)	636	258
Total (Boe per day)	5,036	3,315
Liquids % of Production	84%	92%

Production was 16% lower than the fourth quarter 2018 average of 6,014 Boe per day due to downtime on certain wells to install artificial lift and shut-ins due to offset fracing on adjacent wells. Production was 52% higher than the first quarter of 2018 as a result of new wells that were brought online during 2018. The decrease in production in the first quarter of 2019 over the fourth quarter of 2018 was a result of decreased production on the more productive wells that were brought on in the first quarter of 2018 in the Primus and Horse Camp fields.

Pricing

Average benchmark prices	Three months ended March 31, 2019	2018
Crude oil – WTI (US$ per Bbl)	$ 54.85	$ 62.91
Natural gas – HH (US$ per Mcf)	2.86	3.08
Exchange rate (US$ /CAD$)	1.33	1.27
Realized prices (CAD)		
Crude oil ($ per Bbl)	$ 64.10	$ 74.02
Natural gas ($ per Mcf)	0.73	1.76
NGLs ($ per Bbl)	5.69	21.30
Per Boe	$ 47.06	$ 64.59
Realized prices (USD)		
Crude oil ($ per Bbl)	$ 48.50	$ 58.72
Natural gas ($ per Mcf)	0.56	1.39
NGLs ($ per Bbl)	4.31	16.86
Per Boe	$ 35.38	$ 51.32

Realized oil prices for the three months ended March 31, 2019 decreased compared to the same period in 2018 due to weaker WTI prices and higher Bakken price differentials. Henry Hub natural gas prices were lower in the first quarter of 2019 compared to the comparable period in 2018. Realized natural gas prices remain discounted to Henry Hub benchmark prices reflecting the high demand for gas capture pipeline and processing capacity in the area. The Company does not expect this differential to improve until new plant and gathering capacity is introduced, which is not anticipated until the second half of 2019. NGL average prices declined in the first quarter of 2019 relative to the comparable period in 2018 reflecting a decrease in realized oil prices and the impact of transportation and marketing challenges associated with certain natural gas liquids in the US.

The Company realizes a differential on its oil production relative to WTI. In the first quarter of 2019, that differential was US$6.35 per Bbl on average, compared to US$4.19 per Bbl in the comparative period in 2018. In the fourth quarter of 2018, a number of factors resulted in a widening of the differential paid for Bakken oil production relative to WTI (US$9.61 per Bbl), including US refinery shutdowns impacting 1.1 million Bopd of demand and increased competition from western Canadian production. The Bakken differential narrowed significantly in the first quarter of 2019 with refineries re-commencing operations and anticipated delivery of new rail cars capable of carrying crude oil and a possible expansion of throughput capacity of the Dakota Access Pipeline.

Royalties

	Three months ended March 31,	
	2019	2018
Royalties (in thousands)	$ 4,096	$ 3,699
Royalties per Boe	$ 9.04	$ 12.40
Royalties as % of Revenue	19.2%	19.2%

Royalty expense as a percentage of revenues has remained consistent quarter-over-quarter. Royalty expense is higher on an absolute dollar basis for the quarter compared to the same period in 2018 due to higher overall production and revenues. The royalties per BOE amount is lower for the three months ended March 31, 2019 as a result of lower realized revenue per Boe in the quarter.

Operating Costs, Production Taxes and Transportation Expense

	Three months ended March 31,	
	2019	2018
Operating costs	$ 3,946	$ 1,239
Production taxes	1,607	1,496
Transportation expense	862	280
Total (in thousands)	$ 6,415	$ 3,015
Operating costs per Boe	$ 8.71	$ 4.15
Production taxes per Boe	3.55	5.01
Transportation expense per Boe	1.90	0.94
Total per Boe	$ 14.16	$ 10.10

Operating costs

Operating costs per Boe for the quarter ended March 31, 2019 were higher than the comparative period in 2018 due to workover activity on certain operated and non-operated wells and higher fixed operating costs as a result of reduced production volumes from shut-ins of certain wells. Workover costs accounted for $3.38 per Boe of operating costs for the three months ended March 31, 2019 compared to $0.76 in the comparative prior year period.

Production taxes

North Dakota charges a 5% oil severance tax and a 5% oil extraction tax on net royalty volumes. Production taxes per Boe for the three months ended March 31, 2019 reflect the impact of lower realized prices and are consistent period over period as a percentage of revenue, net of royalties. Management anticipates production taxes in the future to continue to reflect the oil composition of the Company's production.

Transportation expense

Transportation expense reflects costs associated with a certain portion of our oil production transported by pipeline. These costs are higher in the first quarter of 2019 reflecting a higher portion of our production being tied into pipelines. Previously, the majority of our operated oil production was sold at the wellhead and transportation expense was reflected in the net price received from the purchaser.

Operating Netback

($ per Boe)	Three months ended March 31, 2019	2018
Revenue	$ 47.06	$ 64.59
Royalties	(9.04)	(12.40)
Realized loss on derivatives	-	(3.67)
Operating costs	(8.71)	(4.15)
Production taxes	(3.55)	(5.01)
Transportation expense	(1.90)	(0.94)
Operating netback	$ 23.86	$ 38.42
Operating netback prior to hedging	$ 23.86	$ 42.09

Operating netback decreased for the three months ended March 31, 2019 compared to the corresponding prior period due to a decline in world oil prices, a higher oil price differential and higher operating costs per boe.

General and Administrative Expense

	Three months ended March 31, 2019	2018
Gross general and administrative expense	$ 1,723	$ 962
Capitalization of internal development costs	(416)	(369)
Third party recoveries	(73)	(39)
Net general and administrative expense (in thousands)	$ 1,234	$ 554

Gross general and administrative expense ("G&A") increased during the three months ended March 31, 2019 compared to the corresponding period of 2018 due to higher legal costs and the addition of senior personnel.

Depletion and Depreciation Expense

	Three months ended March 31, 2019	2018
Depletion and depreciation expense (in thousands)	$ 6,632	$ 4,421
Depletion and depreciation per Boe	$ 14.63	$ 14.82

Depletion and depreciation expense is calculated using proven and probable reserves. Depletion and depreciation expense increased during the three months ended March 31, 2019 compared to the prior comparable period, due to higher production volumes. The per boe expense is consistent year over year.

Finance Expense

Finance expense in the comparable 2018 period reflects interest on the Company's senior and subordinated credit facilities, including the amortization of certain loan origination and other fees. Finance expense for the three months ended March 31, 2019 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 debt levels in 2019 following the Company's significant drilling and acquisition programs during calendar 2018 and the first quarter of 2019.

Impairment

Management evaluates its developed and producing assets ("D&P") for impairment indicators that suggest the carrying value of a cash generating unit ("CGU") may not be recoverable. If such impairment indicators exist, any impairment is determined by comparing the carrying amount of the CGU to the greater of the CGU's value in use ("VIU") and 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 ended March 31, 2019, management determined that no impairment indicators existed. The continued improvement in WTI prices in 2019 and overall increases in the Company's reserve volumes as well as values as reflected in our December 31, 2018 reserve report, support management's determination.

Deferred Tax

The Company recorded a deferred income tax recovery of $164,000 for the three months ended March 31, 2019 (nil for the prior year comparative period).

Share-based Compensation

Share-based compensation expense reflects the value ascribed to equity-based compensation provided to employees, consultants and directors of the Company, utilizing a fair value methodology, and amortization of those amounts over the anticipated period in which such equity awards will vest. The expense for the three months ended March 31, 2019 of $470,000 is net of stock-based compensation costs of $149,000 capitalized to property, plant and equipment compared to $650,000 for the comparative prior year period. The decrease in expense year over year is due to the grant of 2,625,000 restricted bonus awards in November 2017 compared to the grant of 710,000 restricted bonus awards in 2018.

Foreign Currency Gain and Translation Adjustment

The Company's consolidated interim 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 currency translation adjustment in other comprehensive income. The Company experienced a currency translation loss of $4.1 million for the three months ended March 31, 2019 (2018 – gain of $2.8 million), due to the strengthening of the Canadian dollar relative to the US dollar from December 31, 2018 (US dollar / Canadian dollar 1.36) to March 31, 2019 (US dollar / Canadian dollar 1.33) and the fact that the Company's US dollar-denominated assets exceed its liabilities.

Share Capital

	Three months ended March 31,	
	2019	**2018**
Weighted average common shares outstanding:		
Basic	191,758,236	157,605,212
Diluted	191,758,236	162,832,577
Outstanding securities:		
Common shares, voting and non-voting	191,758,236	159,167,767
Preferred shares, convertible	75,000	75,000
Restricted bonus awards	3,185,000	2,625,000
Stock options	550,000	1,518,264

As at May 23, 2019, we had 192,254,575 common shares, 550,000 stock options and 2,310,000 restricted bonus awards outstanding. The increase in common shares and decrease in restricted bonus awards outstanding in 2019 primarily reflects restricted bonus awards that vested in April 2019 and were settled with common shares issued from treasury. The preferred shares are convertible into 39,308,176 common shares at the election of the holder. As of March 31, 2019, all of the Company's common shares are voting.

The following reflects the outstanding stock options as at March 31, 2019:

Stock Options

Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (Years)	Number of Outstanding Options	Number of Options Exercisable
$0.70	2.31	550,000	419,999

The restricted bonus awards expire before the third year from the date of grant and vest in equal annual tranches following the date of issuance.

Capital Expenditures

The following table represents capital expenditures for the period ended March 31, 2019:

(in thousands)	
Capital expenditures	
Drilling and completion	$ 44,609
Acquisitions	1,985
Other	21
Total capital expenditures	$ 46,615

During the three months ended March 31, 2019, the Company participated in 16 gross (5.1 net) wells, which were in various stages of completion.

The Company has no commitments to make additional capital expenditures following the end of the period, with the exception of approximately US$18 million related to operated and non-operated wells which were partially completed at the end of the quarter. We estimate future development costs of US$382 million related to our proven undeveloped and probable reserves as at March 31, 2019.

Liquidity and Capital Resources

Capital expenditures for acquisitions and drilling and completion activities for the three months ended March 31, 2019 were financed from draws on the Company's senior loan facility and operating cash flows and working capital.

The Company is dependent on cash on hand, operating cash flows and equity and 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 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. Accounts payable and accrued liabilities consist of amounts relating to capital spending, field operating activities and general and administrative expenses. 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 our senior credit facility.

The Company maintains a senior revolving credit facility which is referred to as the senior loan in the statement of financial position. The capacity of this facility is US$125.0 million as at March 31, 2019. The maturity date is June 30, 2019, 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 30, 2020. 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. The senior lenders are expected to complete their year-end review by the end of June 2019. As at May 23, 2019, the facility is drawn approximately US$83 million

($110 million). The undrawn capacity of the senior credit facility is approximately US$42 million which will facilitate the Company's execution of its drilling and completion program over the remainder of 2019.

The senior loan facility is subject to financial and certain non-financial covenants. The financial covenant is a requirement that the ratio of the senior loan amount to bank EBITDA, on a rolling four quarter basis, not exceed 3.0 to 1. Bank EBITDA is defined as net income plus interest expense (as defined above), any provision for income tax, and adjusted for non-cash items, cash payments to settle share-based compensation and EBITDA attributable to assets acquired or sold during the period. As at March 31, 2019, the senior loan to bank EBITDA ratio was 1.27 to 1. As a result, the Company is in compliance with the financial covenant as at that date and is also in compliance with all of the other covenants under the senior loan as at March 31, 2019.

The Company anticipates that it will be able to meet its financial covenants under the senior loan and meet its other financial obligations given the increase in production and operating cash flows.

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$125,000 as security in order to operate in North Dakota.

Summary of Quarterly Results

Three month period ended (in thousands, except per share amounts):	3/31/2019	12/31/2018	9/30/2018	6/30/2018	3/31/2018	12/31/2017	9/30/2017	6/30/2017
Oil and natural gas sales, net of royalties	$ 17,230	$ 20,899	$ 31,980	$ 29,246	$ 15,574	$ 8,171	$ 5,738	$ 8,357
Cash flow from operations(1)	20,210	19,810	20,112	21,734	7,856	2,333	3,627	9,350
Net income (loss)	(996)	7,982	10,449	6,274	2,351	(1,482)	(854)	(847)
Net income (loss) per share - basic and diluted	$ (0.00)	$ 0.04	$ 0.06	$ 0.04	$ 0.01	$ (0.01)	$ (0.01)	$ (0.01)

Factors that influenced quarterly variations

Quarter over quarter fluctuations are attributable to the items discussed below. 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. Revenues in the fourth quarter of 2017 increased compared to the third quarter due to higher production volumes from new wells and a stronger commodity price environment. Despite the increase in revenues in the fourth quarter of 2017, an unrealized loss on financial derivatives resulted in a larger net loss in this period than the third quarter of 2017. Stabilizing production on new wells and lower WTI prices resulted in decreased sales revenue in the three months ended September 30, 2017 and the three months ended June 30, 2017. Cash flow from operations in the third quarter of 2017 decreased relative to the second quarter of 2017 due to a large reduction in non-cash working capital in the second quarter of 2017.

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

Critical Accounting Estimates

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Estimates and underlying assumptions are reviewed on an ongoing basis. Actual results may differ from these estimates.

Reserves

The estimation of oil and natural gas reserves is critical to various accounting estimates. It requires various judgments based on available geophysical, geological, engineering and economic data. These estimates can change materially as information from ongoing exploratory, development and production activities become available. These estimates can also change as economic conditions impacting crude oil and natural gas prices, royalties and operating costs change. Reserve estimates can change net income (loss) through their impact on depletion expense, accretion expense from decommissioning obligations and the application of impairment tests. Revisions or changes in reserve estimates can have either a positive or a negative impact on net income (loss). The Company obtains an independent engineering report annually, with the latest report prepared as at December 31, 2018.

Decommissioning obligation

The calculation of the decommissioning obligation in the statement of financial position is based on estimated costs to abandon and reclaim the Company's net ownership in all wells and facilities, the estimated timing of the costs to be incurred and economic inflation and discount rates. These estimates can be impacted by technological advances, changes in laws and regulations or economic conditions and can impact the amount of the decommissioning obligation and net income (loss) through depletion and depreciation expense and accretion reflected as finance expense in the statement of operations.

Business combinations

In accounting for an acquisition, 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 the estimation of recoverable quantities of proven and probable reserves being acquired. The amounts allocated to PP&E and decommissioning obligations can have an impact on depletion and depreciation expense, future impairments (if any) and accretion expense.

Share-based compensation

The calculation of share-based compensation expense includes estimates of future interest rates, forfeiture rates, stock price volatility and the expected timing of exercise of stock options and share awards. These estimates can impact net income (loss) and contributed surplus.

Preferred Shares

The preferred shares are a compound financial instrument given they have both debt and equity features. This necessitated an estimation of the fair value of the debt component of the preferred shares, requiring judgement in determining equivalent terms of a debt instrument without an equity conversion feature. These estimates can impact net income (loss) and the amounts reflected as preferred share obligation and preferred share equity component on the statement of financial position.

Warrants

In accounting for warrants issued, management is required to make estimates of future interest rates and stock price volatility. These estimates can change the amount recorded to warrants in the statement of financial position as well as finance expense and net income (loss) in the statement of operations.

Deferred income taxes

The calculation of deferred income taxes includes estimates of timing of reversal of temporary differences, tax rates substantively enacted and likelihood of assets being realized. These estimates can impact net income (loss) and deferred tax assets and liabilities.

New and Future Accounting Pronouncements

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 has elected to recognize right-of-use assets based on the corresponding lease obligation. Right-of-use assets and lease obligations of $0.25 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, depletion and depreciation and finance costs and decreases to operating and general and administrative costs.

The right-of-use assets and lease obligations recognized primarily relate to the Company's office lease.

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 equity financing at a reasonable cost, or at all. Operational risks include the performance of the Company's properties, 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; and
- The operator may not have sufficient 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; and
- 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.

The Company is exposed to commodity price and market risk for our principal products of crude oil and natural gas. 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. 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.

As at March 31, 2019 the Company had no outstanding commodity price hedges.

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.

The oil and natural gas industry has various environmental risks subject to regulation by various governmental bodies. Environmental legislation includes, but is not limited to, operational controls, site restoration and abandonment requirements and restrictions on emissions of various substances related to the production of oil and natural gas. The North Dakota Industrial Commission ("NDIC") has adopted rules requiring operators to have a gas capture plan for new wells and placing production restrictions to reduce gas flaring. Compliance with this legislation may require additional costs and a failure to comply may result in fines and penalties, and/or a requirement to shut-in production. This may also result in delays to commencement of production from oil wells where associated gas production may not yet be tied in to gathering and processing facilities. Additionally, an increase in demand for gas gathering infrastructure and supply of natural gas could increase related processing costs and decrease realized prices, negatively impacting realizations from production.

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 off-shore markets.

PetroShale mitigates these 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; and
- 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 this 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 on operating and financial results.

Non-IFRS Measures

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

	Three months ended March 31,	
(in thousands)	**2019**	**2018**
Cash flow from operating activities	$ 20,210	$ 7,856
Change in non-cash working capital	(10,629)	3,054
Adjusted EBITDA	$ 9,581	$ 10,910

The reconciliation of net debt as defined herein is as follows:

(in thousands)	March 31, 2019	March 31, 2018
Total liabilities	$ 238,700	$ 154,823
Decommissioning obligation	(5,217)	(2,663)
Financial derivative liability	-	(4,157)
Current assets	(19,579)	(21,185)
Net debt	$ 213,904	$ 126,818

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.