2019 News Release

CHINOOK energy inc

chinookenergyinc.com TSX:CKE

CHINOOK ENERGY INC. ANNOUNCES FOURTH QUARTER AND 2019 RESULTS AND RESERVES

CALGARY, ALBERTA – March 2, 2020 – Chinook Energy Inc. ("our", "we", or "us") (TSX: CKE) is pleased to announce our three months and year ended December 31, 2019 ("Q419" and "2019", respectively) operating and financial results and the results of our year end reserve evaluation effective December 31, 2019 as prepared by our independent evaluator. Our operating and financial highlights for Q419 and 2019 are noted below and should be read in conjunction with our consolidated financial statements for the years ended December 31, 2019 and 2018 and our related management's discussion and analysis which are available on our website (www.chinookenergyinc.com) and filed on SEDAR (www.sedar.com).

Reserves included herein are stated on a gross basis (our working interest before deduction of royalties and without including any royalty interests) unless noted otherwise. This news release contains several cautionary statements that are specifically required by National Instrument 51-101 ("NI 51-101") under the heading "Reader Advisory" and throughout this news release. In addition to the information contained in this news release more detailed reserves information will be included in our Annual Information Form for the year ended December 31, 2019, which will be filed on SEDAR at www.sedar.com later this month.

Q419 and 2019 Operating Highlights

	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
OPERATIONS				
Production Volumes				
Natural gas liquids (boe/d)	**555**	405	**407**	565
Natural gas (mcf/d)	**16,469**	14,641	**12,950**	18,806
Crude oil (bbl/d)	**4**	12	**7**	19
Average daily production (boe/d) (1)	**3,304**	2,856	**2,572**	3,719
Sales Prices				
Average natural gas liquids price ($/boe)	**$ 39.75**	$ 43.56	**$ 42.26**	$ 59.87
Average natural gas price ($/mcf)	**$ 1.97**	$ 2.60	**$ 1.69**	$ 1.91
Average oil price ($/bbl)	**$ 62.11**	$ 54.13	**$ 61.48**	$ 69.15
Operating Netback (2)				
Average commodity pricing ($/boe)	**$ 16.55**	$ 19.72	**$ 15.33**	$ 19.11
Royalty expense ($/boe)	**$ (0.16)**	$ (0.14)	**$ (0.11)**	$ (0.08)
Realized gain (loss) on commodity price contracts ($/boe)	**$ 0.14**	$ (2.59)	**$ (0.64)**	$ (0.72)
Net production expense ($/boe) (2)	**$ (9.73)**	$ (14.01)	**$ (12.30)**	$ (11.63)
Operating netback ($/boe) (1) (2)	**$ 6.80**	$ 2.98	**$ 2.28**	$ 6.68
Wells Drilled				
Exploratory wells (net)	**-**	-	**-**	2.00

(1) Amounts may not be additive due to rounding.

(2) Adjusted funds flow, adjusted funds flow per share, net debt, operating netback and net production expense are non-GAAP measures. These terms do not have any standardized meanings as prescribed by IFRS and, therefore, may not be comparable with the calculations of similar measures presented by other companies. See headings entitled "Adjusted Funds Flow", "Net Debt", "Operational Netback" and "Net Production Expense" in the Reader Advisory below for further information on such terms.

Q419 and 2019 Financial Highlights

	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
FINANCIAL ($ thousands, except per share amounts)				
Petroleum & natural gas revenues, net of royalties	**$ 4,986**	$ 5,146	**$ 14,291**	$ 25,837
Cash (outflow) inflow from operating activities	**$ (48)**	$ (378)	**$ (3,634)**	$ 255
Adjusted funds flow (outflow)[(2)]	**$ 1,171**	$ (413)	**$ (2,034)**	$ 4,179
Per share - basic and diluted ($/share)	**$ 0.01**	$ -	**$ 0.01**	$ 0.02
Net loss	**$ (13,998)**	$ (21,141)	**$ (42,263)**	$ (27,654)
Per share - basic and diluted ($/share)	**$ (0.06)**	$ (0.09)	**$ (0.19)**	$ (0.12)
Capital expenditures	**$ -**	$ 213	**$ 29**	$ 2,890
Net debt [(2)]	**$ 6,138**	$ 1,994	**$ 6,138**	$ 1,994
Total assets	**$ 63,797**	$ 101,416	**$ 63,797**	$ 101,416
Common Shares (thousands)				
Weighted average during period				
Basic & diluted	**223,682**	223,605	**223,672**	223,594
Outstanding at year end	**223,682**	223,605	**223,682**	223,605

(1) Amounts may not be additive due to rounding.

(2) Adjusted funds flow, adjusted funds flow per share, net debt, operating netback and net production expense are non-GAAP measures. These terms do not have any standardized meanings as prescribed by IFRS and, therefore, may not be comparable with the calculations of similar measures presented by other companies. See headings entitled "Adjusted Funds Flow", "Net Debt", "Operational Netback" and "Net Production Expense" in the Reader Advisory below for further information on such terms.

Recent Developments

Arrangement Agreement

As previously announced on February 24, 2020, we entered into an arrangement agreement (the "Arrangement Agreement") pursuant to which Tourmaline Oil Corp. (the "Purchaser") has agreed to acquire all of the outstanding common shares ("Chinook Shares") of our company for cash consideration of $0.0675 per share (the "Transaction"). The Purchaser will assume our net debt upon closing of the Transaction. The Transaction is subject to various closing conditions, including receipt of Court approval and approval by our shareholders. An annual and special meeting of our shareholders has been called on April 20, 2020, to consider, among other things, the Transaction. The Transaction will require the approval of $66^{2}/_{3}$% of the votes cast by our shareholders at the Meeting. The Transaction is anticipated to close thereafter in late April upon satisfaction of all conditions precedent thereto.

The Transaction offers a liquidity event and cash consideration to our shareholders. Upon closing of the Transaction, the Chinook Shares will be de-listed from the Toronto Stock Exchange. We can provide no assurances that the Transaction will close.

Demand Credit Facility Renewal

Following the execution of the Arrangement Agreement, our lender renewed our demand credit facility agreement with an unchanged maximum availability of $10.0 million. During 2019, we drew $4.7 million of debt to finance our operating activities while there was an extended ongoing review of our demand credit facility. This extended review occurred during a very challenging environment as demonstrated by depressed natural gas pricing and continued weakness in general Canadian exploration and production industry and capital market conditions. We believe our lender provided us with the renewed demand credit facility because of our ongoing discussions with the Purchaser which resulted in the Arrangement Agreement.

Although in our facility renewal we received waivers of past and forecasted financial covenant breaches, we are forecasting that we will be in breach of the *net debt to cash flow* financial covenant per the terms of the renewed demand credit facility agreement as at June 30, 2020. In the event that the Transaction is not completed, when the next borrowing base redetermination commences as scheduled on (or before or later) May 31, 2020, because of the aforementioned market conditions and forecasted breach, no assurance can be provided that the borrowing base will be renewed at the same or a similar amount or on the same or similar terms, nor can any assurance be provided that our lender will not call our debt as a result of these market conditions and forecasted breach or for any other reason. In such event, these material uncertainties cast significant doubt with respect to our ability to continue as a going concern.

2019 Independent Reserves Evaluation

McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated all of our properties effective December 31, 2019 pursuant to a report dated February 25, 2020 (the "McDaniel Report"). The independent reserve evaluation was prepared in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and NI 51-101. The reserve evaluation was based on the average forecast pricing and foreign exchange rates at December 31, 2019 of three evaluators, McDaniel, GLJ Petroleum Consultants Ltd. and Sproule Associates Limited, herein referred to as "the Consultants Average Price Forecast". The Reserves, Safety and Environmental Committee of our Board and our Board of Directors have reviewed and approved the McDaniel Report.

Reserves Breakdown (gross)[1] (utilizing the Consultants Average Price Forecast at December 31, 2019)

(mboe)	**2019**	2018
Proved Producing		
Total proved producing	**6,170**	6,814
Proved		
Total proved	**17,407**	18,393
Proved Plus Probable		
Total proved plus probable	**33,790**	35,626

(1) Gross reserves are our working interest reserves before royalty deductions and do not include royalty interest volumes.

Gross and Net Reserves as at December 31, 2019

The following table summarizes our gross and net reserve volumes utilizing the Consultants Average Price Forecast, and cost estimates, at December 31, 2019.

	Light and medium oil		Heavy oil		Conventional Natural Gas		Natural gas liquids		Oil equivalent (6:1)	
Reserves category	Gross [1] *(mbbl)*	Net [2] *(mbbl)*	Gross [1] *(mbbl)*	Net [2] *(mbbl)*	Gross [1] *(mmcf)*	Net [2] *(mmcf)*	Gross [1] *(mbbl)*	Net [2] *(mbbl)*	Gross [1] *(mboe)*	Net [2] *(mboe)*
Total company										
Proved										
Developed producing	10	10	-	-	31,272	28,066	948	803	6,170	5,491
Developed non-producing	6	6	-	-	40	38	-	-	14	12
Undeveloped	-	-	-	-	56,318	49,129	1,837	1,599	11,223	9,787
Total proved	17	16	-	-	87,631	77,233	2,785	2,402	17,407	15,290
Probable	6	5	-	-	82,669	68,404	2,599	2,163	16,383	13,569
Total proved plus probable	23	21	-	-	170,300	145,637	5,383	4,565	33,790	28,859

(1) Gross reserves are the Company's working interest reserves before royalty deductions and do not include royalty interest volumes.
(2) Net reserves are after royalty deductions and include royalty interest volumes.

Gross Reserve Reconciliation for 2019

(gross reserves before deduction of royalties payable)

	6:1 Oil Equivalent *(mboe)*		
	Total proved	Probable additional	Total proved plus probable
December 31, 2018 – opening balance	18,393	17,233	35,626
Additions and extensions	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Technical revisions	631	(383)	248
Economic factors	(678)	(468)	(1,146)
Production	(939)	-	(939)
December 31, 2019 – closing balance	17,407	16,383	33,790

Our Total proved and Total proved plus probable reserves decreased by 986 mboe and 1,836 mboe, respectively. The decreases were predominantly the result economic factors given the approximate 20% decrease to BC Plantgate gas price forecast as well as production through the period, partially offset by positive technical revisions.

As we did not deploy any capital in the development of our assets, we did not add any developed or undeveloped locations during 2019. At December 31, 2019, in addition to the 13 (11.3 net) proved developed producing wells, McDaniel recognized a total of 37 undeveloped locations, 21 (18.1 net) proved and 16 (13.1 net) probable undeveloped locations. These locations remain unchanged from the report ending December 31, 2018. As at the date of the McDaniel Report, approximately 19% of our greater Birley/Umbach Montney acreage was booked.

Given the lack of development capital spent and no undeveloped locations booked, we have not included Finding and Developing Cost analysis or related Recycle Ratios in this news release.

Reserve Life Index ("RLI")

As at December 31, 2019, our proved plus probable RLI was 31.0 years based upon the McDaniel Report and the forecast 2020 production volumes from the report, while our proved RLI was 16.2 years. The following table summarizes the RLI:

Proved	
Reserves (mboe)	17,407
2020 Forecast production - Proved (mboe) [1]	1,072
Reserve life index (years)	16.2

Proved Plus Probable	
Reserves (mboe)	33,790
2020 Forecast production – Proved Plus Probable (mboe) [1]	1,090
Reserve Life Index (years)	31.0

(1) As evaluated by McDaniel, an independent reserve evaluator, as at December 31, 2019.

Net Present Value ("NPV") Summary (before and after tax) as at December 31, 2019

(utilizing the Consultants Average Price Forecast at December 31, 2019)

Benchmark commodity prices used are adjusted for the quality of the commodities produced and for transportation costs. The calculated NPVs include a deduction for estimated future well and facilities abandonment and reclamation but do not include a provision for interest, debt service charges, general and administrative expenses. It should not be assumed that the NPV estimates represent the fair market value of the reserves.

For the 2019 year-end reserves report, as recommended by the Canadian Oil and Gas Evaluation Handbook (“COGEH”), all of our abandonment, decommissioning and reclamation costs (“ADR”) for active and inactive wells have been included. This is a

significant change to the prior years' practices, when such ADR was not included in the reserves evaluation. Previously, exclusion of these costs was common across our industry.

Given the extent of our unrecognized tax pools, the results of before tax and after tax NPVs are the same and have been presented in a single table.

($ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved developed producing	1,633	17,161	20,431	20,679	20,004
Proved developed non-producing	150	135	122	111	102
Total proved developed	1,783	17,296	20,553	20,790	20,106
Proved undeveloped	55,197	35,686	22,345	13,105	6,590
Total proved	56,980	52,983	42,898	33,895	26,696
Probable additional	154,243	92,177	58,246	38,597	26,589
Total proved plus probable	211,224	145,159	101,144	72,492	53,285

Average of McDaniel & Associates Consultants Ltd., GLJ Petroleum Consultants Ltd. and Sproule Associates Limited Price Forecasts

(the Consultants Average Price Forecast) as at December 31, 2019[1]

	WTI Crude Oil *(US$/bbl)*	Edmonton Light Crude Oil *(Cdn$/bbl)*	Henry Hub Natural Gas *(US$/mmbtu)*	AECO Natural Gas *(Cdn$/mmbtu)*	British Columbia Average Plantgate Gas *(Cdn$/mmbtu)*	Edmonton Condensate and Natural Gasoline *(Cdn$/bbl)*	Ethane *(Cdn$/bbl)*	Propane *(Cdn$/bbl)*	Butane *(Cdn$/bbl)*	US/Cdn Exchange *(US$/Cdn$)*
2020	61.00	72.64	2.62	2.04	1.46	76.83	6.42	26.36	42.10	0.760
2021	63.75	76.06	2.87	2.32	1.79	79.82	7.41	29.80	47.03	0.770
2022	66.18	78.35	3.06	2.62	2.12	82.30	8.33	32.94	50.66	0.785
2023	67.91	80.71	3.17	2.71	2.26	84.72	8.65	34.00	52.21	0.785
2024	69.48	82.64	3.24	2.81	2.35	86.71	8.98	34.88	53.48	0.785
Average	65.66	78.08	2.99	2.50	2.00	82.08	7.96	31.60	49.10	0.777

(1) Prices escalate at two percent per year after 2024.

The foregoing pricing table was utilized by McDaniel in its evaluation of our reserves as at December 31, 2019. When compared to the December 31, 2018 price forecast, commodity pricing for the year 2020 has decreased for Edmonton Light Crude Oil, AECO Natural Gas and British Columbia Average Plantgate Gas by 4%, 12% and 20%, respectively. The longer term BC Plantgate gas price forecast decreased on average over the following 10 years by 18% as compared to the prior year forecast.

Future Development Costs ("FDC")

Changes in forecast FDC occur annually as a result of development activities, acquisition and disposition activities and capital cost estimates that reflect the independent evaluator's best estimate of what it will cost to bring the proved undeveloped and probable reserves on production using forecast prices and costs.

($ millions)	**2019**	2018
Total proved	**94.5**	94.9
Total proved plus probable	**160.5**	161.2

About Chinook Energy Inc.

We are a Calgary-based public oil and natural gas exploration and development company with a large contiguous Montney liquids-rich natural gas position at Birley/Umbach, British Columbia.

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Reader Advisory

Abbreviations

Oil and Natural Gas Liquids

bbl	barrels
bbl/d	barrels per day
NGLs	Natural gas liquids

Natural Gas

mcf	thousand cubic feet
mmcf	million cubic feet
mcf/d	thousand cubic feet per day
mmcf/d	million cubic feet per day
bcf/d	billion cubic feet per day
mmbtu	million British Thermal Units
mmbtu/d	million British Thermal Units per day
GJ	Gigajoules
GJ/d	gigajoules per day

Other

boe	barrel of oil equivalent on the basis of 6 mcf/1 boe for natural gas and 1 bbl/1 boe for crude oil and natural gas liquids (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
boe/d	barrel of oil equivalent per day
mboe	1,000 barrels of oil equivalent
mmboe	1,000,000 barrels of oil equivalent
Station 2	Market point for BC natural gas
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
Chicago City Gate	Market point for eastern US natural gas

Oil and Gas Advisory

Reserves are estimated remaining quantities of oil and natural gas and related substance anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical and engineering data; the use of established technology, and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates as follows:

Proved Reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable Reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

The reserves information contained in this news release have been prepared in accordance with NI 51-101. Complete NI 51-101 reserves disclosure will be included in our annual information form for the year ended December 31, 2019 which will be filed on

SEDAR in March 2020. Listed below are cautionary statements applicable to our reserves information that are specifically required by NI 51-101:

- Individual properties may not reflect the same confidence level as estimates of reserves for all properties due to the effects of aggregation.
- This news release contains estimates of the net present value of our future net revenue from our reserves. Such amounts do not represent the fair market value of our reserves.

Forward-Looking Statements

In the interest of providing our shareholders and readers with information regarding our company, including management's assessment of our future plans and operations, certain statements contained in this news release constitute forward-looking statements or information (collectively "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "could", "plan", "intend", "should", "believe", "outlook", "potential", "target" and similar words suggesting future events or future performance. In particular, this news release contains, without limitation, forward-looking statements pertaining to: the Transaction and the anticipated timing of closing; timing of the annual and special meeting of shareholders, and the benefits of the Transaction for our shareholders; the anticipated filing date on SEDAR for our Annual Information Form for the year ended December 31, 2019, the volumes and estimated value of our oil and natural gas reserves, the life of our reserves, the amount of future development costs associated with producing proved undeveloped and probable reserves, the volume and product mix of our oil and natural gas production, and future oil and natural gas prices and future results from operations.

With respect to the forward-looking statements contained in this news release, we have made assumptions regarding, among other things: the time required to prepare meeting materials for mailing to our shareholders, the timing of receipt of the necessary court and shareholder approvals and the satisfaction of and time necessary to satisfy the conditions to the closing of the Transaction and that the Transaction will be completed on the terms contemplated by the Arrangement Agreement, that we will continue to conduct our operations in a manner consistent with that expressed herein, future oil and natural gas prices, anticipated oil and natural gas production levels, future currency, exchange and interest rates, our ability to obtain equipment in a timely manner to carry out exploration and development activities, the ability of the operator of the projects in which we have an interest in to operate in the field in a safe, efficient and effective manner, the impact of increasing competition, field production rates and decline rates, and the continued availability of adequate debt and cash flow to fund our company. Although we believe that the expectations reflected in the forward-looking statements contained in this news release, and the assumptions on which such forward-looking statements are made, are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned not to place undue reliance on forward-looking statements included in this news release, as there can be no assurance that the plans, intentions or expectations upon which the forward-looking statements are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties that contribute to the possibility that predictions, forecasts, projections and other forward-looking statements will not occur, which may cause our actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, without limitation, the anticipated dates in this news release may change for a number of reasons, including unforeseen delays in preparing shareholder meeting materials, inability to secure necessary court or shareholder approvals in the time assumed or the need for additional time to satisfy the conditions to the completion of the Transaction, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices and currency fluctuations, environmental risks, competition from other producers, inability to retain drilling rigs and other services, unanticipated increases in or unforeseen capital expenditure costs, including drilling, completion and facilities costs, unexpected decline rates in wells, delays in projects and/or operations resulting from surface conditions, wells not performing as expected, delays resulting from or inability to obtain the required regulatory approvals and inability to access sufficient capital from internal and external sources. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the forgoing list of factors is not exhaustive. Additional information on these and other factors that could affect our operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) and at our website (www.chinookenergyinc.com). Furthermore, the forward-looking statements contained in this news release are made as at the date of this news release and we do not undertake any obligation to update publicly or to revise

any of the forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Operating Netback

The reader is cautioned that this news release contains the term operating netback, which is not a recognized measure under IFRS and is calculated as a period's sales of petroleum and natural gas, net of realized gains or losses on commodity price contracts, royalties and net production expenses, divided by the period's sales volumes. We use this non-GAAP measure to assist us in understanding our production profitability relative to current and fixed commodity prices and it provides an analytical tool to benchmark changes in field operational performance against prior periods. Readers are cautioned, however, that this measure should not be construed as an alternative to other terms such as net income determined in accordance with IFRS as a measure of performance. Our method of calculating this measure may differ from other companies, and accordingly, it may not be comparable to measures used by other companies.

Net Production Expense

The reader is cautioned that this news release contains the term net production expense, which is not a recognized measure under IFRS and is calculated as production and operating expense less processing and gathering income. We use net production expense to determine the current periods' cash cost of operating expenses and net production and operating expense per boe is used to measure operating efficiency on a comparative basis. This measure approximates our operating costs relative to only our volumes by excluding the approximated operating costs resulting from third party processing and gathering services. Our method of calculating this measure may differ from other companies, and accordingly, it may not be comparable to measures used by other companies.

Adjusted Funds Flow (Outflow)

The reader is cautioned that this news release contains the term adjusted funds flow (outflow), which is not a recognized measure under IFRS and is calculated from cash inflow (outflow) from operations adjusted for changes in non-cash working capital related to operations, exploration and evaluation expenses related to operations, provision expenditures related to operations and severance/transaction costs. We believe that adjusted funds flow (outflow) is a key measure to assess our ability to finance capital expenditures and when debt is drawn, debt repayments. Adjusted funds flow (outflow) is not intended to represent cash inflow (outflow) from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS and should not be construed as an alternative to, or more meaningful than, cash inflow (outflow) from operating activities as determined in accordance with IFRS as an indicator of our financial performance. Our method of calculating this measure may differ from other companies, and accordingly, it may not be comparable to measures used by other companies. Adjustments to cash inflow (outflow) from operations are for changes in non-cash operating working capital which are expected to reverse and for those costs that are not directly caused by lifting production volumes.

Net Debt

The reader is cautioned that this news release contains the term net debt, which is not a recognized measure under IFRS and is calculated as bank debt adjusted for current assets less current liabilities as they appear on the balance sheets, both of which exclude mark-to-market derivative contracts and assets and liabilities held for sale and current liabilities excludes any current portion of debt, deferred customer obligations, lease liabilities and provisions. We use net debt to assist us in understanding our liquidity at specific points in time. We exclude the current portion of provisions, lease liabilities and the deferred customer obligation as they are not financial instruments. Mark-to-market derivative contracts and assets and liabilities held for sale are excluded as they are unrealized.

Barrels of Oil Equivalent

Barrels of oil equivalent (boe) is calculated using the conversion factor of 6 mcf (thousand cubic feet) of natural gas being equivalent to one barrel of oil. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl (barrel) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Reserve Life Index

The reader is also cautioned that this news release contains the term reserve life index ("RLI"), which is not a recognized measure under International Financial Reporting Standards ("IFRS"). Management believes that this measure is a useful supplemental measure of the length of time the reserves would be produced over at the rate used in the calculation. Readers are cautioned, however, that this measure should not be construed as an alternative to other terms determined in accordance with IFRS as a measure of performance. Our method of calculating this measure may differ from other companies, and accordingly, they may not be comparable to measures used by other companies.

The following Management's Discussion and Analysis ("MD&A") reports on the financial condition and the results of operations of Chinook Energy Inc. and its wholly owned subsidiaries (collectively, "our", "we" or "us") for the three months and years ended December 31, 2019 and 2018 and should be read in conjunction with our audited consolidated financial statements and accompanying notes as at and for the years ended December 31, 2019 and 2018 (the "Financial Statements"). This MD&A is based on information available at March 2, 2020.

The term "fourth quarter" or "year to date" (or "reported year") are used throughout this document and refer to the three months or year ended December 31, 2019, respectively. The term "current reporting periods" is used throughout this document and refers to both the three months and year ended December 31, 2019, in this respective order. The term "same period(s) of 2018" or "comparative period(s)" or similar terms are used throughout this document and refer to the three months or (and) year ended December 31, 2018, depending on the 2019 period(s) under discussion. The term "reported periods" is used throughout this document and refers to both the three months and years ended December 31, 2019 and 2018. The term "first quarter", "second quarter" or "third quarter" or similar terms are used throughout this document and refer to the three months ended March 31, 2019, June 30, 2019, or September 30, 2019, respectively.

This MD&A contains measures ("non-GAAP") which are not prescribed by International Financial Reporting Standards ("IFRS") and, therefore, may not be comparable with the calculations of similar measures presented by other companies including those in the oil and natural gas industry. Statements throughout this MD&A that are not historical facts may be considered "forward-looking statements". Readers should read the advisories under the headings "Non-GAAP Measures" and "Forward-Looking Statements" included at the end of this MD&A.

Additional Information

Additional information on our company, including our Annual Information Form for the year ended December 31, 2019 ("AIF"), once filed, can be found on SEDAR at www.sedar.com or at www.chinookenergyinc.com.

Subsequent Events

Arrangement Agreement

Effective February 22, 2020, we entered into an arrangement agreement (the "Arrangement Agreement") pursuant to which Tourmaline Oil Corp. (the "Purchaser") has agreed to acquire all of the outstanding common shares ("Chinook Shares") of our company for cash consideration of $0.0675 per share (the "Transaction"). The Purchaser will assume our net debt as estimated upon closing. The Transaction is subject to various closing conditions, including receipt of Court approval and approval by our shareholders. An annual and special meeting (the "Meeting") of our shareholders has been called to consider, among other things, the Transaction. The Transaction will require the approval of 66⅔% of the votes cast by our shareholders present in person or by proxy at the Meeting. The Meeting is expected to be held on April 20, 2020 with closing of the Transaction anticipated to occur thereafter in late April upon satisfaction of all conditions precedent thereto. The Transaction offers a liquidity event and cash consideration to our shareholders. Upon closing of the Transaction, the Chinook Shares will be de-listed from the Toronto Stock Exchange. We can provide no assurances that the Transaction will close.

The Arrangement Agreement provides for a non-completion fee of $1.75 million. The non-completion fee is payable to the Purchaser in the event that the Transaction is not completed or is terminated by us in certain circumstances, including if we enter into an agreement

with respect to a superior proposal or if our Board of Directors withdraws or modifies its recommendation with respect to the Transaction.

Demand Credit Facility Renewal

Following our execution of the Arrangement Agreement, on February 28, 2020, our lender renewed the demand credit facility agreement with an unchanged maximum availability of $10.0 million. This renewal waived the breaches of the *net debt to cash flow* financial covenant as at June 30, September 30 and December 31, 2019. This same financial covenant that is forecast to be in breach as at March 31, 2020, per the terms of the renewal has also been waived. The *minimum hedging requirement* was removed as a term of the demand credit facility agreement although additional reporting requirements were added and include weekly forecasted cash flows and monthly abandonment and reclamation activities in addition to requiring that the minimum liability management ratio ("LMR") does not fall below 1.3 as determined for us by the British Columbia Oil & Gas Commission ("BCOGC"). The next renewal is scheduled on May 31, 2020 but may be set at an earlier (or later) date at the sole discretion of the lender.

Future Operations and Liquidity

During the year to date, we drew $4.7 million of debt to finance our operating activities while there was an extended ongoing review of our demand credit facility. This extended ongoing review occurred during a very challenging environment as demonstrated by depressed natural gas pricing and continued weakness in general Canadian exploration and production industry and capital market conditions.

Although in our facility renewal we received waivers of past and forecasted financial covenant breaches, we are further forecasting that we will be in breach of the *net debt to cash flow* financial covenant per the terms of the renewed demand credit facility agreement as at June 30, 2020 assuming average realized natural gas and natural gas liquids' pricing of $1.86/mcf and $41.76/bbl, respectively.

In the event that the Transaction is not completed, when the next borrowing base redetermination commences as scheduled on (or before or later) May 31, 2020, because of the aforementioned market conditions and forecasted breach, no assurance can be provided that the borrowing base will be renewed at the same or a similar amount or on the same or similar terms, nor can any assurance be provided that the lender will not call the debt as a result of these market conditions and forecasted breach or for any other reason. In such event, these material uncertainties cast significant doubt with respect to our ability to continue as a going concern.

Basis of Presentation

The Financial Statements have been prepared in accordance with IFRS issued by the International Accounting Standards Board. They include the accounts of our direct subsidiaries, all of which are wholly owned. They have also been prepared on a going concern basis, which presumes we will continue our operations for the foreseeable future and will be able to realize our assets and discharge our liabilities and commitments in the normal course of business (see "Future Operations and Liquidity"). As a result, the Financial Statements do not reflect adjustments and classifications of assets, liabilities, revenues and expenses which would be necessary if we were unable to continue as a going concern.

All amounts are in Canadian dollars, unless otherwise stated and all tabular amounts are in thousands of Canadian dollars, except per unit amounts or as otherwise noted.

Introduction to Chinook

We are a Calgary-based upstream oil and natural gas company whose main business activities include exploration, development and production of natural gas liquids and natural gas from our large contiguous Montney liquids-rich natural gas position at our Birley/Umbach property in northeast BC.

We are incorporated under the laws of the Province of Alberta, Canada. Our common shares are listed and posted for trading on the Toronto Stock Exchange under the symbol "CKE". Our head office and principal address is Suite 1610, 222 – 3rd Avenue S.W., Calgary, Alberta, Canada T2P 0B4.

Operating and Financial Highlights

	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
OPERATIONS				
Production [1]				
Natural gas liquids (boe/d)	**555**	405	**407**	565
Natural gas (mcf/d)	**16,469**	14,641	**12,950**	18,806
Crude oil (bbl/d)	**4**	12	**7**	19
Average daily production (boe/d) [2]	**3,304**	2,856	**2,572**	3,719
Sales Prices				
Average natural gas liquids price ($/boe)	**$ 39.75**	$ 43.56	**$ 42.26**	$ 59.87
Average natural gas price ($/mcf)	**$ 1.97**	$ 2.60	**$ 1.69**	$ 1.91
Average oil price ($/bbl)	**$ 62.11**	$ 54.13	**$ 61.48**	$ 69.15
Operating Netback [3]				
Average commodity pricing ($/boe)	**$ 16.55**	$ 19.72	**$ 15.33**	$ 19.11
Royalty expense ($/boe)	**$ (0.16)**	$ (0.14)	**$ (0.11)**	$ (0.08)
Realized gain (loss) on commodity price contracts ($/boe)	**$ 0.14**	$ (2.59)	**$ (0.64)**	$ (0.72)
Net production expense ($/boe) [3]	**$ (9.73)**	$ (14.01)	**$ (12.30)**	$ (11.63)
Operating netback ($/boe) [2] [3]	**$ 6.80**	$ 2.98	**$ 2.28**	$ 6.68
Wells Drilled				
Exploratory wells (net)	**-**	-	**-**	2.00
FINANCIAL ($ thousands, except per share amounts)				
Petroleum & natural gas revenues, net of royalties	**$ 4,986**	$ 5,146	**$ 14,291**	$ 25,837
Cash (outflow) inflow from operating activities	**$ (48)**	$ (378)	**$ (3,634)**	$ 255
Adjusted funds flow (outflow)[3]	**$ 1,171**	$ (413)	**$ (2,034)**	$ 4,179
Per share - basic & diluted ($/share)	**$ 0.01**	$ -	**$ (0.01)**	$ 0.02
Net loss	**$ (13,998)**	$ (21,141)	**$ (42,263)**	$ (27,654)
Per share - basic and diluted ($/share)	**$ (0.06)**	$ (0.09)	**$ (0.19)**	$ (0.12)
Capital expenditures	**$ -**	$ 213	**$ 29**	$ 2,890
Net debt [3]	**$ 6,138**	$ 1,994	**$ 6,138**	$ 1,994
Total assets	**$ 63,797**	$ 101,416	**$ 63,797**	$ 101,416
Common Shares (thousands)				
Weighted average during period				
Basic & diluted	**223,682**	223,605	**223,672**	223,594
Outstanding at year end	**223,682**	223,605	**223,682**	223,605

(1) Throughout this MD&A our production is presented in either barrels of oil ("bbl"), thousands of cubic feet ("mcf") or barrels of oil equivalent ("boe"); production per day is presented as bbl/d, mcf/d, and boe/d, respectively; commodity prices or revenues and expense per sales are presented as $/bbl, $/mcf, and $/boe, respectively. Production volumes and sales volumes are equal and are used interchangeably throughout this MD&A.

(2) May not be additive due to rounding.

(3) Non-GAAP measures which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A.

Operating and Financial Results

Petroleum and Natural Gas Production Volumes

	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
Natural gas liquids (boe/d)	**555**	405	**407**	565
Natural gas (mcf/d)	**16,469**	14,641	**12,950**	18,806
Crude oil (bbl/d)	**4**	12	**7**	19
Total (boe/d)	**3,304**	2,856	**2,572**	3,719

During the fourth quarter our production increased by 448 boe/d whereas for the year to date it decreased by 1,147 boe/d compared to the same periods of 2018. All reported periods were effected by production restrictions. Since being repaired in November 2018 following a rupture, Enbridge had operated its natural gas T-South Pipelines ("T-South Pipelines") at reduced pressures which had limited throughput capacity. After a year since being repaired, starting on November 1, 2019, Enbridge began to increase these pipelines' maximum operating pressures and associated capacities where they were returned to full service on December 1, 2019. Because take away volumes were previously limited from BC, it had an unfavorable effect on the year to date BC Station 2 benchmark price. To limit natural gas volumes previously sold at this benchmark, we voluntarily restricted our production throughout the majority of the year to date except to fulfill, when we could, contracts benchmarked to either the Chicago City Gate or Alliance Trading Pool ("ATP").

In addition to Enbridge previously operating its T-South Pipelines at reduced operating pressures, starting on January 2, 2019, there was an unplanned outage at the Enbridge McMahon Gas Plant ("McMahon Plant") that continued through to January 20, 2019. We began to ramp-up our production on January 23, 2019. This involuntary 20 day restricted period partially prevented us from realizing peak pricing during last winter. In addition, during the second and third quarters there was a combined 33 days of unplanned outages at either the McMahon Plant or on the Alliance Pipeline. When we could not fulfil our contracts benchmarked to either the Chicago City Gate or ATP by delivering our own production because of these various outages, we purchased and sold third party production as respectively reported through the line items take-or-pay expenses and revenues (see "Take-or-Pay").

The production restriction for the comparative quarter also resulted from the aforementioned T-South Pipelines' capacity constraints. In addition, the comparative year's production restriction also resulted from integrity and maintenance issues on a portion of Enbridge's Oak 16" gathering line (the "Oak Pipeline"). This portion of the Oak Pipeline was permanently replaced during the first quarter. As previously alluded, during the majority of the comparative quarter we voluntarily suspended our production in response to depressed BC Station 2 benchmark pricing attributed to lower operating pressures on the T-South Pipelines. The easing of this restriction during the fourth quarter resulted in higher production volumes compared to the same quarter of 2018.

Our fourth quarter production volumes increased 46% compared to the 1,048 boe/d reported during the third quarter. Again, as already alluded, the third quarter was affected by voluntary restrictions to limit natural gas volumes sold at depressed BC Station 2 benchmark pricing. Since November 6, 2019, and throughout the remainder of the fourth quarter, our production averaged 3,770 boe/d. Compared to the overall fourth quarter production of 3,304 boe/d, this increase was in response to the BC Station 2 benchmark's recovery caused by both higher seasonal pricing and higher industry throughput capacity on Enbridge's T-South Pipelines. This also contributed to the fourth quarter increase of production compared to the third quarter.

Petroleum and Natural Gas Revenues and Realized Pricing

	Three months ended December 31		Year ended December 31	
($ thousands, except per unit amounts)	**2019**	2018	**2019**	2018
Natural gas liquids sales	**$ 2,030**	$ 1,621	**$ 6,272**	$ 12,354
$/boe	**39.75**	43.56	**42.26**	59.87
Natural gas sales	**$ 2,979**	$ 3,504	**$ 7,969**	$ 13,103
$/mcf	**1.97**	2.60	**1.69**	1.91
Oil sales	**$ 24**	$ 58	**$ 153**	$ 490
$/bbl	**62.11**	54.13	**61.48**	69.15
Petroleum & natural gas revenue	**$ 5,033**	$ 5,183	**$ 14,394**	$ 25,947
$/boe	**16.55**	19.72	**15.33**	19.11

Our petroleum and natural gas revenue for the current reporting periods decreased compared to the same periods of 2018. These decreases are because of lower overall realized pricing caused by a variety of reasons. These reasons, as further elaborated throughout this MD&A, include various lower benchmarks. Also contributing to the year to date decrease was lower production volumes, incurring higher pipeline tariffs to obtain additional take away capacity to minimize our exposure to the BC Station 2 benchmark and being partially unable to realize peak pricing during last winter caused by the previously discussed unplanned outage at the McMahon Plant.

Our average commodity price during the fourth quarter increased 60% from the $10.34/boe realized during the third quarter. This increase was due to various higher benchmarks but especially the recovery in the BC Station 2 benchmark that increased 103% from the $0.97/mcf reported during the third quarter.

Our current reporting periods' realized natural gas pricing were supported by our efforts to limit exposure to the BC Station 2 benchmark through voluntarily restricting production and finding take away capacity at various other benchmarks, albeit with higher associated pipeline tariffs. Through these combined efforts we continue to realize a premium relative to this benchmark.

Benchmark Prices

	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
Natural gas liquids				
West Texas Intermediate (US$/bbl)	**$ 56.96**	$ 58.81	**$ 57.03**	$ 64.77
Natural gas				
BC Westcoast Station 2 (1) ($/mcf)	**$ 1.49**	$ 0.67	**$ 1.02**	$ 1.25
Alliance Trading Pool (2) ($/GJ)	**$ 1.92**	$ 2.60	**$ 1.66**	$ 2.08
Chicago City Gate (3) (US$/mcf)	**$ 2.44**	$ 3.63	**$ 2.56**	$ 3.06

(1) Market point for BC natural gas.
(2) Market point on the Alliance Pipeline.
(3) Market point for mid-Eastern United States natural gas.

Natural Gas Liquids ("NGL") Pricing

During the current reporting periods, consistent with the directional change in the West Texas Intermediate ("WTI") benchmark, our realized NGL pricing of $39.75/boe and $42.26/boe decreased compared to the same periods of 2018. Our NGL price is a blend of prices received for a range of liquids from propane through to condensates that are produced in association with natural gas. There are various benchmarks for natural gas liquids, depending on the type sold; however, we benchmark our liquids in reference to WTI. The ratio of our NGL price relative to WTI decreased to 53% and 56% for the current reporting periods from 56% and 71% for the same periods of 2018. These lower ratios were due to our NGL annual pricing contracts signed in the spring of 2019 which then included the effect of various lower liquid benchmark pricing. At that time, these lower benchmarks were attributed to a variety of reasons including an increase in supply from both Montney and other Western Canadian shale play producers, a lack of take-away capacity perpetuated by rail shippers focusing on longer-term crude oil contracts and a lower demand from bitumen producers whose own production was

curtailed starting January 1, 2019, due to the Government of Alberta imposing mandatory production curtailments in response to a widening Canadian to WTI crude oil benchmark differential.

Our realized NGL price increased 12% during the fourth quarter compared to the $35.58/boe realized price reported during the third quarter. This increase is due to higher propane through to condensate benchmark pricing.

Natural Gas Pricing

Our realized natural gas prices during the current reporting periods decreased compared to the same periods of 2018. These decreases were due to lower Chicago City Gate benchmark pricing in addition to higher pipeline tariffs for additional take away capacity priced to limit exposure to the BC Station 2 benchmark. Also contributing to the year to date decrease was a lower BC Station 2 benchmark and being partially unable to realize peak pricing during last winter's season caused by the previously discussed unplanned outage at the McMahon Plant.

We have firm pipeline capacity benchmarked to the Chicago City Gate of approximately 5,425 GJ/d through to October 31, 2020, with our option to extend the term. Although our additional firm and fixed price contracts have since expired, for the year to date it resulted in further natural gas production being sold at Chicago City Gate and ATP benchmarks and fixed prices ranging from $1.45/GJ to $1.65/GJ, albeit with higher associated pipeline tolls. As a result of these efforts, we sold 56% of our natural gas production during the year to date at prices other than the BC Station 2 benchmark compared to 35% during the same period of 2018. Selling our natural gas production at either fixed prices or these various other benchmarks resulted in us realizing a premium compared to BC Station 2 pricing. Although during both the fourth and comparative quarters we voluntarily restricted our natural gas production to limit exposure to the BC Station 2 benchmark, this restriction was eased commencing on November 6, 2019 when this benchmark began to recover for reasons already discussed. This resulted in a higher ratio of natural gas production sold at the BC Station 2 benchmark during the fourth quarter compared to the same quarter of 2018.

Our realized natural gas price increased 103% during the fourth quarter compared to the $0.97/mcf realized natural gas price reported during the third quarter. This increase was largely due to a higher BC Station 2 benchmark caused by a return to maximum operating pressures and associated capacities on the T-South Pipelines that took more BC natural gas production out of province. Also contributing to the higher fourth quarter natural gas price were seasonal pricing increases in the Chicago City Gate benchmark which then averaged US$2.03/mcf.

Royalties

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2019**	2018	**2019**	2018
Royalty expense	**$ 47**	$ 37	**$ 103**	$ 110
Per sales ($/boe)	**$ 0.16**	$ 0.14	**$ 0.11**	$ 0.08
Percent of revenues (%)	**1**	1	**1**	-

We are reporting negligible royalties for all reported periods. During a previously reported year, we were granted royalty credits as part of BC's Infrastructure Royalty Credit Program (the "Infrastructure Program"). We have continued to receive additional credits since this initial grant including a further grant during the second quarter for $0.2 million. This program provides credits on our Birley/Umbach development only after sufficient crown royalties have been generated by specific wells. Because our production has been restricted due to depressed BC Station 2 pricing during the year to date, we only recognized $0.3 million of these credits through a decrease to our royalties compared to $0.9 million during the same period of 2018. This credit program is in addition to BC's Natural Gas Deep Well Royalty Credit Program. The 12 (10.47 net) Birley/Umbach wells that have qualified for this credit program bear a minimum crown royalty rate of 6% prior to applying the credits from the Infrastructure Program. Through 2020 we are forecasting nominal BC crown royalties as a result of these credit programs. Overriding and freehold royalties will continue to be payable.

Financial Commodity Price Contracts

To help mitigate commodity price risk, we can enter into financial commodity price contracts which assist us to manage our future adjusted funds flow. This provides more certainty within determined commodity price ranges as to what we will receive on a portion of

our liquids and/or natural gas production. While these financial contracts may have opportunity costs when commodity benchmarks exceed the contracted prices, such transactions are not meant to be speculative and are considered within the broader framework of financial stability and flexibility. We continuously review the need or requirement to utilize financial contracts.

Outstanding commodity price contracts are measured at their approximated fair value on the date of the financial statements. This estimated fair value is determined through the difference in the referenced market forward price of the respective commodity over the remaining periods of the contracts compared to our received price multiplied by the remaining notional volumes. Volatility in forward commodity pricing and decreases in the remaining notional volumes will result in changes in the fair value of our derivative contracts from one period to the next. The change in the fair values between reporting dates are recognized as unrealized gains or losses on commodity price contracts whereas realized gains or losses are recognized over their contractual term.

For the reported periods, we had the following realized and unrealized gains or losses from commodity price contracts:

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2019**	2018	**2019**	2018
Realized (gain) loss on commodity price contracts	**$ (41)**	$ 680	**$ 604**	$ 982
Unrealized loss (gain) on commodity price contracts	**15**	(703)	**(235)**	235
(Gain) loss on commodity price contracts	**$ (26)**	$ (23)	**$ 369**	$ 1,217
Realized (gain) loss on commodity price contract ($/boe)	**$ (0.14)**	$ 2.59	**$ 0.64**	$ 0.72

During the fourth quarter we realized a modest gain on commodity price contracts from a natural gas swap that secured the price we received for a portion of our natural gas production because our contracted price of $1.645/GJ was higher than the Westcoast Station 2 benchmark. This gain was partially offset by a natural gas differential swap because our contracted price of NYMEX less US$0.125/mmbtu was lower than the Chicago City Gate benchmark. Both of these contracts expired at the end of the fourth quarter. Similar natural gas differential swaps that had previously expired also contributed to the realized loss during the year to date. Further contributing to the realized losses during the year to date and its comparative period was a Chicago City Gate price indexed contract, which expired at the end of the first quarter, because the contracted price of US$2.68/mmbtu was lower than this benchmark's average price. If we had included these realized gains/losses in our natural gas revenues, we would have reported adjusted natural gas sale prices for the current reporting periods of $1.99/mcf and $1.56/mcf compared to our reported prices of $1.97/mcf and $1.69/mcf.

Outstanding Commodity Price Contracts

As at December 31, 2019, our outstanding commodity price contracts had the following terms:

Contractual Term	Notional Volumes	Index and Company's Received Price
Natural gas swap		
January 1, 2020 to March 31, 2020	2,000 GJ/d	Westcoast Station 2 CAD$1.785/GJ
Natural gas collars		
January 1, 2020 to March 31, 2020	4,000 mmbtu/d	Chicago City Gate Monthly US$2.15/mmbtu to US$4.11/mmbtu

Mark-to-Market

At December 31, 2019, our natural gas commodity price contracts were in a $nil fair value position because the forward BC Station 2 and Chicago City Gate benchmarks approximate our contracted price or are within our collar's price range.

Net Production Expense

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2019**	2018	**2019**	2018
Production & operating	**$ 3,563**	$ 3,959	**$ 13,001**	$ 16,845
Less:				
Processing & gathering revenues [1]	**(606)**	(276)	**(1,457)**	(1,050)
Net production expense [2]	**$ 2,957**	$ 3,683	**$ 11,544**	$ 15,795
Net production expense ($/boe) [2]	**$ 9.73**	$ 14.01	**$ 12.30**	$ 11.63
Production expense ($/boe)	**$ 11.72**	$ 15.06	**$ 13.85**	$ 12.41

(1) Processing & gathering revenues are included in the line item other revenues as found on the condensed consolidated statements of operations and comprehensive loss.
(2) Non-GAAP measure which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A.

Our overall production & operating expense decreased during the current reporting periods compared to the same periods of 2018. The decrease for the year to date was because of production restrictions caused by various third party outages or our reaction to depressed BC Station 2 benchmark pricing. For the same reasons, production expense on a boe basis increased over this same period. This is because all of the production restrictions had the effect of increasing fixed operating costs, on a boe basis, relative to total operating costs. Unavoidable fixed costs can be significant and include, for example, contract operating fees, BC carbon taxes, operating insurance, municipal property taxes, firm processing tolls, mineral and surface lease costs. Although both reported quarters were also affected by voluntary production restrictions, the decrease in the overall production & operating expenses between these quarters was due to the fourth quarter's absence of the comparative quarter's Oak Pipeline integrity and maintenance issues and higher labour and steamer costs to flow restricted volumes through last winter's extremely cold weather. These higher costs could have been avoided had our production been unimpeded. The combination of higher production volumes and a lower overall production & operating expense during the fourth quarter, compared to the same quarter in 2018, resulted in the production expense on a boe basis decreasing by $3.34/boe. Once the fourth quarter's voluntary production restrictions were eased on November 6, 2019, our Birley/Umbach property's average production expense was estimated at $8.31/boe as compared to the corporate production expense during the fourth quarter of $11.72/boe.

During the second quarter we negotiated an agreement to continue to have our natural gas processed at the McMahon Plant. In addition, during the third quarter we also negotiated an incremental McMahon Plant agreement. These contracts expire May and April 2020, respectively. When combined, these contracts allow us to increase our raw natural gas throughput to 23 mmcf/d.

The majority of our processing & gathering revenues come from tolls applied to a customer's production that flows through our 12" Aitken Creek Pipeline which is directly connected to the Alliance Pipeline. This customer's throughput increased during the fourth quarter causing an increase in this type of revenue during the current reporting periods compared to the same periods of 2018. Our Aitken Creek Pipeline commences at Martin Creek and then passes through our Birley lands. It provides us with optionality upon the future development of a gas plant to flow directly to the Alliance Pipeline with access to the Chicago market, BC Station 2 via Enbridge's T-North Pipeline or connect to the recently expanded and now operational TCPL North Montney Mainline. Additionally, during the year to date we completed another transportation agreement for the partial use of our Aitken Creek Pipeline. The agreement commenced in late February 2020 on the initial delivery of gas, and will continue for a minimum period of two years. Additional annualized gathering charges are at least $1.6 million.

Operating Netback

The following table outlines the calculation of our operating netback[1]:

	Three months ended December 31		Year ended December 31	
Per sales ($/boe)	**2019**	2018	**2019**	2018
Average commodity pricing	**$ 16.55**	$ 19.72	**$ 15.33**	$ 19.11
Royalty expense	**(0.16)**	(0.14)	**(0.11)**	(0.08)
Realized gain (loss) on commodity price contracts	**0.14**	(2.59)	**(0.64)**	(0.72)
Net production expense [1]	**(9.73)**	(14.01)	**(12.30)**	(11.63)
Operating netback [1]	**$ 6.80**	$ 2.98	**$ 2.28**	$ 6.68

(1) Non-GAAP measures which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A.

Despite lower realized commodity pricing, our operating netback increased during the fourth quarter compared to the same quarter of 2018. Although production was initially voluntarily restricted, BC Station 2 pricing recovered in early November 2019 allowing us to produce at unrestricted volumes for the remainder of the fourth quarter. This increase in production volumes had the effect of decreasing fixed operating costs, on a boe basis, relative to total operating quarters. There was also the absence of a realized loss on commodity price contracts that we had previously reported during the comparative quarter. Inversely, our operating netback decreased during the year to date compared to the same period of 2018. Given the extent of restrictions to limit our production sold at depressed BC Station 2 pricing, in addition to third party outages, the year to date operating netback is not representative of the profitability of our operations. These restrictions largely limited production to levels required by our firm pipeline capacity and processing contracts. Also contributing to these netback decreases were lower average liquid prices caused by our annual pricing contracts signed in the spring of 2019 and higher realized losses from commodity price contracts that have since expired.

Take-or-Pay

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Take-or-pay revenues [1]	**$ (608)**	$ (801)	**$ (3,053)**	$ (3,821)
Take-or-pay expense	**$ 665**	$ 945	**$ 4,005**	$ 4,389

(1) Take-or-pay revenues are included in the line item *other revenues* as found on the consolidated statements of operations and comprehensive loss.

Included in both take-or-pay contract revenues and expenses for the year to date are the following cost mitigation programs:

- The revenue and expense of selling and purchasing, respectively, third party natural gas production to meet our firm volume commitments on various third party pipelines was necessitated by the outages at either the McMahon Plant or on the Alliance Pipeline. Although we benefited from the purchase and sale of these third party volumes, the net cost after including the associated pipeline tariffs during the year to date was $0.4 million. Although we cannot say with any certainty, we do not anticipate future cost mitigation programs to be significant.
- The revenue and expense of selling and purchasing, respectively, third party NGL production was necessitated to meet a take-or-pay processing agreement. The $0.6 million net cost during the year to date compares to the same period of 2018 although take-or-pay contracts' revenues and expenses have both decreased because of lower firm commitments and a reduction in NGL pricing. We have partially mitigated our continued exposure to this fee at least through to the first quarter of 2020 under similar terms as previously reported. The take or pay processing agreement has one further lower annual firm commitment through to its expiry on March 31, 2021.

General & Administrative ("G&A") Expense

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2019**	2018	**2019**	2018
G&A expense before recoveries	**$ 947**	$ 1,375	**$ 3,994**	$ 5,862
Recoveries	**(248)**	(356)	**(1,078)**	(1,748)
G&A expense	**$ 699**	$ 1,019	**$ 2,916**	$ 4,114
Per sales ($/boe)	**$ 2.30**	$ 3.88	**$ 3.11**	$ 3.03

For the current reporting periods, we realized lower G&A expenses before recoveries including lower staffing costs due to last year's 40% headcount reduction, the suspension of an employee benefit program and reduced information system costs. We have also implemented a reduced work week since May 2019, where relative to 2018 this was implemented only through the summer months.

During the second quarter we signed a lease for our current Calgary office space that commenced on June 1, 2019 with an initial expiry of August 31, 2022 but with our option to extend, under the same terms, to February 28, 2025. The estimated annual cash savings from this new lease are $2.0 million.

On January 1, 2019, we adopted *IFRS 16, Leases* ("IFRS 16") (see "Adopted New Accounting Standard"). This new accounting standard resulted in office rents of $1.4 million for the year to date, which includes lease and non-lease components, being respectively reported as reductions of $0.2 million and $0.6 million in our prepaids (see "Adopted New Accounting Standard") and lease liabilities (see "Lease Liabilities"), respectively, and a charge of $0.6 million to G&A expense before recoveries. Included in the same period of 2018 are $2.4 million of office rents but reported as a charge of $1.6 million to G&A expense before recoveries and a $0.8 million reduction in our onerous contract provision. Excluding the effect of lower office rents which saved us $1.0 million during the year to date compared to the same period of 2018, as a result of adopting IFRS 16, G&A expense before recoveries decreased $0.4 million during the year to date.

Partially offsetting the above decreases to G&A expense before recoveries were lower G&A recoveries. With lower compensation costs combined with reduced capital and production & operating costs, our capitalized G&A, capital and other associated G&A recoveries decreased by $0.1 million and $0.7 million during the current reporting periods compared to the same periods of 2018.

G&A on a boe basis decreased during the fourth quarter compared to the same quarter of 2018 because of the aforementioned cost reductions combined with higher production volumes. Whereas G&A on a boe basis increased during the year to date compared to the same period of 2018, despite decreases in overall G&A, as a result of lower production.

Financing

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Accretion of decommissioning obligations	**$ 146**	$ 157	**$ 638**	$ 680
Interest on bank debt	**141**	35	**295**	109
Other	**6**	6	**38**	84
Financing	**$ 293**	$ 198	**$ 971**	$ 873

Our effective interest rates on bank debt were 7.5% and 5.3% during the current reporting periods compared to 4.9% and 4.6% for the same periods of 2018. Excluding the effect from these interest rate changes, the increase in the current reporting periods' interest on bank debt compared to the same periods in 2018 was due to higher average drawn debt.

As previously discussed, on January 1, 2019, we adopted IFRS 16 (see "Adopted New Accounting Standard"). Interest expense from lease liabilities included in our other financing costs during the current reporting periods was insignificant.

The accretion charges during the current reporting periods are modestly lower compared to the same periods of 2018 because during the second quarter we lowered the applied decommissioning obligations' risk-free discount rate from 2.1% to 1.7%. Effective January 1, 2020, we decreased our estimated decommissioning obligations' risk-free discount rate to 1.8%.

Other Losses

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Other losses	**$ 58**	$ 65	**$ 188**	$ 149

Other losses during the reported periods were mostly in respect of exploratory mineral and surface rental costs.

Impairment of Development & Production and Exploration & Evaluation Assets

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Impairment of development & production and exploration & evaluation assets	**$ 13,293**	$ 19,600	**$ 32,193**	$ 19,600

We initially identified evidence indicating impairment in the June 30, 2019 carrying values of our development & production assets. This evidence was a significant sustained reduction in forward British Columbia Station 2 natural gas pricing. Further evidence indicating impairment in the June 30, 2019 carrying value of producing properties were concerns about our ability to finance our future development costs and the timing thereof. As a result, we tested for impairment on our one remaining *Peace River Arch* CGU. The CGU's recoverable value was estimated using a value-in-use calculation based on a roll forward of the December 31, 2018 independently prepared reserve report adjusted by management for the three engineering firms' average July 1, 2019 price forecasts, reserves produced during the first six months ended June 30, 2019 and deferring future development costs. We used this report's expected future net revenues anticipated to be produced from the combined reserve categories proved developed, proved undeveloped and probable reserves, using before income tax discount rates ranging from 10% to 20% depending on the reserve category. This test revealed impairment of $18.9 million as originally reported during the second quarter.

We identified further evidence indicating impairment in the December 31, 2019 carrying values of our development & production and exploration & evaluation assets. This evidence was the execution of the Arrangement Agreement where the associated consideration of $0.0675 per common share (the "Share Consideration") was less than our equivalent per common share book amount. As a result of the Arrangement Agreement, the recoverable value of both our producing and exploratory properties was determined from their combined fair value less costs to sell which also approximates a value-in-use measure because our intention is now to sell the company. As at June 30, 2019 and December 31, 2018, our producing properties recoverable value was measured using a value-in-use model partially because the intended use at that time was to continue operations.

The combined net carrying amount prior to recognizing any further impairment as at December 31, 2019 of our producing and exploratory properties less decommissioning obligations was $36.1 million. This net carrying amount was then compared to the proceeds pursuant to the Arrangement Agreement as detailed as follows:

- $15.1 million as determined from the Share Consideration of $0.0675 per common share times the 223.7 million outstanding common shares; and
- Estimated net debt, as defined by the Arrangement Agreement.

These combined proceeds, which approximates the fair value of the Transaction on its estimated closing date in late April 2020, is after forecasted costs to sell which have been assumed by the Purchaser. The estimated fair value less costs to sell at April 2020 was then used to determine the equivalent measure at December 31, 2019. The total consideration to be paid to our shareholders plus estimated net debt and cash flow growth through to the closing of the Transaction is estimated to be $22.8 million. Because the combined net carrying amount exceeded the fair value less costs to sell, this resulted in a fourth quarter impairment charge totalling $13.3 million.

Including the recognized impairment of $18.9 million as originally reported during the second quarter, the combined year to date impairment was $32.2 million ($19.6 million for the comparative periods).

No impairment expense sensitivity analysis has been provided as the fair value less costs to sell was contractually determined.

Depletion, Depreciation and Amortization ("DD&A") Expense

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2019**	2018	**2019**	2018
Depletion, depreciation & amortization	**$ 2,404**	$ 2,367	**$ 8,390**	$ 11,654
Depletion per sales ($/boe)	**$ 6.51**	$ 7.51	**$ 6.70**	$ 7.36

Lower production volumes and depletion rates resulted in depletion expense being $3.7 million lower during the year to date compared to the same period of 2018. Inversely, higher production volumes, despite lower depletion rates, resulted in depletion expense being modestly higher during the fourth quarter compared to the same quarter of 2018. These lower depletion rates were due to both the second quarter and previous year's impairment expenses of $18.9 million and $19.6 million, respectively, that each lowered the net carrying value of our development & production assets combined with a modest increase in the December 31, 2018 measure of our proved plus probable reserves.

As previously discussed, on January 1, 2019, we adopted IFRS 16 (see "Adopted New Accounting Standard"). During the year to date this new accounting standard resulted in us reporting additional depreciation of $0.4 million against right-of-use assets. As we adopted this new accounting standard using a modified retrospective approach, there is no comparable depreciation expense in the same period of 2018. This partially offset the effects from lower production volumes and depletion rates, as previously discussed, that resulted in a decrease to the overall DD&A expense during the year to date compared to the same period of 2018.

Deferred Customer Obligation Amortization

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Deferred customer obligation amortization	**$ (194)**	$ (194)	**$ (777)**	$ (777)

During a previously reported year, a customer transferred a section of pipeline to us which connected our 12" Aitken Creek Pipeline, located in northeast BC, to the Alliance Pipeline. The estimated fair value of this connecting pipeline resulted in a deferred customer obligation which is being amortized over the term of the agreement, which expires October 31, 2020, pursuant to which we are contractually obligated to provide this customer with access to a portion of our Aitken Creek Pipeline.

Indemnification Provision Change in Estimate

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Indemnification provision change in estimate	**$ (660)**	$ -	**$ (660)**	$ -

We are involved in litigation and claims arising from indemnifications provided to the buyer of our former Tunisian operations (see "Provisions") that are attributable to years prior to 2014. During the current reporting periods, the Tunisian Appellant Court ruled on a claim initiated by a previous Tunisian service provider. This ruling was lower than what we had previously measured and resulted in a decrease to our indemnification provision reported as a $0.7 million change in estimate with no associated expenditure.

Share-Based Compensation

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Share-based compensation	**$ 104**	$ 149	**$ 468**	$ 508

The number of share-based awards granted during the year to date decreased compared to the same period of 2018. When combined with each granted share-based award having a lower estimated fair value, this resulted in decreases of share-based compensation for the current reporting periods compared to the same periods of 2018. The lower number of granted share-based awards was attributable to headcount reductions throughout the comparative year whereas each award's lower estimated fair value was due to a decrease in our publically traded share price.

Severance Costs

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Severance costs	**$ -**	$ -	**$ -**	$ 834

Severance costs incurred during the comparative year related to staffing reductions that reduced our headcount by 40% as we assessed our staffing requirements.

Gain on Dispositions of Properties

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Gain on dispositions of properties	**$ -**	$ (721)	**$ -**	$ (721)

During the comparative year, we disposed of mineral rights with associated undeveloped lands, shut-in and suspended wells located in Rigel, British Columbia and Gordondale, Alberta to third parties in consideration for them assuming the decommissioning obligations. There were no reserves associated with these mineral rights. The $0.2 million net carrying amount of the undeveloped lands less $0.9 million of associated decommissioning obligations resulted in a gain on the transfer of properties of $0.7 million.

Amortization of Flow-Through Common Shares Premium

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Amortization of flow-through common shares premium	**$ -**	$ -	**$ -**	$ (323)

During the comparative year, we incurred the required $2.0 million of qualifying Canadian exploration expenditures pursuant to a previous reported year's issuance of 6,450,000 common shares on a flow-through basis. As a result of incurring these exploration expenditures, we amortized the associated $0.3 million flow-through common shares premium.

Income Tax

We have not reported deferred tax assets because it is not probable that we can utilize our tax pools against future taxable profit. We estimate we had the following tax pools at December 31, 2019:

($ thousands)	December 31 2019
Canadian oil & gas property expense	**$ 994**
Canadian development expense	**24,630**
Canadian exploration expense	**55,078**
Undepreciated capital costs	**21,158**
Net operating losses	**316,985**
Net capital loss	**10,987**
Other	**1,796**
Total	**$ 431,628**

The Government of Alberta's Bill 3, *Job Creation Tax Cut Act*, received Royal Assent during the second quarter. This reduced the general Alberta corporate tax rate from 12% to 11.5% during 2019 and will further reduce this rate from 10% to 8% from 2020 to 2022. Because our head office is in Calgary whereas our operations are located in northeastern BC, approximately one-half of any future corporate taxable income would be allocated to Alberta with the other half allocated to BC. These reduced tax rates have lowered the value of our unrecognized deferred tax asset and the associated valuation allowance.

Net & Comprehensive Loss

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2019**	2018	**2019**	2018
Weighted average shares outstanding - basic & diluted (thousands)	**223,682**	223,605	**223,672**	223,594
Net & comprehensive loss	**$ (13,998)**	$ (21,141)	**$ (42,263)**	$ (27,654)
Net loss per share - basic & diluted ($/share)	**$ (0.06)**	$ (0.09)	**$ (0.19)**	$ (0.12)

The net loss increased during the year to date compared to the same period of 2018. This increase was due to both lower production volumes and commodity pricing for reasons previously explained. To reiterate, during the year to date the lower commodity pricing includes being partially unable to realize peak pricing during last winter's season caused by the unplanned outage at the McMahon Plant. The associated production restriction was further exacerbated as we had previously entered into incremental short-term firm volume pipeline commitments, with their associated tariffs, to deliver natural gas production at various benchmarks and fixed prices with the objective to limit exposure to the BC Station 2 benchmark. These firm volume pipeline tariffs during the unplanned outage at the McMahon Plant, net of our mitigation efforts, caused an increase in our net take-or-pay cost. Further contributing to the increase in the net loss was impairment of $32.2 million charged against our producing and exploratory assets for the year to date compared to $19.6 million charged against producing assets for the comparative year. The impairment expense for the year to date was due to the Arrangement Agreement (see "Subsequent Events") that provided a contractually determined fair value less costs to sell of our producing and exploratory assets less the associated decommissioning obligation.

The net loss decreased during the fourth quarter compared to the same quarter of 2018. This decrease was due to previously reporting a portion of the year to date impairment charge whereas this same charge was reported in its entirety during the fourth quarter of 2018. Further contributing to this decrease was both higher production volumes and third party throughput on our Aitken Creek Pipeline combined with a favorable change in estimate to our indemnification provision.

Capital Resources and Capital Expenditures

Adjusted Funds Flow (Outflow) & Cash (Outflow) Inflow from Operating Activities

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2019**	2018	**2019**	2018
Cash (outflow) inflow from operating activities	**$ (48)**	$ (378)	**$ (3,634)**	$ 255
Add (deduct):				
Change in operating non-cash working capital	**913**	(690)	**310**	1,311
Provision expenditures	**249**	595	**1,094**	1,608
Exploration & evaluation expenses [1]	**57**	60	**196**	171
Severance costs	**-**	-	**-**	834
Adjusted funds flow (outflow)[2]	**$ 1,171**	$ (413)	**$ (2,034)**	$ 4,179
Per share - basic & diluted	**$ 0.01**	$ -	**$ (0.01)**	$ 0.02

(1) Exploration & evaluation expenses are included in the line item *other losses* as found on the consolidated statements of operations and comprehensive loss.
(2) Non-GAAP measure which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A.

An adjusted funds flow for the fourth quarter increased by $1.6 million, despite lower overall commodity pricing, compared to the outflow during the same quarter of 2018. This increase was due to higher production volumes and lower overall production & operating and G&A expenses, an increase in a third party's volumes through our Aitken Creek Pipeline and modest realized gains on commodity price

contracts versus losses on similar contracts during the fourth quarter of 2018. Inversely, adjusted funds for the year to date decreased compared to the same period in 2018. This decrease was due to both lower production volumes and commodity pricing and increases in the take-or-pay net expense. Further contributing to the year to date decrease was higher realized losses from commodity price contracts. These year to date effects were partially offset by lower overall production & operating and G&A expenses.

For the same reasons as just explained for adjusted funds flow, cash flows from operating activities changed during the current reporting periods compared to the same periods of 2018. The cash outflow from operating activities for the year to date benefited from both a decrease in provision expenditures and the absence of severance costs reported during the same period of 2018. Contributing to the year to date decrease in operating non-cash working capital was the return of a $1.0 million deposit that previously guaranteed additional firm volume pipeline capacity, which has since expired, less a $0.5 million deposit we recently posted to guarantee future processing tolls through the McMahon Plant.

Capital Expenditures

Our development and exploration expenditures and proceeds from a disposition during the reported periods were as follows:

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Proceeds from a disposition	**$ -**	$ -	**$ 33**	$ -
Expenditures				
Land & lease	**$ -**	$ 88	**$ -**	$ 262
Drilling & completions	**-**	125	**-**	2,225
Facilities & equipment	**-**	-	**-**	253
Field expenditures	**-**	213	**-**	2,740
Right-of-use asset	**-**	-	**29**	-
Capitalized G&A	**-**	-	**-**	150
Total expenditures	**$ -**	$ 213	**$ 29**	$ 2,890

Our focus during the current reporting periods, as it continues to be, is capital preservation. As a result, during the current reporting periods we did not incur any capital expenditures. During the comparative year to date, we drilled and completed two (2.0 net) exploratory vertical Birley/Umbach wells. The drilling and completion costs for these two (2.0 net) wells totaled $2.2 million. These wells further delineated 21 gross (20.5 net) undrilled contiguous sections of Montney rights (located three kilometres north of our main Montney land block and eight kilometres from the nearest well drilled into the Montney). These vertical wells, which also preserved undeveloped lands, were funded by the proceeds from a previous reported year's flow-through share issuance. Each well encountered approximately 225 metres of total Montney thickness. The quality of the reservoir encountered, particularly in the top 75 metres of the Montney and as seen from wireline log data, had consistent hydrocarbon charged porosity. Each well was perforated to obtain pressure information. We abandoned these wells which satisfies our flow-through financing obligations.

Disposition of Properties

During the year to date, we sold our mineral rights located in Gordondale, Alberta to a third party. There were $nil million in both proceeds and net carrying amounts associated to this property disposition. There were no wells associated with these mineral rights.

During the comparative reporting periods, we transferred mineral rights located in Rigel, British Columbia and Gordondale, Alberta to third parties in consideration for them assuming the associated decommissioning obligations of suspended and shut-in wells and associated infrastructure.

For the above dispositions, there were no reserves associated with these mineral rights.

Net Debt

($ thousands)	December 31 2019	December 31 2018
Debt	**$ 7,022**	$ 2,361
Accounts receivable	**(3,568)**	(3,386)
Prepaids & deposits	**(1,525)**	(2,528)
Accounts payable & accrued liabilities	**4,209**	5,547
Net debt [1]	**$ 6,138**	$ 1,994

(1) Non-GAAP measure which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A.

We had net debt of $6.1 million and $2.0 million at December 31, 2019 and December 31, 2018, respectively. Net debt increased between these reported dates because of the year to date adjusted funds outflow of $2.0 million and expenditures of $1.9 million which included both decommissioning obligations and lease payments (see "Adopted New Accounting Standard"). Prepaid rents associated with our previous Calgary office space for $0.2 million was also reclassified as a right-of-use asset on adoption of IFRS 16 (see "Adopted New Accounting Standard"). This resulted in a January 1, 2019 decrease in our non-cash working capital and a corresponding increase in our net debt.

Our ability to discharge our financial liabilities, as included in net debt, and fund our future operations is discussed within this MD&A under the "Future Operations and Liquidity" header.

We normally manage expenditures not to exceed our annual adjusted funds flow. However, during the year to date we incurred $0.9 million of decommissioning obligation expenditures which included abandonments of 2.0 (2.0 net) vertical wells. As previously discussed, these abandonments were necessary in order to satisfy our flow-through financing obligations. For the year to date we are also reporting an adjusted funds outflow because of the various third party outages that partially prevented us from realizing peak pricing during last winter's season in addition to us continuing to incur both firm volume pipeline tolls and fixed production & operating costs in the absence of production combined with voluntary restrictions in response to depressed BC Station 2 pricing.

Credit Facility

Our amended demand credit facility agreement with a Canadian chartered bank had an availability of $10.0 million as at December 31, 2019 and 2018 (the "Demand Credit Facility"). Subsequent to December 31, 2019, our lender completed the borrowing base redetermination. The maximum availability remained unchanged at $10.0 million. This most recent renewal as signed on February 28, 2020 removed the minimum hedging requirement that previously was required as at December 31, 2019 and 2018 in addition to waiving breaches in the net debt to cash flow financial covenant as determined at June 30, September 30 and December 31, 2019 and as forecast for March 31, 2020. The next renewal is scheduled on May 31, 2020 but may be set at an earlier (or later) date at the sole discretion of the lender.

At December 31, 2019, we had debt borrowings of $7.0 million, which included $4.7 million of borrowings drawn during the year to date and undrawn letters of credit of $0.9 million, as secured by our lender, which reduced the available credit to $2.1 million (at December 31, 2018 – drawings of $2.4 million, undrawn letters of credit of $0.9 million and available credit of $6.7 million).

All borrowings under the Demand Credit Facility have always been classified as a current liability, as the lender can request repayment of all outstanding drawn amounts at any time. Borrowings incur interest at the prime rate plus an applicable margin and are collateralized by floating charges and security interests over all of our present and future properties and other assets. In addition, the Demand Credit Facility includes operating and financial restrictions on us that include restrictions on paying dividends or making other distributions in respect of our securities.

The Demand Credit Facility has financial covenants requiring that at each reporting period the *adjusted working capital* equals or exceeds a one-to-one ratio and that *net debt to cash flows* (waived for March 31, 2020) does not exceed a three-to-one ratio. Because the lender's definition of cash flows includes lease payments, this measure, was unaffected by adopting IFRS 16 (see "Adopted New Accounting Standard"). For the purposes of these covenants:

- *Adjusted working capital* is defined as working capital excluding both the current portion of commodity price contracts and debt but including the undrawn portion of the Demand Credit Facility,
- *Net debt* is defined as working capital but excluding the current portion of commodity price contracts, and
- *Cash flows* are determined over the last 12 months and are defined as cash flows from operating activities before changes in non-cash working capital less lease payments.

The February 28, 2020 renewal also has additional reporting requirements including weekly forecasted cash flows and monthly abandonment and reclamation activities in addition to requiring that the minimum LMR does not fall below 1.3 as determined for us by the BCOGC.

Although we recently received waivers for past financial covenant breaches and a forecasted breach, we are further forecasting to be in breach of the *net debt to cash flow* financial covenant per the terms of the renewed demand credit facility agreement as at June 30, 2020 assuming average realized natural gas and natural gas liquids' pricing of $1.86/mcf and $41.76/bbl, respectively. In the event that the Transaction is not competed, when the next borrowing base redetermination commences as scheduled on (or before or later) May 31, 2020, because of the forecasted breach, no assurance can be provided that the borrowing base will be renewed at the same or a similar amount or on the same or similar terms, nor can any assurance be provided that the lender will not call the debt as a result of this forecasted breach or for any other reason.

Lease Liabilities

On adoption of IFRS 16 (see "Adopted New Accounting Standard") we recognized $0.6 million of lease liabilities that mostly consist of our previous Calgary head office space. Although there was an available optional short-term expedient because this lease expired in June 2019, we chose not to take this option because our current Calgary office space and its associated payments are also captured under IFRS 16. The effect of discounting this liability at our incremental borrowing rate, estimated at 6% and 7.8% on adoption and at December 31, 2019, respectively, was insignificant because of the magnitude of this liability. Lease payments during the year to date totaled $0.6 million. At December 31, 2019, we are reporting $0.2 million of lease liabilities mostly associated with our current Calgary office space.

Provisions

Decommissioning Obligations

At December 31, 2019, the net present value of our decommissioning obligations was $35.8 million which was higher than $32.4 million at December 31, 2018. During the year to date, an increase of $3.3 million in decommissioning obligations was caused by an increase in cost estimates recently released by the BCOGC and accretion which reflects the increase in the obligation associated with the passage of time as partially offset by expenditures and an increase in the risk free rate. We estimate this net present value based on a total future undiscounted and uninflated liability of $37.1 million (December 31, 2018 - $33.3 million).

As at December 31, 2019 and 2018, the estimated obligations include assumptions in respect of actual costs to abandon wells and facilities or reclaim the property, the time frame in which such costs will be incurred, respective annual inflation rates of 1.5% and 2.0% used to calculate the obligations' future value and respective average risk-free interest rates of 1.8% and 2.1% used to calculate the obligations' present value.

Onerous Contract

On adoption of IFRS 16 (see "Adopted New Accounting Standard"), we applied a practical expedient that allowed us to decrease our previous Calgary office space right-of-use asset by the associated onerous contract provision of $0.4 million last reported at December

31, 2018. As a result, on adoption of IFRS 16 and thereafter we no longer report an onerous contract provision associated with our previous Calgary office space.

Indemnifications

We are also involved in litigation and claims arising from indemnifications provided to the buyer of our wholly-owned subsidiary's former Tunisian operations that are attributable to years prior to 2014. During the current reporting periods, the Tunisian Appellant Court ruled on a claim initiated by a previous Tunisian service provider. This ruling was lower than what we had previously measured and resulted in a decrease to our indemnification provision reported as a $0.7 million change in estimate with no associated expenditure. During the year to date, indemnification provision expenditures associated with defending our interests totaled $0.1 million. Our estimated remaining indemnification provision is $0.1 million as at December 31, 2019.

Share Capital

Authorized

- Unlimited number of common shares
- Unlimited number of first preferred shares

Outstanding

Details of our outstanding share capital in addition to share options and restricted awards are as follows:

	December 31 2019	December 31 2018
Common shares outstanding	**223,682,001**	223,604,601
Share options	**15,475,900**	13,177,200
Restricted awards	**49,900**	127,300
Weighted average common shares - basic and diluted	**223,672,022**	223,594,409

As at March 2, 2020, we had 223,731,901 common shares, 15,020,900 share options and nil restricted awards outstanding.

Commitments and Guarantees

At December 31, 2019, we had the following unrecognized contractual payments without giving effect to any offsetting third party agreements, which are anticipated to reduce some of these amounts:

	2020	**2021**	**2022**	**2023**	**2024**	**Thereafter**	**Total**
Office contracts	$ 348	$ 320	$ 304	$ 300	$ 301	$ 47	$ 1,620
Operating and transportation contracts	2,338	220	-	-	-	-	2,558
	$ 2,686	**$ 540**	**$ 304**	**$ 300**	**$ 301**	**$ 47**	**$ 4,178**

The office contracts include the non-lease component of our current Calgary office space whereas the operating and transportation contracts relate to minimum contractual payments if we do not benefit from the operating services or pipeline transportation. The latter captures our most recent McMahon Plant processing agreements executed during the second and third quarters that expire on May 31 and April 30, 2020, respectively.

At December 31, 2019 and 2018, we had guaranteed a pipeline commitment through undrawn letters of credit of $0.9 million (see "Future Operations and Liquidity" and "Credit Facility") as secured by our lender. At December 31, 2018, our prepaids and deposits included a payment of $1.2 million to further guarantee this pipeline commitment that was mostly refunded during the year to date.

At December 31, 2019, we have guaranteed future processing tolls through a payment of $0.5 million as included in prepaids and deposits. We have also guaranteed indemnifications provided by our wholly owned subsidiary to the buyer of our former Tunisian operations (see "Indemnifications").

Off Balance Sheet Arrangements

We did not enter into any off balance sheet arrangements during the reported periods.

Related Party Transactions

We determined that our key management personnel consist of our officers and directors. In addition to the salaries and directors fees paid to the officers and directors, respectively, the officers and directors participate in our share option plan. The officers' salaries, directors' fees and other benefits, as mostly included in G&A expense for the reported and comparable years, totaled $1.2 million and $1.7 million. The share option plan benefits for our officers and directors, as included in share-based compensation for the reported and comparable years, totaled $0.4 million and $0.5 million.

Alberta Investment Management Corporation ("AIMCo"), as investment manager to Her Majesty the Queen in Right of the Province of Alberta ("HMQ"), maintains investment control and direction over approximately 36% of our outstanding common shares for the benefit of HMQ. Pursuant to a management and administration services agreement (the "Services Agreement") dated June 29, 2010, we were engaged to manage, administer and maintain the properties and the books, accounts and records of WOGH Limited Partnership ("WOGH"). WOGH was formed to hold working interests in certain of our assets which are held by nominees of AIMCo on behalf of HMQ. As we manage, administer and maintain the properties and the books, accounts and records of WOGH, we are reimbursed for such services. In accordance with the Services Agreement, we reported a recovery from WOGH, as mostly reported against our G&A expense, of $0.5 million and $0.9 million for the reported and comparable years. The recovery for the reported and comparative years was generally determined from WOGH's pro rata share as estimated at 11% and 12% of its and our combined production volumes. At December 31, 2019 and 2018, $nil million and $0.1 million, respectively, of this G&A recovery was included in accounts receivable.

Selected Annual Information

Summarized information for the reported year and the two preceding years appears below:

Year ended December 31	2019	2018	2017
($ thousands, except per share amounts)			
Petroleum & natural gas revenue, net of royalties	**$ 14,291**	$ 25,837	$ 21,271
Net loss [1]	**$ (42,263)**	$ (27,654)	$ (16,914)
Per share - basic & diluted ($/share)	**$ (0.19)**	$ (0.12)	$ (0.08)
Total assets	**$ 63,797**	$ 101,416	$ 130,571
Long-term liabilities [2]	**$ 35,770**	$ 33,794	$ 33,377

(1) Includes $32.2 million, $19.6 million and $17.1 million of impairment charges for the years ended December 31, 2019, 2018 and 2017, respectively.
(2) Includes provisions and other long-term liabilities.

Petroleum & natural gas revenues, net of royalties increased from 2017 to 2018 but then decreased from 2018 to the reported year. The increase during 2018, compared to 2017, was due to higher liquid benchmark pricing and a modest increase in volumes resulting from our 2016 and 2017 Montney drilling programs at our Birley/Umbach area which added seven (6.27 net) horizontal wells. As previously explained, the reported year's volumes were negatively affected by a combination of third party and voluntary restrictions where the latter originated from the rupture of one of the T-South Pipelines resulting in both pipelines subsequently being operated at reduced pressures and the associated effect on depressing the BC Station 2 benchmark. The reported year's lower realized liquid price, compared to 2018, resulted from a precipitous decrease in the Canadian light sweet crude oil benchmark. The combination of the aforementioned resulted in the reported year's decrease in petroleum & natural gas revenue, net of royalties, compared to 2018.

The net losses for each of the above successive years largely resulted from impairment charges caused by sustained decreases in forward BC Station 2 benchmark pricing. These impairment charges combined with DD&A contributed to each consecutive year's decrease in total assets.

The increase in long-term liabilities from 2017 to 2018 was caused by the latter year's higher estimated decommissioning obligations caused by both a decrease in the risk free rate and the associated obligations from drilling and completing two (2.0 net) exploratory vertical Birley/Umbach wells on our north Montney block. The increase in long-term liabilities from 2018 to the reported year was due to the latter year's higher cost estimates included in our decommissioning obligations' measure that were recently released by the BCOGC.

Please refer to "Operations" and other sections of this MD&A for detailed discussions on variations between the reported year and its comparative period and to our previous annual management's discussion and analysis for changes between the prior years.

Quarterly Information from Operations

Summarized information by quarter for the two years ended December 31, 2019, appears below:

	Dec. 31 2019	Sept. 30 2019	Jun. 30 2019	Mar. 31 2019	Dec. 31 2018	Sept. 30 2018	Jun. 30 2018	Mar. 31 2018
Production Volumes								
Natural gas liquids (boe/d)	**555**	337	279	455	405	707	680	468
Natural gas (mcf/d)	**16,469**	11,488	8,457	15,389	14,641	24,454	22,253	13,806
Crude oil (bbl/d)	**4**	5	10	9	12	24	23	19
Average daily production (boe/d)	**3,304**	2,256	1,698	3,029	2,856	4,807	4,413	2,788
Sales Prices								
Average natural gas liquids price ($/boe)	**$ 39.75**	$ 35.58	$ 43.02	$ 49.96	$ 43.56	$ 63.73	$ 66.65	$ 58.35
Average natural gas price ($/mcf)	**$ 1.97**	$ 0.97	$ 1.38	$ 2.10	$ 2.60	$ 1.54	$ 1.40	$ 2.64
Average oil price ($/bbl)	**$ 62.11**	$ 55.63	$ 67.20	$ 57.89	$ 54.13	$ 71.35	$ 75.11	$ 68.34
Operating Netback[1]								
Average commodity pricing ($/boe)	**$ 16.55**	$ 10.34	$ 14.33	$ 18.34	$ 19.72	$ 17.59	$ 17.75	$ 23.35
Royalty expense ($/boe)	**$ (0.16)**	$ (0.05)	$ (0.22)	$ (0.04)	$ (0.14)	$ -	$ (0.07)	$ (0.17)
Realized gain (loss) on derivative contracts ($/boe)	**$ 0.14**	$ (0.24)	$ (0.89)	$ (1.69)	$ (2.59)	$ (0.17)	$ 0.17	$ (1.18)
Net production expenses ($/boe)[1]	**$ (9.73)**	$ (13.70)	$ (17.26)	$ (11.28)	$ (14.01)	$ (9.74)	$ (10.17)	$ (14.84)
Operating netback ($/boe)[1][2]	**$ 6.80**	$ (3.65)	$ (4.04)	$ 5.33	$ 2.98	$ 7.68	$ 7.68	$ 7.16
Wells Drilled								
Exploratory wells (net)	**-**	-	-	-	-	-	-	2.00
Natural gas wells (net)	**-**	-	-	-	-	-	-	-
FINANCIAL ($ thousands, except per share amounts)								
Petroleum & natural gas revenues, net of royalties	**$ 4,986**	$ 2,136	$ 2,178	$ 4,991	$ 5,146	$ 7,778	$ 7,098	$ 5,815
Adjusted funds flow (outflow)[1]	**$ 1,171**	$ (1,691)	$ (1,708)	$ 194	$ (413)	$ 2,285	$ 1,836	$ 471
Per share - basic & diluted ($/share)	**$ 0.01**	$ (0.01)	$ (0.01)	$ -	$ -	$ 0.01	$ 0.01	$ -
Cash (outflow) inflow from operating activities	**$ (48)**	$ (1,489)	$ (1,940)	$ (157)	$ (378)	$ 1,132	$ 1,223	$ (1,722)
Net loss [3]	**$ (13,998)**	$ (3,527)	$ (22,242)	$ (2,496)	$ (21,141)	$ (1,944)	$ (2,471)	$ (2,098)
Per share - basic & diluted ($/share)	**$ (0.06)**	$ (0.02)	$ (0.10)	$ (0.01)	$ (0.09)	$ (0.01)	$ (0.01)	$ (0.01)
Development and exploration expenditures	**$ -**	$ -	$ -	$ -	$ 213	$ -	$ 180	$ 2,497
Net debt [1]	**$ 6,138**	$ 6,982	$ 5,207	$ 3,120	$ 1,994	$ 713	$ 2,654	$ 3,961
Total assets	**$ 63,797**	$ 75,920	$ 77,284	$ 97,022	$ 101,416	$ 120,572	$ 123,637	$ 127,227
Common Shares (thousands)								
Weighted average during period								
Basic and diluted	**223,682**	223,682	223,681	223,642	223,605	223,605	223,603	223,565
Outstanding at period end	**223,682**	223,682	223,682	223,655	223,605	223,605	223,605	223,565

(1) Non-GAAP measure which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A.
(2) May not be additive due to rounding.
(3) Includes $13.3 million, $18.9 million and $19.6 million in impairment charges against properties for the three months ended December 31, 2019, June 30, 2019 and December 31, 2018, respectively.

Factors That Have Caused Variations over the Quarters

The factors described below only apply to the quarterly information presented above.

Since our transition to a Montney play focused company, production trended with our Birley/Umbach property including this area's 2016 and 2017 development programs which added seven (6.27 net) horizontal wells, of which the remaining two (2.00 net) wells came on-stream during the first quarter of 2018. However, other than the second and third quarters of 2018, extended third party restrictions did not allow us to demonstrate our production potential. Production since the third quarter of 2018 was also affected by the rupture on one of the T-South Pipelines. We then reacted to the resulting depressed BC Station 2 benchmark pricing by voluntarily shutting-in our production.

Changes in our petroleum and natural gas revenues, net of royalties and adjusted funds flow have trended with volumes and the BC Station 2 and WTI benchmark prices. The previously described volume changes can shift the weighting of our natural gas production

away from BC Station 2 and towards Chicago City Gate benchmark pricing or vice versa. Since the first quarter of 2018, we acted to preserve capital given depressed and volatile BC Station 2 pricing. Since the third quarter of 2018, our production has been restricted either due to third party constraints or voluntarily in reaction to depressed BC Station 2 pricing. As a result, through to the third quarter we reported nominal or adjusted funds outflows and correspondingly higher net debt. This trend was interrupted during the fourth quarter as peak winter natural gas pricing combined with the T-South Pipelines returning to full operating capacities resulted in a recovery of the BC Station 2 benchmark. This eased our past production restrictions resulting in the fourth quarter's increase to our adjusted funds flow and correspondingly lowering our net debt.

Please refer to other sections of this MD&A for detailed discussions on variations during the comparative quarters and to our previously issued interim and annual management's discussion and analysis for changes in prior quarters.

Risk Factors

Investors should carefully consider the risk factors set out in our AIF, once filed, and consider all other information contained herein and in our other public filings before making an investment decision. The risks set out in our AIF are not an exhaustive list, nor should they be taken as a complete summary or description of all the risks associated with our business and the oil and natural gas business generally. If any of the these risks or other risks occur, our business, prospects, financial condition, results of operations and cash flows could be adversely affected in a material way.

Additional information on risks, assumptions and uncertainties are found under the heading "Forward-Looking Statements". The following are the two most significant risk factors as copied from our AIF:

The Transaction to Sell our Company to the Purchaser May Not Be Completed

The Transaction is subject to various closing conditions, including receipt of Court approval and shareholder approval. Further details on the conditions precedent to the completion of the Transaction are set forth in the Arrangement Agreement which is filed on our SEDAR profile at www.sedar.com. The Transaction may not be completed on the terms contemplated by the Arrangement Agreement or at all due to failure to obtain the receipt of the necessary Court and shareholder approvals or failure to satisfy the other conditions precedent to the closing of the Transaction. There are no assurances that the Transaction will be completed. In addition, the Arrangement Agreement provides for a non-completion fee of $1.75 million in the event that the Transaction is not completed or is terminated by us in certain circumstances, including if we enter into an agreement with respect to a superior proposal or if our Board withdraws or modifies its recommendation with respect to the Transaction.

An additional risk factor in the event that the Transaction is not completed, is that we are forecasting that we will be in breach as at June 30, 2020 of a net debt to cash flow financial covenant contained in our renewed demand credit facility agreement assuming average realized natural gas and natural gas liquids' pricing of $1.86/Mcf and $41.76/Bbl, respectively. Consequently, when the next borrowing base redetermination under the demand credit facility commences as scheduled on (or before or later) May 31, 2020, because of depressed natural gas pricing and the forecasted breach, there can be no assurance provided that the borrowing base of the facility will be renewed at the same or similar amount or on the same or similar terms, nor can any assurance be provided that the lender will not call the debt as a result of the forecasted breach or for any other reason. In such event, if we are unable to secure alternative financing, there is significant doubt with respect to our ability to continue as a going concern.

Management Judgment and Estimation Uncertainty

The preparation of the Financial Statements requires management judgments and estimation uncertainty that affect the reported amounts at the date of the Financial Statements of assets, liabilities, shareholders' equity, revenues and expenses. Actual results could differ from those estimated. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Judgments that management has made through applying accounting policies that have the most significant effect on the Financial Statements are discussed below:

Cash Generating Units

CGUs are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or group of assets. The classification of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, external users, shared infrastructures and the way in which management monitors our operations.

Impairment (reversal) indicators

Judgments are required to assess when impairment (reversal) indicators exist and impairment (reversal) testing is required. When assessing the recoverability of petroleum and natural gas properties, each CGU's carrying value is compared to its recoverable amount, defined as the greater of its fair value less cost to sell and value in use. In determining the recoverable amount of assets, in the absence of quoted market prices or observed market transactions, impairment tests are based on reserve estimates, market value of undeveloped lands and other relevant assumptions.

Key estimates that management has made that affect the measurement of balances and transactions are discussed below:

Estimated cash flows and net debt

Estimated net debt upon the closing of the Transaction and estimated cash flows through to closing were used in the calculation of impairment for the year ended December 31, 2019. Estimated cash flows directly associated with our producing properties were based on future prices, costs and production rates. Estimated net debt includes such cash flows but it further includes future costs not directly associated with our producing properties. Management expects that these estimated cash flows will be revised, either upward or downward, based on updated information such as future realized commodity pricing, production and costs.

Reserve estimates

Petroleum and natural gas reserves are used in the calculation of depletion, impairment and impairment reversals. Reserve estimates and their resulting cash flows are based on engineering data, probability assessments of reserve recoveries, future prices and costs, future production rates, discount rates and the timing and extent of future capital expenditures, all of which are subject to many uncertainties and interpretation. We expect that over time our reserve estimates will be revised, either upward or downward, based on updated information such as the results of future drilling, testing and production levels and changes to forward petroleum and natural prices and production costs.

Decommissioning obligations

Decommissioning obligations are recognized for the future decommissioning and restoration of property, plant and equipment. These obligations are based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, market conditions, discovery and analysis of site conditions and changes in technology. The expected timing of future decommissioning and restoration may change due to certain factors, including reserve life. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented.

Adopted New Accounting Standard

Effective January 1, 2019, we adopted *IFRS 16,* which replaced *IAS 17, Leases* ("IAS 17"), using a modified retroactive approach. This approach does not require restatement of prior period financial information as it applies the standard prospectively. Under IAS 17, operating lease payments were expensed on a straight line basis over the lease term whereas under IFRS 16, there is an increased focus on control of the underlying asset. Under IFRS 16, when we have a contract that transfers substantially all the risks and rewards incidental to ownership of an identified asset, we recognize a lease liability equivalent to the present value of future fixed payments over the contract's non-cancellable term or longer if it is reasonably likely we will exercise an option to extend that term. These future fixed payments are discounted using our incremental borrowing rate if the rate implicit in the lease is not readily determinable. Mineral licenses and surface leases that allow for the extraction of petroleum and natural gas are not within the scope of IFRS 16.

On adoption of IFRS 16, right-of-use assets were initially measured at the amount equal to the lease liabilities but as adjusted by the amount of the prepaids & deposits relating to leases reported at December 31, 2018. We also relied on a practical expedient that the assessment of our previous Calgary office space lease was onerous immediately before adopting IFRS 16 as an alternative to performing an impairment review. By choosing this practical expedient, we also decreased our right-of-use asset on adoption of IFRS 16 by the amount of the onerous contract provision reported at December 31, 2018. We measured the present value of our lease liabilities on adopting IFRS 16 using a discount rate of 6% as determined from our incremental borrowing rate. The adjustments to accounts measured at December 31, 2018 resulting from adopting IFRS 16 are as follows:

($ thousands)	As at December 31 2018	Adjustments	As at January 1 2019
Prepaids & deposits	$ 2,528	$ (244)	**$ 2,284**
Right-of-use assets	-	453	**453**
Lease liabilities	-	(599)	**(599)**
Provisions	(33,721)	390	**(33,331)**
Total	$ (31,193)	$ -	**$ (31,193)**

During the year to date, IFRS 16 caused a decrease of $0.4 million in G&A expense before recoveries (see “G&A Expense”) whereas it increased DD&A (see “DD&A”) by $0.4 million. As a result, our year to date adjusted funds outflow decreased by $0.4 million whereas the net loss was unaffected. The majority of the reported lease liabilities’ amount on adoption of IFRS 16 was associated with our previous Calgary office space contract which expired on June 30, 2019.

Significant Accounting Policies

A summary of our significant accounting policies are included in the notes to the Financial Statements.

Disclosure Controls and Procedures

Our Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to us is made known to our CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by us in our annual filings, interim filings or other reports filed or submitted by us under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of our disclosure controls and procedures at December 31, 2019 and have concluded that our disclosure controls and procedures are effective at December 31, 2019.

Internal Controls over Financial Reporting

Our CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting (“ICOFR”) to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Our CEO and CFO have evaluated, or caused to be evaluated under their supervision, the effectiveness of our ICOFR at December 31, 2019 and have concluded that our ICOFR are effective at December 31, 2019. There were no changes in the ICOFR that occurred during the fourth quarter that have materially affected, or are reasonably likely to materially affect our ICOFR.

We have designed our ICOFR based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

It should be noted that a control system, including our disclosure and internal controls and procedures, no matter how well conceived can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Other Information

Non-GAAP Measures

Management believes that the presentation of the following non-GAAP measures provides useful information to investors and shareholders as these measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis. Non-GAAP measures do not have any standardized meanings as prescribed by IFRS and, therefore, may not be comparable with the calculations of similar measures presented by other companies including those in the oil and natural gas industry:

- Adjusted funds flow (outflow) is calculated from cash flow from operations adjusted for changes in non-cash operating working capital, exploration and evaluation expenses, provision expenditures and severance costs. Adjusted funds flow (outflow) per share is calculated as adjusted funds flow (outflow) divided by the period's diluted shares. We believe that adjusted funds flow (outflow) is a key measure to assess our ability to finance capital expenditures and when debt is drawn, to finance debt repayments. Adjusted funds flow (outflow) is not intended to represent cash flow from operating activities, net loss or other measures of financial performance calculated in accordance with IFRS and should not be construed as an alternative to, or more meaningful than, cash (outflow) inflow from operating activities as determined in accordance with IFRS as an indicator of our financial performance. Adjustments to cash (outflow) inflow from operations are for changes in non-cash operating working capital which are expected to reverse and for those costs that are not directly caused by lifting production volumes.

- Net debt is calculated as debt adjusted for current assets less current liabilities as they appear on the balance sheets, both of which exclude mark-to-market commodity price contracts and assets and liabilities held for sale and current liabilities excludes any current portion of deferred customer obligations, provisions and lease liabilities. We use net debt to assist us in understanding our liquidity at specific points in time. We exclude the current portion of deferred customer obligations, provisions and lease liabilities as they are either non-cash liabilities, estimates based on management's assumptions and subject to volatility or where the contractual benefit has yet to be received. Mark-to-market commodity contracts and assets and liabilities held for sale are excluded as they are unrealized estimates subject to a high degree of volatility prior to settlement.

- Operating netback is calculated as a period's sales of petroleum and natural gas, net of realized gains or losses on commodity price contracts, royalties and net production expenses, divided by the period's sales volumes. We use this non-GAAP measure to assist us in understanding our production profitability relative to current and fixed commodity prices and it provides an analytical tool to benchmark changes in field operational performance against prior periods. Readers are cautioned, however, that this measure should not be construed as an alternative to other terms such as net loss determined in accordance with IFRS as a measure of performance.

- Net production expense is calculated as production and operating expense less processing and gathering revenues. We use net production expense to determine the period's cash cost of operating expenses and net production expense per boe is used to measure operating efficiency on a comparative basis. This measure approximates our operating costs relative to only our volumes by excluding the approximated operating costs resulting from third party processing and gathering services.

Forward-Looking Statements

In the interest of providing our shareholders and readers with information regarding our company, including management's assessment of our future plans and operations, certain statements contained in this MD&A constitute forward-looking statements or information (collectively "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "could", "plan", "intend", "should", "believe", "outlook", "potential", "target" and similar words suggesting future events or future performance. In particular, this MD&A contains, without limitation, forward-looking statements pertaining to: the Transaction and the anticipated timing of closing of the Transaction; timing of the annual and special meeting of Shareholders called to, among other things, approve the Transaction, and the benefits of the Transaction for Shareholders, forecasted breach of a financial covenant in our demand credit facility as at June 30, 2020, that we forecast minimal BC crown royalties through 2020, estimated annual cost savings of $2.0 million as a result of our new office lease, how we intend to manage our company and financial and business prospects and financial outlook for our company.

With respect to the forward-looking statements contained in this MD&A, we have made assumptions regarding, among other things: the time required to prepare Shareholder meeting materials in respect of the Transaction for mailing, the timing of receipt of necessary Court and shareholder approvals and the satisfaction of and time necessary to satisfy the conditions to the closing of the Transaction, that we will continue to conduct our operations in a manner consistent with that expressed herein, no significant future capital expenditure levels, future oil and natural gas prices, future oil and natural gas production levels, future currency, exchange and interest rates, our ability to obtain equipment in a timely manner to carry out exploration and development activities, the ability of the operator of the projects in which we have an interest in to operate in the field in a safe, efficient and effective manner, the impact of increasing competition, field production rates and decline rates, anticipated production volumes, our ability to replace and expand production and reserves through exploration and development activities, certain cost assumptions and the continued availability of adequate debt and cash flow to fund our company. Although we believe that the expectations reflected in the forward-looking statements contained in this MD&A, and the assumptions on which such forward-looking statements are made, are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned not to place undue reliance on forward-looking statements included in this MD&A, as there can be no assurance that the plans, intentions or expectations upon which the forward-looking statements are based will occur. In particular, we give no assurances that the Transaction will be completed. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties that contribute to the possibility that predictions, forecasts, projections and other forward-looking statements will not occur, which may cause our actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, without limitation, the anticipated dates in this MD&A concerning the Transaction may change for a number of reasons, including unforeseen delays in preparing shareholder meeting materials, inability to secure necessary court or shareholder approval in the time assumed or the need for additional time to satisfy the conditions to the completion of the Transaction, failure to satisfy the conditions precedent to the closing of the Transaction, that in the event the Transaction is not completed our lender may reduce the availability of our $10.0 million demand credit facility or demand repayment of all outstanding debt and undrawn letters of credit precipitated by a forecasted financial covenant breach or for any other reason, and, in such event, that no sufficient alternative financing will be available to us, that there are material uncertainties that may cast significant doubt with respect to our ability to continue as a going concern, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices and currency fluctuations, there is no certainty in the amount of our borrowing base redetermination, environmental risks, competition from other producers, inability to retain drilling rigs and other services, unanticipated increases in or unforeseen capital expenditure costs, including drilling, completion and facilities costs, unexpected decline rates in wells, delays in projects and/or operations resulting from surface conditions, wells not performing as expected, delays resulting from or inability to obtain the required regulatory approvals and inability to access sufficient capital from internal and external sources. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the forgoing list of factors is not exhaustive. Additional information on these and other factors that could affect our operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) and at our website (www.chinookenergyinc.com). Furthermore, the forward-looking statements contained in this MD&A are made as at the date of this MD&A and we do not undertake any obligation to update publicly or to revise any of the forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Selected Definitions and Abbreviations

Oil and Natural Gas Liquids

bbl	barrels
bbl/d	barrels per day
NGLs	natural gas liquids

Natural Gas

mcf	thousand cubic feet
mmcf	million cubic feet
mcf/d	thousand cubic feet per day
mmcf/d	million cubic feet per day
mmbtu	million British Thermal Units
mmbtu/d	million British Thermal Units per day
GJ	gigajoules
GJ/d	gigajoules per day

Other

boe	barrel of oil equivalent on the basis of 6 mcf/1 boe for natural gas and 1 bbl/1 boe for crude oil and natural gas liquids (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
boe/d	barrel of oil equivalent per day
mboe	1,000 barrels of oil equivalent
Canadian Light Sweet	Central market point for Canadian crude oil
Station 2	Market point for BC natural gas
AECO	Central market point for Canadian natural gas
Chicago City Gate	Market point for eastern US natural gas

Barrels of Oil Equivalent

Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Management's Report

The management of Chinook Energy Inc. ("Chinook") is responsible for the preparation of the consolidated financial statements. The consolidated financial statements have been prepared by management in accordance with International Financial Reporting Standards and reflect management's best estimates and judgments. Management has determined amounts in accordance with the significant accounting policies summarized in the notes to the consolidated financial statements.

Management is responsible for the integrity of the consolidated financial statements. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

KPMG LLP (the "Auditor") was appointed by Chinook's shareholders to express an audit opinion on the consolidated financial statements. The Auditor's examination included such tests and procedures, as the Auditor considered necessary, to provide reasonable assurance that the consolidated financial statements are presented fairly in accordance with International Financial Reporting Standards.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Board of Directors exercises this responsibility through the Audit Committee, with the assistance from Reserves, Safety and Environmental Committee regarding the annual review of Chinook's petroleum and natural gas reserves. The Audit Committee, composed of independent directors, meets regularly with management and the Auditor to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of the Auditor and reviews its fees. The Auditor has access to the Audit Committee without the presence of management.

"signed"

Walter J. Vrataric
President & Chief Executive Officer

"signed"

Jason Dranchuk
Vice President, Finance & Chief Financial Officer

Calgary, Alberta

March 2, 2020

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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Chinook Energy Inc.

Opinion

We have audited the financial statements of Chinook Energy Inc. (the "Entity"), which comprise:

- The consolidated statements of financial position as at December 31, 2019 and December 31, 2018
- The consolidated statements of operations and comprehensive loss for the years then ended
- the consolidated statements of changes in shareholders' equity for the years then ended
- the consolidated statements of cash flows for the years then ended
- and notes to the consolidated financial statements, including a summary of significant accounting policies

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

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2019 and December 31, 2018, and its financial performance and its 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 Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

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

Material Uncertainty Related to Going Concern

We draw attention to note 3 in the financial statements, which indicates that the Company is forecasting a potential breach of certain debt covenants in June 2020.

As stated in note 3 in the financial statements, these events or conditions, along with other matters as set forth in note 3 in the financial statements, indicate that a material uncertainty exists that may cast significant doubt on the Company's ability to continue as a going concern.

Our opinion is not modified in respect of this matter.

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

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

Auditors' Responsibilities for the Audit of the Financial Statements

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

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

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

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

We also:

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

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

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

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

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

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

The engagement partner on the audit resulting in this auditors' report is Brad William Robertson.

KPMG LLP

Chartered Professional Accountants

Calgary, Canada
March 2, 2020

Consolidated Statements of Financial Position

(in thousands of Canadian dollars)	December 31 2019	December 31 2018
Assets		
Current		
Accounts receivable (note 6)	**$ 3,568**	$ 3,386
Prepaids & deposits	**1,525**	2,528
Fair value of commodity price contracts (note 6)	**-**	424
	5,093	6,338
Development & production assets (note 7)	**50,027**	82,930
Exploration & evaluation assets (note 8)	**8,523**	12,148
Right-of-use assets (notes 5 & 9a)	**154**	-
	$ 63,797	$ 101,416
Liabilities & Shareholders' Equity		
Current		
Accounts payable & accrued liabilities	**$ 4,209**	$ 5,547
Debt (note 10)	**7,022**	2,361
Fair value of commodity price contracts (note 6)	**-**	659
Provisions (note 11)	**240**	575
Deferred customer obligation (note 7)	**648**	777
	12,119	9,919
Provisions (note 11)	**35,614**	33,146
Lease liabilities (notes 5 & 9b)	**156**	-
Deferred customer obligation (note 7)	**-**	648
Shareholders' Equity		
Share capital	**786,530**	786,507
Contributed surplus	**20,773**	20,328
Deficit	**(791,395)**	(749,132)
	15,908	57,703
	$ 63,797	$ 101,416

Subsequent events (notes 2 & 10)
Future operations (note 3)
Commitments and guarantees (note 19)

See accompanying notes to the consolidated financial statements

On behalf of the Board of Directors:

"signed"
Jill T. Angevine

Chairman of the Board of Directors and Director

"signed"
Robert J. Herdman

Chairman of the Audit Committee and Director

Consolidated Statements of Operations and Comprehensive Loss

(in thousands of Canadian dollars, except per share amounts)	Year ended December 31 2019	2018
Revenues		
Petroleum & natural gas revenues (note 13)	**$ 14,394**	$ 25,947
Royalty expense	**(103)**	(110)
Petroleum & natural gas revenues, net of royalties	**14,291**	25,837
Other revenues (note 13)	**4,510**	4,871
Petroleum, natural gas & other revenues, net of royalties	**18,801**	30,708
Loss on commodity price contracts (note 6)	**(369)**	(1,217)
Total revenues, net of royalties and losses on commodity price contracts	**18,432**	29,491
Expenses		
Production & operating	**13,001**	16,845
Take-or-pay	**4,005**	4,389
General & administrative	**2,916**	4,114
Financing (note 14)	**971**	873
Other losses	**188**	149
Impairment of development & production and exploration & evaluation assets (notes 7 & 8)	**32,193**	19,600
Depletion, depreciation & amortization (notes 7, 8 & 9a)	**8,390**	11,654
Deferred customer obligation amortization (note 7)	**(777)**	(777)
Indemnification provision change in estimate (note 11b)	**(660)**	-
Share-based compensation (note 15)	**468**	508
Severance costs	**-**	834
Gain on disposition of properties (note 16)	**-**	(721)
Amortization of flow-through common shares premium (note 12)	**-**	(323)
Total expenses	**60,695**	57,145
Net & comprehensive loss	**$ (42,263)**	$ (27,654)
Net loss per share, basic and diluted (note 20)	**$ (0.19)**	$ (0.12)

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Changes in Shareholders' Equity

(in thousands of Canadian dollars, except common shares)	Common Shares (thousands)	Share Capital	Contributed Surplus	Deficit	Shareholders' Equity
Balance as at December 31, 2017	**223,565**	**$ 786,492**	**$ 19,835**	**$ (721,478)**	**$ 84,849**
Settlement of restricted share awards	40	15	(15)	-	-
Share-based compensation (note 15)	-	-	508	-	508
Net loss	-	-	-	(27,654)	(27,654)
Balance as at December 31, 2018	**223,605**	**$ 786,507**	**$ 20,328**	**$ (749,132)**	**$ 57,703**
Settlement of restricted share awards	77	23	(23)	-	-
Share-based compensation (note 15)	-	-	468	-	468
Net loss	-	-	-	(42,263)	(42,263)
Balance as at December 31, 2019	**223,682**	**$ 786,530**	**$ 20,773**	**$ (791,395)**	**$ 15,908**

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

(in thousands of Canadian dollars)	Year ended December 31 2019	2018
Operating Activities		
Net loss	**$ (42,263)**	$ (27,654)
Add (deduct):		
Unrealized (gain) loss on commodity price contracts (note 6)	**(235)**	235
Non-cash financing and other expenses	**654**	652
Impairment of development & production and exploration & evaluation assets (notes 7 & 8)	**32,193**	19,600
Depletion, depreciation & amortization (notes 7, 8 & 9a)	**8,390**	11,654
Deferred customer obligation amortization (note 7)	**(777)**	(777)
Indemnification provision change in estimate (note 11b)	**(660)**	-
Share-based compensation (note 15)	**468**	508
Gain on disposition of properties (note 16)	**-**	(721)
Amortization of flow-through common shares premium (note 12)	**-**	(323)
Provision expenditures (notes 11a & 11b)	**(1,094)**	(1,608)
Change in operating non-cash working capital (note 20)	**(310)**	(1,311)
Cash (outflow) inflow from operating activities	**(3,634)**	255
Financing Activities		
Debt borrowings (note 10)	**4,661**	2,361
Lease payments (note 9b)	**(580)**	-
Change in financing non-cash working capital (note 20)	**-**	(20)
Cash inflow from financing activities	**4,081**	2,341
Investing Activities		
Proceeds on property disposition	**33**	-
Development, exploration and right-of-use asset expenditures (notes 7, 8 & 9a)	**(29)**	(2,890)
Change in investing non-cash working capital (note 20)	**(451)**	(4,088)
Cash outflow from investing activities	**(447)**	(6,978)
Change in cash during the year	**-**	(4,382)
Cash, beginning of year	**-**	4,341
Cash, foreign currency gain	**-**	41
Cash, end of year	**$ -**	$ -

Other supplementary information (note 20)

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements

As at and for the years ended December 31, 2019 and 2018

Tabular amounts in thousands of Canadian dollars, except as noted

1. Reporting Entity

Chinook Energy Inc. is a Calgary-based petroleum and natural gas production company focused on development and exploration opportunities in western Canada.

These consolidated financial statements for the years ended December 31, 2019 and 2018 (these “Financial Statements”) include the accounts of Chinook Energy Inc. (“CEI”) and two directly held wholly-owned subsidiaries (collectively, including all subsidiaries, “Chinook” or the “Company”): 1542991 Alberta Ltd. and Storm Ventures International (BVI) Limited (“Storm BVI”).

2. Subsequent Events

Arrangement Agreement

Effective February 22, 2020, Chinook entered into an arrangement agreement (the "Arrangement Agreement") pursuant to which Tourmaline Oil Corp. (the "Purchaser") has agreed to acquire all of the outstanding common shares of Chinook ("Chinook Shares") for cash consideration of $0.0675 per share (the “Transaction”). The Purchaser will assume Chinook’s net debt as estimated upon closing. The Transaction is subject to various closing conditions, including receipt of Court approval and Chinook shareholder approval. An annual and special meeting (the "Meeting") of Chinook shareholders has been called to consider, among other things, the Transaction. The Transaction will require the approval of $66^{2}/_{3}$% of the votes cast by the Chinook shareholders present in person or by proxy at the Meeting. The Meeting is to be held on April 20, 2020 with closing of the Transaction anticipated to occur thereafter in late April upon satisfaction of all conditions precedent thereto. The Transaction offers a liquidity event and cash consideration to Chinook’s shareholders. Upon closing of the Transaction, the Chinook Shares will be de-listed from the Toronto Stock Exchange. No assurances can be provided that the Transaction will close.

The Arrangement Agreement provides for a non-completion fee of $1.75 million. The non-completion fee is payable to the Purchaser in the event that the Transaction is not completed or is terminated by Chinook in certain circumstances, including if Chinook enters into an agreement with respect to a superior proposal or if Chinook’s Board of Directors withdraws or modifies its recommendation with respect to the Transaction.

Demand Credit Facility Renewal

Following our execution of the Arrangement Agreement, on February 28, 2020, Chinook and its lender renewed the demand credit facility agreement with an unchanged maximum availability of $10.0 million (see note 10). This renewal waived the breaches of the *net debt to cash flow* financial covenant as at June 30, September 30 and December 31, 2019. This same financial covenant that is forecast to be in breach as at March 31, 2020, per the terms of the renewal has also been waived. The *minimum hedging requirement* was removed as a term of the demand credit facility agreement although additional reporting requirements were added and include weekly forecasted cash flows and monthly abandonment and reclamation activities in addition to requiring that the minimum liability management ratio (“LMR”) does not fall below 1.3 as determined for Chinook by the British Columbia Oil & Gas Commission (“BCOGC”). The next renewal is scheduled on May 31, 2020 but may be set at an earlier (or later) date at the sole discretion of the lender.

3. Future Operations

During the year ended December 31, 2019, Chinook drew $4.7 million of debt to finance its operating activities while there was an extended ongoing review of its demand credit facility. This extended ongoing review occurred during a very challenging environment as demonstrated by depressed natural gas pricing and continued weakness in general Canadian exploration and production industry and capital market conditions.

Although the facility renewal included waivers of past and forecasted financial covenant breaches, Chinook is further forecasting that it will be in breach of the *net debt to cash flow* financial covenant per the terms of the renewed demand credit facility agreement (see note 2) as at June 30, 2020 assuming average realized natural gas and natural gas liquids' pricing of $1.86/mcf and $41.76/bbl, respectively.

In the event that the Transaction is not completed, when the next borrowing base redetermination commences as scheduled on (or before or later) May 31, 2020, because of the aforementioned market conditions and forecasted breach, no assurance can be provided that the borrowing base will be renewed at the same or a similar amount or on the same or similar terms, nor can any assurance be provided that the lender will not call the debt as a result of these market conditions and forecasted breach or for any other reason. In such event, these material uncertainties cast significant doubt with respect to the ability of the Company to continue as a going concern.

These Financial Statements have been prepared on a going concern basis, which presumes Chinook will continue its operations for the foreseeable future and will be able to realize its assets and discharge its liabilities and commitments in the normal course of business. These Financial Statements do not reflect adjustments and classifications of assets, liabilities, revenues and expenses which would be necessary if Chinook was unable to continue as a going concern.

4. Basis of Presentation

Statement of Compliance

These Financial Statements have been prepared by management using accounting principles consistent with International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board ("IASB"). A summary of Chinook's significant IFRS accounting policies are presented in note 5.

These Financial Statements were approved and authorized for issuance by Chinook's Board of Directors on March 2, 2020.

Basis of Measurement

These Financial Statements have been prepared on the historical cost basis with the exception of certain financial instruments which are measured at fair value with the changes in their fair values recorded in net loss. The methods used to measure fair values are discussed in note 5.

Functional and Presentation Currency

These Financial Statements and the notes thereto are presented in thousands of Canadian dollars, unless otherwise noted. Chinook's functional currency is the Canadian dollar.

Management Judgments and Estimation Uncertainty

The preparation of these Financial Statements requires management judgments and estimation uncertainty that affect the reported amounts at the date of these Financial Statements of assets, liabilities, shareholders' equity, revenues and expenses. Actual results could differ from those estimated. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Judgments that management has made through applying accounting policies that have the most significant effect on the Financial Statements are discussed below:

Cash Generating Units

Cash Generating Units ("CGUs") are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The classification of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, external users, shared infrastructures and the way in which management monitors Chinook's operations.

Impairment (reversal) indicators

Judgments are required to assess when impairment (reversal) indicators exist and impairment (reversal) testing is required. When assessing the recoverability of petroleum and natural gas properties, each CGU's carrying value is compared to its recoverable amount, defined as the greater of its fair value less cost to sell and value in use. In determining the recoverable amount of assets, in the absence of quoted market prices or observed market transactions, impairment tests are based on reserve estimates, market value of undeveloped lands and other relevant assumptions.

Key estimates that management has made that affect the measurement of balances and transactions in the Financial Statements:

Estimated cash flows and net debt

Estimated net debt upon the closing of the Transaction and estimated cash flows through to the Transaction's closing were used in the calculation of impairment for the year ended December 31, 2019. Estimated cash flows directly associated with the Chinook's producing properties were based on future prices, costs and production rates. Estimated net debt includes such cash flows but it further includes future costs not directly associated with Chinook's producing properties. Management expects that these estimated cash flows will be revised, either upward or downward, based on updated information such as future realized commodity pricing, production and costs.

Reserve estimates`

Petroleum and natural gas reserves are used in the calculation of depletion and considered in asset impairment. Reserve estimates and their resulting cash flows are based on engineering data, probability assessments of reserve recoveries, future prices and costs, future production rates, discount rates and the timing and extent of future capital expenditures, all of which are subject to many uncertainties and interpretation. Management expects that over time Chinook's reserve estimates will be revised, either upward or downward, based on updated information such as the results of future drilling, production costs, testing and production levels and changes to forward petroleum and natural gas prices.

Decommissioning obligations

Decommissioning obligations are recognized for the future decommissioning and restoration of development & production and exploration & evaluation assets. These obligations are based on a combination of current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, market conditions, discovery and analysis of site conditions and changes in technology. The expected timing of future decommissioning and restoration may change due to certain factors, including reserve life. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented.

5. **Summary of Significant Accounting Policies**

Basis of Consolidation

Subsidiaries:

Subsidiaries are entities controlled by Chinook. Chinook controls an entity when it is exposed to, or has rights to, variable returns from its involvement with the entity and has the ability to affect those returns through its power over the entity. The financial statements of subsidiaries are included in the Financial Statements from the date that control commences until the date that control ceases.

Jointly Owned Assets:

Certain activities of Chinook are conducted jointly with others where the participants have a direct ownership interest in the related assets. Accordingly, the accounts of Chinook reflect only its working interest share of revenues and expenditures related to these jointly owned assets. Contractual arrangements for Chinook's jointly owned assets govern that the partners have rights to the assets and obligations for associated liabilities. It is possible that at some future date allocation adjustments to revenues or expenditures

could result from revised billings, audit or litigation with these other participants. Where the final outcome of these matters is different from the amounts initially recorded, such differences will affect the revenue or expenditures in the period in which such determination is made.

Transactions eliminated on consolidation:

Intercompany balances and transactions are eliminated in preparing the Financial Statements.

Financial Instruments

Classification of Financial Instruments

There are three principal classification categories for financial instruments: measured at amortized cost, fair value through other comprehensive income or fair value through profit or loss ("FVTPL"). Financial instruments are initially measured at fair value.

The classification of financial assets is generally based on both the business model in which the financial asset is managed and its contractual cash flow characteristics. A financial asset is subsequently measured at amortized cost if it meets both of the following conditions and is not designated as FVTPL:

i) The asset is held with the objective to collect contractual cash flows; and

ii) The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

All other financial assets are subsequently measured at their fair values with changes in fair value recognized in the consolidated statements of operations and comprehensive loss. Financial liabilities are subsequently measured at either their fair value, with changes in fair value recognized in the statements of operations and comprehensive loss, or at amortized cost using the effective interest rate method. Financial instruments are not reclassified as subsequently measured at either amortized cost or FVTPL after their initial recognition.

Chinook evaluates financial instruments classified as FVTPL according to the following hierarchy on the basis of the lowest level observable input that is significant to the fair value measurement of each instrument in its entirety:

- Level 1 – Quoted prices are available in active markets for identical financial instruments as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.
- Level 3 – Valuations in this level are those with inputs that are not based on observable market data.

Impairment of Financial Assets Measured at Amortized Cost

Chinook uses the expected credit loss model for calculating impairment and recognizes expected credit losses as a loss allowance for assets measured at amortized cost. Chinook's accounts receivable are typically short-term with payments received within a three to four month period and they do not have a significant financing component. As a result, Chinook recognizes an amount equal to the expected credit losses based on its historical experience and including forward-looking information. The carrying amount of these assets in the consolidated statements of financial position is net of any loss allowance.

Development and Production Assets ("D&P Assets")

D&P Assets, which include petroleum and natural gas development and production assets, in addition to administrative assets, are measured at cost less accumulated depletion and impairment. These costs are accumulated on an area-by-area basis and represent the cost of developing commercial reserves and bringing them into production, together with the exploration and evaluation expenditures incurred in finding commercial reserves transferred from E&E Assets as outlined above.

Development and production expenditures

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts are recognized as D&P Assets only when they are expected to increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures, including costs of the day-to-day servicing of such assets, are expensed as incurred. Such capitalized costs generally represent expenditures incurred in the development of proved undeveloped or probable reserves in addition to enhancing production from proved producing reserves.

Depletion

D&P Assets with similar useful lives are grouped together for the purposes of performing depletion calculations. Depletion expense is calculated on the unit-of-production basis based on:

- Total estimated proved plus probable reserves calculated in accordance with National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities;
- Total capitalized costs plus estimated future development costs of proved plus probable reserves, which are reviewed annually by an independent reserve engineer; and
- Relative volumes of petroleum and natural gas reserves and production, before royalties, converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of crude oil.

Management reviews these estimates, and changes, if any, are prospectively applied.

Impairment or reversal of previously reported impairment

Chinook's D&P Assets are grouped into CGUs for the purpose of assessing impairment or recovery of prior periods' reported impairments. An impairment test is performed whenever events and circumstances arising during the development and production phase indicate that the carrying value of a CGU may exceed its recoverable amount. On a CGU basis, each carrying amount is compared against its expected recoverable amount, defined as the greater of fair value less costs to sell or its value in use. Fair value less costs to sell is determined as the amount that would be obtained for the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. Fair value less costs to sell of a CGU can also be determined by using assumptions that an independent market participant may take into account. This evaluation could use discounted future net cash flows of proved and probable reserves using forecast prices and costs including the development of prospective lands. Chinook's management determines fair value in use for each CGU by estimating the present value of future net cash flows from continued production through exploitation of its proved and probable reserves. Management applies a present value to these cash flows using a discount rate range depending on the category of reserves being discounted. When it is determined that any CGU's carrying value exceeds its recoverable amount, that CGU is considered impaired and an impairment expense is reported that equals this excess.

If there are indicators that a previously recognized impairment charge may no longer be valid, the recoverable amount of the relevant CGU is determined and compared against its carrying amount. An impairment charge is reversed to the extent that the CGU's carrying amount does not exceed the value that would have been determined, net of depletion, if no impairment loss had been recognized.

Capitalized overhead costs

Overhead costs which are directly attributable to bringing an asset to the location and condition necessary for it to be capable of use in the manner intended by management are capitalized. These costs include directly attributable compensation costs paid to Chinook personnel.

Exploration and Evaluation Assets ("E&E Assets")

Exploration and evaluation expenditures

Exploration and evaluation expenditures are initially capitalized within E&E Assets until the technical feasibility and commercial viability of the project has been determined. Such exploration and evaluation expenditures may include undeveloped land license acquisitions, exploration drilling and testing and directly attributable general and administrative costs. Expenditures incurred prior to obtaining the legal right to explore are expensed as incurred. All other exploration and evaluation expenses, including geological, geophysical and annual lease costs for undeveloped lands, are expensed as incurred.

Amortization

Undeveloped land license acquisition costs for continuing operations are amortized over a term of ten years, which is based on the license term assuming capital requirements are met. All other E&E Assets are not amortized.

Impairment

E&E Asset expenditures are accumulated by well and are carried forward until the existence of commercial reserves are established. Chinook defines commercial reserves as the existence of proved and probable reserves which are determined to be technically feasible and commercially viable to extract. On discovering commercial reserves, the specific exploration and evaluation expenditures are tested for impairment. The carrying value, after any impairment loss, of the relevant exploration and evaluation expenditures are then reclassified as developed and producing assets. If specific exploration and evaluation expenditures, or a portion thereof, are no longer pursued for further evaluation or future development, the relevant costs are charged through exploration and evaluation expense.

In the absence of establishing commercial reserves, E&E Assets are assessed for impairment at the operating segment level. These assets are assessed for impairment if:

- Sufficient data exists to determine technical feasibility and commercial viability; and
- Facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

Provisions

Chinook recognizes a provision in the period in which it has a present legal or constructive liability and a reasonable estimate of the amount can be made. On a periodic basis, management reviews these estimates, and changes, if any, are prospectively applied. Decommissioning obligation provisions are recorded as a liability, with a corresponding increase to the carrying amount of the related asset. The capitalized amount is depleted on a unit-of-production basis over the life of the associated proved plus probable reserves. Other provisions are expensed on initial recognition. Periodic revisions to the liability specific discount rates, estimated timing of cash flows and/or to the original estimated undiscounted costs can also result in changes to provisions. Provisions are increased each reporting period with the passage of time as reported in accretion expense. Actual costs incurred upon settlement are recorded against provisions.

Decommissioning obligations for Chinook's pipelines are not measured because they are considered indeterminable. There is no data or information that can be derived from past practice, industry practice or management intentions to allow management to reasonably estimate the timing and scope of pipeline retirements.

Deferred Taxes

Deferred tax is recognized by providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the balance sheet date.

Deferred tax assets are not recognized unless it is probable that taxable profits will be available against which the deductible temporary differences can be utilized. Deferred tax assets and tax liabilities are offset to the extent there is a legally enforceable right to offset the recognized amounts and the intent is to either settle on a net basis or to simultaneously realize the asset and settle the liability.

Deferred income tax expense is recognized in the consolidated statements of operations and comprehensive loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Share Capital

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

Revenue Recognition

Chinook applies a single, principles-based five-step analysis of transactions to determine the nature of its obligation to perform and whether, how much and when revenue is recognized.

Chinook's revenues are from the following major sources:

- Revenue from its production of petroleum liquids and natural gas;
- Fees charged to third parties for product processing and distribution services provided at facilities or pipelines where Chinook has an ownership interest; and
- Revenue from a take or pay contract where production is delivered by a third party.

Revenues from the sale of petroleum liquids, natural gas and a take or pay contract is measured using the consideration specified in contracts with customers. Chinook recognizes these types of revenues when it transfers control of the product to the buyer and collection is reasonably assured. This is generally at the point in time the purchaser obtains legal title to the product which is when it is physically transferred at an agreed upon delivery point, often a pipeline or other terminal point. Revenues from product processing and distribution services are recognized as these services are provided.

The nature of each of its performance obligations, including roles of third parties and partners, are evaluated to determine if Chinook acts as the principal or as an agent. In making this evaluation, management considers if Chinook obtains control of the product delivered, which is indicated by Chinook having the primary responsibility for the delivery of the product, having the ability to establish prices or having inventory risk. If Chinook acts as the principal in a transaction, revenue is recognized on a gross-basis. If Chinook acts in the capacity of an agent in a transaction, then the revenue only reflects the fee, if any, realized by it from the transaction.

Share-based Compensation

Chinook has the following two types of share-based incentive plans pursuant to which, share awards and share options may be granted to directors, officers, employees and other service providers of Chinook:

Share award incentive plan

The Company has a restricted and performance award incentive plan (the "Share Award Incentive Plan") pursuant to which it began to grant restricted awards ("RSUs") and performance awards ("PSUs") on June 26, 2014. Subject to the terms and conditions of the Share Award Incentive Plan, restricted awards and performance awards entitle the holder to a sum (the "Award Value") to be paid in equal tranches on the first and second anniversaries of the date of grant (the "Payment Date") of such restricted awards or performance awards, as applicable.

On the applicable Payment Date, Chinook, in its sole and absolute discretion, has the option of settling the Award Value to which a holder of restricted awards or performance awards is entitled in the form of either cash or in common shares which may either be acquired by Chinook on the stock exchange on which the common shares may be listed from time to time or issued from the treasury of Chinook, or some combination thereof. Chinook's current non-binding intention is to settle the applicable Award Value in common shares and it has therefore accounted for the fair value of the restricted awards and performance awards as though they will be equity-settled. Provided Chinook maintains this intention and settles the Award Values through the issuance of common shares, it will continue to account for the restricted awards and performance awards as equity-settled throughout their vesting

period. The fair value of the restricted awards and performance awards is determined as of their grant date based on the market price of Chinook's common shares adjusted for an estimated forfeiture rate. The fair value of the performance awards is further adjusted by an estimated payout multiplier.

Share-based compensation expense is recorded over the period that the restricted awards and performance awards vest, with a corresponding increase to contributed surplus, on the basis that the award is expected to be equity settled. Forfeitures are re-estimated throughout the vesting period based on past experience and future expectations with a final adjustment upon actual vesting. The expected life of these granted awards is adjusted based on Chinook's best estimate for the effects of non-transferability and exercise restrictions. When either the restricted awards or performance awards vest they are immediately settled, at which time the related fair value amounts previously recorded in contributed surplus are reclassified to share capital.

In the case of restricted awards, the Award Value is calculated at the Payment Date(s) by multiplying the number of restricted awards by the fair market value of the Chinook common shares. The fair market value is determined on the applicable Payment Date as the volume weighted average trading price of the common shares on the Toronto Stock Exchange (or other stock exchange on which the common shares may be listed) for the five trading days immediately preceding such date.

With respect to performance awards, on each Payment Date, or such other dates as may be determined by the Compensation, Nominating and Corporate Governance Committee (the "Committee") of the Board of Directors, the holder will be entitled to an amount equal to one-half of the Award Value underlying such performance awards multiplied by a payout multiplier. The payout multiplier is determined by the Committee based on an assessment of the achievement of the pre-defined corporate performance measures in respect of the applicable period. The payout multiplier for a particular period can range from one-half to two depending on the point within the target range that Chinook satisfies the corporate performance measures. Annually, prior to the Payment Date in respect of any performance award, the Committee assesses the performance of Chinook for the applicable period.

When a restricted award or performance award vests on a Payment Date, it is immediately settled by Chinook. As a result, the reported outstanding awards will always be unvested.

Share option plan

Share options granted pursuant to Chinook's share option plan are intended to be settled through the issuance of common shares from treasury of Chinook. The fair value of share options is determined on their grant date using the Black-Scholes option pricing model. Share-based compensation expense is recorded over the period that the share options vest, with a corresponding increase to contributed surplus. Forfeitures are re-estimated throughout the vesting period based on past experience and future expectations with a final adjustment upon actual vesting. When share options are exercised, the proceeds, together with the amounts recorded in contributed surplus, are recorded in share capital. The cashless exercise of share options results in a portion of the optionee's share options being forfeited in consideration for the share option exercise price. Upon exercise, the consideration received plus the amount previously recorded as contributed surplus are recognized as share capital.

Gains or Losses on the Transfer or Disposition of Properties

Gains or losses on the transfer or disposition of properties are determined by comparing any proceeds from each transfer or sale with the specific E&E and/or D&P Assets' carrying amounts and disposed decommissioning obligations.

Exchanges of properties are measured at fair value unless the exchange transaction lacks commercial substance or the fair value of neither the asset received nor the asset given up is reliably measurable. The cost of the acquired property is measured at the fair value of the property given up, unless the fair value of the property received is more clearly evident. Chinook will report a gain or loss equal to the difference between the fair value determined for the property acquired relative to the carrying amount of the property given up.

Income (Loss) per Share

Basic income (loss) per share is calculated by dividing the net income or loss attributable to Chinook's common shareholders by the weighted average number of common shares outstanding during the period. Diluted income (loss) per share is determined by the same calculation as basic income (loss) per share except diluted income per share increases the reporting period's weighted average number of outstanding common shares by the weighted average number of outstanding RSUs, PSUs and "in-the-money" options.

Leases

Chinook adopted IFRS 16 "Leases" ("IFRS 16") effective January 1, 2019, using the modified retrospective approach. This approach does not require restatement of prior period financial information as it applies the standard prospectively. This standard replaced *IAS 17, Leases* ("IAS 17"). Under IAS 17, operating lease expenditures were expensed on a straight line basis over the lease term whereas under IFRS 16, there is an increased focus on control of the underlying asset. Mineral licenses and surface leases that allow for the extraction of petroleum and natural gas are not within the scope of IFRS 16.

Right-of-use asset

A lease is a contract that transfers substantially all the risks and rewards incidental to ownership of an identified asset. Chinook initially recognizes a lease at its commencement date which is when an identified asset is made available for use. Right-of-use assets are measured at the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date and any initial direct or estimated restoration costs. A right-of-use asset is then depreciated on a straight-line basis over the shorter of the asset's useful life or the lease term. After the commencement date, Chinook measures its right-of-use assets by applying the net carrying value of these assets to another similar asset grouping where a revaluation model is already applied.

Lease liabilities

Lease liabilities include the present value of future fixed payments (including in-substance fixed payments), less any lease incentives receivable, and the exercise price of a purchase option if it is reasonably certain to be exercised. Future fixed lease payments are discounted using Chinook's incremental borrowing rate if the rate implicit in the lease is not readily determinable. The term of each lease includes its non-cancellable period. The term can also include periods covered by an option to extend the lease if Chinook is reasonably certain to exercise that option. After the commencement date, Chinook would re-measure its lease liabilities to reflect any reassessment or lease modification or to reflect revised in-substance fixed lease payments using a revised discount rate, assuming it cannot be readily determined from the lease, with an offsetting adjustment to right-of-use assets.

Each lease payment is comprised of both a financing and principal component. Financing costs are charged to the consolidated statements of operations and comprehensive loss over each lease's term. Lease payments are applied against lease liabilities using the effective interest method.

Short-term leases with an initial lease term of less than twelve months are evaluated by class of the underlying asset whereas lease payments for low-value assets are evaluated on a lease-by-lease basis. Short-term and low-value leases can be accounted for as either leases or expensed.

Adoption of IFRS 16

On adoption of IFRS 16, right-of-use assets were initially measured at the amount equal to the lease liabilities but as adjusted by the amount of the prepaids & deposits relating to leases recognized in the consolidated statement of financial position immediately before the date of adoption. Chinook also relied on a practical expedient that its assessment of its previous Calgary office space lease was onerous immediately before the date of IFRS 16 adoption as an alternative to performing an impairment review. By choosing this practical expedient, Chinook decreased its previous Calgary office space right-of-use asset on adoption of IFRS 16 by the amount of the onerous contract provision recognized as at December 31, 2018 in the consolidated statements of financial position. Chinook measured the present value of its lease liabilities on adoption of IFRS 16 using a discount rate of 6% as determined from its incremental borrowing rate. The adjustments to the consolidated statements of financial position as at December 31, 2018 resulting from the January 1, 2019 adoption of IFRS 16 are as follows:

	December 31		**January 1**
	2018	**Adjustments**	**2019**
Prepaids & deposits	$ 2,528	$ (244)	**$ 2,284**
Right-of-use assets	**-**	453	**453**
Lease liabilities	**-**	(599)	**(599)**
Provisions	(33,721)	390	**(33,331)**
Total	$ (31,193)	$ -	**$ (31,193)**

Chinook reported its remaining operating lease commitments of $0.8 million as at December 31, 2018 whereas its lease liabilities on adoption of IFRS 16 are $0.6 million. The difference between these two measures was caused by excluding non-lease components from lease liabilities but as partially offset by a portion of lease payments previously reported as onerous.

6. Financial Instruments and Market Risk Management

Financial Instrument Classification and Measurement

Chinook's accounts receivable, debt and accounts payable & accrued liabilities are classified and subsequently measured at amortized cost. The fair value of all of these financial instruments as presented on the consolidated statements of financial position at December 31, 2019, approximates their carrying amount due to their short-term nature.

Chinook's commodity price contracts are financial instruments classified as FVTPL. These contracts were assessed on the fair value hierarchy as Level 2. The estimated commodity price contract's fair value is subject to changes in historical benchmark price volatilities, forward benchmark prices, and rates for both foreign exchange and interest. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy level.

At December 31, 2019 and 2018, Chinook does not have any measurements classified on the fair value hierarchy as either Level 1 or 3.

Market Risk Management

Chinook is exposed to a number of market risks that are part of its normal course of business. Management has primary responsibility for monitoring and managing financial instrument risks under direction from the Board of Directors, which has overall responsibility for establishing Chinook's risk management framework. In the sections below, Chinook prepared a sensitivity analysis in an attempt to demonstrate the effect of changes in these market risk factors on its consolidated statements of operations and comprehensive loss. For the purposes of the sensitivity analysis, the effect of a variation in a particular variable was calculated independently of any change in another variable. In reality, changes in one variable may contribute to changes in another, which may increase or decrease the change. The assumptions made to derive the changes in the relevant risk variables in each sensitivity analysis were based on Chinook's assessment of reasonably possible changes that could occur at December 31, 2019. The results of the sensitivity analysis should not be considered to be predictive of future performance.

Commodity Price Risk

Chinook is exposed to commodity price risk as prices it receives for its petroleum and natural gas production fluctuate. Commodity prices fluctuate as a result of a number of local and global factors including supply and demand, inventory levels, pipeline transportation constraints, weather, political stability and economic factors. Chinook enters into various commodity price contracts to mitigate the exposure to commodity price risk. The use of such instruments is subject to limits established and approved by the Board of Directors. Chinook's policy precludes the use of financial instrument contracts for speculative purposes.

Chinook's outstanding commodity price contracts at December 31, 2019 had the following terms:

Contractual Term	Notional Volumes	Index and Company's Received Price
Natural gas swap		
January 1, 2020 to March 31, 2020	2,000 GJ/d	Westcoast Station 2 CAD$1.785/GJ
Natural gas collars		
January 1, 2020 to March 31, 2020	4,000 mmbtu/d	Chicago City Gate Monthly US$2.15/mmbtu to US$4.11/mmbtu

At December 31, 2019, the above natural gas contracts had a combined fair value of $nil whereas at December 31, 2018, crude oil swaps and natural gas contracts, both of which expired during 2019, had a combined fair value asset and liability of $0.4 million and $0.7 million as reported through the line items fair value of commodity price contracts in current assets and liabilities, respectively, on the consolidated statements of financial position. The fair value of each contract was determined through the difference in the referenced benchmark forward price as compared to the contract's strike price multiplied by the notional volumes during the remaining contractual term.

Although Chinook's commodity price contracts are sensitive to commodity price volatility, because the outstanding contracts as at December 31, 2019 expire on March 31, 2020 and given the modest associated notional volumes, the sensitivity was evaluated as being insignificant.

Chinook's loss on commodity price contracts was comprised of:

	Year ended December 31	
	2019	2018
Realized loss on commodity price contracts	**$ (604)**	$ (982)
Unrealized gain (loss) on commodity price contracts	**235**	(235)
Loss on commodity price contracts	**$ (369)**	$ (1,217)

Interest Rate Risk

Interest rate risk occurs because of changes in market interest rates. Chinook is exposed to interest rate fluctuations on its debt which bears a floating rate of interest. If the interest rate applicable to Chinook's variable rate debt were to increase by 100 basis points, its effect would increase Chinook's consolidated statements of operations and comprehensive loss by $0.1 million for the year ended December 31, 2019.

Foreign Exchange Risk

Foreign exchange risk occurs as financial instruments fluctuate as a result of changes in foreign exchange rates. Most of Chinook's financial instruments are indirectly exposed to currency risk as the underlying commodity prices in Canada for petroleum and natural gas are impacted by changes in the exchange rate between the Canadian and the United States dollars. At December 31, 2019, Chinook held a natural gas commodity price contract where the contracted price was denominated in United States dollars. The associated sensitivity of future foreign exchange rate changes was evaluated as being insignificant for this commodity price contract.

Financial Assets and Credit Risk

Credit risk is the risk of financial loss to Chinook if a partner or counterparty to a product sales contract or financial instrument fails to meet its contractual obligations. At December 31, 2019, Chinook was exposed to credit risk with respect to its accounts receivable. Most of Chinook's accounts receivable relate to petroleum and natural gas sales and operations in jointly owned assets and are subject to typical industry credit risk. During 2019, Chinook had four purchasers that individually accounted for 10% or more of the Company's revenues. Chinook transacts with a number of commodity purchasers and historically has not experienced any purchaser credit losses. Purchasers typically remit amounts to Chinook prior to the end of the month following production. Receivables from partners within jointly owned assets are typically collected within one to three months following production.

Chinook's accounts receivable balance was aged as follows:

	December 31	December 31
	2019	2018
Not past due	**$ 3,546**	$ 3,335
Past due by more than 90 days, net of allowance	**22**	51
	$ 3,568	$ 3,386

Chinook's allowance for doubtful accounts was $0.1 million at December 31, 2019 (December 31, 2018 - $0.2 million). During the year ended December 31, 2019, Chinook wrote-off $0.1 million of receivables that it had previously provided for. Chinook recognizes a loss allowance equal to the expected credit losses based on its historical experience and forward-looking information. Chinook considers all amounts greater than 90 days after the due date to be past due. At December 31, 2019, $nil million of accounts receivable, net of the allowance, were past due and considered to be collectible.

Maximum credit risk is calculated as the total recorded value of accounts receivable as at December 31, 2019.

Financial Liabilities and Liquidity Risk

"Future Operations" and "Debt" (notes 3 & 10) discuss Chinook's immediate liquidity concerns. The following financial liabilities on the consolidated statements of financial position at December 31, 2019 are due within one year:

		Within 1 year
Accounts payable & accrued liabilities	$	4,209
Debt		7,022
	$	**11,231**

7. Development and Production Assets ("D&P Assets")

The following table reconciles Chinook's D&P Assets:

Cost of Assets		**2019**		2018
Balance, beginning of year	**$**	**284,341**	$	281,904
Decommissioning asset change in estimate (note 11a)		**3,639**		1,987
Transfer from exploration & evaluation assets (note 8)		**-**		352
Capital expenditures		**-**		98
Balance, end of year	**$**	**287,980**	$	284,341
Accumulated Depletion & Depreciation				
Balance, beginning of year	**$**	**(201,411)**	$	(171,826)
Impairment		**(30,257)**		(19,600)
Depletion & depreciation		**(6,285)**		(9,985)
Balance, end of year	**$**	**(237,953)**	$	(201,411)
Net book values	**$**	**50,027**	$	82,930

Impairment of D&P and E&E Assets (E&E Assets)

Chinook initially identified evidence indicating impairment in the June 30, 2019 carrying values of its development and production assets. This evidence was a significant sustained reduction in forward British Columbia Station 2 natural gas pricing. Further evidence indicating impairment in the June 30, 2019 carrying value of development & production assets were concerns about Chinook's ability to finance its future development costs and the timing thereof (see note 3). As a result, Chinook tested for impairment on its one remaining *Peace River Arch* CGU. The CGU's recoverable value was estimated using a value-in-use calculation based on a roll forward of the December 31, 2018 independently prepared reserve report adjusted by management for the three engineering firms' average July 1, 2019 price forecasts, reserves produced during the first six months ended June 30, 2019 and deferring future development costs. Management used this report's expected future net revenues anticipated to be produced from the combined reserve categories proved developed, proved undeveloped and probable reserves, using before income tax discount rates ranging from 10% to 20% depending on the reserve category. This test revealed impairment of $18.9 million for the three and six months ended June 30, 2019.

Chinook identified further evidence indicating impairment in the December 31, 2019 carrying value of its D&P and E&E Assets. This evidence was the execution of the Arrangement Agreement (see note 2) where the associated consideration of $0.0675 per common share (the "Share Consideration") was less than Chinook's equivalent per common share book amount. As a result of the Arrangement Agreement, the recoverable value of both Chinook's D&P and E&E Assets was determined from their combined fair value less costs to sell which also approximates a value-in-use measure because Chinook's intention is now to sell the Company. As at June 30, 2019 and December 31, 2018, Chinook's D&P Assets' recoverable value was measured using a value-in-use model partially because the intended use at that time was to continue operations.

The combined net carrying amount prior to recognizing any further impairment as at December 31, 2019 of Chinook's D&P and E&E Assets (see note 8) less decommissioning obligations (see note 11) was $36.1 million. This net carrying amount was then compared to the proceeds pursuant to the Arrangement Agreement as detailed as follows:

- $15.1 million as determined from the Share Consideration of $0.0675 per Chinook common share times the 223.7 million of outstanding common shares; and
- Estimated net debt, as defined by the Arrangement Agreement.

These combined proceeds which approximate the fair value of the Transaction on its estimated closing date in late April 2020 are after forecasted costs to sell which have been assumed by the Purchaser. The estimated fair value less costs to sell at April 2020 was then used to determine the equivalent measure at December 31, 2019. The total consideration to be paid to Chinook shareholders plus estimated net debt and cash flow growth through to the closing of the Transaction is estimated to be $22.8 million. Because the combined net carrying amount exceeded the fair value less costs to sell, this resulted in Chinook charging impairment of $13.3 million as then allocated to both D&P and E&E Assets. This allocation was determined from the respective carrying values of D&P and E&E Assets immediately prior to recognizing this latter impairment. Including the recognized impairment of $18.9 million charged against the D&P assets for the three and six months ended June 30, 2019, the combined impairment of D&P and E&E Assets of $32.2 million for the year ended December 31, 2019 was respectively allocated at $30.3 million and $1.9 million as then charged against each of the carrying amounts of these assets ($19.6 million and $nil, respectively, for the year ended December 31, 2018).

No impairment expense sensitivity analysis has been provided as the fair value less costs to sell was contractually determined.

Transfer of pipeline from customer

During a previously reported year, a customer transferred to Chinook a section of pipeline which connected Chinook's Martin Creek Sales Line, located in northeast BC, to a third party pipeline. Management's estimated fair value of this connecting pipeline resulted in a corresponding deferred customer obligation that is being amortized over the term of the agreement, which expires October 31, 2020, pursuant to which Chinook is contractually obligated to provide this customer with access to a portion of the Martin Creek Sales Line. As a result, for the years ended December 31, 2019 and 2018, $0.8 million per year was recognized through the line item deferred customer obligation amortization as included on the consolidated statements of operations and comprehensive loss. The remaining deferred customer obligation at December 31, 2019, of $0.6 million as presented on the consolidated statements of financial position was classified as a current liability (December 31, 2018 - $1.4 million presented as $0.8 million and $0.6 million current and long-term liabilities, respectively).

8. Exploration & Evaluation Assets

At December 31, 2019 and 2018, Chinook's exploration properties, are prospective for the Montney formation as located in the Peace River Arch area. The following table reconciles Chinook's E&E Assets:

Cost of Assets	**2019**	2018
Balance, beginning of year	**$ 32,818**	$ 30,529
Cost of properties sold (note 16)	**(115)**	(384)
Capital expenditures	**-**	2,792
Transfer to development & production assets (note 7)	**-**	(352)
Decommissioning asset additions (note 11a)	**-**	233
Balance, end of year	**$ 32,703**	$ 32,818
Accumulated Amortization		
Balance, beginning of year	**$ (20,670)**	$ (19,240)
Impairment (note 7)	**(1,936)**	-
Amortization	**(1,656)**	(1,669)
Properties sold (note 16)	**82**	239
Balance, end of year	**$ (24,180)**	$ (20,670)
Net book values	**$ 8,523**	$ 12,148

Capitalized general and administrative expenses

Chinook capitalized $nil and $0.2 million of direct general and administrative costs related to its exploration activity during the years ended December 31, 2019 and 2018, respectively.

Exploration & Evaluation expense

Exploratory lease rental costs of $0.2 million per year were expensed during the years ended December 31, 2019 and 2018 as included in the line item "other losses" on the consolidated statements of operations and comprehensive loss.

9. Leases

Chinook's current portfolio of leases mostly consists of its new Calgary head office space.

a) Right-of-use assets

A reconciliation of Chinook's right-of-use assets for the year ended December 31, 2019 is as follows:

Balance, January 1, 2019 (note 4)	**$ 453**
Additions (note 9b)	121
Expenditures	29
Depreciation	(449)
Balance, end of year	**$ 154**

b) Lease liabilities

A reconciliation of Chinook's lease liabilities for the year ended December 31, 2019 is as follows:

Balance, January 1, 2019 (note 4)	**$**	**599**
Lease payments (note 9a)		(580)
Additions		121
Interest expense		16
Balance, end of year	**$**	**156**

As at December 31, 2019, Chinook measured the present value of its lease liabilities using a discount rate of 7.8% as estimated from its incremental borrowing rate. Lease liabilities as at December 31, 2019, are expected to be paid through to February 2025.

10. Debt

Chinook's amended demand credit facility agreement with a Canadian chartered bank had an availability of $10.0 million as at December 31, 2019 and 2018 (the "Demand Credit Facility"). Subsequent to December 31, 2019, Chinook and its lender completed the borrowing base redetermination. The maximum availability remained unchanged at $10.0 million. This most recent renewal as signed on February 28, 2020 (see note 2) removed the minimum hedging requirement that previously was a requirement as at December 31, 2019 and 2018 in addition to waiving breaches in the net debt to cash flow financial covenant as determined at June 30, September 30 and December 31, 2019 and as forecast for March 31, 2020. The next renewal is scheduled on May 31, 2020 but may be set at an earlier (or later) date at the sole discretion of the lender.

At December 31, 2019, Chinook had debt borrowings of $7.0 million, which included $4.7 million of borrowings drawn during the year ended December 31, 2019, and undrawn letters of credit of $0.9 million (notes 3 & 19), as secured by its lender, which reduced the available credit to $2.1 million (at December 31, 2018 – drawings of $2.4 million, undrawn letters of credit of $0.9 million and available credit of $6.7 million). The annualized effective interest rates on draws against the Demand Credit Facility for the years ended December 31, 2019 and 2018 was 5.3% and 4.6%, respectively.

All borrowings under the Demand Credit Facility have always been classified as a current liability, as the lender can request repayment of all outstanding drawn amounts at any time. Borrowings incur interest at the prime rate plus an applicable margin and are collateralized by floating charges and security interests over all of Chinook's present and future properties and other assets. In addition, the Demand Credit Facility includes operating and financial restrictions on Chinook that include restrictions on paying dividends or making other distributions in respect of Chinook's securities.

The Demand Credit Facility has financial covenants requiring that at each reporting period the *adjusted working capital* equals or exceeds a one-to-one ratio and that *net debt to cash flows* (waived for March 31, 2020) does not exceed a three-to-one ratio. For the purposes of these covenants:

- *Adjusted working capital* is defined as working capital excluding both the current portion of commodity price contracts and debt but including the undrawn portion of the Demand Credit Facility,
- *Net debt* is defined as working capital but excluding the current portion of commodity price contracts, and
- *Cash flows* are determined over the last 12 months and are defined as cash flows from operating activities before changes in non-cash working capital less lease payments.

The February 28, 2020 renewal also has additional reporting requirements including weekly forecasted cash flows and monthly abandonment and reclamation activities in addition to requiring that the minimum LMR does not fall below 1.3 as determined for Chinook by the BCOGC.

Although Chinook recently received waivers for past financial covenant breaches and a forecasted breach, it is further forecasting that it will be in breach of the *net debt to cash flow* financial covenant per the terms of the renewed demand credit facility agreement as at June 30, 2020 assuming average realized natural gas and natural gas liquids' pricing of $1.86/mcf and $41.76/bbl, respectively. In the event that the Transaction is not completed, when the next borrowing base redetermination commences as scheduled on (or before or later) May 31, 2020, because of the forecasted breach, no assurance can be provided that the borrowing base will be renewed at the

same or a similar amount or on the same or similar terms, nor can any assurance be provided that the lender will not call the debt as a result of this forecasted breach or for any other reason.

11. Provisions

As described in note 5, Chinook relied on a practical expedient resulting in the December 31, 2018, onerous contract provision recognized in the consolidated statements of financial position decreasing its right-of-use asset on adoption of IFRS 16. The following table details the resulting change in the provisions' classification on adoption of IFRS 16:

	December 31		January 1
	2018	**Adjustments**	**2019**
Current portion	$ 575	$ (390)	**$ 185**
Long term portion	33,146	-	**33,146**
Total	$ 33,721	$ (390)	**$ 33,331**

Chinook's remaining provisions after adopting IFRS 16 consisted of both decommissioning obligations and indemnifications as detailed in the following table:

	December 31	January 1
	2019	2019
Decommissioning obligations (a)	**$ 35,754**	$ 32,417
Indemnifications (b)	**100**	914
Total provisions	**$ 35,854**	$ 33,331

As classified as follows:

	December 31	January 1
	2019	2019
Current portion	**$ 240**	$ 185
Long term portion	**35,614**	33,146
Total provisions	**$ 35,854**	$ 33,331

a) Decommissioning obligations

The total future decommissioning obligations were estimated by management based on Chinook's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. At December 31, 2019, Chinook has estimated the net present value of its total decommissioning obligation based on a total future undiscounted liability of $37.1 million ($33.3 million - December 31, 2018). At December 31, 2019, management estimates that these payments are expected to be made over the next 14 years (23 years – December 31, 2018). At December 31, 2019 and, 2018, risk free rates of 1.8% and 2.1% and inflation rates of 1.5% and 2.0%, respectively, were used to calculate the present values of the decommissioning obligations.

The following table reconciles Chinook's decommissioning obligations:

	2019	2018
Balance, beginning of year	**$ 32,417**	$ 31,125
Decommissioning obligations' additions and change in estimate (notes 7 & 8)	**3,639**	2,220
Expenditures	**(940)**	(742)
Accretion of decommissioning obligations (note 14)	**638**	680
Property dispositions (note 16)	**-**	(866)
Balance, end of year	**$ 35,754**	$ 32,417

The increase in the decommissioning obligations' change in estimate during the year ended December 31, 2019 was caused by an increase in cost estimates recently released by the British Columbia Oil & Gas Commission and an expectation that such costs will be incurred earlier as partially offset by an increase in the difference between the risk free and inflation rates. This same increase during the year ended December 31, 2018 was caused by exploration activities and a change in estimate resulting from a decrease in the risk free rate.

b) Indemnifications

Chinook is involved in litigation and claims arising from indemnifications provided to the buyer of its former Tunisian operations that are attributable to years prior to 2014. During the year ended December 31, 2019, the Tunisian Appellant Court ruled on a claim initiated by a previous Tunisian service provider. This ruling was lower than what Chinook had previously measured and resulted in a decrease to its indemnification provision reported as a $0.7 million change in estimate with no associated expenditure. During the year ended December 31, 2019, indemnification provision expenditures associated with defending Chinook's interests totaled $0.1 million. Chinook's estimated remaining indemnification provision was $0.1 million as at December 31, 2019.

Expenditures applied against Chinook's onerous contract (see note 5) and indemnification provision for the year ended December 31, 2018 totaled $0.9 million.

12. Share Capital

Authorized

An unlimited number of no par value common shares and first preferred shares.

Issued and Outstanding Common Shares

The holders of common shares are entitled to share equally in dividends, returns of capital and to vote at shareholders' meetings.

During a previously reported year, Chinook completed a private placement on a flow-through basis. A premium of $0.3 million received on the flow-through common shares was determined from the difference between the total gross proceeds and the estimated fair value of the equivalent number of Chinook's common shares immediately preceding the date of the flow-through common share announcement. During the year ended December 31, 2018, Chinook incurred the required qualifying Canadian exploration expenditures pursuant to this issuance of common shares on a flow-through basis. As a result, for the year ended December 31, 2018, Chinook amortized the associated $0.3 million flow-through common shares premium.

13. Revenues

Chinook sells its petroleum and natural gas production and take-or-pay contract deliveries pursuant to fixed or variable price volume contracts. Petroleum and natural gas production is sold under various contracts with terms of up to one year. Take-or-pay is sold pursuant to a contract with a term through to March 2021. During the year ended December 31, 2019, Chinook also reported take-or-pay revenues for sales of third party acquired natural gas volumes which were necessary to meet its natural gas production performance obligations. Take-or-pay, petroleum and natural gas revenues are normally collected in the month following revenue recognition. The transaction prices for the take-or-pay and variable price production contracts are based upon benchmark pricing for petroleum or natural gas commodities adjusted for quality, location, transportation or other factors. Under these types of contracts, Chinook is required to deliver a variable volume of petroleum liquids or natural gas to the purchaser. The amount of revenue recognized is based on the agreed transaction price, whereby any variability in revenue relates specifically to Chinook's efforts to transfer production, and therefore the resulting revenue is allocated to the production delivered in the period during which the variability occurs. Petroleum and natural gas revenues are recognized when Chinook gives up control of the unit of production at the delivery point agreed to under the terms of the contracts. As a result, none of the variable revenue is considered constrained.

Processing and distribution services are generally sold under multi-year contracts at fixed fees that vary by volume. Revenues from these contracts are typically collected within three months from billing.

Chinook's production revenue was primarily generated by its Birley/Umbach area located in British Columbia.

The following table presents Chinook's total revenues disaggregated by source:

	Year ended December 31	
	2019	2018
Petroleum & natural gas revenues		
Natural gas liquids	**$ 6,272**	$ 12,354
Natural gas	**7,969**	13,103
Crude oil	**153**	490
Petroleum & natural gas revenues	**14,394**	25,947
Other revenues		
Processing & gathering	**1,457**	1,050
Take-or-pay	**3,053**	3,821
Other revenues	**4,510**	4,871
Total petroleum, natural gas and other revenues	**$ 18,904**	$ 30,818

Included in accounts receivable at December 31, 2019 is $3.1 million of accrued and billed revenues ($2.8 million - December 31, 2018). Changes in accrued production revenues result from changes in Chinook's production and transaction prices. There were no significant revenue adjustments from prior periods reflected in the revenues reported for the years ended December 31, 2019 and 2018.

As at December 31, 2019, Chinook did not have any contracts for the sale of its future production beyond a one year term. However, it has one processing & gathering contract to provide pipeline transportation services to a third party for a minimum of $1.6 million per year for at least a two year period commencing at the earlier of that party's tie-in to the Company's pipeline, at their cost, or October 2020.

14. Financing

	Year ended December 31	
	2019	2018
Accretion of decommissioning obligations (note 11a)	**$ 638**	$ 680
Interest on bank debt	**295**	109
Other	**38**	84
Financing expense	**$ 971**	$ 873

15. Long-term Incentive Plans

Chinook grants share options, restricted awards and performance awards (collectively, "Share-Based Awards") to employees, officers, directors, consultants and other service providers pursuant to its long-term incentive plans. The maximum number of common shares potentially issuable from treasury upon conversion of outstanding Share-Based Awards may not exceed 10% of Chinook's issued and outstanding common shares.

For the years ended December 31, 2019 and 2018, share-based compensation expense resulting from Chinook's granted Share-Based Awards was $0.5 million per year.

Share Option Plan

Outstanding options granted pursuant to Chinook's share option plan vest evenly over a period of three years and expire five years after the grant date. The following table reconciles Chinook's outstanding options:

	Number of Options (thousands)	Weighted Average Exercise Price ($/option)
Balance as at December 31, 2017	**10,277**	**$ 0.71**
Granted	6,285	0.20
Cancelled or forfeited	(2,939)	(0.55)
Expired	(446)	(1.18)
Balance as at December 31, 2018	**13,177**	**$ 0.49**
Granted	4,560	0.14
Cancelled or forfeited	(1,006)	(0.30)
Expired	(1,255)	(1.71)
Balance as at December 31, 2019	**15,476**	**$ 0.30**
Exercisable	**6,359**	**$ 0.45**

The table below summarizes the outstanding and exercisable share options, their respective weighted average exercise prices and remaining lives at December 31, 2019:

	Outstanding Options			Outstanding Exercisable Options		
Range of Exercise Prices ($/option)	**Options Outstanding (thousands)**	**Weighted Average Exercise Prices ($/option)**	**Weighted Average Remaining Life (years)**	**Options Outstanding (thousands)**	**Weighted Average Exercise Prices ($/option)**	**Weighted Average Remaining Life (years)**
$0.14	4,275	$ 0.14	4.0	-	$ -	-
$0.20	5,261	$ 0.20	3.1	1,754	$ 0.20	3.1
$0.38	4,005	$ 0.38	2.3	2,670	$ 0.38	2.3
$0.54 - $1.24	1,935	$ 0.76	0.7	1,935	$ 0.76	0.7
	15,476	**$ 0.30**	**2.8**	**6,359**	**$ 0.45**	**2.0**

In addition to forfeiture rates of approximately 14% and 13%, which were used in the measure of share-based compensation, the following factors were used in the Black-Scholes pricing model for the determination of the fair value of options granted during the years ended December 31, 2019 and 2018, respectively:

	2019	2018
Expected average life (years) [1]	**3 to 5**	**3 to 5**
Weighted average risk-free interest rate (%)	**1.9**	**2.0**
Weighted average volatility factor (%) [2]	**64 to 80**	**59**
Share option exercise price ($/option)	**0.14**	**0.20**

(1) The expected average life of the share option is based on time to vest plus a historical calculation.

(2) The volatility factor is based on historical price volatility of Chinook's common shares over the expected life of the option.

The determined weighted average fair value for options granted during the years ended December 31, 2019 and 2018 was $0.08 and $0.09 per option, respectively.

Share Award Incentive Plan

The following table reconciles Chinook's outstanding restricted awards issued pursuant to the Share Award Incentive Plan:

	Number of Restricted Awards (thousands)
Balance as at December 31, 2017	200
Granted	191
Distributed	(40)
Cancelled	(224)
Balance as at December 31, 2018	**127**
Distributed	(77)
Balance as at December 31, 2019	**50**

The fair value determined for restricted awards granted during the year ended December 31, 2018 was $0.20 per award. This fair value was based on the market price of Chinook's common shares on the grant date of the restricted awards. No restricted awards were granted during the year ended December 31, 2019.

There were no outstanding performance awards as at December 31, 2019 and 2018.

16. Property Dispositions

During the year ended December 31, 2019, Chinook sold its rights to undeveloped lands located in Gordondale, Alberta. There were negligible proceeds and net carrying amounts associated to this property disposition.

During the year ended December 31, 2018, Chinook disposed of its rights to undeveloped lands and suspended wells located in Rigel, British Columbia and Gordondale, Alberta. The $0.2 million net carrying amount of the undeveloped lands less $0.9 million of associated decommissioning obligations resulted in a gain on the transfer of property rights of $0.7 million for the year ended December 31, 2018.

17. Income Taxes

The provision for income taxes reflects an effective tax rate which differs from the expected statutory rate. Differences were accounted for as follows:

	Year ended December 31	
	2019	2018
Net loss before tax	**$ (42,263)**	$ (27,654)
Effective tax rate	**26.8%**	27.0%
Expected income tax recovery	**$ (11,305)**	$ (7,467)
Effect on income tax resulting from:		
Decrease in future expected statutory tax rates	**7,148**	-
Change in unrecognized tax asset excluding renounced expenditures	**3,469**	6,970
Tax rate differences on decrease in future expected statutory tax rates and unrecognized tax assets	**743**	-
Permanent differences	**(51)**	37
Adjustments to opening deferred tax balances	**(4)**	(35)
Expenditures renounced to flow-through common shares	**-**	495
Total income tax expense	**$ -**	$ -

The statutory tax rate consists of the combined federal and provincial tax rates applicable for the Company and its subsidiaries.

Unrecognized deferred tax assets

Deferred tax assets have not been recognized in respect of the following items, because it is not probable that there will be available future taxable profitability against which Chinook can realize the benefits therefrom:

	December 31 2019	December 31 2018
Development & production/exploration & evaluation assets	**$ 35,358**	$ 15,421
Provisions	**35,754**	32,807
Non-capital losses	**316,985**	296,363
Net capital losses	**10,987**	10,987
Other	**733**	1,774
	$ 399,817	$ 357,352

At December 31, 2019, Chinook had $317.0 million of non-capital losses (December 31, 2018 - $296.4 million). The losses will expire commencing in 2029 through to 2040.

Change in effective tax rate

The Government of Alberta's Bill 3, *Job Creation Tax Cut Act*, received Royal Assent during the year ended December 31, 2019. This reduced the general Alberta corporate tax rate from 12% to 11.5% during 2019 and will further reduce this rate from 10% to 8% from 2020 to 2022. Because Chinook's head office is in Calgary whereas its operations are in located in northeast BC, approximately one-half of any future corporate taxable income would be allocated to Alberta with the other half allocated to BC. These reduced tax rates have lowered the value of Chinook's unrecognized deferred tax assets and their associated valuation allowance.

Uncertain tax position

Chinook is subject to taxation in Canada and was subject to taxation in international jurisdictions. There are many transactions and calculations during the course of business for which the ultimate tax determination is uncertain. Chinook maintains provisions for uncertain tax positions that it believes appropriately reflect its risk. These provisions are made using the best estimate of the amount expected to be paid based on a qualitative assessment of all relevant factors. Chinook reviews the adequacy of these provisions at the end of the reporting period. However, it is possible that at some future date, liabilities in excess of Chinook's provisions could result from audits by, or litigation with, tax authorities. Where the final outcome of these tax-related matters is different from the amounts that were initially recorded, such differences will affect the tax provisions in the period in which such determination is made.

18. Related Party and Significant Shareholder

Chinook has determined that its key management personnel consist of its officers and directors. In addition to the salaries and directors fees paid to the officers and directors, respectively, the officers and directors participate in Chinook's share option plan. The officers' salaries, directors' fees and other benefits, as mostly included in general and administrative expense for the years ended December 31, 2019 and 2018, totaled $1.2 million and $1.7 million, respectively. The share option plan benefits for Chinook's officers and directors, as included in share-based compensation for the years ended December 31, 2019 and 2018, totaled $0.4 million and $0.5 million, respectively.

Alberta Investment Management Corporation ("AIMCo"), as investment manager to Her Majesty the Queen in Right of the Province of Alberta ("HMQ"), maintains investment control and direction over approximately 36% of Chinook's outstanding common shares for the benefit of HMQ. Pursuant to a management and administration services agreement (the "Services Agreement") dated June 29, 2010, Chinook was engaged to manage, administer and maintain the properties and the books, accounts and records of WOGH Limited Partnership ("WOGH"). WOGH is held by nominees of AIMCo on behalf of HMQ. As Chinook manages, administers and maintains the properties and the books, accounts and records of WOGH, the Company is reimbursed for such services. In accordance with the Services Agreement, Chinook reported a recovery from WOGH, which is mostly reported against the Company's general and administrative expense of $0.5 million and $0.9 million for the years ended December 31, 2019 and 2018, respectively. The recovery for the years ended December 31, 2019 and 2018 was generally determined from WOGH's pro rata share as estimated at 11% and 12%, respectively, of its and Chinook's combined production volumes. At December 31, 2019 and 2018, $nil million and $0.1 million, respectively, of this general and administrative recovery was included in accounts receivable.

19. Commitments and Guarantees

At December 31, 2019, Chinook had the following unrecognized minimum future contractual payments without giving effect to any offsetting third party agreements, which are anticipated to reduce some of these amounts:

	2020	2021	2022	2023	2024	Thereafter	Total
Office contracts	$ 348	$ 320	$ 304	$ 300	$ 301	$ 47	$ 1,620
Operating and transportation contracts	2,338	220	-	-	-	-	2,558
	$ 2,686	**$ 540**	**$ 304**	**$ 300**	**$ 301**	**$ 47**	**$ 4,178**

The office contracts include the non-lease component of Chinook's current Calgary office space whereas the operating and transportation contracts relate to minimum contractual payments should Chinook not benefit from the operating services or pipeline transportation.

At December 31, 2019 and 2018, Chinook has guaranteed a pipeline commitment through undrawn letters of credit of $0.9 million (notes 3 & 10) as secured by its lender. At December 31, 2018, Chinook's prepaids and deposits included a payment of $1.2 million to further guarantee this pipeline commitment that was mostly refunded during the year ended December 31, 2019. At December 31, 2019, Chinook guaranteed future processing tolls through a payment of $0.5 million as included in prepaids and deposits. CEI has also guaranteed indemnifications provided by its wholly-owned subsidiary, Storm BVI, to the buyer of its former Tunisian operations (see note 11b).

20. Other Supplementary Information

Changes in non-cash working capital

	Year ended December 31	
	2019	2018
Cash provided by (used for):		
Accounts receivable	**$ (182)**	$ 104
Prepaids & deposits	**759**	(1,155)
Accounts payable & accrued liabilities	**(1,338)**	(4,368)
	$ (761)	$ (5,419)
Cash provided by (used for):		
Operating activities	**$ (310)**	$ (1,311)
Financing activities	**-**	(20)
Investing activities	**(451)**	(4,088)
	$ (761)	$ (5,419)

Chinook's prepaids & deposits' balance at December 31, 2018 was lowered by prepaid office space rents on the January 1, 2019 adoption of IFRS 16 (see note 5).

Cash interest and financing fees paid

	Year ended December 31	
	2019	2018
Cash interest & financing fees paid	**$ 317**	$ 137

Per share amounts

	Year ended December 31	
	2019	2018
Weighted average shares outstanding - basic & diluted (thousands)	**223,672**	223,594
Net loss	**$ (42,263)**	$ (27,654)
Net loss per share - basic & diluted ($/share)	**$ (0.19)**	$ (0.12)

For the years ended December 31, 2019 and 2018, because Chinook reported net losses, the effect of outstanding Share-Based Awards would have been anti-dilutive resulting in them being excluded in the calculation of diluted weighted average shares outstanding.

Consolidated statements of operations and comprehensive loss presentation

Chinook's consolidated statements of operations and comprehensive loss was prepared primarily by nature of expense, with the exception of employee compensation costs which were included in the production and operating, general and administrative, severance and exploration and evaluation expense line items.

The following table details the amount of total employee compensation costs included in these line items in the consolidated statements of operations and comprehensive loss:

	Year ended December 31	
	2019	2018
Production & operating	**$ 445**	$ 476
General & administrative	**1,138**	1,052
Severance costs	**-**	834
Exploration & evaluation	**-**	45
Total employee compensation costs	**$ 1,583**	$ 2,407

Corporate Information

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STOCK EXCHANGE / SYMBOL

TSX: CKE

DIRECTORS

Jill T. Angevine, Chairman (1) (2) (3)
Robert J. Herdman (1) (3)
Robert J. Iverach (1) (2) (3)
Walter J. Vrataric (2)

(1) Member of the Audit Committee
(2) Member of the Reserves, Safety and Environmental Committee
(3) Member of the Compensation, Nominating and Corporate Governance Committee

MANAGEMENT

Walter J. Vrataric
President & Chief Executive Officer

Timothy S. Halpen
Chief Operating Officer

Jason B. Dranchuk
Vice President, Finance & Chief Financial Officer

Darrel G. Zacharias
Vice President, Exploration

Chad T. Lerner
Vice President, Land

Fred D. Davidson
Corporate Secretary

SOLICITOR

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

AUDITORS

KPMG LLP, Calgary, Alberta

BANKERS

National Bank of Canada

REGISTRAR & TRANSFER AGENT

Alliance Trust Company, Calgary, Alberta

RESERVE ENGINEER

McDaniel & Associates Consultants Ltd., Calgary, Alberta

ABBREVIATIONS

AECO	Western Canadian Natural Gas reference price
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
bbl	barrels
bbl/d	barrels per day
IFRS	International Financial Reporting Standards
GJ	gigajoules
GJ/d	gigajoules per day
mboe	thousand barrels of oil equivalent
mcf	thousands of cubic feet
mcf/d	thousands of cubic feet per day
mmbtu	millions of British Thermal Units
mmbtu/d	millions of British Thermal Units per day
mmcf	millions of cubic feet
mmcf/d	millions of cubic feet per day
NGL	natural gas liquids
WCSB	Western Canadian Sedimentary Basin
WTI	West Texas Intermediate oil price
Station 2	market point for BC natural gas
Chicago City Gate	market point for eastern natural gas

CONVERSION

Six thousand cubic feet (mcf) of natural gas equals one barrel of oil equivalent