HIGHWOOD
OIL COMPANY LTD.

MANAGEMENT DISCUSSION & ANALYSIS
FOR THE YEAR ENDED DECEMBER 31, 2018

April 29, 2019

Management's Discussion and Analysis

This management's discussion and analysis (MD&A) of operating and financial results of Highwood Oil Company Ltd. ("Highwood" or the "Company") is dated April 29, 2019 and is based on currently available information. It should be read in conjunction with the audited consolidated financial statements and accompanying notes for the years ended December 31, 2018 and 2017. Unless otherwise noted, all financial information is presented in Canadian dollars, and is in accordance with International Financial Reporting Standards (IFRS) as set out in Part 1 of the Chartered Professional Accountants Canada Handbook – Accounting. Additional information can be found at www.sedar.com and www.highwoodoil.com.

Effective October 29, 2018, the Company changed its name from Predator Oil Ltd. to Highwood Oil Company Ltd.

Refer to the end of the MD&A for commonly used abbreviations.

Readers should read "Forward-Looking Statements" at the end of the MD&A, which explains the basis for and limitations of statements throughout this report that are not historical facts and may be considered "forward-looking statements" under securities regulations.

Description of Business

The Company is engaged in the acquisition, exploration, development and production of oil and natural gas reserves in Western Canada. The Company's focus is to generate and develop its own prospects, acquire oil and natural gas properties directly and/or through farm-in, and participate with joint ventures and other industry partners in oil and natural gas exploration and development in Alberta.

2018 Corporate Highlights

- Achieved production of 1,117 bbl/d of oil in the fourth quarter of 2018, flat from 1,120 bbl/d in the fourth quarter of 2017.

- Acquired 62.5 gross (32.25 net) sections of Clearwater formation lands in 2018, bringing total sections to 196 gross (99 net) at December 31, 2018. Subsequent to year-end the Clearwater land position has grown to 226 gross (115 net) sections and presents exciting drilling opportunities with short cycle times. Minimal bookings for the Clearwater formation have been incorporated into the December 31, 2018 reserves providing significant reserve upside.

- Successfully drilled 4 gross (2 net) wells in the Clearwater Formation in the fourth quarter which have performed as per internal type curves. 3 gross (1.5 net) wells were drilled in Q1 2019, bringing total wells drilled to 7 gross (3.5 net). Assuming WCS realized pricing remains in the range of current strip pricing, Highwood would plan to drill another 6 to 10 gross (3 to 5 net) wells in the Clearwater before the end of 2019.

- Transportation and pipeline revenue from the Wabasca River Pipeline of $3.9 million for the year and $1.3 million for the quarter ended December 31, 2018.

- Additionally, current production from Highwood is approximately 1,550 bbl/d of oil.

Highwood Oil Company Ltd. – Financial and Operating Highlights

	Three months ended December 31,				Year ended December 31,			
		2018		2017		**2018**		2017
Financial								
Oil and natural gas sales	**$**	**3,159,126**	$	6,276,681	**$**	**24,985,489**	$	28,289,467
Transportation pipeline revenues		**1,308,526**		-		**3,948,611**		-
Total revenues, net of royalties [(1)]		**8,802,798**		1,127,095		**27,679,711**		28,293,860
Income (loss)		**1,223,306**		(1,073,072)		**(1,809,819)**		598,854
Capital expenditures		**6,419,621**		4,657,830		**23,248,021**		36,440,187
Proceeds from dispositions [(7)]		**3,013,900**		8,352,653		**3,154,991**		34,380,459
Working capital deficit *(end of period)* [(2)]						**29,630,459**		14,573,417
Shareholders' equity *(end of period)*					**$**	**24,579,552**	$	26,863,521
Shares outstanding *(end of period)*						**5,744,204**		5,538,674
Options outstanding *(end of period)*						**-**		636,000
Weighted-average basic shares outstanding		**5,695,056**		5,538,674		**5,578,091**		5,538,674
Operations [(3)]								
Production								
Natural gas *(Mcf/d)*		**12**		73		**30**		2,403
Natural gas liquids (NGL) *(bbls/d)*		**0**		1		**0**		144
Crude oil *(bbls/d)*		**1,117**		1,111		**1,120**		1,214
Total *(boe/d)*		**1,119**		1,124		**1,125**		1,759
Benchmark prices								
Natural gas								
AECO *(Cdn$/GJ)* [(6)]	**$**	**2.16**	$	1.36	**$**	**1.62**	$	1.46
Crude oil								
Canadian Light *(Cdn$/bbl)*		**43.30**		61.41		**63.93**		55.09
Average realized prices [(4)]								
Natural gas *(per Mcf)* [(6)]		**2.01**		1.30		**1.35**		2.86
NGL *(per bbl)* [(6)]		**72.03**		43.79		**71.30**		23.25
Crude oil *(per bbl)*		**30.27**		61.30		**61.06**		55.42
Operating netback *(per boe)* [(5)]		**(3.38)**		23.83		**7.21**		13.28

(1) Includes gain and losses on commodity contracts

(2) Working capital deficit includes commodity contract asset of $1,316,000 (December 31, 2017 – commodity contract liability of $523,000). Excluding this, the working capital deficit would be $30,946,459 (December 31, 2017 – $14,050,417). Working capital deficit also includes revolving operating demand loan of $33,000,000 (December 31, 2017 - $16,400,000).

(3) For a description of the boe conversion ratio, see "Basis of Barrel of Oil Equivalent".

(4) Before hedging.

(5) See "Non-GAAP measures".

(6) For 2018, natural gas and NGL production and revenues are immaterial to the Company

Includes $3,487,981 in proceeds on disposal of investment for the year ended December 31, 2017

Financial and Operating Results

Production

	Three months ended December 31, 2018	2017	Year ended December 31, 2018	2017
Daily average volume				
Natural gas *(Mcf/d)*	**12**	73	**30**	2,403
NGL *(bbls/d)*	**0**	1	**0**	144
Crude oil *(bbls/d)*	**1,117**	1,111	**1,120**	1,214
Total sales *(boe/d)*	**1,119**	1,124	**1,125**	1,759
Total sales *(boe)*	**102,950**	103,396	**410,710**	641,889
Production weighting				
Natural gas	**0%**	1%	**0%**	23%
NGL	**0%**	0%	**0%**	8%
Crude oil	**100%**	99%	**100%**	69%
	100%	100%	**100%**	100%

Production was lower for the year ended December 31, 2018 compared to the prior period, mainly due to the production that was realized from the West Central assets. Production on the Company's remaining core producing area in Red Earth declined slightly compared to the prior period. The Company drilled 2 wells (1.5 net) during 2018 in the Red Earth area, which along with other capital work performed offset the natural production declines. The Company also drilled 4 gross wells (2 net) in the Clearwater area during the fourth quarter of 2018, however, production from these wells was minimal in 2018 as it was not economical to produce in November and December due to the significant market differentials. In January 2019, production was brought online for all Clearwater wells as prices improved. Production declines are mainly due to natural production declines and shut-in production. However, due to the pipeline release that occurred in June 2018, the Company shut-in production in the Remote Panny area of its Red Earth CGU which resulted in approximately 150-200 boe/day reduced production from June 2018 to December 2018. The majority of natural gas and NGL production during 2017 came from the West Central assets that were acquired and disposed during the year ended December 31, 2017.

Sales

Oil and natural gas sales

	Three months ended December 31, 2018	2017	Year ended December 31, 2018	2017
	$	$	**$**	$
Natural gas	**2,274**	8,664	**14,588**	2,508,185
NGL	**936**	4,718	**10,409**	1,223,568
Crude oil	**3,109,989**	6,263,299	**24,960,492**	24,557,714
Total	**3,113,199**	6,276,681	**24,985,489**	28,289,467
Average realized prices before hedging				
Natural gas *($/Mcf)*	**2.01**	1.30	**1.35**	2.86
NGL *($/bbl)*	**72.03**	43.79	**71.30**	23.25
Crude oil *($/bbl)*	**30.27**	61.30	**61.06**	55.42
Combined average *($/boe)*	**30.24**	60.71	**60.83**	44.07

The Company realized improved oil prices during year ended 2018 resulting in an increase in oil revenues compared to the prior year, despite the decline in production. For the three months ended December 31, 2018, the Company's realized oil price was significantly impacted by record high pricing differentials and major pipeline capacity restraints from high apportionment levels on pipelines and lower take away capacity that was felt in the Province of Alberta during the fourth quarter of 2018. In the fourth quarter of 2018, the Alberta Government announced a mandatory curtailment program to relieve excess supply of oil in Western Canada. The program came into effect in January 2019 and has resulted in significant improvement of market differentials, resulting in improved realized pricing.

Natural gas and NGL revenue are immaterial for the Company in 2018. The revenues for natural gas and NGL's in the comparative period primarily relate to the West Central assets that were acquired and disposed of during the year ended December 31, 2017.

Over the short term, the Company anticipates continued price volatility. With respect to oil prices, a significant factor is the unknown impact of transportation constraints in Alberta, as well as global inventory levels. The Company anticipates that there will be continued price volatility for at least the next several quarters as various dynamics play out.

The Company's realized prices were consistent with the changes in the benchmark prices, although additional negative pricing was realized due to pipeline capacity constraints which reduced the realized price for the fourth quarter of 2018.

Transportation pipeline revenues

	Three months ended December 31,		Year ended December 31,	
	2018	2017	**2018**	2017
	$	$	**$**	$
Total	**1,308,526**	-	**3,948,611**	-

Transportation pipeline revenues relate to the Wabasca River pipeline system that the Company acquired during 2018. Revenues are generated from a tariff charged to vendors who transport product on the pipeline. Revenue increased for the fourth quarter of 2018 compared to prior quarters as the Company closed a transaction on October 5, 2018 to acquire the remaining 25.491% working interest in the pipeline, bringing the Company's total working interest in the Wabasca River pipeline system to 100%.

Royalties

	Three months ended December 31,		Year ended December 31,	
	2018	2017	**2018**	2017
	$	$	**$**	$
Royalties	**536,510**	690,559	**4,135,056**	3,137,014
Per boe	**5.21**	6.68	**10.07**	4.89
Percentage of oil and natural gas sales	**17.2%**	11.0%	**16.58%**	11.1%

Highwood's royalty burden includes crown, gross over-riding and freehold royalties applicable on the Company's production sales.

The royalty rate as a percentage of sales was higher in 2018 than in 2017 due to increased commodity reference pricing used by the Alberta government to calculate royalties. The Company also has a few wells where the royalty holiday ended in 2018 which increased the overall royalty rate. The percentage of sales value is also higher compared to the 2017 due to the change in production mix for the Company where 100% of production relates to oil in 2018, compared to just 69% for the year ended December 31, 2017.

Operating and Transportation Expense

	Three months ended December 31,		Year ended December 31,	
	2018	2017	**2018**	2017
	$	$	**$**	$
Operating and transportation	**2,924,432**	3,121,886	**17,887,813**	16,629,094
Per boe	**28.41**	30.19	**43.55**	25.91

Operating and transportation expenses increased on a per boe basis mainly due to one-time costs that were incurred in 2018, such as the self-insured portion of the pipeline release, a significant workover program undergone and the impact of the West Central assets on the comparative period. Included in operating costs is the self-insured portion of the pipeline releases of $500,000 for the year ended December 31, 2018. Operating costs per boe are generally lower for gas and NGL production than compared to oil weighted production. With the Company's production mix being primarily oil in 2018, this would lead to an increase in the per boe amount. There was also approximately $1.6 million spent on workovers in 2018 compared to approximately $500,000 for the comparative 2017 period on an annual basis. This resulted in additional operating costs while production was shut-in for the work to be performed. The work was done in order to bring additional production online. Operating and transportation costs on a per boe basis was also impacted by shut-in production in Remote Panny, which resulted in a decline in production of approximately 20%. Operating and transportation expenses also includes expenditures related to the Company's non-producing Clearwater lands and expenditures related to the Wabasca River Pipeline System. The Clearwater lands, until late 2018, and Wabasca River Pipeline System do not provide any production which increases the costs per boe. Management continues to look at production and operating costs to identify additional efficiencies.

The table below shows the normalized operating and transportation expense per boe (*see Non-GAAP measures for definition*) for the past eight quarters:

	Dec. 31, 2018	**Sept. 30, 2018**	**Jun. 30, 2018**	**Mar. 31, 2018**	**Dec. 31, 2017**	**Sept. 30, 2017**	**Jun. 30, 2017**	**Mar. 31, 2017**
	$	$	$	$	$	$	$	$
Total operating and transportation per boe	28.41	53.34	37.41	57.09	30.23	38.43	25.67	19.15
Normalizing items per boe								
Wabasca River Pipeline System	(1.46)	(1.40)	(2.00) -	1.46	-	-	-	-
Turnarounds	0.00 -	1.60	-	0.00	(0.30) -	3.18	-	-
Workovers	(0.82)	(1.47)	(1.47)	(11.78)	(2.55)	(0.74)	(0.87)	(1.16)
Undeveloped Clearwater lands	0.00	(0.64)	(0.14)	-	(0.00) -	0.64	-	-
Pipeline release	9.71	(10.49) -	4.39	-	-	-	-	-
Normalized operating and transporation per boe	35.84	37.74	29.41	43.86	27.38	33.88	24.81	17.99

The Company estimates that the operating costs per boe for the fourth quarter of 2018 would have been approximately $28.65 considering the fixed costs incurred on shut-in production.

Risk Management

Highwood's cash flow is highly variable, in large part because oil and natural gas are commodities whose prices are determined by worldwide and/or regional supply and demand, transportation constraints, weather conditions, availability of alternative energy sources and other factors, all of which are beyond Highwood's control. World prices for oil and natural gas have fluctuated widely in recent nine months.

Oil prices have been slightly improving since the beginning of 2016 and continued this trend until the fourth quarter of 2018 with average benchmark prices increasing from $55.09 in 2017 to $61.06 in 2018. However, for the fourth quarter of 2018, average benchmark prices were significantly lower than the comparative period of 2017, decreasing from $61.17 in 2017 to $30.89 in 2018. Crude oil prices in Alberta during the fourth quarter of 2018 were negatively impacted by pipeline capacity constraints resulting in oil being sold at significant discounts. Subsequent to December 31, 2018, the impacts of pipeline capacity constraints and market differentials have lessened significantly.

Management of cash flow variability is an integral component of the Company's business strategy. Business conditions are monitored regularly and reviewed with the Board of Directors to establish risk management guidelines used by management in carrying out the Company's strategic risk management program.

The Company has elected not to use hedge accounting and, accordingly, the fair value of the financial contracts is recorded at each period-end. The fair value may change substantially from period to period depending on commodity forward strip prices for the financial contracts outstanding at the balance sheet date. The change in fair value from period-end to period-end is reflected in the income for that period. As a result, income may fluctuate considerably.

At December 31, 2018 Highwood had the following commodity contracts, with a total mark-to-market asset of $1,316,000.

CAD Swaps:

Product	Notional Volume	Term	Fixed Price (CAD/bbl)	Index
Crude Oil	100bbls/day	October 1, 2019 to December 31, 2019	$ 89.09	WTI - NYMEX

USD Swaps:

Product	Notional Volume	Term	Fixed Price (USD/bbl)	Index
Crude Oil	100bbls/day	January 1, 2019 to March 31, 2019	$ 58.85	WTI - NYMEX
Crude Oil	100bbls/day	January 1, 2019 to March 31, 2019	$ 57.00	WTI - NYMEX
Crude Oil	100bbls/day	January 1, 2019 to March 31, 2019	$ 58.25	WTI - NYMEX
Crude Oil	100bbls/day	April 1, 2019 to June 30, 2019	$ 57.00	WTI - NYMEX

CAD Collars:

Product	Notional Volume	Term	Collar Cap (CAD/bbl)	Collar floor (CAD/bbl)	Index
Crude Oil	50bbls/day	July 1, 2019 to September 30, 2019	$ 87.50	$ 70.00	WTI - NYMEX
Crude Oil	100bbls/day	July 1, 2019 to December 31, 2019	$ 85.50	$ 70.00	WTI - NYMEX
Crude Oil	50bbls/day	July 1, 2019 to December 31, 2019	$ 91.80	$ 70.00	WTI - NYMEX
Crude Oil	100bbls/day	July 1, 2019 to September 30, 2019	$ 88.40	$ 70.00	WTI - NYMEX
Crude Oil	50bbls/day	October 1, 2019 to December 31, 2019	$ 91.75	$ 70.00	WTI - NYMEX
Crude Oil	100bbls/day	October 1, 2019 to December 31, 2019	$ 69.00	$ 59.00	WTI - NYMEX

USD Collars:

Product	Notional Volume	Term	Collar Cap (USD/bbl)	Collar floor (USD/bbl)	Index
Crude Oil	100bbls/day	January 1, 2019 to March 31, 2019	$ 55.20	$ 45.00	WTI - NYMEX
Crude Oil	100bbls/day	April 1, 2019 to June 30, 2019	$ 55.05	$ 45.00	WTI - NYMEX
Crude Oil	100bbls/day	April 1, 2019 to June 30, 2019	$ 60.32	$ 55.00	WTI - NYMEX
Crude Oil	100bbls/day	April 1, 2019 to June 30, 2019	$ 66.00	$ 55.00	WTI - NYMEX

Crude Oil	100bbls/day	July 1, 2019 to September 30, 2019	$ 63.10	$ 55.00	WTI - NYMEX

Differential:

Product	Notional Volume	Term	Fixed Price Differential (USD/bbl)	Index
Crude Oil	50bbls/day	January 1, 2019 to December 31, 2019	$ (13.50)	Edmonton Light vs. WTI - NYMEX
Crude Oil	50bbls/day	January 1, 2019 to December 31, 2019	$ (13.35)	Edmonton Light vs. WTI - NYMEX
Crude Oil	50bbls/day	January 1, 2019 to December 31, 2019	$ (12.50)	Edmonton Light vs. WTI - NYMEX
Crude Oil	50bbls/day	January 1, 2019 to December 31, 2019	$ (21.00)	WCS vs. WTI - NYMEX

Subsequent to December 31, 2018, the Company entered into the following commodity contracts:

CAD Swaps:

Product	Notional Volume	Term	Fixed Price (CAD/bbl)	Index
Crude Oil	100bbls/day	January 1, 2020 to March 31, 2020	$ 72.10	WTI - NYMEX
Crude Oil	100bbls/day	January 1, 2020 to March 31, 2020	$ 76.04	WTI - NYMEX
Crude Oil	50bbls/day	January 1, 2020 to June 30, 2020	$ 77.16	WTI - NYMEX
Crude Oil	50bbls/day	January 1, 2020 to December 31, 2020	$ 74.90	WTI - NYMEX
Crude Oil	50bbls/day	January 1, 2020 to December 31, 2020	$ 76.27	WTI - NYMEX
Crude Oil	50bbls/day	January 1, 2020 to December 31, 2020	$ 77.02	WTI - NYMEX
Crude Oil	50bbls/day	January 1, 2020 to December 31, 2020	$ 78.00	WTI - NYMEX
Crude Oil	50bbls/day	January 1, 2020 to June 30, 2020	$ 77.16	WTI - NYMEX
Crude Oil	50bbls/day	January 1, 2020 to December 31, 2020	$ 80.93	WTI - NYMEX

Differential:

Product	Notional Volume	Term	Fixed Price Differential (USD/bbl)	Index
Crude Oil	100bbls/day	February 1, 2019 to June 30, 2019	$ (7.25)	Edmonton Light vs. WTI - NYMEX
Crude Oil	50 bls/day	February 1, 2019 to December 31, 2019	$ (10.50)	Edmonton Light vs. WTI - NYMEX
Crude Oil	50bbls/day	February 1, 2019 to June 30, 2019	$ (15.75)	WCS vs. WTI - NYMEX
Crude Oil	50bbls/day	February 1, 2019 to December 31, 2019	$ (18.10)	WCS vs. WTI - NYMEX

Commodity contracts are considered financial instruments, and the resulting derivative financial asset or liability was recorded on the Company’s balance sheet, with the unrealized gain or loss being recorded on the statement of loss and comprehensive loss.

	Three months ended December 31,		Year ended December 31,	
	2018	2017	**2018**	2017
	$	$	**$**	$
Realized gain (loss) on commodity contracts	**442,553**	(155,575)	**(1,018,784)**	1,465,140
Unrealized gain (loss) on commodity contracts	**3,798,000**	(809,000)	**1,939,000**	544,000

The realized gain on commodity contracts during the three months ended December 31, 2018 and for the year ended December 31, 2017 was due to oil commodity prices being lower than the contract price. The realized loss on commodity contracts during the three months ended December 31, 2017 and for the year ended December 31, 2018 was due to oil commodity prices being higher than the contract price.

The unrealized loss for the three-month period ended December 31, 2017 was a result of increased future strip prices during the period. The unrealized gains for the three-month period and for the year ended December 31, 2017 and 2018 was a result of decreased future strip prices during the respective periods.

General and Administrative (G&A)

	Three months ended December 31,		Year ended December 31,	
	2018	2017	**2018**	2017
	$	$	**$**	$
G&A	**1,099,182**	1,455,975	**3,008,785**	3,727,280
G&A expense per boe	**10.68**	14.08	**7.33**	5.81

G&A expenses decreased for the year ended December 31, 2018 compared to the prior year mainly due to a decrease in staff as a result of the disposition of the West Central assets in the second quarter of 2017 along with a one-time employee compensation costs of $835,901 that was distributed in the fourth quarter of 2017. The fourth quarter of 2018 incurred additional one-time costs relating to insurance, compensation and also for the Company's reserve engineering report. Due to the pipeline release in 2018, the Company paid approximately $155,000 to provide additional insurance coverage to offset anticipated draws on the existing coverage. There were also additional costs incurred due to the timing of the reserve report as the Company commissioned a December 31, 2018 reserve report, in addition to the March 31, 2018 reserve report that was commissioned in the first quarter of 2018. Furthermore, the Company incurred additional legal, accounting and tax costs associated with winding up of Predator Oil Partnership and with the transaction that closed in January 2019 which resulted in the Company becoming public. Adjusting for these costs, including one-time compensation costs of $225,000, the adjusted G&A expense per boe would be $6.98 and $6.40, respectively for the three months and year ended December 31, 2018. For the year ended December 31, 2018 per boe is higher than 2017 mainly due to economies of scale, in addition to the one-time costs mentioned above. There was significantly higher production during 2017 from the West Central assets resulting in a lower G&A per boe relating to fixed costs such as rent.

Stock-Based Compensation

	Three months ended December 31,		Year ended December 31,	
	2018	2017	**2018**	2017
	$	$	**$**	$
Stock-based compensation	**-**	50,000	**229,000**	192,000

The Company granted 81,000 stock options to purchase common shares during the year ended December 31, 2018 at an exercise price of $3.50 per option.

In August of 2018, one shareholder acquired control of the Company via an acquisition of shares from another shareholder. As a result of the transaction, all outstanding stock options were deemed to have fully vested. Furthermore, in October of 2018, the Company settled 717,000 outstanding options for cash consideration of $203,150 and issued 305,530 common shares. The consideration paid to settle the shares was recorded as a reduction to contributed surplus. The value of the common shares issued was deemed to be $5.00 per common share, resulting in an increase to share capital of $1,527,650 with a corresponding reduction to contributed surplus of $1,056,125 and $674,675 to retained earnings.

At December 31, 2018, the Company had no options outstanding.

Exploration and Evaluation (E&E) Expenditures

	Three months ended December 31,		Year ended December 31,	
	2018	2017	**2018**	2017
	$	$	**$**	$
E&E expense	**3,000**	-	**3,000**	206,000

All E&E expenditures are non-cash mineral rights expiries relate to mineral rights voluntarily relinquished by the Company as a result of low commodity prices.

Depletion and Depreciation (D&D)

	Three months ended December 31,		Year ended December 31,	
	2018	2017	**2018**	2017
	$	$	**$**	$
D&D	**1,594,540**	1,391,000	**5,853,540**	5,408,600
Per boe	**15.49**	13.45	**14.25**	8.43

The increase in D&D for the three-month period and year ended December 31, 2018, compared to the prior year, is a direct result of the acquisitions and capital activity the company completed during the year. During the year, the Company recorded $229,000 of D&D with respect to the Wabasca Pipeline system, which resulted in an increase to D&D per boe as the Wabasca Pipeline does not provide production. The increase in D&D is also due to a decline in the reserve base, particularly with respect to the Company's Panny CGU which was impacted by the pipeline release that occurred in 2018. The increase in D&D per boe from 2017 to 2018 for the year is also due to the impact of the production from the West Central assets. As these assets were classified as assets held for sale, they were not depleted while the Company owned and operated the assets during 2017.

Impairment

	Three months ended December 31, 2018	2017	Year ended December 31, 2018	2017
	$	$	**$**	$
Impairment loss	**2,700,000**	-	**2,700,000**	-

Impairment loss for the three months and year ended December 31, 2018 relate to one of the Company's non-core CGUs. The Company determined that the non-core CGUs would no longer be pursued and the Company intends to allow the leases to expire. The Company recognized an impairment loss relating to the non-core CGU of $2,700,000, representing the full carrying value of the non-core CGU, due to the carrying value exceeding its recoverable amount of $nil.

Finance Income and Expenses, Net

	Three months ended December 31, 2018	2017	Year ended December 31, 2018	2017
	$	$	**$**	$
Interest on bank debt	**194,663**	76,643	**570,741**	473,922
Stamping fees on bank debt	**318,699**	74,575	**1,026,473**	421,760
Financing fees	**-**	-	**273,500**	40,500
Interest and other income	**(61,644)**	(7,104)	**(69,541)**	(27,881)
Cash finance income and expenses	**451,718**	144,114	**1,801,173**	908,301
Accretion of decommissioning liabilities	**166,000**	157,000	**631,000**	606,000
Non-cash finance expense	**166,000**	157,000	**631,000**	606,000
Total finance income and expenses	**617,718**	301,114	**2,432,173**	1,514,301

Interest on bank debt and stamping fees relates to interest and fees paid to Highwood's bankers to service the bank debt and bank overdraft. Interest on bank debt and stamping fees increased in the three-month period and the year ended December 31, 2018 compared to 2017 due to increased borrowing to fund the capital program and acquisitions the Company deployed in 2018. For the three-month period and the year ended December 31, 2018 the Company had increased borrowings using bankers acceptances, resulting in increased stamping fees compared to 2017. Interest rates are based on the Company's most recent quarter net debt to cash flow ratio. Net debt is defined by the agreement as working capital deficit plus bank debt and cash flow is defined effectively as cash flow from operating activities before changes in non-cash working capital for the most recent quarter annualized and normalized for extraordinary and nonrecurring earnings, gains, and losses.

Deferred Income Tax

Deferred income tax was an expense of $1,449,000 and $475,000, respectively, for the three months and year ended December 31, 2018, compared to an expense of $305,000 and an expense of $156,000 in the respective comparative periods in 2017.

Income (Loss)

The Company generated income of $1,223,306 and incurred a loss of $1,809,819, respectively, for the three months and year ended December 31, 2018, compared to a loss of $1,073,072 and income of $598,854 for the respective comparative periods in 2017. For the three-month period ended December 31, 2018, the Company's income was a result of $2,600,000 gain on disposal of a royalty interest partially offset by the market differentials and pipeline capacity constraints resulting in depressed realized oil prices and also an impairment loss that was charged in the fourth quarter of 2018 on a non-core CGU that the Company has decided to no longer pursue.

Selected Annual Information

Years ended December 31,	2018	2017	2016
	$	$	$
Oil and natural gas sales	24,985,489	28,289,467	20,961,301
Royalties	(4,135,056)	(3,137,014)	(1,679,592)
Transportation pipeline revenues	3,948,611	-	-
Processing and other income	1,960,451	1,132,267	1,433,601
Realized gain on commodity contracts	(1,018,784)	1,465,140	7,628,762
Unrealized gain (loss) on commodity contracts	1,939,000	544,000	(8,757,000)
Total revenue, net of royalties	27,679,711	28,293,860	19,587,072
Cash flows from operating activities	(2,512,242)	6,463,600	11,636,829
Per share, basic	(0.45)	1.17	2.10
Per share, diluted	(0.45)	1.11	1.99
Income (loss)	(1,809,819)	598,854	(3,336,569)
Per share, basic	(0.32)	0.11	(0.60)
Per share, diluted	(0.32)	0.10	(0.60)
Total assets	126,545,439	79,806,935	79,408,935
Total non-current financial liabilities [1]	1,386,750	100,000	143,000

[1] Excludes decommissioning liabilities and deferred tax liabilities.

Supplemental Information

The following tables summarize key financial and operating information for the periods indicated:

Cash Flows from Operating Activities

	Three months ended December 31, 2018	Three months ended December 31, 2017	Year ended December 31, 2018	Year ended December 31, 2017
	$	$	**$**	$
Income (loss)	**1,223,306**	(1,073,072)	**(1,809,819)**	598,854
Non-cash items:				
Unrealized (gain) loss on commodity contracts	**(3,798,000)**	809,000	**(1,939,000)**	(544,000)
E&E	**3,000**	-	**3,000**	206,000
D&D	**1,594,540**	1,391,000	**5,853,540**	5,408,600
Impairment loss	**2,700,000**	-	**2,700,000**	-
Bargain purchase gain	**-**	197,720	**-**	(2,489,031)
Realized loss on investment	**-**	-	**-**	2,013,750
Gain on disposal of assets	**(2,908,756)**	-	**(3,275,721)**	(70,000)
Finance expense	**166,000**	157,000	**631,000**	606,000
Deferred income tax expense (recovery)	**1,449,000**	(305,000)	**475,000**	156,000
Stock-based compensation	**-**	50,000	**229,000**	192,000
Cash abandonment expenditures	**(299,092)**	(8,976)	**(361,423)**	(750,040)
Change in long-term accounts receivable	**-**	154,523	**115,166**	239,457
Change in long-term accounts payable and accrued liabilities	**1,386,750**	-	**1,386,750**	-
Change in non-cash working capital	**(3,038,907)**	(175,103)	**(6,519,735)**	896,010
	(1,522,159)	1,127,095	**(2,512,242)**	6,463,600

Netback Analysis

	Three months ended December 31, 2018	Three months ended December 31, 2017	Year ended December 31, 2018	Year ended December 31, 2017
	$/boe	$/boe	**$/boe**	$/boe
Average sales price	**30.24**	60.71	**60.83**	44.07
Royalties	**(5.21)**	(6.68)	**(10.07)**	(4.89)
Operating and transportation	**(28.41)**	(30.19)	**(43.55)**	(25.91)
Operating netback	**(3.38)**	23.83	**7.21**	13.28

Selected Quarterly Information

Three months ended	Dec. 31, 2018	Sept. 30, 2018	Jun. 30, 2018	Mar. 31, 2018	Dec. 31, 2017	Sept. 30, 2017	Jun. 30, 2017	Mar. 31, 2017
Financial ($000s, except per share amounts and share numbers)								
Oil and natural gas sales	3,113	7,337	8,059	6,430	6,277	5,120	7,313	9,580
Transportation pipeline revenues	1,309	976	1,083	581	-	-	-	-
Income (loss)	1,223	(837)	(412)	(1,784)	(1,073)	(2,705)	232	4,145
Capital expenditures	6,420	2,118	2,127	12,583	4,658	2,456	(1,066)	30,392
Total assets *(end of quarter)*	126,545	122,308	105,427	103,376	79,807	79,443	86,185	133,098
Working capital deficit, excluding commodity contracts *(end of quarter)*	29,630	31,204	26,741	27,349	14,050	18,768	10,114	11,295
Shareholders' equity *(end of quarter)*	24,580	24,059	24,705	26,618	26,864	28,863	31,520	31,240
Weighted-average basic shares outstanding *(000s)*	5,695	5,539	5,539	5,539	5,539	5,539	5,539	5,539
Operations								
Production								
Natural gas *(Mcf/d)*	12	16	52	38	73	91	3,358	6,202
NGL *(bbls/d)*	0	0	1	0	1	2	238	410
Crude oil *(bbls/d)*	1,117	1,033	1,242	1,087	1,111	1,128	1,166	1,389
Total *(boe/d)*	1,119	1,036	1,252	1,094	1,124	1,145	1,964	2,833
Average realized prices *($)*								
Natural gas *(per Mcf)*	2.01	1.33	0.54	1.67	1.30	1.29	2.93	2.86
NGL *(per bbl)*	72.03	82.25	66.85	65.49	43.79	31.95	26.56	27.32
Crude oil *(per bbl)*	30.27	77.15	71.24	64.59	61.30	49.07	54.66	56.28

Inherent to the nature of the oil and gas industry, fluctuations in Highwood's quarterly oil and natural gas sales, cash flows from operating activities, and income or loss are primarily caused by variations in production volumes, realized commodity prices and the related impact on royalties, realized and unrealized gains/losses on financial instruments, changes in per-unit expenses, and deferred income taxes. Please refer to the Financial and Operating Results section above for an explanation of changes.

Capital Activity

	Three months ended December 31, 2018	2017	Year ended December 31, 2018	2017
	$	$	**$**	$
Land	**198,724**	4,350,566	**3,630,381**	6,486,059
Seismic and other pre-drilling costs	**261,096**	202,026	**729,845**	217,026
Production equipment and facilities	**995,500**	98,623	**2,288,950**	438,278
Drilling and completions	**2,342,647**	-	**5,279,756**	-
Recompletions	**176,199**	6,615	**3,200,392**	2,442,919
Acquisitions	**2,445,455**	-	**8,118,697**	26,855,905
	6,419,621	4,657,830	**23,248,021**	36,440,187

At December 31, 2018, the Company had E&E assets of $8,130,352 (December 31, 2017 – $4,992,805). This included approximately 330,000 net acres of undeveloped land, of which approximately 143,000 net acres are located in the Company's Clearwater core area the Company began acquiring in September 2017.

During the year ended December 31, 2018, $4,655,154 of E&E assets were determined to be technically feasible and commercially viable after proved and probable reserves were assigned and were transferred to property and equipment.

At December 31, 2018, the Company had gross property and equipment of $111,843,108 (December 31, 2017 - $89,271,666). This included developed land and costs associated with the wells the Company has drilled and acquired to date and the transportation pipelines the Company acquired in 2018.

During 2018, the Company has drilled 2 wells (1.5 net) in its Red Earth core area and drilled another 4 wells (2 net) in its Clearwater core area. As of the date of this MD&A, the Company has drilled 7 wells (3.5 net) it its Clearwater core area.

The acquisitions in 2018 mainly related to the transportation pipelines the Company acquired a 100% working interest in three transactions during 2018. The Company also acquired petroleum and natural gas assets in its Trout CGU, a core area for the Company.

The Company acquired additional lands in the Jarvie & Nipisi areas of Alberta (Clearwater formation) during 2018, building on the land position the Company added in 2017. The Company has a joint venture partner in the lands, a private company, where each company holds a 50% working interest. The Company began drilling in the Clearwater late in the third quarter of 2018 and has 7 gross (3.5 net) wells in the play as of today's date. The Company is confident it will be able to generate the strong return and operating netbacks that other companies are generating in the area. During the year ended December 31, 2018, the Company and it's joint venture partner entered into a overriding royalty purchase and sale agreement ("royalty agreement") with a company where the Company sold a 4% non-deduct royalty over the jointly held Clearwater lands to the private company for gross proceeds of $12,000,000 ($6,000,000 Company share), subject to a drilling commitment escrow agreement. As a condition of the royalty divestiture, the parties must drill a minimum of eight wells in the formation prior to March 31, 2020. Upon rig release of each well, $1,500,000 of the gross proceeds will be released from escrow. Should total drill, completion and equipping costs be less than $1,500,000 per well, the parties will be required to drill additional wells prior to September 30, 2020 in order to recoup the remaining funds. As of December 31, 2018, the Company had drilled 4 gross (2 net) wells in the Clearwater and $6,000,000 gross ($3,000,000 net) of the royalty proceeds had been released. The Company determined that the additional proceeds to be received can not be recognized until the Company meets its performance obligation to drill the additional wells and spend the required amounts. Therefore, the Company has not recorded a receivable for the $3,000,000 net proceeds that remained held in escrow at December 31, 2018, nor has the Company recognized these as proceeds with respect to the disposition. Subsequent to December 31, 2018, the Company received $2,250,000 of remaining net proceeds as an additional three wells were rig released.

Share Capital and Option Activity

As at December 31, 2018 the Company had 5,744,204 common shares, and no stock options outstanding.

During the year ended December 31, 2018, the Company granted 81,000 stock options at an exercise price of $3.50 per option. The options granted vest 1/3 on each of the twelve, twenty-four, and thirty-six-month anniversaries from the grant date and have a five-year term.

During the year ended December 31, 2018, the Company settled 717,000 outstanding options for cash consideration of $203,150 and issued 305,530 common shares at as estimated value of $5.00 per share for total consideration of $1,730,800. The excess of the $1,730,800 cancellation costs over the balance in contributed surplus of $1,056,125, being $674,675 was charged to retained earnings.

During the year ended December 31, 2018, the Company repurchased 100,000 shares from a shareholder for gross consideration of $500,000. The shares were returned to treasury and cancelled. The stated amount of the shares that were repurchased and cancelled was $208,000. The difference between the consideration and the stated amount of $292,000 was charged directly to retained earnings.

Subsequent to December 31 2018, the Company completed an amalgamation transaction (the "Amalgamation") with a public company. The public company is a capital pool company and the transaction will be considered a qualifying transaction for the public company. The public company received common shares of the Company at a ratio of 53:1, resulting in 188,679 common shares of the Company being issued to shareholders of the public company at a deemed price of $9.00 per common share. In conjunction with the transaction, the Company completed a private placement, resulting in 7,600 shares being issued for gross proceeds of $68,400. At the closing of the Amalgamation the Company had 5,940,483 common shares issued and outstanding. The Company began trading on the TSX Venture Exchange under the symbol "HOCL" on January 30, 2019.

Subsequent to December 31, 2018, the Company issued 88,100 options to directors, officers and employees. The options are exercisable and a price of $9.00 for a period of five years, vesting evenly over a three-year period. The Company also issued 88,100 restricted stock units to directors, officers and employees that will vest evenly over a three-year period.

As at the date of this MD&A, the Company had 6,013,965 common shares, 106,968 stock options and 88,100 restricted share units outstanding.

Liquidity and Capital Resources

At December 31, 2018, the Company had a working capital deficit of $29,630,459 (December 31, 2017 – $14,573,417), and working capital surplus of $2,053,541 (December 31, 2017 – surplus of $2,349,583) excluding the credit facility and commodity contracts.

The Company's credit facility is a demand loan and as such the bank could demand repayment at any time. Management is not aware of any indications that the bank would demand repayment. Should the lender demand repayment, the Company would need to seek alternative sources of debt or equity financing or sell assets.

The credit facility includes a number of covenants including working capital ratio and net debt to cash flow ratio.

The Company will be required to maintain a current ratio of not less than 1.0:1.0, and such ratio is to be tested at the end of each fiscal quarter. Current ratio is defined as the ratio of (i) current assets, excluding financial derivatives, plus any undrawn availability under the credit facility to (ii) current liabilities, excluding financial derivatives and any amounts drawn under the credit facility. At December 31, 2018, the Company's current ratio was 1.22:1.0 (December 31, 2017 – 4.98:1.0). The Company will be required to maintain a net debt to cash flow ratio no greater than 3.0:1.0 as at the last day of the fiscal quarter ended December 31, 2018 and as at the last day of the fiscal quarter for each quarter thereafter. Prior to December 31, 2018, the net debt to cash flow ratio for the fiscal quarter ended December 31, 2018 was waived by the lender. For the purposes of the covenant, net debt is defined by the agreement as working capital deficit plus bank debt and cash flow is defined effectively as cash flow from operating activities before changes in non-cash working capital for the most recent two quarters annualized and normalized for extraordinary and nonrecurring earnings, gains, and losses. The Company will also be required to meet certain reporting requirements on a quarterly and annual basis and may not make dividend payments or redeem any outstanding shares in an amount exceeding $1,350,000 in any fiscal year. The Company is also restricted from entering into notional commodity contracts exceeding three years in term and cannot exceed 60% of gross production volumes (by commodity) for the three-month trailing period, at the time the contracts are entered into.

Subsequent to December 31, 2018, the Company entered into a new credit facility agreement for a maximum available draw of $38,000,000. The subsequent credit facility will replace in its entirety the Company's previous credit facility agreement. The credit facility can be used for general corporate purposes including capital expenditures and advances may be made by way of direct advances, bankers acceptances, or standby letters of credit/guarantees. The credit facility bears interest at the Bank's prime rate or bankers acceptance discount rates plus an applicable margin of 100bps to 350bps on prime rate loans and 200bps to 450bps on stamping fees related to bankers acceptances, determined by reference to the Company's net debt to cash flow ratio (as defined in the credit facility agreement). Interest on the credit facility is due monthly. The credit facility is secured by a $100,000,000 debenture with a fixed and floating charge over all the assets of the Company. The loan facility will revolve until the first scheduled term out date which is June 30, 2019. The end of the revolving period (the "term out date") can be extended for 364 day periods with mutual agreement of the Company and the lender. Should the revolving period not be extended, the maturity date of the facility will be one year form the term out date, resulting in the earliest maturity date under the facility being June 30, 2020, subject to borrowing base reviews by the lender.

The borrowing base, currently set at $38,000,000, will be reviewed at least semi annually by the lender, and more frequent under certain circumstances. The borrowing base can be determined at the sole discretion of the lender and any amount outstanding under the credit facility in excess of a newly established borrowing base must be repaid in full within 30 days.

The Company will be required to maintain a current ratio of not less than 1.0:1.0, and such ratio is to be tested at the end of each fiscal quarter. Current ratio is defined as the ratio of (i) current assets, excluding financial derivatives, plus any undrawn availability under the credit facility to (ii) current liabilities, excluding financial derivatives and any amounts drawn under the credit facility and any current liabilities related to lease contracts. The Company will be required to maintain a net debt to cash flow ratio no greater than 4.5:1.0 as at the last day of the fiscal quarter ended March 31, 2019, 3.5:1.0 as at the last day of the fiscal quarter ended June 30, 2019 and 3.0:1.0 as at the last day of the fiscal quarter for each quarter thereafter. For the purposes of the covenant, net debt is defined by the agreement as working capital deficit (excluding financial derivatives) plus bank debt and cash flow is defined effectively as cash flow from operating activities before changes in non-cash working capital for the most recent two quarters annualized and normalized for extraordinary and nonrecurring earnings, gains, and losses. The Company will also be required to meet certain reporting requirements on a quarterly and annual basis. The Company is also restricted from entering into notional commodity contracts exceeding three years in term and cannot exceed

60% of gross production volumes (by commodity) for the three month trailing period, at the time the contracts are entered into. The Company's next review and borrowing base determination is scheduled on or before May 31, 2019 but may be set at an earlier or later date at the discretion of the bank.

The Company generally relies on operating cash flows and its credit facility to fund its capital requirements and provide liquidity. Future liquidity depends primarily on funds generated from operations, drawing on existing credit facilities and accessing debt and equity markets.

In relation to the remediation work described in note 19 of the financial statements the Company has estimated its full exposure for the pipeline release to be $520,000, being the self-insured portion and known adjusted amounts excluded from the Company's insurance policy. The Company expects to pay these expenses through operational cash flows and the Company's credit facility.

Off-Balance-Sheet Arrangements

The Company does not have any special-purpose entities nor is it a party to any arrangements that would be excluded from the balance sheet.

Environmental Initiatives Affecting Highwood

In October 2018, the Government of Canada announced a national carbon pricing regime in response to the Paris Agreement ratified by Canada earlier that month. Under the Carbon Strategy, a benchmark carbon pricing program will be applied, pricing carbon emissions at a minimum of $10 per tonne in 2018, rising by $10 per tonne each nine months to $50 per tonne by 2022. The Carbon Strategy also proposes a federal backstop in the event that jurisdictions fail to meet the benchmark. The Government of Alberta established a carbon pricing system referenced in the federal announcement; therefore, in the short term, the national price on carbon will likely have little additional impact to Highwood beyond that imposed by the Government of Alberta.

Commitments and Contingencies

(a) Commitments

At December 31, 2018, the Company had the following commitments:

Minimum future payments for operating leases:

	Within 12 months	After 12 months but not more than 5 years	More than 5 years	Total
Head office lease (base rent)	$ 237,000	$ 614,000	$ -	$ 851,000

Subsequent to December 31, 2018, the Company entered into the following physical delivery electricity services contract:

	Average monthly contracted kW	Term	Fixed Price
Electricity	405 kW	January 1, 2020 to December 31, 2020	5.046 ¢/kWh

(b) Contingencies

By nature of its oil and gas operations in Northern Alberta, the Company is subject to numerous safety and environmental regulations, with which non-compliance may result in adverse financial impact. The Company mitigates these risks through the adherence to formal safety and environmental policies, as well as adequate insurance coverage. The Company is currently remediating three environmental pipeline releases at Red Earth, Alberta, all relating to the same segment of pipeline. While the Company believes it has recorded its best estimate of the impact of this contingency in these financial statements, the ultimate outcome is uncertain. The Company anticipates that this event is insurable and will be making payments on the majority of remediation in 2018 and 2019. There will be ongoing monitoring costs which the Company anticipates paying over the next several years subject to the overview and approval of the provincial regulatory bodies. The Company anticipates the majority of the $32,150,000 pipeline release related costs will be paid out from anticipated insurance proceeds of $31,630,000 to be received prior to December 31, 2019. In relation to the pipeline release, for the year ended December 31, 2018 the Company has recorded $31,630,000 of accounts receivable for the anticipated insurance proceeds, estimated $32,150,000 of accounts payable and accrued liabilities in relation to the estimated costs of the remediation work and $520,000 in operating costs for the remediation work the Company will be responsible for as part of the self-insured portion of the insurance coverage and expenses not covered by insurance. At December 31, 2018, $26,630,000 and $24,933,613 were included in insurance proceeds receivable and accounts payable and accrued liabilities, respectively. The Company has received an additional $15,000,000 from insurers subsequent to December 31, 2018, reducing the receivable amount to $11,630,000.

Related-Party Transactions

During the year ended December 31, 2018, the Company incurred charges of $132,965 (2017 – $368,763) from a company with common officers and directors, Tidewater Midstream and Infrastructure Ltd., for management fees, office space, subscriptions and supplies which was recorded as an increase in general and administrative expense and was charged $499,711 (2017 - $431,717) for net non-operated gas sales, butane purchases and gas processing fees which is included in operating and transportation expense. During the year ended December 31, 2018, the related party marketed natural gas production for the Company with total receipts of $nil (2017 - $2,083,188). During the year ended December 31, 2018, the Company was also charged $1,174,119 (2017 - $1,038,100) for propane purchases and distribution from a subsidiary of this company, Midwest Propane Ltd., which is included in operating and transportation expenses on the statement of income (loss) and comprehensive income (loss). As at December 31, 2018, $nil (2017 - $nil) is included within accounts receivable and $314,263 (2017 - $259,686) is included within accounts payable with respect to these charges.

During the year ended December 31, 2018, the Company loaned Fireweed Energy Ltd., a company with common officers and directors $400,000. The amount bore interest at 5.00% per annum, accrued monthly, with interest payments due on or before maturity of the loan, March 31, 2018. Under the terms on the Company's revolving operating demand loan, the bank provided consent to the Company for the loan contingent on the amount being repaid on or before March 31, 2018. The maturity of the loan was subsequently extended to May 31, 2018. During the year ended December, 2018, the loan and interest of $7,898 was repaid in full.

During the year ended December 31, 2018, the Company purchased undeveloped lands from a company with common officers and directors, Predator Oil BC Ltd., for total consideration of $650,990. Consideration was comprised of cash consideration of $500,000 and settlement of $150,990 of receivables from the related party. On June 15, 2018, this party ceased to be related.

During the year ended December 31, 2018, the Company posted a $750,000 irrevocable standyby letter of credit in favour of Battle River Energy Ltd., a company with a common director. The letter of credit was approved by the Company's bank as required under the terms of the Company's credit facility. The letter of credit accrued interest at a rate of 30% per annum, due two business days following the date upon which the letter of credit is returned. Interest income in the amount of $61,644 has been recorded and is included in accounts receivable at December 31, 2018. During the year ended December 31, 2018, the letter of credit was returned to the Company and cancelled.

Hedging

The Company historically practiced an active hedging program, with the objective to provide a measure of downside protection for its oil and natural gas sales and cash flow from operations, while maximizing exposure to potential commodity pricing upside. At December 31, 2018, the Company's hedges covered approximately 40 percent of forecast production for the next 12 months (see "Risk Management" above).

Critical Accounting Judgments, Estimates and Policies

The Company's critical accounting judgements, estimates and policies are described in notes 2 and 3 to the December 31, 2018 annual consolidated financial statements. There have been no changes to the use of estimates or management's judgments since December 31, 2017, with the exception of judgements and estimates relating to an insurable event (note 19), the estimates related to variable consideration and original cost of the Clearwater assets (note 6) and the depreciation method used on the Company's transportation pipeline assets. Certain accounting policies are identified as critical because they require management to make judgments and estimates based on conditions and assumptions that are inherently uncertain, and because the estimates are of material magnitude to revenue, expenses, funds flow from operations, income or loss and/or other important financial results. These accounting policies could result in materially different results should the underlying conditions change or the assumptions prove incorrect.

Critical accounting estimates are those requiring management to make particularly subjective or complex judgments about inherently uncertain matters. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recognized in the same period.

Management's assumptions are based on factors that, in management's opinion, are relevant and appropriate, and may change over time as operating conditions change.

New accounting standards

(i) IFRS 9, "Financial Instruments"

On January 1, 2018, the Company adopted IFRS 9, "Financial Instruments", which replaces IAS 39 "Financial Instruments". This new standard accounts for all aspects of financial instruments and includes a logical model for classification and measurement, a single forward looking 'expected-loss' impairment model and a substantially reformed approach to hedge accounting. The Company does not employ hedge accounting for its commodity contracts currently in place. Adoption of this new standard did not have any material impact on the Company's consolidated financial statements. The Company has adopted IFRS 9 using a retrospective approach with no impact to opening retained earnings of comparative periods and no adjustments to the carrying value of any of the Company's financials instruments.

The Company has revised the description of its accounting policy for financial instruments to reflect the new classification approach as follows:

Financial Instruments

On initial recognition, financial instruments are measured at fair value. Measurement in subsequent periods depends on the classification of the financial instrument as described below:

Financial Assets	**IAS 39**	**IFRS 9**
Cash and cash equivalents (bank overdraft)	Fair value through profit or loss	Amortized cost
Accounts receivable	Amortized cost	Amortized cost
Commodity contracts	Fair value through profit or loss	Fair value through profit or loss
Due from related party	Amortized cost	Amortized cost
Deposits	Amortized cost	Amortized cost
Financial Liabilities	**IAS 39**	**IFRS 9**
Accounts payable and accrued liabilities	Amortized cost	Amortized cost
Commodity contracts	Fair value through profit or loss	Fair value through profit or loss
Bank debt	Amortized cost	Amortized cost

IFRS 9 also introduces a new model for the measurement of impairment of financial assets based on expected credit losses which replaces the incurred losses impairment model under IAS 39. Under this new model, the majority of the Company's accounts receivable are considered collectible within one year or less; therefore, these financial assets are not considered to have significant financing component and a lifetime expected credit loss ("ECL") is measured as the date of initial recognition of accounts receivable.

Within the Company's accounts receivable, the Company assesses the lifetime ECL applicable to its commodity product sales receivables and joint venture receivables at initial recognition and re-assesses the provision at each reporting date. Lifetime ECLs are a probability-weighted estimate of all possible default events over the expected life of a financial asset and are measured as the difference between the present value of the cash flows due to the Company and the cash flows the Company expects to receive. In making an assessment as to whether the Company's financial assets are credit-impaired, the Company considers bad debts that the Company has incurred historically, evidence of a debtor's present financial condition and whether a debtor has breached certain contracts, the probability that a debtor enter bankruptcy or other financial reorganization, changes in economic conditions that correlate to increased levels of default, and the term to maturity of the specified receivable. The carrying amounts of receivables are reduced by the amount of the ECL through an allowance account and losses are recognized was bad debt expense in the statements on income and comprehensive income.

Based on industry experience, the Company considered financial assets to be in default when the receivable is more than 90 days past due. Once the Company has pursued collection activities and it has been determined that the incremental cost of collection pursuits outweigh the benefits of collection, the Company derecognizes the gross carrying amount of the asset and the associated allowance from the statement of financial position.

(ii) IFRS 15, "Revenue from Contracts with Customers"

On January 1, 2018, the Company adopted IFRS 15, "Revenue from Contracts with Customers". IFRS 15 replaces the existing revenue recognition guidance with a single comprehensive accounting model. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive when control is transferred to the purchaser. The Company has adopted IFRS 15 using a modified retrospective approach. In its modified retrospective application of IFRS 15, the Company applied a practical expedient that allows the Company to avoid re-considering the accounting for sales contracts that were completed prior to January 1, 2018 and were accounted for under its previous revenue accounting policy. As a result of the adoption of IFRS 15, no changes to the Company's comparative consolidated financial statements were required. IFRS 15 did not have any material impact on the consolidated statement of income and comprehensive income for the year ended December 31, 2018 or its consolidated statement of financial position as at December 31, 2018.

The Company has revised the description of its accounting policy for revenue recognition to reflect the new standard as follows:

Revenue from the sale of crude oil, natural gas and natural gas liquids is recorded when control of the product is transferred to the buyer based on the consideration specified in the contracts with customers. This usually occurs when the product is physically transferred at the delivery point agreed upon in the contract and legal title to the product passes to the customer (often at terminals, pipelines, or other transportation methods).

The Company evaluates its arrangements with third parties and partners to determine if the Company acts as the principal or as an agent. In making this evaluation, the Company considers if it obtains control of the product delivered or services provided, which is indicated by the Company having the primary responsibility for the delivery of the product or rendering of the service, having the ability to establish prices or having inventory risk. If the Company acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net-basis, only reflecting the fee, if any, realized by the Company from the transaction.

Fees charged to other entities for use of pipelines, processing facilities and roads owned by the Company are evaluated by management to determine if these originate from contracts with customers or from incidental or collaborative arrangements. Fees charged to other entities that are from contracts with customers are recognized in revenue when the related services are provided. Generally, as the Company performs the distinct services stipulated under the contract, it does not have any remaining performance obligations to its customer for those services.

Accounting standards issued but not yet applied

In January 2016, the IASB issued IFRS 16, "*Leases*" to replace IAS 17, "*Leases*". Under IFRS 16, a single recognition and measurement model will apply for lessees, which will require recognition of assets and liabilities for most leases. IFRS 16 is effective for years beginning on or after January 1, 2019 with earlier adoption permitted. The Company is currently identifying, gathering and analyzing contracts impacted by the adoption of the new standard, as well as evaluating the system requirements for implementation. The Company is currently evaluating the impact of adopting IFRS on the Company's consolidated financial statements as more fully discussed in note 4 to the Company's financial statements.

Non-GAAP Measures

This MD&A includes references to financial measures commonly used in the oil and natural gas industry. The term "operating netback" (oil and natural gas sales less royalties and production, operating and transportation expenses, all expressed on a per-unit-of-production basis) is not defined under IFRS, and may not be comparable with similar measures presented by other companies. Operating netback is a per-unit-of-production measure that may be used to assess the Company's performance and efficiency.

The term "normalized operating and transportation expense" is not defined under IFRS, and may not be comparable with similar measures presented by other companies. Normalized operating and transportation expense is normalized in order to present what the operating and transportation expense per boe would be for the Company's producing assets, assuming no unusual or non-recurring expenditures.

The term "adjusted G&A per boe" is not defined under IFRS, and may not be comparable with similar measures presented by other companies. Adjusted G&A per boe is normalized in order to present what the G&A expense per boe for the Company assuming no unusual or non-recurring expenditures.

Basis of Barrel of Oil Equivalent

Petroleum and natural gas reserves and production volumes are stated as a "barrel of oil equivalent" (boe), derived by converting natural gas to oil equivalency in the ratio of 6,000 cubic feet of gas to one barrel of oil. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6,000 cubic feet of gas to one barrel of oil is based on energy equivalency, which is primarily applicable at the burner tip, and does not represent a value equivalency at the wellhead. Readers are cautioned that boe figures may be misleading, particularly if used in isolation.

Forward-Looking Statements

This document contains certain forward-looking statements. Forward-looking statements are subject to known and unknown risks, uncertainties and other factors that could influence actual results or events and cause them to differ materially from those stated, anticipated or implied. Such forward-looking statements necessarily involve risks including, without limitation, those associated with oil and natural gas exploration, property development, production, marketing and transportation, such as dry holes and non-commercial wells, facility and pipeline damage, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, production declines, health, safety and environmental risks, competition from other producers and the ability to access sufficient capital from internal and external sources. Forward-looking information typically includes statements with words such as “anticipate”, “believe”, “expect”, “plan”, “intend”, “estimate”, “propose”, “project”, or similar words suggesting future outcomes. The Company cautions readers and prospective investors in the Company’s securities not to place undue reliance on forward-looking information as, by its nature, it is based on current expectations regarding future events that involve a number of assumptions, inherent risks and uncertainties, which could cause actual results to differ materially from those anticipated by the Company.

Forward-looking information typically involves substantial known and unknown risks and uncertainties, certain of which are beyond the Company’s control. Such risks and uncertainties include, without limitation: financial risk of marketing reserves at an acceptable price given market conditions; volatility in market prices for oil and natural gas; delays in business operations; pipeline restrictions; blowouts; the risk of carrying out operations with minimal environmental impact; industry conditions including changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; uncertainties associated with estimating oil and natural gas reserves; risks and uncertainties related to oil and gas interests and operations on aboriginal lands; economic risk of finding and producing reserves at a reasonable cost; uncertainties associated with partner plans and approvals; operational matters related to non-operated properties; increased competition for, among other things, capital, acquisitions of reserves and undeveloped lands; competition for and availability of qualified personnel or management; incorrect assessments of the value of acquisitions and exploration and development programs; unexpected geological, technical, drilling, construction, processing and transportation problems; availability of insurance; fluctuations in foreign exchange and interest rates; stock market volatility; general economic, market and business conditions; uncertainties associated with regulatory approvals; uncertainty of government policy changes; uncertainties associated with credit facilities and counterparty credit risk; changes in income tax laws, Crown royalty rates and incentive programs relating to the oil and gas industry; and other factors, many of which are outside the Company’s control. The Company’s actual results, performance or achievements could, therefore, differ materially from those expressed in, or implied by, these forward-looking estimates and whether or not any such actual results, performance or achievements transpire or occur, there can be no certainty as to what benefits or detriments the Company will derive therefrom.

The forward-looking information included herein is expressly qualified in its entirety by this cautionary statement. It is made as of the date hereof and the Company assumes no obligation to update or revise any forward-looking information to reflect new events or circumstances, except as required by law.

Abbreviations

The following summarizes the abbreviations used in this document:

Crude Oil and Natural Gas Liquids

bbl	barrel
Mbbl	thousand barrels
bbls/d	barrels per day
boe	barrel of oil equivalent
Mboe	thousand barrels of oil equivalent
boe/d	barrel of oil equivalent per day
NGL	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
GJ	Gigajoule; 1 Mcf of natural gas is about 1.05 GJ
MMBtu	million British thermal units; 1 GJ is about 0.95 MMBtu

Other

$000s	thousands of dollars
IFRS	International Financial Reporting Standards
IAS	International Accounting Standard

Corporate Information

BOARD OF DIRECTORS

GREG MACDONALD
President & CEO
Highwood Oil Company Ltd.
Calgary, Alberta

STEPHEN HOLYOAKE
Independent Businessman
Calgary, Alberta

TREVOR WONG-CHOR
Independent Businessman
Calgary, Alberta

ARIF SHIVJI
Independent Businessman
Calgary, Alberta

OFFICERS

GREG MACDONALD
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KELLY McDONALD
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