HIGHWOOD
OIL COMPANY LTD.

MANAGEMENT DISCUSSION & ANALYSIS
FOR THE YEAR ENDED DECEMBER 31, 2019

April 28, 2020

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 28, 2020 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, 2019 and 2018. 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.

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.

Q4 2019 Corporate Highlights and Outlook

- Achieved production of 1,515 bbl/d of oil in the fourth quarter of 2019, an increase from 1,117 bbl/d in the fourth quarter of 2018.

- Acquired 45 gross (24.5 net) sections of Clearwater formation lands in 2019, bringing total sections to 215 gross (109.5 net) at December 31, 2019, presenting a significant inventory of exciting drilling opportunities with short cycle times. Minimal bookings for the Clearwater formation have been incorporated into the December 31, 2019 reserves providing significant reserve upside with only six and a half sections having booked locations.

- Drilled 4 wells (2.0 net) in the Clearwater play at Nipisi during the fourth quarter of 2019. The drilling activity included delineation of the Company's 32,000 acre gross (50.0 gross sections) Nipisi land position, further validating additional Nipisi drilling inventory.

- Drilled 5 wells (2.5 net) in the Clearwater play during the first quarter of 2020 where one well remains left outstanding to drill past casing point when commodity prices improve. The drilling activity included further delineation of the Company's Nipisi land position as well as a step-out well at Craigend where the Company holds a 17,920 acre gross land position (8,960 net). Since the Company began its Clearwater development program in the fourth quarter of 2018, it has drilled 19 wells (9.5 net) to today's date.

- Given current oil price environment, the Company ceased capital spending in March 2020 and will contemplate further Clearwater drilling once sustained price recoveries are seen.

- With current select shut-ins, current production from Highwood is approximately 150 bbl/d of oil post-disposition of the Red Earth Divestiture.

Red Earth Divestiture Update

The Alberta Energy Regulator provided their conditional approval of the license transfers associated with the Red Earth Divestiture on April 24, 2020. The Company is currently addressing the transfer conditions and will move towards closing of the transaction in accordance with the terms of the purchase and sale agreement in the next few weeks.

2019 Fourth Quarter Overview

Highwood's fourth quarter results were highlighted by revenues (excluding commodity contracts) of $9.6 million, an increase of $4.5 million from the same period in 2018 where the Company saw historically high pricing differentials in Western Canada. Netbacks in the fourth quarter of 2019 averaged $10.88/bbl compared to a loss of $3.38/bbl in the fourth quarter of 2018. Fourth quarter 2019 netbacks would have been higher without the $0.7 million of workover expenses Highwood incurred to bring Red Earth production back online. Highwood recognized $1.2 million of pipeline revenues during the fourth quarter, consistent with the $1.3 million of revenue recognized in the same quarter of 2018.

2019 Fourth Quarter Operations

Highwood successfully drilled 5 wells (2.5 net) in the Clearwater play at Nipisi during the fourth quarter of 2019. The drilling activity included delineation of the Company's 32,000 acre gross Nipisi land position, further validating Nipisi drilling inventory. Including 5 gross wells (2.5 net) drilled in January & February 2020, the Company has drilled 19 gross wells (9.5 net) in the Clearwater play since it started the Clearwater program in the fourth quarter of 2018. Total capital spend in the fourth quarter of 2019 was $4.9 million compared to $6.4 million in the fourth quarter of 2018 where the Company drilled 4 gross (2 net) wells in the Clearwater play. Of the $4.9 million expenditure, $4.5 million was development capital with $3.6 million spent on the drilling & completion of Clearwater wells and $0.9 million spent on the expansion of the Company's multi-well oil battery in Nipisi.

The Company continually reviews and revises its technical approach to drilling in the Clearwater and has shortened well cycle times and decreased costs as the program has evolved. The Company continues to have its land position delineated by offset operators who are also showing success with secondary recovery method pilot projects. The Company is currently undergoing a waterflood study project at Nipisi which would help to increase ultimate recovery factors if a producing well bore was switched to an injection well.

Outlook

The Company has ceased 2020 non-discretionary capital as a result of the Covid-19 Pandemic and the current price collapse seen in Western Canada and around the world. The Company has also undertaken corporate cost saving initiatives including reducing salaries and non-essential services to help protect its balance sheet in this suppressed market.

The Company remains excited about the drilling inventory it currently has in its portfolio for when pricing shows a significant, sustained recovery. The Clearwater oil resource play continues to deliver positive delineation results which underpin an expanding opportunity set for Highwood to pursue lower risk, highly economic, oil-weighted growth. Since early 2017, industry has spud more than 290 wells to delineate and quickly grow the Clearwater play to achieve production in excess of 25,000 bbl/d. Even within a pricing environment that has been very suppressed by historical standards, strong well economics characterized by short cycle times and quick payback periods supported industry drilling over 130 wells in 2019.

The Company has, and will continue to, evaluate acquisition opportunities in the M&A market, but will remain disciplined to pursue only those opportunities that are accretive and deleveraging to its balance sheet. The Company intends to build a growing profile of recurring free funds flow that will provide maximum flexibility fund growth, debt repayment and / or other strategic M&A opportunities in a non-dilutive fashion.

The Company is subject to covenants under the terms of the Company's credit facility (see Liquidity and Capital Resources section in this MD&A). The current price collapse in oil as a result of the demand shock caused by concerns over the COVID-19 pandemic and supply concerns due to the Saudi Arabia – Russia price war, the Company expects that the full available funds available under the existing credit facility will need to be drawn to settle current obligations. The Company was in default of certain covenants at December 31, 2019 and has subsequently received waivers for the default on its credit facility. The Company's covenants for the first quarter of 2020 have been amended with the working capital covenant was temporarily reduced to 0.65:1.00 for the quarter and the Net Debt to Cash Flow waived. The credit facility is due May 31, 2021, subject to the lenders upcoming borrowing base redetermination, and the Company continues to work with its lender on several initiatives to assist the Company in these difficult times. The Company is also closely paying attention to programs and strategies deployed by the Provincial and Federal governments that will assist the Oil industry. The Company has focused on cost reductions across all areas of the business and has shut-in production that is no longer economical to produce at current prices. The Company's hedge portfolio will provide significant cash flows while prices are suppressed and the Company's midstream asset provides a source of revenue diversification.

Economic Uncertainty and Oil Price Volatility

Significant declines and abnormal volatility in oil prices and global economic uncertainty have occurred as a result of the COVID-19 pandemic and Saudi Arabia-Russia price war, The scale and duration of these developments is unknown and could have significant impact on the Company's future earnings, cash flow and overall financial condition.

Highwood Oil Company Ltd. – Financial and Operating Highlights

	Three months ended December 31, **2019**	2018	Year ended December 31, **2019**	2018
Financial				
Oil and natural gas sales	**$ 7,907,718**	$ 3,159,126	**$ 33,348,020**	$ 24,985,489
Transportation pipeline revenues	**1,228,329**	1,308,526	**5,276,121**	3,948,611
Total revenues, net of royalties and commodity contracts [1]	**6,114,166**	8,802,798	**25,910,232**	27,679,711
Income (Loss)	**(6,582,622)**	1,223,306	**(11,012,724)**	(1,809,819)
Cash flows from (used in) operations	**274,438**	(1,522,159)	**11,666,869**	(2,512,242)
Capital expenditures	**4,894,550**	6,419,621	**11,949,471**	23,248,021
Proceeds from dispositions	**-**	3,013,900	**3,000,000**	3,154,991
Working capital surplus (deficit), excluding current bank debt *(end of period)* [2]			**(8,110,651)**	3,369,541
Net debt [3]			**41,990,051**	30,946,459
Shareholders' equity *(end of period)*			**$ 17,966,713**	$ 24,579,552
Shares outstanding *(end of period)*			**6,013,965**	5,774,204
Options outstanding *(end of period)*			**136,468**	-
Restricted share units outstanding *(end of period)*			**117,600**	-
Weighted-average basic shares outstanding	**6,013,965**	5,695,056	**5,979,869**	5,578,091
Operations [4]				
Production				
Natural gas *(Mcf/d)*	**-**	12	**-**	30
Natural gas liquids (NGL) *(bbls/d)*	**-**	0	**-**	0
Crude oil *(bbls/d)*	**1,515**	1,117	**1,493**	1,120
Total *(boe/d)*	**1,515**	1,119	**1,493**	1,125
Benchmark prices				
Natural gas				
AECO *(Cdn$/GJ)* [7]	**$ 2.62**	$ 2.16	**$ 1.80**	$ 1.62
Crude oil				
Canadian Light *(Cdn$/bbl)*	**59.33**	43.30	**62.53**	63.93
Average realized prices [5]				
Natural gas *(per Mcf)* [7]	**-**	2.01	**-**	1.35
NGL *(per bbl)* [7]	**-**	72.03	**-**	71.30
Crude oil *(per bbl)*	**56.74**	30.27	**61.17**	61.06
Operating netback *(per boe)* [6]	**10.88**	(3.38)	**18.28**	7.21

(1) Includes unrealized gain and losses on commodity contracts

(2) Working capital deficit includes commodity contract liability of $3,015,000, (December 31, 2018 – commodity contract asset of $1,316,000). Excluding this, the working capital deficit would be $5,095,651 (December 31, 2018 – surplus of $2,053,541). Working capital deficit also excludes bank debt of $36,894,000 for the period ended December 31, 2019 (December 31, 2018 - $33,000,000).

(3) Net debt consists of bank debt and working capital surplus (deficit) excluding commodity contract assets and/or liabilities.

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

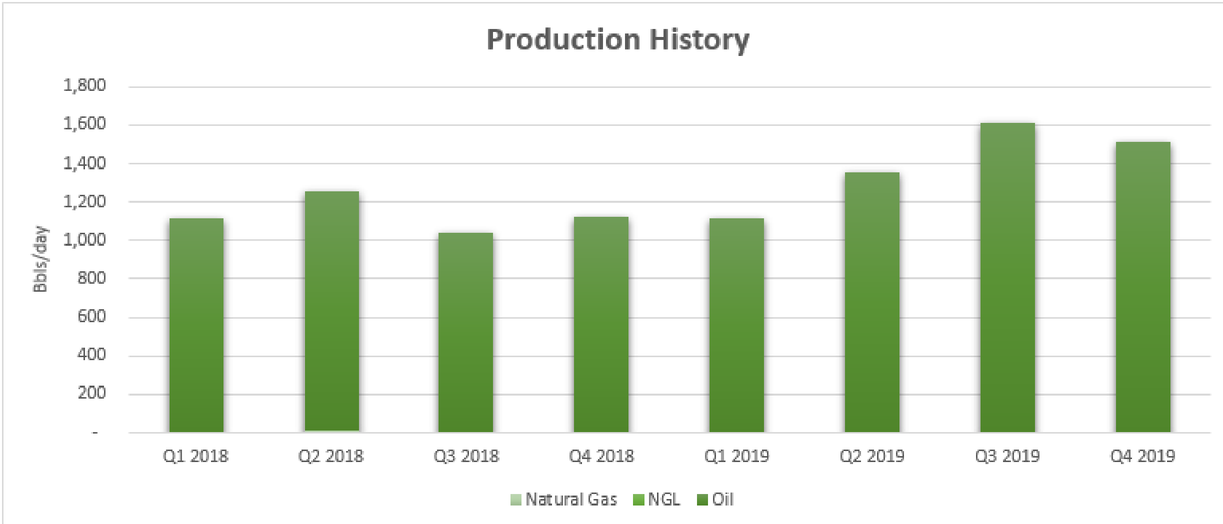
(5) Before hedging.

(6) See "Non-GAAP measures".

(7) Natural gas and NGL production and revenues are immaterial to the Company

Financial and Operating Results

Production



	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
Daily average volume				
Natural gas *(Mcf/d)*	**-**	12	**-**	30
NGL *(bbls/d)*	**-**	0	**-**	0
Crude oil *(bbls/d)*	**1,515**	1,117	**1,493**	1,120
Total sales *(boe/d)*	**1,515**	1,119	**1,493**	1,125
Total sales *(boe)*	**139,360**	102,950	**545,125**	410,710
Production weighting				
Natural gas	**0%**	0%	**0%**	0%
NGL	**0%**	0%	**0%**	0%
Crude oil	**100%**	100%	**100%**	100%
	100%	100%	**100%**	100%

Production was higher for the three months and the year ended December 31, 2019 compared to the prior period, mainly due to the production that was realized from the Company's drilling activity in its Clearwater CGU and the acquisition of 7 gross (5.5 net) wells in Saskatchewan on April 29, 2019. Since the fourth quarter of 2018, the Company has drilled and completed 14 gross (7.0 net) wells in the Clearwater area. During the fourth quarter of 2019, the Clearwater production averaged approximately 350 bbls/d. Production on the Company's other core producing area in Red Earth was consistent with the comparative periods. 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. Subsequent to December 31, 2019, the Company drilled an additional five gross wells (2.5 net) in the Clearwater area.

Production for the fourth quarter of 2019 was consistent with the prior quarter.

Sales

Oil and natural gas sales

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
	$	$	**$**	$
Natural gas	**-**	2,274	**-**	14,588
NGL	**-**	936	**-**	10,409
Crude oil	**7,907,718**	3,109,989	**33,348,020**	24,960,492
Total	**7,907,718**	3,113,199	**33,348,020**	24,985,489
Average realized prices before hedging				
Natural gas *($/Mcf)*	**-**	2.01	**-**	1.35
NGL *($/bbl)*	**-**	72.03	**-**	71.30
Crude oil *($/bbl)*	**56.74**	30.27	**61.17**	61.06
Combined average *($/boe)*	**56.74**	30.24	**61.17**	60.83

The Company realized an increase in oil revenues compared to the prior year, mainly due to the increase in production. For the first few months of 2019 the Company's realized oil price was impacted by 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 and first quarter of 2019. 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 from the fourth quarter of 2018 where realized crude oil price was $30.27/bbl.

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. Subsequent to December 31, 2019, there have been significant declines in oil prices and the stock markets worldwide for various reasons linked to the Coronavirus pandemic and other conditions impacting worldwide oil prices.

The Company's realized prices were consistent with the changes in the benchmark prices.

Transportation pipeline revenues

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
	$	$	**$**	$
Total	**1,228,329**	1,308,526	**5,276,121**	3,948,611

Transportation pipeline revenues relate to the Wabasca River pipeline system that the Company acquired throughout 2018. Revenues are generated from a tariff charged to vendors who transport product on the pipeline. Revenue increased for the year ended December 31, 2019 compared to the year ended December 31, 2018 as the Company increased its working interest from 64.4% on January 15, 2018 to 74.6% on April 30, 2018 and then to 100% on October 3, 2018. Therefore, the full year ended December 31, 2019 includes 100% working interest metrics. The Company increased the pipeline tariff effective May 1, 2020 to $22.00/m3 from $21.50/m3. The fourth quarter of 2019 was consistent with the fourth quarter of 2018.

Royalties

	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
	$	$	**$**	$
Royalties	**1,021,688**	536,510	**4,263,797**	4,135,056
Per boe	**7.33**	5.21	**7.82**	10.07
Percentage of oil and natural gas sales	**12.9%**	17.2%	**12.8%**	16.58%

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 lower in 2019 than in 2018 due to decreased commodity reference pricing used by the Alberta government to calculate royalties. The decrease is also due to the production from the Company's Clearwater CGU which is subject to a lower royalty rate (9%). The Company is focused on increased production in the Clearwater CGU with 4 additional gross wells (2 net) drilled in the fourth quarter of 2019. The decrease is slightly offset by the increased royalty rate from the properties acquired in Saskatchewan during the second quarter of 2019.

Operating and Transportation Expense

	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
	$	$	**$**	$
Operating and transportation	**5,369,666**	2,924,432	**19,117,485**	17,887,813
Per boe	**38.53**	28.41	**35.07**	43.55

Operating and transportation expenses decreased on a per boe basis for the year ended December 31, 2019, compared to the prior periods, mainly due to the increased production (from 1,125 bbls/d in 2018 to 1,493 bbls/d in 2019) from the Company's Clearwater CGU and from the acquisition of the properties in Saskatchewan. The Clearwater play has significantly lower costs on a per boe basis compared to the Company's historical production from Red Earth. The decrease was partially offset as the Company spent approximately $400,000 on environmental assessments and maintenance above and beyond its regular maintenance program.

The fourth quarter of 2019 saw an increase in operating and transportation costs on a per boe basis compared to the fourth quarter of 2018. This increase was primarily due to a workover program that was conducted in the fourth quarter of 2019 to restore 150 boe/day of production in the Red Earth area. The fourth quarter of 2019 had a workover program of approximately $780,000 compared to just $84,000 in the fourth quarter of 2018. In addition, a number of the drills in the fourth quarter of 2019 did not start producing until late in the quarter and required some production to be shut in while pad drilling operations were conducted. As a significant portion of the Companies operating and transportation expense is fixed, any decrease in production can have a significant impact on the per boe expense. The Company continues to focus on the Clearwater play and the attractive economics and low operating costs that are realized. During the three months ended December 31, 2019, operating and transportation expense per boe was $10.39 for the Clearwater CGU. Subsequent to the year ended December 31, 2019, the Company entered into a purchase and sale agreement that will see the Company dispose of the majority of the Red Earth CGU which the Company anticipates will result in a significant decrease to operating and transportation costs.

Operating and transportation expenses also includes expenditures related to the Wabasca River Pipeline System. The Wabasca River Pipeline System does not provide any production which increases the costs per boe. During the third quarter of 2019, the Company incurred increased expenditures to correct abnormalities on the Wabasca River Pipeline System, which has impacted operating and transportation expenses for the year ended December 31, 2019. The Company does not anticipate such abnormalities going forward. Management continues to look at production and operating costs to identify additional efficiencies.

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

	Dec. 31, 2019	Sept. 30, 2019	June 30, 2019	Mar. 31, 2019	Dec. 31, 2018	Sept. 30, 2018	Jun. 30, 2018	Mar. 31, 2018
	$	$	$	$	$	$	$	$
Total operating and transportation per boe	38.53	37.40	28.84	35.96	28.41	53.34	37.41	56.14
Adjusting items per boe								
Wabasca River Pipeline System	(2.61)	(6.31)	(1.97)	(1.35)	(1.46)	(1.40)	(2.00)	(1.46)
Turnarounds	(0.09)	(1.16)	-	-	-	(1.60)	-	-
Workovers	(5.60)	(0.04)	(0.74)	(3.90)	(0.82)	(1.47)	(1.47)	(11.78)
Undeveloped Clearwater lands	-	-	-	-	-	(0.64)	(0.14)	-
Pipeline release	-	-	-	-	9.71	(10.49)	(4.39)	-
Adjusted operating and transporation per boe	30.23	29.89	26.13	30.71	35.84	37.74	29.41	42.90

Adjusted operating and transportation expense is adjusted 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.

Netback Analysis

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
	$/boe	$/boe	**$/boe**	$/boe
Average sales price	**56.74**	30.24	**61.17**	60.83
Royalties	**(7.33)**	(5.21)	**(7.82)**	(10.07)
Operating and transportation	**(38.53)**	(28.41)	**(35.07)**	(43.55)
Operating netback	**10.88**	(3.38)	**18.28**	7.21

The main reason for the increase in operating netback for the year ended December 31, 2019 compared to respective period in 2018 is due to the reduction in operating and transportation costs per boe along with a reduction in royalties. The main reason for the increase in operating netback in the fourth quarter of 2019 compared to 2018 is due to the increase in commodity pricing. Management continues to look at ways to maximize the operating netback, including but not limited to the continued development of the Clearwater CGU. For the three months and year ended December 31, 2019, the Company realized a netback of $31.93 and $35.57, respectively, in the Clearwater CGU. The Company continued drilling in the Clearwater CGU in the first quarter of 2020 to take advantage of the lower operating, transportation and royalty costs.

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 months.

Oil prices improved in 2019 after being impacted by record low discounts and capacity constraints in the fourth quarter of 2018. Average benchmark prices have improved from $43.30 in the fourth quarter of 2018 to $59.33 in the fourth quarter on 2019, representing an increase of approximately 37%.

Subsequent to year end, oil prices have dramatically collapsed due to the impact of the Coronavirus pandemic and other conditions. On January 30, 2020, the World Health Organization declared the Coronavirus outbreak (COVID-19) a "Public Health Emergency of International Concern" and on March 11, 2020 declared COVID-19 a pandemic. As a result there has been a significant demand shock worldwide which creates downward pressure on oil prices. There has also been increased supply due to the dispute between Saudi Arabia and Russia which has had a further adverse impact on oil prices.

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, 2019 Highwood had the following commodity contracts, with a total mark-to-market liability of $3,442,000.

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	$ 70.05	WTI - NYMEX
Crude Oil	50bbls/day	January 1, 2020 to December 31, 2020	$ 71.53	WTI - NYMEX
Crude Oil	250bbls/day	January 1, 2020 to December 31, 2020	$ 65.00	WTI - NYMEX
Crude Oil	100bbls/day	January 1, 2020 to December 31, 2020	$ 66.00	WTI - NYMEX
Crude Oil	250bbls/day	January 1, 2021 to December 31, 2021	$ 65.40	WTI - NYMEX
Crude Oil	250bbls/day	January 1, 2020 to December 31, 2020	$ 43.75	WCS - BLENDED
Crude Oil	250bbls/day	January 1, 2020 to December 31, 2020	$ 44.20	WCS - BLENDED

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,**	
	2019	2018	**2019**	2018
	$	$	**$**	$
Realized gain (loss) on commodity contracts	**(783,224)**	442,553	**(5,926,394)**	(1,018,784)
Unrealized gain (loss) on commodity contracts	**(1,658,000)**	3,798,000	**(4,758,000)**	1,939,000

The realized losses on commodity contracts during the three months and year ended December 31, 2019 and for the year ended December 31, 2018 was due to oil commodity prices being higher than the contract price along with the impact of the commodity contract premium payable in the second quarter of 2019. The fourth quarter of 2018 saw suppressed commodity prices resulting in a realized gain. The realized loss for the year ended December 31, 2019 includes a $3,514,100 premium paid related to commodity contract entered into in anticipation of the acquisition that was terminated during 2019.

The unrealized gain for the three months and year ended December 31, 2018 was a result of decreased future strip prices during the period from when the contracts were entered into.

The unrealized loss for the three and year ended December 31, 2019 was a result of increased future strip prices during the period from when the contracts were entered into. Subsequent to year end and as a result of the oil price collapse the Company's hedges had a positive value of approximately $5.05 million at March 31, 2020.

Subsequent to December 31, 2019, 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, 2021 to December 31, 2021	$ 71.24	WTI - NYMEX

Differential:

Product	Notional Volume	Term	Fixed Price Differential (CAD/bbl)	Index
Crude Oil	200bbls/day	April 1, 2020 to December 31, 2020	$ (21.20)	WCS vs. WTI - NYMEX
Crude Oil	100bbls/day	April 1, 2020 to December 31, 2020	$ (21.40)	WCS vs. WTI - NYMEX

General and Administrative (G&A)

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
	$	$	**$**	$
G&A	**1,551,607**	1,099,182	**5,528,362**	3,008,785
G&A expense per boe	**11.13**	10.68	**10.14**	7.33

G&A expenses increased for the three months and year ended December 31, 2019 compared to the prior periods mainly due to an increase in staff and an increase in risk mitigation expenditures. Risk mitigation expenditures for the three months and year ended December 31, 2019 was $801,339 ($5.75 per boe) and $3,074,322 ($5.64/boe), respectively, compared to $233,502 ($2.27 per boe) and $441,315 ($1.07 per boe), respectively, in the comparative periods. The Company expects risk mitigation expenditures to significantly decline upon closing of the Red Earth divestiture as a majority of these costs are related to the Red Earth assets.

Stock-Based Compensation

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
	$	$	**$**	$
Stock-based compensation	**300,000**	-	**825,000**	229,000

During the year ended December 31, 2019, the Company granted 117,600 stock options, at an average weighted exercise price of $11.28. 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, 2019, the Company granted 88,100, RSU's exercisable for nominal consideration. The RSU's granted vest 1/3 on each of December 31, 2019, December 31, 2020 and December 31, 2021 and expire on December 31, 2022.

During the year ended December 31, 2019, the Company granted 29,500, RSU's exercisable for nominal consideration. The RSU's granted vest 1/3 on each of June 30, 2020, June 30, 2021 and June 30, 2022 and expire on December 31, 2022.

At December 31, 2019 the Company had 136,468 options and 117,600 RSU's outstanding.

Depletion and Depreciation ("D&D")

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
	$	$	**$**	$
D&D	**1,912,995**	1,594,540	**8,640,183**	5,835,540
Per boe	**13.73**	15.49	**15.85**	14.25

The increase in D&D for the three months year ended December 31, 2019, compared to the prior periods, is mainly a result of the increase in production from the Clearwater CGU and the Saskatchewan acquisition. These CGU's accounted for $2,075,000 of D&D in 2019. The increase in D&D is also due to a decline in the reserve base, particularly with respect to the Company's Panny CGU (Red Earth).

In addition, the Company currently has a higher D&D per boe in its Clearwater CGU, which has begun to decline as additional reserves are assigned through the Company's capital activity in the area. The average D&D per boe for the Clearwater CGU was $16.07, but was reduced to $11.36 per boe in the fourth quarter of. 2019. At December 31, 2018 the Clearwater CGU has proved and probable reserves of 638,000 bbls compared to 3,623,000 bbls at December 31, 2019 as successful drilling activity in the area delineated the Company's land base and generated further booked reserves.

Finance Income and Expenses, Net

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
	$	$	**$**	$
Interest on bank debt	**192,089**	194,663	**830,968**	570,741
Stamping fees on bank debt	**274,521**	318,699	**1,179,349**	1,026,473
Finance fees	**-**	-	**-**	273,500
Other interest expense (income)	**-**	(61,644)	**21,772**	(69,541)
Cash finance income and expenses	**466,609**	451,718	**2,032,089**	1,801,173
Amortization of finance fees	**29,000**	-	**88,400**	-
Accretion of decommissioning liabilities	**133,000**	166,000	**590,000**	631,000
Other expense	**3,346**	-	**16,656**	-
Non-cash finance expense	**165,346**	166,000	**695,056**	631,000
Total finance income and expenses	**631,955**	617,718	**2,727,145**	2,432,173

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 year ended December 31, 2019 compared to 2018 due to increased borrowing to fund the capital program and acquisitions the Company deployed in 2019. For the year ended December 31, 2019 the Company had increased borrowings using bankers acceptances, resulting in increased stamping fees compared to 2018. Interest on bank debt and stamping fees were fairly consistent between the fourth quarter of 2019 and 2018. While the fourth quarter of 2019 saw a higher overall draw, the further quarter of 2018 had a higher rate applied. Finance fees for year ended December 31, 2018 of $273,500 were expensed when incurred as the Company's credit facility was due on demand at the time. For the year ended December 31, 2019, finance fees associated with the Company's credit facility are amortized over the term of the credit facility.

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 a recovery of $737,000 and $2,466,000, respectively, for the three months and year ended December 31, 2019, compared to an expense of $1,449,000 and $475,000, respectively for the three months and year ended December 31, 2018. A significant reason for the deferred tax recovery in 2019, other than the loss before taxes, was due to the implementation of Bill 3, Job Creation Tax Cut (Alberta Corporate Tax Amendment Act) Act, which received Royal Assent on September 28, 2019. As a result of Bill 3, Alberta's general corporate income tax rate will decrease from 12% to 11% effective July 1, 2019, to 10% effective January 1, 2020, to 9% effective January 1, 2021 and to 8% effective January 1, 2022.

Loss

The Company incurred a loss of $6,582,622 and $11,012,724, respectively, for the three months and year ended December 31, 2019, compared to income of $1,223,306 and a loss of $1,809,819, respectively, for the comparative three months and year ended December 31, 2018. For the year ended December 31, 2019, the Company's loss was partially a result of a non-cash $1,329,552 listing expense related to the Company's acquisition and amalgamation of Predator Blockchain Capital Corp. The listing expense represents the difference between the compensation paid by the Company and the net assets the Company acquired. The listing expense was incurred in order for the Company to begin trading on the TSX Venture Exchange. In addition, the three months and year ended December 31, 2019 include a non-cash charge to allowance on deposit of $3,074,754 relating to the $6,149,509 disputed deposits as disclosed in note 8 of the consolidated financial statements. For the three months and year ended December 31, 2019, the Company also incurred a one-time expense of $3,514,100 relating to a premium to acquire hedges as part of the transaction that was ultimately terminated. This extraordinary and non-recurring expense is not anticipated to be realized in future periods.

	Three months ended December 31,		**Year ended December 31,**	
	2019	2018	**2019**	2018
	$	$	**$**	$
Income (Loss)	**(6,582,622)**	1,223,306	**(11,012,724)**	(1,809,819)
Per share, basic and diluted	**(1.09)**	0.21	**(1.84)**	(0.32)

Supplemental Information

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

Cash Flows from (used in) Operating Activities

	Three months ended December 31, **2019**	Three months ended December 31, 2018	Year ended December 31, **2019**	Year ended December 31, 2018
	$	$	**$**	$
Income (Loss)	**(6,582,622)**	1,223,306	**(11,012,724)**	(1,809,819)
Non-cash items:				
Unrealized (gain) loss on commodity contracts	**1,658,000**	(3,798,000)	**4,758,000**	(1,939,000)
Exploration and evaluation expenditures	**396,929**	3,000	**418,629**	3,000
Depletion and depreciation expense	**1,912,995**	1,594,540	**8,640,183**	5,853,540
Impairment loss	**-**	2,700,000	**-**	2,700,00
Finance expense	**165,346**	166,000	**695,056**	631,000
Deferred income tax recovery	**(737,000)**	1,449,000	**(2,466,000)**	475,000
Stock-based compensation	**300,000**	-	**825,000**	229,000
Gain on disposal of assets	**-**	(2,908,756)	**(2,600,000)**	(3,275,721)
Listing expense	**-**	-	**1,329,552**	-
Allowance on deposit	**3,074,754**	-	**3,074,754**	-
Cash abandonment expenditures	**-**	(299,092)	**(167,772)**	(361,423)
Change in long-term accounts payable and accrued liabilities	**16,000**	1,386,750	**(241,750)**	1,386,750
Change in long-term accounts receivable	**-**	-	**-**	115,166
Change in non-cash working capital	**70,036**	(3,038,907)	**8,413,941**	(6,519,735)
	274,438	(1,522,159)	**11,666,869**	(2,512,242)

Selected Quarterly Information

Three months ended	Dec. 31, 2019	Sept. 30, 2019	Jun. 30, 2019	Mar. 31, 2019	Dec. 31, 2018	Sept. 30, 2018	Jun. 30, 2018	Mar. 31, 2018
Financial ($000s, except per share amounts and share numbers)								
Oil and natural gas sales	7,908	8,850	9,662	6,929	3,113	7,337	8,059	6,430
Transportation pipeline revenues	1,228	1,316	1,498	1,234	1,309	976	1,083	581
Income (loss)	(6,583)	(1,447)	(475)	(2,508)	1,223	(837)	(412)	(1,784)
Capital expenditures	4,895	2,382	595	4,077	6,420	2,118	2,127	12,583
Total assets *(end of quarter)*	114,187	120,543	119,614	119,065	126,545	122,308	105,427	103,396
Working capital surplus (deficit), excluding commodity contracts and bank debt *(end of quarter)*	(8,811)	2,311	(1,594)	1,333	3,370	1,077	(3,962)	(5,017)
Shareholders' equity *(end of quarter)*	17,997	24,279	25,532	24,167	24,580	24,059	24,705	25,100
Weighted-average basic shares outstanding *(000s)*	6,014	6,014	5,994	5,890	5,695	5,539	5,539	5,539
Operations								
Production								
Natural gas *(Mcf/d)*	-	-	-	-	12	16	52	38
NGL *(bbls/d)*	-	-	-	-	-	-	1	-
Crude oil *(bbls/d)*	1,515	1,495	1,608	1,354	1,117	1,033	1,242	1,105
Total *(boe/d)*	1,515	1,495	1,608	1,354	1,119	1,036	1,252	1,112
Average realized prices *($)*								
Natural gas *(per Mcf)*	-	-	-	-	2.01	1.33	0.54	2.14
NGL *(per bbl)*	-	-	-	-	72.03	82.25	66.85	63.94
Crude oil *(per bbl)*	56.74	64.32	66.04	56.85	30.27	77.15	71.24	64.55

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, 2019	Three months ended December 31, 2018	Three months ended December 31, 2019	Three months ended December 31, 2018
	$	$	**$**	$
Land	**5,526**	198,724	**501,330**	3,630,381
Seismic and other pre-drilling costs	**102,029**	261,096	**332,663**	729,845
Production equipment and facilities	**1,193,039**	995,500	**3,089,042**	2,288,950
Drilling and completions	**3,593,956**	2,342,647	**7,382,999**	5,279,756
Recompletions	**-**	176,199	**653,437**	3,200,392
Acquisitions	**-**	2,445,455	**-**	8,118,697
	4,894,550	6,419,621	**11,949,471**	23,248,021

At December 31, 2019, the Company had E&E assets of $7,568,935 (December 31, 2018 – $8,130,352). This included approximately 334,000 net acres of undeveloped land, of which approximately 140,000 net acres are located in the Company's Clearwater core area the Company began acquiring in September 2017. During the year ended December 31, 2019, $8,486,480 was transferred to property and equipment as the Company determined the assets were technically feasible and commercially viable. All the costs transferred related to properties in the Clearwater core area.

At December 31, 2019, the Company had gross property and equipment of $128,555,324 (December 31, 2018 - $111,843,108). 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 the year ended December 31, 2019, the Company drilled 10 wells (5 net) in its Clearwater core area. As of the date of this MD&A, the Company has drilled 19 wells (9.5 net) it its Clearwater core area. The first eight drills in the Clearwater core area were primarily funded by the proceeds from the sale of the 4% non-deduct royalty and the remaining funded from cash flows. One of the wells drilled in the first quarter of 2020 was funded by proceeds from the sale of an additional non-deduct royalty of 4% on additional lands.

During the second quarter of 2019, the Company completed a corporate acquisition of a private oil and gas company with properties location in Saskatchewan. As a result of the transaction the Company acquired 7 gross wells (5.5 net) which provide light sweet crude oil produced from the Tilston formation. The Company closed the acquisition of a private oil and gas company for total consideration of $5,059,022, comprised of $3,410,647 cash and $1,648,375 of common shares (being 65,935 common shares issued at a fair value of $25.00 per common share based on the trading price of the Company's shares on the date of closing). Consideration was derived from the agreed upon purchase price of $3,450,000 cash and 65,935 common shares, with the cash component increased by $560,647 being the working capital surplus at March 31, 2019 plus 50% of the amount by which the working capital on the date of closing was greater than the working capital at March 31, 2019. The acquisition was recognized as a business combination in accordance with IFRS 3 – Business Combinations, as the acquired private company constitutes a business. The values attributable to property, plant and equipment were determined by reference to a discounted cash flow model. The Company acquired the private company for the purpose of producing cash flows.

The acquisitions in 2018 mainly related to the transportation pipelines the Company acquired a 100% working interest in three transactions during 2018, 64.4% of which was acquired in the first quarter of 2018, 10.2% was acquired in the second quarter of 2018 and the remaining working interest was acquired in the fourth quarter of 2018.

The Company acquired additional lands in the Jarvie & Nipisi areas of Alberta (Clearwater formation) during 2019, building on the land position the Company has acquired since 2017. The Company has a joint venture partner in the lands, a private company, where each company holds a 50% working interest in a majority of the lands. The Company began drilling in the Clearwater late in the third quarter of 2018 and has completed 19 gross (9.5 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 needed to 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 were 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 December 31, 2020 in order to recoup the remaining funds. At December 31, 2019, the Company had received $6,000,000 representing the Company's 50% share of the gross proceeds from the eight rig releases.

During the year ended December 31 2019, the Company, along with its 50% joint venture partner in the Clearwater area, entered into an Overriding Royalty Purchase and Sale Agreement (the "Royalty Agreement") whereby the Company will dispose of a 4% royalty over certain jointly held Clearwater mineral rights in the Craigend area for deferred gross proceeds of $1,296,296 ($648,148 being the Company's share). As a condition of the royalty divesture, the Company and its joint venture partner were required to drill one well in the Craigend area prior to March 31, 2020. The qualifying well was drilled subsequent to December 31, 2019 but prior to March 31, 2020 and the proceeds were received in full.

Share Capital and Option Activity

As at December 31, 2019 the Company had 6,013,965 common shares, 136,468 stock options and 117,600 RSU's outstanding.

During the year ended December 31, 2019, the Company granted 117,600 stock options, at an average weighted exercise price of $11.28. 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, 2019, Company 88,100, RSU's exercisable for nominal consideration. The RSU's granted vest 1/3 on each of December 31, 2019, December 31, 2020 and December 31, 2021 and expire on December 31, 2022.

During the year ended December 31, 2019, Company 29,500, RSU's exercisable for nominal consideration. The RSU's granted vest 1/3 on each of June 30, 2020, June 30, 2021 and June 30, 2022 and expire on December 31, 2022.

During the year ended December 31, 2019, the Company completed an amalgamation transaction (the "Amalgamation") with a public company. The public company was a capital pool company and the transaction was 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 deemed to be 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. The Company inherited 7,547 agent options and 18,868 stock options, both with an exercise price of $5.30 which are fully vested.

During the year ended December 31, 2019, the Company closed the acquisition of a private oil and gas company resulting in 65,935 common shares issued at a fair value of $25.00 per common (fair value based on the trading price of the Company's shares on the date of closing).

As at the date of this MD&A, the Company had 6,013,965 common shares, 136,468 stock options and 117,600 restricted share units outstanding.

Liquidity, Capital Resources and Going Concern

At December 31, 2019, the Company had negative working capital of $45,005,051 ($8,110,651, excluding bank debt). In addition, the Company is required to make certain minimum payments under other commitments. The Company expects to repay its financial liabilities in the normal course of operations and to fund future operational and capital requirements through operating cash flows and through deleveraging transactions. The Company also has a credit facility to facilitate the management of liquidity risk. At December 31, 2019, approximately $1,000,000 was available under the credit facility.

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 bank facility is subject to semi-annual reviews of the borrowing base, with the next review to be undergone prior to May 31, 2020. The lender has sole discretion on the determination of the borrowing base which is based predominantly on the Company's cash flows forecast from proved developed producing oil and natural gas reserves. The current state of the Western Canadian energy sector coupled with the suppressed global oil and natural gas commodity price environment has negatively impacted the availability for credit within the industry. The credit facility maximum will also be reduced from $38 million to $30 million upon closing of the Red Earth property sale and the receipt by the Company of $8 million in cash sale proceeds.

The Company is 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, any amounts drawn under the credit facility and any current liabilities related to lease contracts. At December 31, 2019, the Company's current ratio was 0.80:1.0 (December 31, 2018 – 1.22:1.0), however the Company obtained a waiver from the bank for the covenant breach subsequent to year end. As the Company was in technical violation of the covenant at December 31, 2019, the bank debt had been classified as current. For the quarter ended March 31, 2020 the Company anticipates the bank debt being classified as long-term, as the bank has waived the Company's net debt to cash flow covenant and waived the working capital covenant as long as the working capital covenant does not fall below 0.65:1.0, which the Company believes it will be able to achieve. The Company is required to maintain a net debt to cash flow ratio no greater than 5.25:1.0 as at the last day of the fiscal quarter ended December 31, 2019 and 3.5:1.0 as at the last day of the fiscal quarter ended March 31, 2020 (prior to the waiver of this covenant for quarter ended March 31, 2020 as described above) and 3.0:1.0 for each quarter thereafter. At December 31, 2019, the Company's net debt to cash flow ratio is 5.00:1.0. 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 forty-two months 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, 2020 but may be set at an earlier or later date at the discretion of the bank.

The Company was in violation of certain covenants at December 31, 2019 for which it has obtained a waiver from the bank subsequent to year end. At planned production rates and forward prices for crude oil being traded in the futures market, management is forecasting a breach in covenants within the next 12 months. The Company forecasts that it can continue to meet its obligations including interest payments, general & administrative expenses and operating expenses within its internally generated cash flows and available borrowing capacity. However, there are no assurances that the lender will maintain the borrowing base at the current level, which may result in a borrowing base shortfall. If the Company cannot generate sufficient funds to meet the borrowing base shortfall it would constitute an event of default under the loan agreement and the bank could demand immediate repayment of the outstanding loan amount. The Company is evaluating and planning to act on several liquidity options to help ensure the short-term availability of funds in this tumultuous time. Subsequent to December 31, 2019, the Company has shut-in certain producing properties that are uneconomic at current prices. The Company is also in discussions with its lender to amend go forward financial covenants as part of the Company's semi-annual renewal.

The Company has reduced accounts payable and accrued liabilities by approximately $10.1 million during year ended December 31, 2019 from December 31, 2018. The main reason for the decrease is due to the Company collecting insurance proceeds along with generating positive cash flows from operating activities. The majority of the decrease in accounts payable and accrued liabilities relates to amounts incurred due to the insurable event that occurred in 2018. Accounts payable and accrued liabilities not relating to the insurable event have increased since December 31, 2018 due to the significant capital activity the Company performed during 2019.

Accounts payable and accrued liabilities increased by approximately $4.7 million during the three month period ended December 31, 2019 from September 30, 2019. The main reasons for the increase are due to the capital activity the company performed during the fourth quarter.

The Company believes it has sufficient funds to meet foreseeable obligations by actively monitoring its credit facilities through use of the revolving debt, coordinating payment and revenue cycles each month, and an active commodity hedge program to mitigate commodity price risk and secure cash flows. The Company will also seek secondary financing to meet obligations if terms are considered to be economic by the Company.

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.

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards applicable to a going concern, which assumes that the Company will be able to realize its assets and discharge its liabilities in the normal course of business.

The oil and natural gas commodity price environment has been extremely volatile and suppressed by historical standards in the past few years and has been made significantly worse with the recent COVID-19 outbreak and the resulting global oversupply of oil. The Company has to the best of its ability, managed through this low price environment by maintaining an active risk management and hedging program, targeting low risk capital projects and accretive, long life asset acquisitions. The recent downward shift on global oil and natural gas commodity pricing has resulted in the deterioration in the Company's projected cash flows over the next 12 months.

Due to the factors mentioned above, there is a material uncertainty that may cast significant doubt on the Company's ability to continue as a going concern. These financial statements do not include necessary adjustments to reflect the recoverability and classification of recorded assets and liabilities and related expenses that might be necessary should the Company be unable to continue as a going concern and therefore be required to realize its assets and liquidate its liabilities and commitments in other than the normal course of business and such adjustment could be material.

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, 2019, the Company had the following commitments in addition to the leases described in note 12:

(i) 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

(ii) Drilling Commitment

During the year ended December 31 2019, the Company, along with its 50% joint venture partner in the Clearwater area, entered into an Overriding Royalty Purchase and Sale Agreement (the "Royalty Agreement") whereby the Company will dispose of a 4% royalty over certain jointly held Clearwater mineral rights for deferred gross proceeds of $1,296,296 ($648,148 being the Company's share). As a condition of the royalty divesture, the Company and its joint venture partner were required to drill one well in the Craigend formation prior to March 31, 2020. The qualifying well was drilled subsequent to year end but prior to March 31, 2020 and the proceeds were received in full.

(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 event is insurable and the Company has made payments on the majority of remediation work 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 estimated $33,250,000 pipeline release related costs will be paid out from anticipated insurance proceeds of $32,730,000 which $30,000,000 was received as at December 31, 2019 and remainder of the proceeds are expected to be received prior to December 31, 2020. In relation to the pipeline release the Company has initially recorded $32,730,000 of accounts receivable for the anticipated insurance proceeds, $33,250,000 of accounts payable and accrued liabilities in relation to the estimated costs of the remediation work and $520,000 in operating costs during 2018 and $nil for 2019 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, 2019, $2,730,000 and $2,489,765 were included in insurance proceeds receivable and accounts payable and accrued liabilities, respectively related to this insurable event.

Related-Party Transactions

During the year ended December 31, 2019, the Company incurred charges of $196,671 (2018 – $132,965) from a company with common directors, Tidewater Midstream and Infrastructure for management fees, office space, subscriptions and supplies of which $75,915 (2018 - $132,965), was recorded as an increase in general and administrative expense and $120,756 (2018 - $nil), was recorded as interest expense and a reduction to lease liabilities. In addition, the Company was charged $498,930 (2018 - $499,711) 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, 2019, the Company was also charged $1,410,015 (2018 - $1,174,119) for propane purchases and distribution from a subsidiary of this related party which is included in operating and transportation expenses on the statement of loss and comprehensive loss. As at December 31, 2019, $3,559 (2018 - $nil) is included within accounts receivable and $1,000,274 (2018 - $314,263) is included within accounts payable with respect to these charges.

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.

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, 2019 annual consolidated financial statements. 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 and policies issued but not yet applied

a) *Accounting Policies Adopted*

During the year ended December, 31, 2019, the Company adopted the following policy:

IFRS 16, "Leases"

IFRS 16, *"Leases"* was issued in January 2016 to replace IAS 17, *"Leases"*. The standard introduces a single lessee accounting model for leases with required recognition of assets and liabilities for most leases. On January 1, 2019 the Company adopted IFRS 16 using the modified retrospective approach, whereby the cumulative effect of initially applying the standard was recognized as an increase to right-of-use assets with a corresponding increase to lease obligations. Under the modified retrospective approach the comparative information was not restated and continues to be reported in accordance with IAS 17.

On initial adoption, the Company elected to use the practical expedients, whereby certain short-term (less than 12 months) and low-value leases (as defined in the standard) are excluded from recognition on the statement of financial position, and the Company continues to treat these leases as expenses. Leases to explore for or use crude oil, natural gas, minerals and similar non-regenerative resources are also exempt from the standard. The Company treats there types of leases as an expense when incurred over the lease term.

The right-of-use assets recognized were measured at amounts equal to the lease obligations. The weighted average incremental borrowing rate used to determine the lease obligations at adoption was approximately 6%. The right-of-use assets and lease obligations recognized largely relate to the Company's head office lease in Calgary and vehicle leases.

A reconciliation of the operating commitments previously disclosed as at December 31, 2018 is as follows:

IFRS 16 Transition Impact	January 1, 2019
Undiscounted operating commitments (1)	$ 851,000
Discounted operating commitments (2)	763,971
Immaterial vehicle leases not previously disclosed	34,611
Variable payments not included in lease liability	(485,852)
Lease liabilities recognized January 1, 2019	$ 312,730

(1) As disclosed in the Company's December 31, 2018 consolidated financial statements
(2) Using a 6% weighted average incremental borrowing rate

b) Future accounting pronouncements

Business Combinations

On October 22, 2018, the IASB issued amendments to the guidance in IFRS 3, "*Business Combinations*" ("IRFS 3"), revising the definition of a business and providing for the addition of an optional 'concentration test' to determine if the acquisition is a business. To be considered a business under the amendments to IFRS 3, an acquisition would have to include an input and a substantive process that together significantly contribute to the ability to create outputs. The three elements of a business are defined as follows:

- Input – Any economic resource that creates outputs, or has the ability to contribute to the creation of outputs, when on or more processes are applied to it.
- Process – Any system, standard, protocol, convention or rule that, when applied to an input or inputs, creates outputs or has the ability to contribute to the creation of outputs.
- Output – The result of inputs and processes applied to those inputs that provide goods or services to customers, generate investment income or generate other income from ordinary activities.

The optional 'concentration test' permits a simplified assessment that results in as asset acquisition if substantially all of the fair value of the gross assets is concentrated in a single identifiable asset or group of similar identifiable assets. An entity may elect to apply, or not apply, the rest. An entity may make such an election separately for each transaction or other event. If the concentration test is met, the sets of activities and assets is determined to not be a business and no further assessment is needed.

The amendments to IFRS 3 apply to businesses acquired in annual reporting periods beginning on or after January 1, 2020, with early adoption permitted. The Company has chose to adopt the amendments to IFRS effective January 1, 2020.

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 “adjusted operating and transportation expense” is not defined under IFRS, and may not be comparable with similar measures presented by other companies. Adjusted operating and transportation expense is adjusted 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 “working capital surplus (deficit), excluding bank debt” is not defined under IFRS, and may not be comparable with similar measures presented by other companies. Working capital surplus (deficit), excluding bank debt is included to show what the working capital relating to customers, vendors, and joint venture partners would be.

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

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