MANAGEMENT DISCUSSION & ANALYSIS
FOR THE THREE AND NINE MONTH PERIODS ENDED
SEPTEMBER 30, 2019

November 27, 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 November 27, 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, and the unaudited condensed interim consolidated financial statements and accompanying notes for the three and nine months ended September 30, 2019. 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.

Q3 2019 Corporate Highlights and Outlook

- Drilled three wells (1.5 net) in the Clearwater play at Nipisi during the third quarter of 2019 with another three (1.5 net) wells rig released subsequent to September 30, 2019. To date, three of the wells are on production and early production indications meet the Company's expectation. The remaining three wells should be on-stream early December.

- Throughout 2019, industry production and delineation activity has remained robust surrounding Highwood's core lands at Nipisi / Marten Hills and recently, offset operators around Highwood's exploratory Clearwater lands have drilled wells that expand the prospective scope of the play. Highwood continued to survey, construct and submit approvals for drilling locations it seeks to drill in the fourth quarter of 2019 and into 2020.

- Achieved average corporate production of 1,495 bbl/d of oil in the third quarter of 2019, reflecting a modest decrease from an average of 1,608 bbl/d in the second quarter of 2019. The decrease was primarily due to required shut-ins during pad drilling, turnarounds and workovers completed during the period. Production has increased from the prior year on account of new Clearwater production that's been brought on-stream and due to the acquisition of Gambit Oil in April 2019. Production from the three gross (1.5 net) wells drilled during the quarter was not brought online until after September 30, 2019.

- Operating netbacks remained strong at more than $18.25/boe for the three months ended September 30, 2019 but were down from $27.36/boe during the three months ended June 30, 2019 due to an increase in operating and transportation expenses that were impacted by shut-in production at Nipisi. Operating netbacks have increased from the prior year, mainly due to Clearwater production adds that realized netback of $38/boe for the nine months ended September 30, 2019.

- Continued strong quarterly cashflow from operating activities of $2.2 million for the three months ended September 30, 2019, to provide for $11.4 million of cashflow from operating activities for the first nine months of 2019.

- Current production is approximately 1,550 bbl/d of oil, including 100 bbl/d from the Q3 drilled Clearwater wells currently producing at low rates consistent with the Company's initial production techniques.

2019 Third Quarter Overview

Highwood's third quarter results were highlighted by strong cash flow from operating activities of $2.2 million, a $5.2 million increase from the same period in 2018. A planned Company owned facility turnaround, as well as shut-in Clearwater production required for continued pad drilling, resulted in average daily production of 1,495 bbl/d during the quarter. As a result of decreased production and slightly lower benchmark oil pricing, operating netbacks were $18.25/boe compared with $27.36/boe for the second quarter of 2019. Amidst recent price volatility in Western Canada, the Company has adopted a flexible capital program that is purposely setup to will be responsive to the fluxes in the current pricing environment. The Company also continues to hedge a significant level of its production related to new drilling activity.

2019 Third Quarter Operations

Highwood successfully drilled three (1.5 net) wells in the Clearwater oil play during the third quarter of 2019 with another three (1.5 net) wells spud after September 30, 2019. Since its inaugural drilling program began in Q4 2018, the Company has drilled a total of 13 (6.5 net) wells in the emerging resource play since it's drilling program began in Q4 2018. The Company continues to focus its drilling efforts within the area of Nipisi, Alberta where compelling pad and infill development opportunities present themselves. Provided that production results remain encouraging, the Company intends to keep a rig in the Nipisi area until breakup 2020 providing production results are continually positive.

Highwood's Clearwater land position has grown to 215 (109 net) sections. Management continues to dynamically assess and tier its prospective drilling inventory to pursue drilling those development opportunities that are characterized by short cycle times and quick payback periods at current strip pricing. Meanwhile, ongoing industry delineation drilling continues to de-risk the Company's exploration portfolio.

Outlook

The Company has, and will continue to, evaluate acquisition opportunities in the M&A market, bit will remain disciplined to pursue only those opportunities that are accretive an deleveraging with a drilling inventory that is economic at current strip pricing. 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 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 200 wells to delineate and quickly grow the Clearwater play to achieve production in excess of 20,000 bbl/d. Even within a pricing environment that has been suppressed by historical standards, strong well economics characterized by short cycle times and quick payback periods have supported industry to already spud 110 new wells in 2019. Highwood will continue to focus its efforts throughout 2019 and into 2020 on delineating its Clearwater lands in a capital-efficient manner, while mainly pursuing infill and pad drilling development opportunities offsetting positive initial production results.

Highwood Oil Company Ltd. – Financial and Operating Highlights

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
Financial				
Oil and natural gas sales	**$ 8,849,696**	$ 7,336,814	**$ 25,440,302**	$ 21,826,363
Transportation pipeline revenues	**1,316,317**	975,964	**4,047,792**	2,640,085
Total revenues, net of royalties and commodity contracts (1)	**7,410,354**	6,870,212	**19,796,066**	18,876,913
Loss	**1,447,053**	837,471	**4,430,102**	3,033,125
Cash flows from (used in) operations	**2,225,868**	(2,965,870)	**11,392,431**	(1,349,015)
Capital expenditures	**2,382,201**	2,118,155	**7,054,921**	16,828,400
Proceeds from dispositions	**750,000**	141,091	**3,000,000**	141,091
Working capital surplus (deficit) *(end of period)* (2)			**420,907**	(30,923,039)
Net debt (3)			**(34,179,493)**	(28,558,039)
Shareholders' equity *(end of period)*			**$ 24,279,335**	$ 24,059,396
Shares outstanding *(end of period)*			**6,013,965**	5,538,674
Options outstanding *(end of period)*			**106,968**	717,000
Restricted share units outstanding *(end of period)*			**88,100**	-
Weighted-average basic shares outstanding	**6,013,965**	5,538,674	**5,968,379**	5,538,674
Operations (4)				
Production				
Natural gas *(Mcf/d)*	**-**	16	**-**	36
Natural gas liquids (NGL) *(bbls/d)*	**-**	-	**-**	-
Crude oil *(bbls/d)*	**1,495**	1,033	**1,486**	1,120
Total *(boe/d)*	**1,495**	1,036	**1,486**	1,127
Benchmark prices				
Natural gas				
AECO *(Cdn$/GJ)* (7)	**$ 1.43**	$ 1.45	**$ 1.52**	$ 1.44
Crude oil				
Canadian Light *(Cdn$/bbl)*	**66.95**	76.76	**64.32**	70.81
Average realized prices (5)				
Natural gas *(per Mcf)* (7)	**-**	1.33	**-**	1.27
NGL *(per bbl)* (7)	**-**	82.25	**-**	71.14
Crude oil *(per bbl)*	**64.32**	77.15	**62.70**	71.29
Operating netback *(per boe)* (6)	**18.25**	11.10	**20.83**	10.61

(1) Includes unrealized gain and losses on commodity contracts

(2) Working capital surplus (deficit) includes commodity contract liability of $1,890,000, (September 30, 2018 – commodity contract liability of $2,365,000). Excluding this, the working capital surplus would be $2,310,907 (September 30, 2018 – deficit of $28,558,039). Working capital deficit also includes revolving operating demand loan of $32,000,000 for the period ended September 30, 2018.

(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".

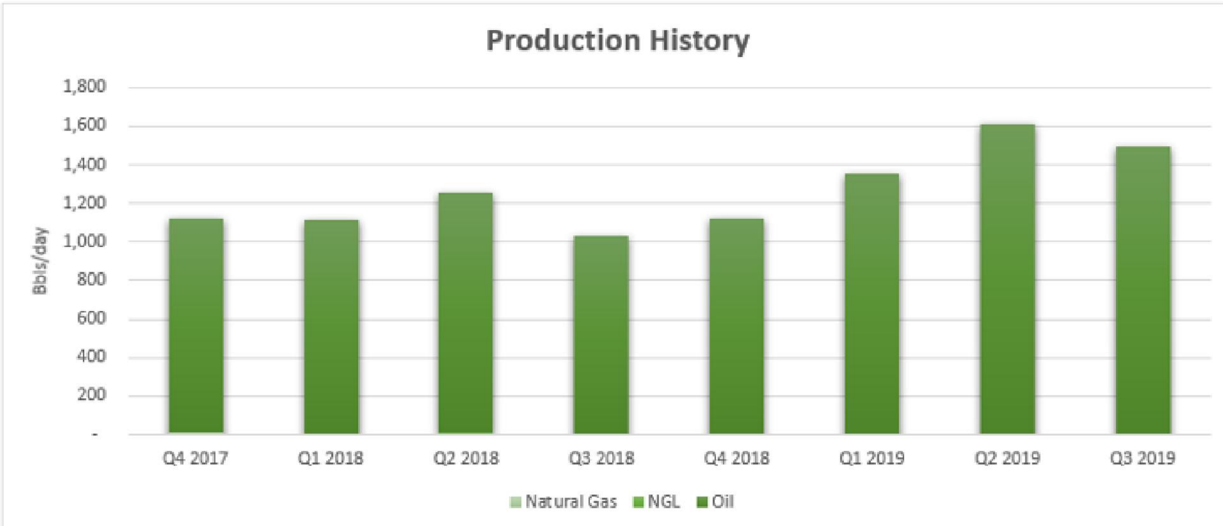
(5) Before hedging.

(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 September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
Daily average volume				
Natural gas *(Mcf/d)*	**-**	16	**-**	36
NGL *(bbls/d)*	**-**	-	**-**	-
Crude oil *(bbls/d)*	**1,495**	1,033	**1,486**	1,120
Total sales *(boe/d)*	**1,495**	1,036	**1,486**	1,127
Total sales *(boe)*	**137,578**	95,324	**405,765**	307,628
Production weighting				
Natural gas	**0%**	0%	**0%**	1%
NGL	**0%**	0%	**0%**	0%
Crude oil	**100%**	100%	**100%**	99%
	100%	100%	**100%**	100%

Production was higher for the three and nine month period ended September 30, 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 9 gross (4.5 net) wells in the Clearwater area. During the third quarter of 2019, the Clearwater production averaged approximately 280 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.

Production was down from the second quarter of 2019 due to production being temporarily shut in while drilling, workovers and turnarounds were conducted in the third quarter of 2019.

Sales

Oil and natural gas sales

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
	$	$	**$**	$
Natural gas	**-**	2,007	**-**	12,314
NGL	**-**	1,708	**-**	9,473
Crude oil	**8,849,696**	7,333,099	**25,440,302**	21,804,576
Total	**8,849,696**	7,336,814	**25,440,302**	21,826,363
Average realized prices before hedging				
Natural gas *($/Mcf)*	**-**	1.33	**-**	1.27
NGL *($/bbl)*	**-**	82.25	**-**	71.14
Crude oil *($/bbl)*	**64.32**	77.15	**62.70**	71.29
Combined average *($/boe)*	**64.32**	76.97	**62.70**	70.95

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.

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

Transportation pipeline revenues

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
	$	$	**$**	$
Total	**1,316,317**	975,964	**4,047,792**	2,640,085

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 both the three and nine month periods of 2019 compared to prior periods 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% during the fourth quarter of 2018. Therefore, the three and nine month periods ended September 30, 2019 include a 100% working interest. In addition, there has been increased capital activity in the area resulting in increased volumes by shippers leading to additional revenue.

Royalties

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
	$	$	**$**	$
Royalties	**1,192,878**	1,194,395	**3,242,049**	3,598,546
Per boe	**8.67**	12.53	**7.99**	11.70
Percentage of oil and natural gas sales	**13.5%**	16.3%	**12.7%**	16.5%

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. The Company is focused on increased production in the Clearwater CGU with three additional gross wells drilled in the third quarter of 2019. The decrease is slightly offset by the increased royalty rate that the properties acquired in Saskatchewan during the second quarter of 2019 are subject to.

Operating and Transportation Expense

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
	$	$	**$**	$
Operating and transportation	**5,144,885**	5,084,434	**13,747,819**	14,963,381
Per boe	**37.40**	53.34	**33.88**	48.64

Operating and transportation expenses decreased on a per boe basis for the three and nine months ended September 30, 2019, compared to the prior periods, mainly due to the increased production (from 1,127 bbls/d in 2018 to 1,486 bbls/d in 2019) from the Company's Clearwater CGU and from the acquisition of the properties in Saskatchewan. Clearwater has significantly lower costs on a per boe basis compared to the Company's historical production from Red Earth. The decrease in operating and transportation costs on a per boe basis for the nine months ended September 30, 2019 was also due to a significant workover program that was conducted in the first quarter of 2018. There was approximately $1.2 million spent on workovers in first quarter of 2018 compared to approximately $475,000 for the first quarter of 2019. Workovers result in additional operating costs per boe as production is shut-in for the work to be performed. The work was done in order to bring additional production online.

The third quarter of 2019 saw an increase in operating and transportation costs on a per boe basis compared to the prior three months ($28.84 per boe for the three months ended June 30, 2019) mainly due to production being shut in while the Company drilled 3 gross wells in the Clearwater area. The Clearwater area focuses on pad drilling (multiple wellbores from a single surface location). When new wells are in the process of being drilled, any current wells producing on the pad need to be shut in. 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 third quarter of 2019 also saw production out of the Company's Red Earth CGU shut in for turnarounds and workovers to be conducted. The Company also spent approximately $400,000 on environmental assessments and maintenance above and beyond its regular maintenance program. 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 September 30, 2019, operating and transportation expense per boe was $10.05 for the Clearwater CGU.

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. 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:

	Sept. 30, 2019	June 30, 2019	Mar. 31, 2019	Dec. 31, 2018	Sept. 30, 2018	Jun. 30, 2018	Mar. 31, 2018	Dec. 31, 2017	Sept. 30, 2017
	$	$	$	$	$	$	$	$	$
Total operating and transportation per boe	37.40	28.84	35.96	28.41	53.34	37.41	56.14	30.23	38.43
Adjusting items per boe									
Wabasca River Pipeline System	(6.31)	(1.97)	(1.35)	(1.46)	(1.40)	(2.00)	(1.46)	-	-
Turnarounds	(1.16)	-	-	- -	1.60	-	-	(0.30)	(3.18)
Workovers	(0.04)	(0.74)	(3.90)	(0.82)	(1.47)	(1.47)	(11.78)	(2.55)	(0.74)
Undeveloped Clearwater lands	-	-	-	-	(0.64)	(0.14)	-	-	(0.74)
Pipeline release	-	-	-	9.71	(10.49)	(4.39)	-	-	-
Adjusted operating and transporation per boe	29.89	26.13	30.71	35.84	37.74	29.41	42.90	27.38	33.78

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 September,		Nine months ended September 30,	
	2019	2018	**2019**	2018
	$/boe	$/boe	**$/boe**	$/boe
Average sales price	**64.32**	76.97	**62.70**	70.95
Royalties	**(8.67)**	(12.53)	**(7.99)**	(11.70)
Operating and transportation	**(37.40)**	(53.34)	**(33.88)**	(48.64)
Operating netback	**18.25**	11.10	**20.83**	10.61

The main reason for the increase in operating netback for the three and nine months ended September 30, 2019 compared to respective periods in 2018 is due to the reduction in operating and transportation costs per boe along with a reduction in royalties. 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 ended September 30, 2019, the Company realized a netback of $38.93 in the Clearwater CGU.

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 have 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 $66.95 in the third quarter on 2019, representing an increase of approximately 55%.

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 September 30, 2019 Highwood had the following commodity contracts, with a total mark-to-market liability of $1,784,000

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
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	75bbls/day	May 1, 2019 to December 31, 2019	$ 84.71	WTI - NYMEX
Crude Oil	100bbls/day	April 1, 2020 to December 31, 2020	$ 69.00	WTI - NYMEX
Crude Oil	250bbls/day	January 1, 2021 to December 31, 2021	$ 65.40	WTI - NYMEX
Crude Oil	500bbls/day	September 1, 2019 to December 31, 2019	$ 49.30	WCS – BLENDED
Crude Oil	250bbls/day	July 1, 2019 to December 31, 2019	$ 49.01	WCS – BLENDED
Crude Oil	250bbls/day	July 1, 2019 to December 31, 2020	$ 43.75	WCS – BLENDED
Crude Oil	250bbls/day	July 1, 2019 to December 31, 2020	$ 44.20	WCS – BLENDED
Crude Oil	100bbls/day	July 1, 2019 to December 31, 2020	$ 45.50	WCS – BLENDED
Crude Oil	250bbls/day	January 1, 2020 to December 31, 2020	$ 42.50	WCS - BLENDED
Crude Oil	250bbls/day	January 1, 2020 to December 31, 2020	$ 43.95	WCS - BLENDED

CAD Collars:

Product	Notional Volume	Term	Collar Cap (CAD/bbl)	Collar floor (CAD/bbl)	Index
Crude Oil	100bbls/day	October 1, 2019 to December 31, 2019	$ 69.00	$ 59.00	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	February 1, 2019 to December 31, 2019	$ (12.50)	Edmonton Light vs. WTI - NYMEX
Crude Oil	50bbls/day	February 1, 2019 to December 31, 2019	$ (10.50)	Edmonton Light vs. WTI - NYMEX
Crude Oil	50bbls/day	January 1, 2019 to December 31, 2019	$ (21.00)	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 September 30,		**Nine months ended September 30,**	
	2019	2018	**2019**	2018
	$	$	**$**	$
Realized loss on commodity contracts	**(1,003,719)**	(817,395)	**(5,143,170)**	(1,461,337)
Unrealized gain (loss) on commodity contracts	**(1,325,000)**	305,000	**(3,100,000)**	(1,859,000)

The realized losses on commodity contracts during the three and nine months ended September 30, 2019 and for three and nine months ended September 30, 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 realized loss for the nine months ended September 30, 2019 includes a $3,514,100 premium paid related to commodity contract entered into in anticipation of the acquisition described in note 19 of the June 30, 2019 interim financial statements.

The unrealized gain for the three months ended September 30, 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 nine months ended September 30, 2019 and for nine months ended September 30, 2018 was a result of increased future strip prices during the period from when the contracts were entered into.

Subsequent to September 30, 2019, the Company entered into the following commodity contracts:

CAD Swaps:

Product	Notional Volume	Term	Fixed Price (CAD/bbl)	Index
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

General and Administrative (G&A)

	Three months ended September 30,		**Nine months ended September 30,**	
	2019	2018	**2019**	2018
	$	$	**$**	$
G&A	**1,360,256**	720,058	**3,976,755**	1,909,603
G&A expense per boe	**9.89**	7.55	**9.80**	6.21

G&A expenses increased for the three and nine months ended September 30, 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 and nine months ended September 30, 2019 was $801,300 ($5.82 per boe) and $2,272,983 ($5.60/boe), respectively, compared to $93,353 ($0.98 per boe) and $207,813 ($0.68 per boe), respectively, in the comparative periods.

Stock-Based Compensation

	Three months ended September 30,		**Nine months ended September 30,**	
	2019	2018	**2019**	2018
	$	$	**$**	$
Stock-based compensation	**194,000**	192,000	**525,000**	229,000

During the nine month period ended September 30, 2019, the Company granted 88,100 stock options at an exercise price of $9.00 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 nine month period ended September 30, 2019, the Company granted 88,100 restricted share units (“RSU’s”). The RSU’s granted vest 1/3 on each on December 31, 2019, December 31, 2020, December 31, 2021 and expire on December 31, 2022.

At September 30, 2019 the Company had 106,968 options and 88,100 RSU’s outstanding.

Depletion and Depreciation (D&D)

	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
	$	$	**$**	$
D&D	**2,305,667**	1,273,000	**6,727,188**	4,259,000
Per boe	**16.76**	13.35	**16.58**	13.84

The increase in D&D for the three and nine month periods ended September 30, 2019, compared to the prior periods, is mainly a result of the increase in 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. D&D has also increased in the second and third quarter of 2019 due to the addition of the producing properties in Saskatchewan that were added in the Company's acquisition of a private company on April 29, 2019.

In addition, the Company currently has a higher D&D per boe in its Clearwater CGU, which the Company anticipates to decline as additional reserves are assigned through the Company's capital activity in the area.

Finance Income and Expenses, Net

	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
	$	$	**$**	$
Interest on bank debt	**221,414**	156,995	**638,879**	376,080
Stamping fees on bank debt	**408,493**	276,884	**904,829**	707,774
Finance fees	**-**	273,500	**-**	273,500
Other interest expense (income)	**-**	-	**21,772**	(7,898)
Cash finance income and expenses	**629,907**	707,379	**1,565,480**	1,349,456
Amortization of finance fees	**27,400**	-	**59,400**	-
Accretion of decommissioning liabilities	**139,000**	152,000	**457,000**	465,000
Accretion of finance lease obligations	**3,656**	-	**13,310**	-
Non-cash finance expense	**170,056**	152,000	**529,710**	465,000
Total finance income and expenses	**799,963**	859,379	**2,095,190**	1,814,456

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 and nine month periods ended September 30, 2019 compared to 2018 due to increased borrowing to fund the capital program and acquisitions the Company deployed in 2019. For the three and nine month periods ended September 30, 2019 the Company had increased borrowings using bankers acceptances, resulting in increased stamping fees compared to 2018. Finance fees for the three and nine month periods ended September 30, 2018 of $273,500 were expensed when incurred as the Company's credit facility was due on demand at the time. For the three and nine months ended September 30, 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 $413,000 and $1,729,000, respectively, for the three and nine months ended September 30, 2019, compared to a recovery of $169,000 and $974,000, respectively for the three and nine months ended September 30, 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 $1,447,053 and $4,430,102, respectively, for the three and nine months ended September 30, 2019, compared to a loss of $837,471 and $3,033,125, respectively, for the comparative three and nine month periods in 2018. For the nine month period ended September 30, 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. For the three and nine month ended September 30, 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 September 30,		**Three months ended September 30,**	
	2019	2018	**2019**	2018
	$	$	**$**	$
Loss	**1,447,053**	837,471	**4,430,102**	3,033,125
Per share, basic and diluted	**0.24**	0.15	**0.74**	0.55

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 September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
	$	$	**$**	$
Loss	**(1,447,053)**	(837,471)	**(4,430,102)**	(3,033,125)
Non-cash items:				
Unrealized (gain) loss on commodity contracts	**1,325,000**	(305,000)	**3,100,000**	1,859,000
Exploration and evaluation expenditures	**-**	-	**21,700**	-
Depletion and depreciation expense	**2,305,667**	1,273,000	**6,727,188**	4,259,000
Finance expense	**170,056**	152,000	**529,710**	465,000
Deferred income tax recovery	**(413,000)**	(169,000)	**(1,729,000)**	(974,000)
Stock-based compensation	**194,000**	192,000	**525,000**	229,000
Gain on disposal of assets	**(650,000)**	(266,965)	**(2,600,000)**	(366,965)
Listing expense	**-**	-	**1,329,552**	-
Cash abandonment expenditures	**(6,671)**	(62,331)	**(167,772)**	(62,331)
Change in long-term accounts payable and accrued liabilities	**(257,750)**	-	**(257,750)**	-
Change in long-term accounts receivable	**-**	49,100	**-**	115,166
Change in non-cash working capital	**1,005,619**	(2,991,203)	**8,343,905**	(3,839,760)
	2,225,868	(2,965,870)	**11,392,431**	(1,349,015)

Selected Quarterly Information

Three months ended	Sept. 30, 2019	Jun. 30, 2019	Mar. 31, 2019	Dec. 31, 2018	Sept. 30, 2018	Jun. 30, 2018	Mar. 31, 2018	Dec. 31, 2017
Financial ($000s, except per share amounts and share numbers)								
Oil and natural gas sales	8,850	9,662	6,929	3,113	7,337	8,059	6,430	6,277
Transportation pipeline revenues	1,316	1,498	1,234	1,309	976	1,083	581	-
Income (loss)	(1,447)	(475)	(2,508)	1,223	(837)	(412)	(1,784)	(1,073)
Capital expenditures	2,382	595	4,077	6,420	2,118	2,127	12,583	4,658
Total assets *(end of quarter)*	120,543	119,614	119,065	126,545	122,308	105,427	103,396	79,807
Working capital surplus (deficit), excluding commodity contracts *(end of quarter)*	2,311	(1,594)	1,333	(29,630)	(30,923)	(26,741)	(26,753)	(14,050)
Shareholders' equity *(end of quarter)*	24,279	25,532	24,167	24,580	24,059	24,705	25,100	26,864
Weighted-average basic shares outstanding *(000s)*	6,014	5,994	5,890	5,695	5,539	5,539	5,539	5,539
Operations								
Production								
Natural gas *(Mcf/d)*	-	-	-	12	16	52	38	73
NGL *(bbls/d)*	-	-	-	-	-	1	-	1
Crude oil *(bbls/d)*	1,495	1,608	1,354	1,117	1,033	1,242	1,105	1,111
Total *(boe/d)*	1,495	1,608	1,354	1,119	1,036	1,252	1,112	1,124
Average realized prices *($)*								
Natural gas *(per Mcf)*	-	-	-	2.01	1.33	0.54	2.14	1.30
NGL *(per bbl)*	-	-	-	72.03	82.25	66.85	63.94	43.79
Crude oil *(per bbl)*	64.32	66.04	56.85	30.27	77.15	71.24	64.55	61.30

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 September 30,		Three months ended September 30,	
	2019	2018	**2019**	2018
	$	$	**$**	$
Land	**35,561**	138,823	**495,804**	3,431,657
Seismic and other pre-drilling costs	**88,447**	55,738	**220,634**	468,749
Production equipment and facilities	**451,782**	43,450	**1,896,003**	1,293,450
Drilling and completions	**1,806,411**	724,904	**3,789,043**	2,937,109
Recompletions	**-**	23,155	**653,437**	3,024,193
Acquisitions	**-**	1,132,085	**-**	5,673,242
	2,382,201	2,118,155	**7,054,921**	16,828,400

At September 30, 2019, the Company had E&E assets of $10,209,563 (December 31, 2018 – $8,130,352). This included approximately 340,000 net acres of undeveloped land, of which approximately 147,000 net acres are located in the Company's Clearwater core area the Company began acquiring in September 2017. During the second quarter of 2019, $1,808,057 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 September 30, 2019, the Company had gross property and equipment of $126,440,075 (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 first quarter of 2019, the Company drilled 3 wells (1.5 net) in its Clearwater core area, one of which was completed early in the second quarter of 2019. During the third quarter of 2019, the Company drilled an additional 3 wells (1.5 net) in the Clearwater core area, one of which was drilled over quarter end and completed in the fourth quarter. As of the date of this MD&A, the Company has drilled 10 wells (5 net) it its Clearwater core area. The first eight drills in the Clearwater core area were funded by the proceeds from the sale of the 4% non-deduct royalty and the remaining funded from cash flows. The Company plans to drill another 3-7 gross (1.5-3.5) net wells before the end of 2019. As commodity prices unfold, the Company will continually evaluate the drilling program. Drilling for the remainder or 2019 will be funded through the Company's existing credit facility, existing cash flows, secondary financing and/or via an equity or raise.

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 purchase price was reduced by deferred compensation of $600,000 as the conditions for the vendor to receive these funds was not met under the Workover Program Plan and Production Plan. During the three months ended September 30, 2019, the Company entered into an Amended and Restated Workover Program Plan and Production Plan (the "Workover Plan") whereby the vendor was be responsible for all costs and expenses incurred directly as a result of the Workover Plan. Following the completion of the workover, if the volume of petroleum produced by the well was greater than 5 cubic meters per day for a period of twenty-one days following the consummation of the Workover Plan based on the average value of three well tests with respect to the program well jointly conducted by the vendor and the Company, the vendor will receive compensation of $600,000. If the volume of petroleum produced by the well was equal to or greater than 2 cubic meters per day but less than 5 cubic meters per day for a period of twenty-one days following the consummation of the Workover Plan based on the average value of three well tests with respect to the program well jointly conducted by the vendor and the Company, the vendor will receive compensation of $300,000. If the volume of petroleum produced by the well was less than 2 cubic meters per day for a period of twenty-one days following the consummation of the Workover Plan based on the average value of three well tests with respect to the program well jointly conducted by the vendor and the Company, the vendor will not receive any additional compensation. The results of the testing determined the vendor did not receive any additional compensation.

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 12 gross (6.0 net) wells in the play as of today's date, with one well additional well currently being drilled . 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. At September 30, 2019, the Company had received $6,000,000 representing the Company's 50% share of the gross proceeds from the eight rig releases.

Share Capital and Option Activity

As at September 30, 2019 the Company had 6,013,965 common shares, 106,968 stock options and 88,100 RSU's outstanding.

During the nine month period ended September 30, 2019, the Company granted 88,100 stock options at an exercise price of $9.00 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 nine month period ended September 30, 2019, the Company granted 88,100 restricted share units ("RSU's"). The RSU's granted vest 1/3 on each of December 31, 2019, December 31, 2020, December 31, 2021 and expire on December 31, 2022.

During the nine month period ended September 30, 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 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 nine month period ended September 30, 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).

Subsequent to September 30, 2019, the Company granted 29,500 stock options at an exercise price of $18.00 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. The Company also granted 29,500 RSU's exercisable for nominal consideration. The RSU's granted vest 1/3 on June 30, 2020, 1/3 on June 30, 2021, 1/3 on June 30, 2022 and expire on December 31, 2022.

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 and Capital Resources

At September 30, 2019, the Company had a working capital surplus (defined as current assets less current liabilities) of $420,907. In addition, the Company is required to make certain minimum payments under other commitments as described in the "Commitments and Contingencies" section. 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. The Company also has a credit facility to facilitate the management of liquidity risk. At September 30, 2019, $1,400,000 was available under the credit facility. The Company's credit facility comes due in more than twelve months, and is therefore classified as long-term.

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

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 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 current liabilities related to lease contracts. At September 30, 2019, the Company's current ratio was 1.23:1.0 (December 31, 2018 – 1.22:1.0). The Company is 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 September 30, 2019 and as at the last day of the fiscal quarter for each quarter thereafter. At September 30, 2019, the Company's net debt to cash flow ratio is 2.70:1.0. 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 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. For the period ended September 30, 2019, the Company received a waiver with respect to the permitted hedging as the Company exceeded 60% of gross production. In addition the credit facility agreement was amended to allow the Company to enter into notional commodity contracts exceeding no more than forty two months in term. Subsequent to September 30, 2019, the Company underwent a borrowing base review. As a result of the review, the Company's borrowing base will remain at $38,000,000. The net debt to cash flow ratio covenant for the quarter ended December 31, 2019 and the quarter ended March 31, 2020 were amended to 5.25:1.0 and 3.5:1.0, respectively. In addition, the Company received consent for a $3,500,000 Subordinated Credit Facility, subject to a satisfactory Intercreditor Agreement. 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 has reduced accounts payable and accrued liabilities by approximately $14.8 million during the nine month period ended September 30, 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 $2.5 million during the three month period ended September 30, 2019 from June 30, 2019. The main reasons for the increase are due to the capital activity the company performed at the end of the third quarter along with expenditures relating to the terminated transaction that impacted cash flows during the third quarter of 2019.

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.

In relation to the remediation work described in note 15 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 September 30, 2019, the Company had the following commitments in addition to the leases described in note 8 of the financial statements for the three and nine month periods ended September 30, 2019.

(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 three and nine months ended September 30, 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 potentially 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 must drill one well in the Craigend formation prior to March 31, 2020. The gross proceeds will be due within five business days of the Company notifying the purchaser that the qualifying well has been completed. In the event that the qualifying well is not completed the Royalty Agreement shall immediately terminate, without penalty to the Company.

(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 has made or will be making 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 $33,050,000 pipeline release related costs will be paid out from anticipated insurance proceeds of $32,530,000 which are expected to be received prior to December 31, 2019. In relation to the pipeline release the Company has initially recorded $32,530,000 of accounts receivable for the anticipated insurance proceeds, $33,050,000 of accounts payable and accrued liabilities in relation to the estimated costs of the remediation work and $520,000 in operating costs during 2018 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 September 30, 2019, $3,530,000 and $3,648,566 were included in insurance proceeds receivable and accounts payable and accrued liabilities, respectively

Related-Party Transactions

During the three and nine month periods ended September 30, 2019, the Company incurred charges of $62,134 and $135,743, respectively (three and nine months ended September 30, 2018 –$59,368 and $80,460, respectively) from a company with common directors, Tidewater Midstream and Infrastructure for management fees, office space, subscriptions and supplies of which $31,945 and $45,176, respectively, was recorded as an increase in general and administrative expense and $30,189 and $90,567, respectively, was recorded as a reduction to lease liabilities. In addition, the Company was charged $124,013 and $330,334, respectively (three and nine months ended September 30, 2018 - $242,859 and $320,890, respectively) for net non-operated gas sales, butane purchases and gas processing fees which is included in operating and transportation expense. During the three and nine month periods ended September 30, 2019, the Company was also charged $168,811 and $1,032,101, respectively (three and nine months ended September 30, 2018 - $92,173 and $794,136, respectively) 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 Loss and Comprehensive Loss. As at September 30, 2019, $3,559 (December 31, 2018 - $nil) is included within accounts receivable and $746,364 (December 31, 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, 2018 annual consolidated financial statements. There have been no changes to accounting policies or to the use of estimates or management's judgments since December 31, 2018, with the exception of judgements and estimates relating to, and the adoption of IFRS 16 as discussed in note 2(b) on the Condensed Interim Consolidated Financial Statements for the three and nine month periods ended September 30, 2019. 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

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. The details of the Company's accounting policies under the previous standard were disclosed in the consolidated financial statements for the year ended December 31, 2018.

Certain short-term (less than 12 months) and low-value leases (as defined in the standard) are exempt from the requirements, 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 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.

As a result of this adoption, the Company has revised the description of its accounting policy for leases as follows:

At inception of a contract, the Company assesses whether a contract is, or contains a lease. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. To assess whether a contract conveys the right to control the use of an identified asset, the Company assesses whether: the contract involves the use of an identified asset; the Company has the right to obtain substantially all of the economic benefits from the use of the asset throughout the period of use; and, the Company has the right to direct the use of the asset.

The Company recognizes a lease asset and a lease liability at the commencement date of the lease contract, which is the date that the lease asset is available to the Company. The lease asset is initially measured at cost. The cost of a lease asset includes the amount of the initial measurement of the lease liability, lease payments made prior to the commencement date, initial direct costs and estimates of the decommissioning liability, if any. Subsequent to initial recognition, the lease asset is depreciated using the straight-line method over the earlier of the end of the useful life of the lease asset or the lease term. A lease obligation is recognized at the commencement of the lease term at the present value of the lease payments that are not paid at that date discounted using the rate implicit in the lease or the

Company's incremental borrowing rate if the implicit rate is not readily available. Interest expense is recognized on the lease obligations using the effective interest rate method and payments are applied against the lease obligation. Optional renewal periods, or periods which are cancellable by the Company, are included in the lease payments if the Company is reasonably certain to exercise the renewal option or not cancel the lease. The lease liability is measured at amortized cost using the effective interest method. The lease liability is remeasured when there is a change in the Company's assessment of the expected lease term.

The preparation of the condensed consolidated interim financial statements in accordance with IFRS requires management to make judgments, estimates, and assumptions that affect the reported amount of assets, liabilities, income, and expenses. Actual results could differ significantly from these estimates. Key areas where management has made judgments, estimates, and assumptions related to the application of IFRS 16 include:

Judgments

Judgments are required to determine if a contract is, or contains, a lease. These judgments require an assessment of whether the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. Judgment is required to determine the interest rate used to discount the lease payments.

Estimates

The likelihood of renewal, cancellation or termination of lease contracts is a significant estimate required to determine the lease term of the contract. Estimates are used by management to determine the stand-alone price of the lease and non-lease components of contracts in order to allocate the contracted consideration to the components.

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

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.

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
CEO, Fireweed Energy Ltd.
Calgary, Alberta

TREVOR WONG-CHOR
Partner, DLA Piper (Canada) LLP
Calgary, Alberta

ARIF SHIVJI
Independent Businessman
Calgary, Alberta

OFFICERS

GREG MACDONALD
President & Chief Executive Officer

GRAYDON GLANS
Chief Financial Officer

KELLY McDONALD
Vice President, Exploration

HEAD OFFICE
Suite 900, 222 – 3rd Avenue S.W.
Calgary, Alberta
T2P 0B4

Telephone: 403-719-0499
Facsimile: 587-296-4916

AUDITORS
RSM Alberta LLP
Calgary, Alberta

BANKERS
National Bank of Canada
Calgary, Alberta

EVALUATION ENGINEERS
GLJ Petroleum Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL
DLA Piper (Canada) LLP
Calgary, Alberta