Management's Discussion and Analysis
For the Three and Nine Months Ended September 30, 2019 and 2018

This Management's Discussion and Analysis ("MD&A") is a review of the results of operations, liquidity and capital resources of High Arctic Energy Services Inc. ("High Arctic" or the "Corporation"). This MD&A is dated November 7, 2019 and should be read in conjunction with the unaudited consolidated interim financial statements for the three and nine months ended September 30, 2019 and 2018 (the "Financial Statements") and the audited consolidated financial statements for the years ended December 31, 2018 and 2017. Additional information relating to the Corporation including the Corporation's Annual Information Form ("AIF") for the year ended December 31, 2018, is available under the Corporation's profile on SEDAR at www.sedar.com. All amounts are expressed in millions of Canadian dollars, unless otherwise noted, and have been prepared in accordance with International Financial Reporting Standards ("IFRS").

Readers are cautioned that this MD&A contains certain forward-looking information. Please refer to the end of this MD&A for the Corporation's disclaimer on forward-looking information and statements.

Select Comparative Financial Information

The following is a summary of select financial information of the Corporation.

	Three Months Ended September 30			Nine Months Ended September 30		
$ millions (except per share amounts)	**2019**	2018	% Change	**2019**	2018	% Change
Revenue	**49.6**	54.7	(9%)	**142.7**	155.5	(8%)
EBITDA(1)	**6.9**	17.0	(59%)	**17.7**	42.6	(58%)
Adjusted EBITDA(1)	**6.3**	17.4	(64%)	**15.8**	45.0	(65%)
Adjusted EBITDA % of revenue	**13%**	32%	(59%)	**11%**	29%	(62%)
Operating earnings (loss)	**(0.8)**	10.6	(108%)	**(5.5)**	24.5	(122%)
Net earnings (loss)	**(1.1)**	7.5	(115%)	**(6.1)**	13.7	(145%)
per share (basic and diluted)(2)	**(0.02)**	0.14	(115%)	**(0.12)**	0.26	(146%)
Funds provided from operations(1)	**5.3**	14.3	(63%)	**12.2**	34.8	(65%)
per share (basic and diluted)(2)	**0.11**	0.27	(59%)	**0.24**	0.66	(64%)
Dividends	**2.4**	2.6	(8%)	**7.4**	7.8	(5%)
Capital expenditures	**3.0**	2.2	36%	**9.9**	6.1	62%

	As at		
	September 30, 2019	**December 31, 2018**	**% Change**
Working capital(1)	**38.2**	56.8	(33%)
Total assets	**256.4**	272.4	(6%)
Total non-current financial liabilities	**19.7**	14.6	35%
Net cash, end of period(1)	**12.1**	31.5	(62%)
Shareholders' equity	**212.5**	234.2	(9%)
Shares outstanding	**49.6**	51.0	(3%)

(1) Readers are cautioned that EBITDA, Adjusted EBITDA, Adjusted net earnings (loss), Funds from operations, working capital and Net cash do not have standardized meanings prescribed by IFRS – see "Non IFRS Measures" on page 21 for calculations of these measures.
(2) The number of shares used in calculating the net earnings (loss) per share and adjusted net earnings (loss) per share amounts is determined as explained in note 15 of the Financial Statements.

Corporate Profile

Headquartered in Calgary, Alberta, Canada, High Arctic provides oilfield services to exploration and production companies operating in Canada, the United States and Papua New Guinea ("PNG"). High Arctic is a publicly traded company listed on the Toronto Stock Exchange under the symbol "HWO".

High Arctic conducts its business operations in three separate operating segments: Drilling Services; Production Services; and Ancillary Services.

Drilling Services
The Drilling Services segment consists of High Arctic's drilling services in PNG where the Corporation has operated since 2007. High Arctic currently operates the largest fleet of tier-1 heli-portable drilling rigs in PNG, with two owned rigs and two rigs managed under operating and maintenance contracts for one of the Corporation's customers. The Corporation also provides additional drilling services in PNG as requested by its customers.

Production Services
The Production Services segment consists of High Arctic's well servicing and snubbing operations. These operations are primarily conducted in the Western Canadian Sedimentary Basin ("WCSB") and the United States through High Arctic's fleet of well servicing rigs, operating as Concord Well Servicing, and its fleet of stand-alone and rig assist snubbing units. In addition, High Arctic also provides work-over services in PNG with its heli-portable work-over rig. The revenue, expenses and assets related to the 2018 third quarter acquisition of Powerstroke and Saddle Well Services have been reported within the Production Services segment as have the revenue, expenses and assets related to the 2019 second quarter acquisition of Precision Drilling snubbing business.

Ancillary Services
The Ancillary Services segment consists of High Arctic's oilfield rental equipment in Canada and PNG as well as its Canadian nitrogen and compliance consulting services.

Highlights

High Arctic generated revenue of $49.6 million in the third quarter 2019, a decrease of $5.1 million or 9% lower than the comparable quarter of 2018. Year to date, revenue was $142.7 million compared to $155.5 million in 2018, an 8% decrease year on year. These results were driven by lower customer demand in Canada carried over from 2018 and the Q4 2018 take or pay contract expiry for Rig 116. Canadian well servicing operating hours were 14% lower compared to the same quarter 2018 and 9% lower on hours year to date with revenue per hour lower by 1% for the third quarter 2019 over the same quarter 2018 and revenue per hour the same year over year for nine months. This was offset with increased activity in the United States operations in both well servicing and snubbing and Canadian snubbing. United States operations generated 8% of the third quarter revenue.

In Drilling Services, Rig 103 worked continuously through the quarter and Rig 104 completed its field work and was demobbed to Moro base to await its next assignment. High Arctic equipment is poised to go to work but does not have a definitive timetable.

Capital expenditures were $3.0 million in the third quarter and $9.9 million in the first nine months of 2019 representing most of the year's spending on equipment. This is offset by proceeds on sale of equipment of $0.2 million in the quarter and $1.6 million year to date.

The Corporation's strategic priorities remain targeted on:

- Regional work force development to strengthen safety, expertise, work standards and local communities.
- A strong capital structure to provide liquidity and strength throughout the energy services economic cycles.
- Specialty niche operations with noteworthy barriers to entry.

- Deep value opportunities to consolidate existing markets and diversify into new regions.
- Solidifying customer relationships to gain market share and expand when industry conditions permit.
- Disciplined capital allocation to deliver shareholder value consistent with past performance.

Execution on these strategic priorities led to the following noteworthy developments during the first nine months of 2019:

- Safety excellence, four recordable incidents, and further delivery on training and education initiatives continuing in all operating areas
  - PNG completed 3 years and 2 million man-hours Total Recordable Incident Frequency ("TRIF") free as of 27th September
  - Canadian operations have achieved 1 year Lost Time Injury Free as of 25th of September with Cold Lake operations recording 6.2 years and 1.5 million manhours of Total Recordable Incident Free
  - High Arctic received the IADC-AC Australasian Safety Statistics Award for 2018, which High Arctic also won in 2017 and 2015
- Continued preservation of a strong capital structure characterized by no long-term debt, an extension of the Facility Letter to August 2021 with fewer convenants.
- High performing operating capabilities in pressure control snubbing and deep heli-portable drilling.
- Further consolidation of the pressure control snubbing business in Canada including acquisition of Precision Drilling snubbing assets and several snubbing units available via auction from a competitor exiting the business.
- Further diversification of revenue with snubbing and well servicing expansion to the United States customer base expanding and have worked in three states (ND, Wyoming and Colorado). High Arctic has two service rigs and six snubbing units in the USA now and in the fourth quarter.

Third Quarter 2019:

- High Arctic reported revenue of $49.6 million ($54.7 million in 2018), net loss of $(1.1) million ($7.5 million earnings in 2018) and Adjusted EBITDA of $6.3 million ($17.4 million in 2018).
- Utilization for High Arctic's 56 registered Concord Well Servicing rigs was 51% in the quarter for the industry utilization of 36% (source: Canadian Association of Oilwell Drilling Contractors "CAODC") generating more hours than previous periods and increasing market share while providing safety excellence to our customers.
- PNG activity was lower than last year with Rig 103 working the entire quarter and Rig 104 finishing field work and being stacked mid September until its next assignment. The expiry of the Rig 116 take or pay contract in November 2018 represented a decrease of $4.6 million in EBITDA in the third quarter year over year.
- The company incurred a general and administrative expense of $0.4 million for an uncollectable receivable in Canada, nil in the comparable third quarter of 2018.
- The Company maintained strong working capital through the quarter including an undrawn $45 million line and cash of $12.1 million.

Year to Date 2019:

- High Arctic reported revenue of $142.7 million ($155.5 million in 2018), net loss of $(6.1) million ($13.7 million earnings in 2018) and Adjusted EBITDA of $15.8 million ($45.0 million in 2018).

- Utilization for High Arctic's 56 registered Concord Well Servicing rigs was 54% year to date versus industry utilization of 36% (source: Canadian Association of Oilwell Drilling Contractors "CAODC").
- High Arctic declared $7.4 million ($0.148 per share) in dividends year to date. High Arctic repurchased and cancelled 1,397,247 shares with a value of $5.1 million under the Corporation's NCIB during 2019 resulting in a total of $12.5 million being returned to shareholders via dividends and share repurchases.
- High Arctic continues to maintain a strong financial position with $12.1 million in net cash, an undrawn $45 million credit facility and a positive working capital position of $38.2 million.

Consolidated Results

	Three Months Ended September 30				Nine Months Ended September 30			
($ millions)	2019	2018	Change	%	2019	2018	Change	%
Revenue	**49.6**	54.7	(5.1)	(9%)	**142.7**	155.5	(12.8)	(8%)
EBITDA(1)	**6.9**	17.0	(10.1)	(59%)	**17.7**	42.6	(24.9)	(58%)
Adjusted EBITDA(1)	**6.3**	17.4	(11.1)	(64%)	**15.8**	45.0	(29.2)	(65%)
Adjusted EBITDA % of Revenue	**13%**	32%	(19%)	(59%)	**11%**	29%	(18%)	(62%)
Net earnings (loss)	**(1.1)**	7.5	(8.6)	(115%)	**(6.1)**	13.7	(19.8)	(145%)
per share (basic and diluted)(2)	**(0.02)**	0.14	(0.16)	(115%)	**(0.12)**	0.26	(0.38)	(146%)
Adjusted net earnings (loss)(1)	**(1.5)**	7.7	(9.2)	(119%)	**(7.2)**	14.5	(21.7)	(150%)
per share (basic and diluted)(2)	**(0.02)**	0.15	(0.17)	(113%)	**(0.14)**	0.28	(0.42)	(150%)

(1) Readers are cautioned that EBITDA, Adjusted EBITDA and Adjusted net earnings (loss) do not have standardized meanings prescribed by IFRS – see "Non IFRS Measures" on page 21 for calculations of these measures.
(2) The number of shares used in calculating the net earnings (loss) per share and adjusted net earnings (loss) per share amounts is the month end actual.

Third Quarter:

- Consolidated revenue decreased 9% to $49.6 million in the third quarter from $54.7 million in the third quarter 2018. Revenue for the Corporation's Drilling Services segment decreased by $6.8 million in the quarter compared to the third quarter 2018 and Ancillary Services revenue was down $0.7 million year over year. This was offset by the Production Services revenue increase of $2.1 million year over year.

- The decrease in consolidated revenue combined with the decreased contribution from the Drilling Services segment resulted in Adjusted EBITDA decreasing to $6.3 million in the third quarter from $17.4 million in the same quarter 2018. The decreased revenue and increase in oilfield services expenses resulted in a decrease in Net earnings to $(1.1) million, ($(0.02) per share (basic)) in the quarter versus $7.5 million, ($0.14 per share (basic)) in September 2018.

Year to Date 2019:

- Revenue for the Corporation's Drilling Services segment decreased by $14.2 million in the first nine months of 2019 compared to the same period in 2018 while Ancillary Services revenue decreased by $3.7 million. This was partially offset by the revenue increase of $4.6 million provided by Production Services. Consolidated revenue decreased $12.8 million to $142.7 million year to date from $155.5 million in the same period of 2018.

- Adjusted EBITDA decreased to $15.8 million in the first nine months of 2019 from $45.0 million in the same period of 2018. Net earnings (loss) decreased to $(6.1) million, (($0.12) per share (basic)) for the nine months ended September 30, 2019 versus $13.7 million, ($0.26 per share (basic)) in the same period of 2018.

Operating Segments

Segmented Financial Results

	Three Months Ended September 30				Nine Months Ended September 30			
($ millions)	2019	2018	Change	%	2019	2018	Change	%
Revenue:								
Drilling Services	**18.7**	25.5	(6.8)	(27%)	**58.0**	72.2	(14.2)	(20%)
Production Services	**24.3**	22.2	2.1	9%	**68.1**	63.5	4.6	7%
Ancillary Services	**7.4**	8.1	(0.7)	(9%)	**19.0**	22.7	(3.7)	(16%)
Inter-segment eliminations	**(0.8)**	(1.1)	0.3	(27%)	**(2.4)**	(2.9)	0.5	(17%)
	49.6	**54.7**	(5.1)	(9%)	**142.7**	**155.5**	(12.8)	(8%)
Oilfield Service Operating Margin (1)								
Drilling Services	**3.8**	11.6	(7.8)	(67%)	**12.3**	31.2	(18.9)	(61%)
Production Services	**2.8**	4.1	(1.3)	(32%)	**4.9**	11.5	(6.6)	(57%)
Ancillary Services	**4.0**	5.5	(1.5)	(27%)	**10.7**	14.9	(4.2)	(28%)
	10.6	**21.2**	(10.6)	(50%)	**27.9**	**57.6**	(29.7)	(52%)
Oilfield Service Operating Margin Percentage (1)								
Drilling Services	**20%**	45%	(25%)	(56%)	**21%**	43%	(22%)	(51%)
Production Services	**12%**	18%	(6%)	(33%)	**7%**	18%	(11%)	(61%)
Ancillary Services	**54%**	68%	(14%)	(21%)	**56%**	66%	(10%)	(15%)
	21%	39%	(18%)	(46%)	**20%**	37%	(17%)	(46%)

(1) See 'Non-IFRS Measures' on page 21

Drilling Services

	Three Months Ended September 30				Nine Months Ended September 30			
($ millions)	2019	2018	Change	%	2019	2018	Change	%
Revenue	**18.7**	25.5	(6.8)	(27%)	**58.0**	72.2	(14.2)	(20%)
Oilfield services expense (1)	**14.9**	13.9	1.0	7%	**45.7**	41.0	4.7	11%
Oilfield services operating margin (1)	**3.8**	**11.6**	**(7.8)**	**(67%)**	**12.3**	**31.2**	**(18.9)**	**(61%)**
Operating margin (%)	**20%**	45%	(25%)	(56%)	**21%**	43%	(22%)	(51%)

(1) See 'Non-IFRS Measures' on page 21

The Corporation owns two heli-portable drilling rigs (Rigs 115 and 116) and operates two rigs (Rigs 103 and 104) on behalf of a major oil and gas exploration company in PNG.

Third Quarter:

Drilling Services revenue decreased 27% in the third quarter to $18.7 million from $25.5 million in the third quarter of 2018. This decrease was due primarily to the end of the take or pay contract for Rig 116 which generated $6.6 million revenue and $6.2 million in operating margin in the third quarter of 2018 and the one off Rig 115 contract break fee received in Q3 2018 and was partially offset by revenue from increased customer rig activity of $3.3 million in 2019.

Rig 103 continued drilling operations throughout the quarter while Rig 104 completed its program in June, began moving back to Moro Base to be stacked until its next well which was completed in mid September. Rig 115 and Rig 116 were preserved in cold stack during the quarter and remain ready to redeploy.

Year to Date 2019:

Drilling Services revenue decreased 20% to $58.0 million from $72.2 million in 2018 year to date. This decrease was driven by the end of the take or pay contract for Rig 116 in the fourth quarter of 2018 which is reflected in the 2018 year to date numbers and Rig 115 remaining stacked through 2019 YTD, having worked the first half of 2018 and generating a contract break fee in Q3 2018. Rig 116 contributed $19.3 million revenue and $18.0 million operating margin for the first 9 months of 2018. Loss of revenue from Rigs 115 and 116 has been partially offset by increased drilling and associated ancilliary drilling support services for our primary PNG customer with Rigs 103 and 104.

Rig 115 and Rig 116 have been in cold stack throughout 2019 and remain ready to redeploy.

Production Services

	Three Months Ended September 30				Nine Months Ended September 30			
($ millions)	**2019**	**2018**	**Change**	**%**	**2019**	**2018**	**Change**	**%**
Revenue	**24.3**	22.2	2.1	9%	**68.1**	63.5	4.6	7%
Oilfield services expense (1)	**21.5**	18.1	3.4	19%	**63.2**	52.0	11.2	22%
Oilfield services operating margin (1)	**2.8**	**4.1**	**(1.3)**	**(32%)**	**4.9**	**11.5**	**(6.6)**	**(57%)**
Operating margin (%)	**12%**	18%	(6%)	(33%)	**7%**	18%	(11%)	(61%)
Operating Statistics - Canada:								
Service rigs								
Average Fleet (2)	56	58	(2)	(3%)	56	57	(1)	(2%)
Utilization (3)	51%	57%	(6%)	(11%)	54%	58%	(4%)	(7%)
Operating hours	26,482	30,630	(4,148)	(14%)	81,780	90,232	(8,452)	(9%)
Revenue per hour	608	613	(5)	(1%)	616	616	-	0%
Snubbing rigs								
Average Fleet (4)	18	12	6	50%	18	9	9	100%
Utilization (3)	17%	23%	(6%)	(26%)	15%	22%	(7%)	(32%)
Operating hours	2,811	2,499	312	12%	7,300	5,369	1,931	36%
Operating Statistics - United States:								
Service rigs								
Average Fleet	2	-	2	0%	2	-	2	0%
Utilization (3)	112%	-	112%	0%	62%	-	62%	0%
Operating hours	2,068	-	2,068	0%	3,358	-	3,358	0%
Revenue per hour	1,028	-	1,028	0%	1,051	-	1,051	0%
Snubbing rigs								
Average Fleet (4)	6	-	6	0%	6	-	6	0%
Utilization (3)	34%	-	34%	0%	23%	-	23%	0%
Operating hours	1,868	-	1,868	0%	3,826	-	3,826	0%

(1) Non-IFRS Measures
(2) Average service rig fleet represents the average number of rigs registered with the CAODC during the period.
(3) Utilization is calculated on a 10-hour day using the number of rigs registered with the CAODC during the period.
(4) Average snubbing fleet represents the average number of rigs marketed during the period and includes acquisition of Precision Drilling snubbing units in 2019.

High Arctic's well servicing and snubbing operations are provided through its Production Services segment. These operations are primarily conducted in the WCSB and United States through High Arctic's fleet of well servicing rigs, operating as Concord Well Servicing, and its fleet of stand-alone and rig assist snubbing units.

The Production Services segment also provides heli-portable workover services in PNG through Rig 102. The net book value of Rig 102 is not material and no workover services were provided in PNG during 2019 or 2018 and as such no revenue was generated during the periods presented.

Third Quarter:

Increased quarter over quarter activity for High Arctic's US service rigs and the Corporation's snubbing operations resulted in a 9% increase in revenue for the Production Services segment to $24.3 million in the quarter versus $22.2 million in the same period 2018. Operating hours for the Concord rigs decreased 14% to 26,482 hours in the quarter from 30,630 hours in the third quarter 2018 but was offset by Canadian snubbing hours being up 12% year over year to 2,811 hours from 2,499 in the third quarter 2018 and the addition of US snubbing and well servicing. The Concord rigs achieved utilization of 51% versus the 36% utilization generated by the industry's registered well servicing rigs in the quarter (source: CAODC). Pricing remains competitive with the average revenue per hour for the Concord rigs at $608 down from $613 per hour in the third quarter 2018. Operating margin was 12% for the third quarter 2019, down from 18% in the same period 2018.

Year to Date 2019:

Increased overall activity for High Arctic's US service rigs and the Corporation's snubbing operations resulted in a 7% increase in revenue for the Production Services segment to $68.1 million year to date versus $63.5 million in 2018. Operating hours for the Concord rigs decreased 9% to 81,780 hours year to date from 90,232 hours in 2018. Concord rigs achieved utilization of 54% consistent with the 54% utilization generated by the industry's registered well servicing rigs (source: CAODC). Average revenue per hour for the Concord rigs was flat at $616 per hour year over year. Canadian snubbing hours were 7,300 year to date 2019 compared to 5,369 in 2018, US snubbing was 3,826 hours and the US service rigs recorded 3,358 hours year to date.

Ancillary Services

	Three Months Ended September 30				Nine Months Ended September 30			
($ millions)	**2019**	**2018**	**Change**	**%**	**2019**	**2018**	**Change**	**%**
Revenue	**7.4**	8.1	(0.7)	(9%)	**19.0**	22.7	(3.7)	(16%)
Oilfield services expense (1)	**3.4**	2.6	0.8	31%	**8.3**	7.8	0.5	6%
Oilfield services operating margin (1)	**4.0**	**5.5**	**(1.5)**	**(27%)**	**10.7**	**14.9**	**(4.2)**	**(28%)**
Operating margin (%)	**54%**	68%	(14%)	(21%)	**56%**	66%	(10%)	(15%)

(1) Revenue includes inter-segment revenue charged to Production Services and Drilling Services from Ancillary Services division of $0.8 million for the quarter and $2.4 million YTD. In 2018 inter-segment revenue was $1.1 million for the quarter and $2.9 million YTD.

(2) See 'Non-IFRS Measures' on page 21

The Ancillary Services segment consists of High Arctic's oilfield rental equipment in Canada and PNG as well as its Canadian nitrogen and business operations.

Third Quarter:

All contributing divisions of this segment showed decreases during the quarter relative to the third quarter 2018 driven by lower activity levels. Internationally the loss of the take or pay matting rental contract in PNG associated with Rig 116 contributed most of the reduced revenue with other rental equipment and ancilliary services relatively flat.

Operating margin as a percentage of revenue decreased to 54% in the quarter versus 68% in same period of 2018, incurred mostly in North America with International margin flat year on year.

Year to Date:

Operating margin as a percentage of revenue is down at 56% year to date 2019 consistent with earlier quarters, compared to 66% for the same period in 2018. The decrease is due to decreased contributions from both PNG and Canadian rental divisions which generate higher margins.

General and Administration

	Three Months Ended September 30				Nine Months Ended September 30			
($ millions)	**2019**	**2018**	**Change**	**%**	**2019**	**2018**	**Change**	**%**
General and administration	**4.3**	3.8	0.5	13%	**12.1**	12.6	(0.5)	(4%)
Percent of revenue	**9%**	7%	2%	29%	**8%**	8%	0%	0%

General and administrative costs were up 13% at $4.3 million in the third quarter 2019 compared to 2018 but down $0.5 million year over year as a result of cost reduction initiatives taken throughout 2019. General and administrative costs as a percentage of revenue increased 2% quarter over quarter and were flat year over year.

Depreciation

Depreciation expense increased to $7.2 million in the third quarter from $6.5 million in the third quarter 2018 due to additional depreciation resulting from the Precision Drilling asset acquisition and the adoption of IFRS 16, Leases (“IFRS 16”).

Year to date, the Corporation incurred depreciation costs of $21.0 million versus $19.3 million year to date 2018. The Corporation has incurred depreciation costs of $1.2 million associated with right of use assets in 2019 as a result of the adoption of IFRS 16 offset by a reduction in operating lease expense by the same amount.

Share-based Compensation

The decrease in share-based compensation to ($0.1) million in the third quarter and $0.3 million year to date from $0.3 million and $1.2 million in the respective periods in 2018 is a result of the reduction in the number of shares granted under share-based incentive programs.

Foreign Exchange Transactions

The Corporation has exposure to the U.S. dollar and other currencies such as the PNG Kina through its international operations. As a result, the Corporation is exposed to foreign exchange gains and losses through the settlement of foreign currency denominated transactions as well as the conversion of the Corporation’s U.S. dollar based subsidiaries into Canadian dollars for financial reporting purposes.

Gains and losses recorded by the Canadian parent on its U.S. denominated cash accounts, receivables, payables and intercompany balances are recognised as a foreign exchange gain or loss in the statement of earnings.

High Arctic is further exposed to foreign currency fluctuations through its net investment in foreign subsidiaries. The value of these net investments will increase or decrease based on fluctuations in the U.S. dollar relative to the Canadian dollar. These gains and losses are unrealized until such time that High Arctic divests its investment in a foreign subsidiary and are recorded in other comprehensive income as foreign currency translation gains or losses for foreign operations.

The U.S. dollar remained strong relative to the Canadian dollar with an average exchange rate of $1.3229 during the third quarter of 2019 (2018 – $1.30057). The stronger U.S. dollar benefits the Corporation as the majority of the Corporation’s PNG business is conducted in U.S. dollars.

The small change in exchange rates for the period resulted in a foreign exchange gain of $0.1 million being recorded on the various foreign exchange transactions (2018 - $0.2 million gain). The Corporation does not currently hedge its foreign exchange transactions or exposure.

Interest and Finance Expense

During the quarter, the Corporation did not have any long term debt outstanding but incurred $0.3 million in bank fees and other interest charges and have incurred $0.7 million year to date ($0.2 million in Q3 2018 and $0.4 million year to date 2018).

Income Taxes

	Three Months Ended September 30			Nine Months Ended September 30		
($ millions)	**2019**	**2018**	**Change**	**2019**	**2018**	**Change**
Net earnings (loss) before income taxes	**(0.6)**	10.3	(10.9)	**(4.0)**	22.9	(26.9)
Current income tax expense	**0.7**	2.5	(1.8)	**2.9**	8.5	(5.6)
Deferred income tax expense (recovery)	**(0.2)**	0.3	(0.5)	**(0.8)**	0.7	(1.5)
Total income tax expense	**0.5**	2.8	(2.3)	**2.1**	9.2	(7.1)
Effective tax rate	**-83%**	27%		**-53%**	40%	

During the third quarter of 2019 the Corporation had no withholding taxes on the payment of intercompany dividends from PNG to Canada versus $2.2 million paid out in the third quarter of 2018. The deferred income tax recovery is due to changes in timing differences between tax and accounting depreciation in PNG.

As at September 30, 2019, High Arctic had $98.8 million in unrecognized tax pools, consisting of $60.5 million in non-capital loss pools and $38.3 million in capital loss pools, which may be utilized to offset future taxable earnings generated by the Corporation’s Canadian business operations. These losses expire no earlier than 2025.

Alberta's general provincial tax rate was decreased on June 28, 2019 from 12% to 11% for the second half of 2019, 10% for 2020, 9% for 2021, and 8% for 2022 and thereafter. As a result of the rate change, the Company recognized $3.4 million in deferred income tax expense, which was offset with a reversal of the valuation allowance during the year.

Other Comprehensive Income (Loss)

The Corporation recorded a $1.4 million foreign currency translation gain in other comprehensive income (loss) in the third quarter as compared to a loss of $2.1 million in the third quarter of 2018.

Liquidity and Capital Resources

	Three Months Ended September 30			Nine Months Ended September 30		
($ millions)	2019	2018	Change	2019	2018	Change
Cash provided by (used in):						
Operating activities	**2.6**	4.9	(2.3)	**11.5**	25.6	(14.1)
Investing activities	**(2.7)**	(9.1)	6.4	**(16.4)**	(12.8)	(3.6)
Financing activities	**(3.3)**	(1.2)	(2.1)	**(13.9)**	(12.7)	(1.2)
Effect of exchange rate changes	**0.8**	(0.4)	1.2	**(0.6)**	0.1	(0.7)
Increase (decrease) in cash and cash equivalents	**(2.6)**	(5.8)	3.2	**(19.4)**	0.2	(19.6)

	As At		
	September 30, 2019	December 31, 2018	Change
Working capital[1]	38.2	56.8	(18.6)
Working capital ratio[1]	2.6 : 1	3.4 : 1	0.7:1
Net cash[1]	12.1	31.5	(19.4)
Undrawn availability under debt facilities	45.0	45.0	0.0

[1] See 'Non-IFRS Measures' on page 21

As at September 30, 2019, the Corporation had $nil outstanding on its debt facilities and $12.1 million in cash.

The Bank of PNG policy continues to encourage the use of the local market currency (Kina). Due to High Arctic's requirement to transact with international suppliers and customers, High Arctic has received approval from the Bank of PNG to maintain its U.S. dollar account within the conditions of the Bank of PNG currency regulations. The Corporation has taken steps to increase its use of PNG Kina for local transactions when practical. Included in the Bank of PNG's conditions is for future PNG drilling contracts to be settled in PNG Kina, unless otherwise approved by the Bank of PNG for the contracts to be settled in U.S. dollars. The Corporation has received such approval for its existing contracts with its key customers in PNG. The Corporation will continue to seek Bank of PNG approval for future customer contracts to be settled in U.S. Dollars on a contract by contract basis, however, there is no assurance the Bank of PNG will continue to grant these approvals.

If such approvals are not received in future, the Corporation's PNG drilling contracts will be settled in PNG Kina which would expose the Corporation to exchange rate fluctuations related to the PNG Kina. In addition, this may delay the Corporation's ability to receive U.S. Dollars which may impact the Corporation's ability to settle U.S. Dollar denominated liabilities and repatriate funds from PNG on a timely basis. The Corporation also requires the approval from the PNG Internal Revenue Commission ("IRC") to repatriate funds from PNG and make payments to non-resident PNG suppliers and service providers. While delays can be experienced for the IRC approvals, such approvals have been received in the past.

Operating Activities

The decrease in net earnings and working capital, offset by the increase in deferred tax recovery and depreciation has resulted in funds provided from operations to decrease to $2.6 million from $4.9 million quarter on quarter 2019 to 2018.

The reduced year to date net earnings combined with increased depreciation offset by reduced share based compensation, increased gain on sale of assets, increase in foreign exchange gain and deferred tax recovery has resulted in funds provided from operations to decrease to $11.5 million from $25.6 million in the first nine months of 2019.

Investing Activities

In the third quarter the Corporation has invested $3.0 million (2018 - $2.2 million) in capital expenditures primarily related to maintenance capital and upgrades to the Corporation's well servicing rigs.

Year to date the Corporation has invested an additional $9.9 million (2018 - $6.1 million) in capital expenditures primarily related to maintenance capital and upgrades to the Corporation's well servicing rigs to enhance the efficiencies and marketability of rigs in the Corporation's various operating areas and the acquisition of the Precision Drilling assets. The Corporation has also generated $1.0 million on the sale of short term investments.

Financing Activities

During the quarter, the Corporation distributed $2.4 million in dividends to its shareholders. In addition, the Corporation purchased and cancelled 140,120 shares for a total of $0.4 million under its NCIB, resulting in a total of $2.8 million being returned to shareholders via dividends and share buybacks during the quarter.

For the nine months ended September 30, the Corporation distributed $7.4 million in dividends to its shareholders. In addition, the Corporation purchased and cancelled 1,397,247 shares for a total of $5.1 million under its NCIB, resulting in a total of $12.5 million being returned to shareholders via dividends and share buybacks year to date.

Credit Facility

As at September 30, 2019, High Arctic's credit facility consisted of a $45.0 million revolving loan facility which matures on August 31, 2021. The facility is renewable with the lender's consent and is secured by a general security agreement over the Corporation's assets.

The available amount under the $45.0 million revolving loan facility is limited to 60% of the net book value of the Canadian fixed assets plus 75% of acceptable accounts receivable (85% for investment grade receivables), plus 90% of insured receivables, less priority payables as defined in the loan agreement. As at September 30, 2019, there was no amount drawn on the facility and total credit available to draw was $45.0 million.

The Corporation's loan facilities are subject to two financial covenants, which are reported to the lender on a quarterly basis. These changed from the previous three financial covenants with the extension of the facility to the maturity date to August 31, 2021. The Corporation remains in compliance with the financial covenants under its credit facility as at September 30, 2019. The two covenants are to keep the Funded Debt to EBITDA Ratio under 3.00 to 1.00 (previously 2.50 to 1.00) and maintain its ratio of Interest Expense to EBITDA at any time to be less than 3.00 to 1.00. Both are calculated quarterly on the last day of each Fiscal Quarter on a rolling four quarter basis.

The Corporation's loan facilities are subject to two financial covenants, which are reported to the lender on a quarterly basis:

Covenant	Required	September 30, 2019
Funded debt to EBITDA(1)(2)	3.00 : 1 Maximum	0.06 : 1
Interest Expense to EBIDTA(2)	3.00 : 1 Minimum	22.4 : 1

(1) Funded debt to EBITDA is defined as the ratio of consolidated Funded Debt to the aggregate EBITDA for the trailing 4 quarters.
(2) EBITDA for the purposes of calculating the covenants, "covenant EBITDA," is defined as net income plus interest expense, current tax expense, depreciation, amortization, future income tax expense (recovery), share based compensation expense less gains from foreign exchange and sale or purchase of assets.

There have been no changes to these financial covenants subsequent to September 30, 2019 and the Corporation remains in compliance with the financial covenants under its credit facility as at September 30, 2019.

Contractual Obligations and Contingencies

High Arctic's contractual financial obligations as at September 30, 2019 are summarized as follows:

($ millions)	1 Year	2-3 Years	4-5 Years	Beyond 5 Years	Total
Accounts payable	22.0	-	-	-	22.0
Dividends payable	0.8	-	-	-	0.8
Lease liability	1.4	2.4	1.1	6.1	11.0
Total	**24.2**	**2.4**	**1.1**	**6.1**	**33.8**

Inventory

As part of the Corporation's contractual rig management and operations, the Corporation has been supplied an inventory of spare parts with a total value of $7.6 million by a customer and a third-party supplier for the Corporation's operations in PNG. The inventory is owned by these parties and has not been recorded on the books of High Arctic. At the end of the contracts, the Corporation must return an equivalent amount of inventory to these parties.

Outstanding Share Data

The Corporation's authorized share capital consists of an unlimited number of common shares and an unlimited number of preferred shares. Directors, officers and certain employees have been granted stock options and incentive shares and units under the Corporation's approved equity compensation plans. As at September 30, 2019, there were 49,620,098 issued and outstanding common shares. In addition, 980,000 options were outstanding at an average exercise price of $3.76 as well as 379,246 units under the Corporation's Performance Share Unit Plan and 158,051 units under the Deferred Share Unit plan.

On November 15, 2018 the Corporation received approval from the Toronto Stock Exchange to acquire for cancellation up to 2,700,386 common shares, representing approximately 10 percent of the Corporation's public float, under a NCIB. The NCIB is valid for one year and will expire on November 18, 2019. A total 1,643,335 common shares have been purchased and cancelled under this NCIB through September 30, 2019 at a cost of $6.0 million. A total of 140,120 common shares have been purchased and cancelled in Q3 2019 at a cost of $0.4 million.

Quarterly Financial Review

Selected Quarterly Consolidated Financial Information (Three Months Ended)

The following is a summary of selected financial information of the Corporation for the last eight completed quarters:

	2019			2018				2017
$ (millions, except per share amounts)	Q3[3]	Q2[3]	Q1	Q4[2]	Q3[2]	Q2	Q1	Q4
Revenue	**49.6**	**46.6**	**46.5**	**47.8**	**54.7**	**47.1**	**53.7**	**51.5**
Adjusted EBITDA[1]	6.3	4.0	5.5	6.6	17.4	13.9	13.7	12.4
Net earnings (loss)	(1.1)	(4.0)	(1.0)	(2.3)	7.5	1.8	4.4	3.5
per share - basic	(0.02)	(0.08)	(0.02)	(0.04)	0.14	0.04	0.08	0.06
Adjusted net earnings (loss)[1][2][3]	(1.5)	(4.0)	(1.0)	(2.3)	7.7	2.4	4.4	3.5
per share - basic	(0.02)	(0.08)	(0.02)	(0.4)	0.15	0.05	0.08	0.06
Funds provided from operations[1]	5.3	2.1	4.8	2.0	14.3	8.6	11.9	9.3

(1) See 'Non-IFRS Measures' on page 21
(2) Adjusted net earnings (loss) in Q3 and Q4 2018 excludes the impact of $0.6 million and $0.2 million, respectively, of expenses incurred related to the closing of the Corporation's Blackfalds facility and transaction costs related to the Powerstroke Acquisition.
(3) Adjusted net earnings (loss) in Q2 2019 excludes the impact of $0.7 million of income recognised related to the write down of the contingent liability associated with the Powerstroke acquisition in 2018.

Various factors have affected the quarterly profitability of the Corporation's operations. The take-or-pay contract for Rig 116 expired on November 2, 2018 resulting in reduced revenue and EBITDA in 2019. The corporation continues to promote both Rig 116 and Rig 115 for service in PNG and abroad. The Corporation's results have also benefited from the Powerstroke and Saddle Well Services acquisitions which closed in 2018 and most recently the acquisition of Precision Drilling's snubbing business.

Industry Indicators and Market Trends in PNG

The following table provides information for the last eight quarters to assist with the understanding of the PNG oilfield services industry and the effect that commodity prices have on industry activity levels. In addition, the Corporation's international financial results are impacted by fluctuations in the U.S. dollar to Canadian dollar exchange rate.

	2019			2018				2017
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Oil and natural gas prices (Average for the period)								
Brent Crude Oil *(U.S. $/bbl)* [1]	$62	$63	$64	$68	$76	$75	$68	$61
Japan LNG *(U.S. $/mmbtu)* [2]	$10.62	$9.91	$11.87	$11.69	$10.73	$10.26	$8.98	$7.76
U.S./Canadian dollar exchange rate	1.32	1.31	1.34	1.32	1.31	1.29	1.26	1.27

(1) Source: Sproule
(2) Source: World Bank Commodities Price Data

The Corporation's PNG activity has historically been based on longer term, U.S. dollar denominated contracts and therefore is less affected over the short term by volatility in oil and gas prices. The U.S./Canadian dollar exchange rate has remained strong over the last eight quarters which has benefited the Corporation's financial results.

Activity levels for the Corporation's major customers in PNG are less dependent on short term fluctuations in oil and gas prices and instead are based on medium and long-term decisions, particularly with their significant interest in large scale LNG projects both on-stream and in development. Pricing for oil and natural gas production in PNG is generally tied to world prices such as Brent Crude and Japan LNG.

Industry Indicators and Market Trends in Canada

The following table provides information for the last eight quarters to assist with the understanding of the Canadian oilfield services industry and the effect that commodity prices have on industry activity levels.

	2019			2018				2017
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Oil and natural gas prices								
Average for the period:								
West Texas Intermediate (U.S. $/bbl)(1)	$56	$55	$55	$59	$69	$68	$63	$55
West Canada Select (Cdn. $/bbl)(1)	$58	$55	$57	$37	$62	$63	$49	$54
Canadian Light Sweet Oil (Cdn $/bbl)(1)	$69	$64	$67	$48	$76	$78	$70	$66
AECO (C$/mmbtu)(1)	$1.00	$0.61	$2.62	$1.62	$1.28	$1.20	$2.06	$1.72
Other industry indicators								
Total wells drilled in Western Canada(2)	1,407	778	1,546	1,380	1,528	1,268	1,696	1,852
Average service rig utilization rates(2)	55%	35%	48%	37%	41%	30%	47%	40%
Average drilling rig utilization rates(2)	23%	13%	29%	28%	30%	17%	41%	32%

(1) Source: Sproule
(2) Source: CAODC

Decreases in oil and natural gas prices and lack of access to markets have had a material impact on drilling and well completion activities in Canada since 2015 and continue to curtail industry activity levels relative to historical industry activity levels.

Outlook

The continued uncertainty surrounding the addition of takeaway capacity, and the mandated production apportionment in Alberta, has caused many Canadian oil and gas operators to reduce capital spending. Continual wet weather conditions in the northern operating areas affected activity in Q3 of 2019. Overall activity levels in Canada are expected to be lower year over year for the balance of 2019. Many customers have indicated they are reducing activity and will focus on maintaining existing production versus more drilling and new production for the balance of 2019 in an effort to manage their expenses against budget.

In line with our strategic priorities, maintaining a strong balance sheet and strict cost control are priorities for the Company, to continue operating effectively in an environment with surplus equipment and low prices for High Arctic services. High Arctic recognizes the unique challenges faced by the industry and our clients and will continue to focus on providing the highest quality of service delivered with industry leading safety standards at fair and reasonable prices. Cost reduction activities undertaken have included reducing overheads, consolidating overhead roles, continued review of further overall organizational efficiencies and re-organizing work as required.

The acquisition of Powerstroke opened a new market for snubbing and well services in the United States. The subsequent acquisition of Precision Drilling's snubbing assets provides High Arctic with additional quality equipment and access to experienced personnel and crews to continue to move under utilized assets in Canada into the United States where there is better utilization and day rates. The acquisitions result in High Arctic consolidating Canada Snubbing services and is the largest snubbing provider in Canada with 33 units estimated to represent 60% of the Canada market. Furthermore, High Arctic is now the largest snubbing operator in the DJ Basin with five active units. US operations (snubbing and well service) continue to increase operating hours as they become more established.

In Papua New Guinea, activity has continued to be light as the oil price and associated LNG pricing has remained subdued and with the prolonged negotiations between the State and the partners in the Papua LNG project for a gas agreement project work has continued to defer. The announcement that the gas sales agreement would be honoured by the Government and Total's indication that they would consider certain amendments was positively received, but will take some time to impact the onshore drilling market. Combined with the parallel project of co-habited PNG-LNG expansion train, the proposed Papua LNG facility is expected to double LNG export capacity in PNG and project partners have indicated they still target timing for commencement of LNG shipments from expansion production in 2024. Based on exploration license well commitments and increased optimism ahead of the LNG expansion, we anticipate drilling activity to increase in PNG from H2 2020.

In PNG, Rig 103 continues with infield well works and we anticipate it to continue to do so into 2020. Rig 104 completed movement back to Moro where it has been stacked and preserved for a short period until its next assignment. Rig 116 and Rig 115 are cold stacked in Port Moresby maintained ready for reactivation at short notice. Timing is undetermined at present. Rig 102 is undergoing refurbishment for return to service with customers showing interest in using the rig in 2020 for production maintenance and well abandonment workscopes.

High Arctic continues to be active examining acquisitions domestically and abroad, that are consistent with our strategic objective of deep value opportunities to consolidate existing markets and diversify into new regions, solidifying customer relationships to gain market share, specialty niche operations with noteworthy barriers to entry and expand when industry conditions permit.

Financial Risk Management

Credit Risk, Customers and Economic Dependence

Credit risk is the risk of a financial loss occurring as a result of a default by a counter party on its obligation to the Corporation. The Corporation's financial instruments that are exposed to credit risk consist primarily of accounts receivable and cash balances held in banks. The Corporation mitigates credit risk by regularly monitoring its accounts receivable position and depositing cash in properly capitalized banks. The Corporation also institutes credit reviews prior to commencement of contractual arrangements.

The Corporation's accounts receivable is predominantly with customers who explore for and develop petroleum reserves and are subject to normal industry credit risks. The Corporation assesses the credit worthiness of its customers on an ongoing basis and monitors the amount and age of balances outstanding.

The Corporation views the credit risks on these amounts as normal for the industry. The carrying amount of accounts receivable represents the maximum credit exposure on this balance. The Corporation has a wide range of customers comprised of small independent, intermediate and large multinational/regional oil and gas producers. Notwithstanding its large customer base, the Corporation provides services to two large customers (2018 – three) which individually accounted for more than 10% of its consolidated revenues during the nine months ended September 30, 2019. Sales to these two customers were approximately $68.6 million and $17.7 million for the nine months ended September 30, 2019 (2018 - $64.6 million, $20.7 million and $16.0 million). As at September 30, 2019, these two customers represented 34% and 7% respectively of outstanding accounts receivable (September 30, 2018 – three customers represented a total of 61%). Management has assessed the two customers as creditworthy and the Corporation has had no history of collection issues with these customers.

The Corporation's accounts receivable is aged as follows:

Days outstanding:	September 30, 2019	December 31, 2018
Less than 31 days	23.3	17.4
31 to 60 days	7.2	11.3
61 to 90 days	4.2	5.0
Greater than 90 days	2.2	2.9
Allowance for doubtful accounts	(0.1)	(0.1)
Total	**36.8**	**36.5**

Liquidity Risk
Liquidity risk is the risk that the Corporation will not be able to meet its financial obligations as they fall due. The Corporation's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due. The Corporation's processes for managing liquidity risk include preparing and monitoring capital and operating budgets, coordinating and authorizing project expenditures, and authorization of contractual agreements. The Corporation seeks to manage its financing based on the results of these processes.

Market Risk
Market risk is the risk that the fair value or future cash flows of financial assets or liabilities will fluctuate due to movements in market rates of interest, foreign currency exchange rates, commodity prices and other prices.

Interest rate risk
Interest rate risk is the risk that the value of a financial instrument will fluctuate as a result of changes in market interest rates. The Corporation is exposed to interest rate risk as its long-term debt is a floating rate credit facility and fluctuates in response to changes in the prime interest rates.

Foreign exchange rate risk
Foreign currency risk is the risk that a variation in the exchange rate between Canadian and foreign currencies will affect the Corporation's results. The majority of the Corporation's international revenue and expenses are transacted in U.S. dollars and the Corporation does not actively engage in foreign currency hedging. For the quarter ended September 30, 2019, a 0.10 basis point change in the value of the Canadian dollar relative to the U.S. dollar would have resulted in a $0.3 million change in net earnings (loss) for the quarter as a result of changes in foreign exchange.

The Corporation's financial instruments have the following foreign exchange exposure at September 30, 2019:

(millions)	U.S. Dollar[(1)] (in USD)	PNG Kina[(2)] (in Kina)	Australian Dollar[(3)] (in AUD)
Cash and cash equivalents	6.3	2.0	0.1
Trade and other receivables	10.6	0.3	-
Trade and other payables	(5.9)	(9.4)	(0.5)
Total	**11.0**	**(7.1)**	**(0.4)**

(1) As at September 30, 2019, one U.S. dollar was equivalent to 1.32430 Canadian dollars.
(2) As at September 30, 2019, one PNG Kina was equivalent to 0.2940 Canadian dollars.
(3) As at September 30, 2019, one Australian dollar was equivalent to 0.8941 Canadian dollars.

As at September 30, 2019, U.S. $3.2 million was on deposit with a large international bank in PNG. The Bank of PNG ("BPNG") has provided approval for High Arctic to maintain a U.S. dollar bank account in accordance with the BPNG currency regulations and again approved the U.S. dollar denomination and settlement of all new agreements executed this quarter, however, if such approval is withdrawn in the future these funds may be converted into PNG Kina and the Corporation would be required to access the foreign currency market in PNG to meet its foreign currency obligations, thus exposing the Corporation to greater foreign exchange exposure for the Kina. The BPNG currency regulations also limit the amount of foreign currency that companies can maintain in order to meet their forecasted three-month cash flow requirements, with excess funds required to be held in Kina.

Commodity price risk
The Corporation is not directly exposed to commodity price risk as it does not have any contracts that are directly based on commodity prices. A change in commodity prices, specifically petroleum and natural gas prices could have an impact on oil and gas production levels and could therefore affect the demand for the Corporation's services. However, given that this is an indirect influence, the financial impact to the Corporation of changing petroleum and natural gas prices cannot be quantified.

Other price risk
Other price risk is the risk that the fair value or future cash flows of financial instruments will fluctuate as a result of changes in market prices (other than those arising from interest rate risk or foreign currency risk) whether those changes are caused by factors specific to the individual financial instrument, its issuer or factors affecting all similar financial instruments in the market or a market segment. Exposure to other price risk is primarily in short term investments where changes in quoted prices on investments in equity securities impact the underlying value of the investment.

Critical Accounting Estimates and Judgements

Information on the Corporation's critical accounting policies, estimates and judgements can be found in the notes to the annual audited consolidated financial statements for the year ended December 31, 2018.

The Corporation undertakes a review for impairment of its cash-generating units ("CGUs") at each reporting date to determine whether there is any indication of impairment. At September, 2019, as a result of the decline in the Corporation's publicly traded market value, the Corporation determined that an indicator existed and conducted an impairment test to assess whether the respective carrying value of property and equipment was recoverable. The recoverable amount used in assessing impairment was calculated using a value in use model, based on five year discounted future cash flows. The key assumptions used for the impairment calculations were as follows:

	As at September 30, 2019				
	Well Servicing & Snubbing Operations	Nitrogen Operations	Canadian Rental Operations	Rig 102	Drilling and PNG Rental Operations
Utilization	10% - 60%	25% - 33%	9% of well servicing and snubbing revenue	0% - 41%	0% - 85%
Revenue and cost escalations	0% - 2%	0% - 2%	0% - 2%	NA	0% - 10%
Terminal value multiple (gross profit)	6.0x	4.5x	3.5x	2.5x	2.5x
Discount rate	15%	15%	15%	15%	15%

Management's estimates of recoverable amounts are subject to measurement uncertainty as the recoverable amounts are based upon current operating forecasts, utilization rates, rates and costs for available equipment (margin), terminal values and discount rates.

At September 30, 2019, the recoverable amount of the CGUs exceeded their respective carrying values and no impairment loss was recognized.

Accounting Policies

High Arctic's significant accounting policies are set out in note 3 of the Corporation's annual audited consolidated financial statements for the year ended December 31, 2018.

IFRS 16 – Leases

The Corporation applied IFRS 16, Leases ("IFRS 16") with an initial application date of January 1, 2019. As a result, the Corporation has changed its accounting policy for lease contracts as detailed in the "Significant Accounting Policies".

The Corporation applied IFRS 16 using the modified retrospective approach. As the standard allows for prospective application, the comparative periods for 2018 have not been restated. For leases entered into prior to January 1, 2019, the Corporation has chosen to measure the right-of-use asset at an amount equal to the lease liability.

a) Definition of a lease
Previously, the Corporation determined at contract inception whether an agreement was or contained a lease under IAS 17 and IFRIC 4. Under IFRS 16, the Corporation assesses whether a contract is or contains a lease based on the definition of a lease as explained in "Significant Accounting Policies".

b) Lessee arrangements
As a lessee, the Corporation previously classified leases as operating or finance leases based on their assessment of whether the lease transferred significantly all of the risks and rewards incidental to ownership of the underlying asset to the Corporation.

Under IFRS 16, the Corporation recognizes right-of-use assets and lease liabilities for most leases. The Corporation decided to apply recognition exemptions to short-term leases.

(i) Leases classified as operating under IAS 17

- At transition, lease liabilities were measured at the present value of the remaining lease payments, discounted at the Corporation's incremental borrowing rate as at January 1, 2019. Right-of-use assets were measured at an amount equal to the lease liability.
- The Corporation used the following practical expedients when applying IFRS 16 to leases previously classified as operating leases under IAS 17.
    - Adjusted the right-of-use assets by the amount of IAS 37 onerous contract provision immediately before the date of initial application, as an alternative to an impairment review;
    - Applied the exemption not to recognize right-of-use assets and liabilities for leases with less than 12 months of lease term;
    - Excluded initial direct costs from measuring the right-of-use asset at the date of initial application;
    - By class of underlying assets, elected to combine lease and non-lease components as a single lease component; and
    - Used hindsight when determining the lease term if the contract contains options to extend or terminate the lease.

(ii) Leases classified as finance leases under IAS 17
For leases that were classified as finance leases under IAS 17, the carrying amount of the right-of-use asset and the lease liability as at January 1, 2019 are determined at the carrying amount of the lease asset and lease liability under IAS 17 immediately before that date.

c) Lessor arrangements
The Corporation is not required to make any adjustments on transition to IFRS 16 for leases in which it acts as a lessor, except for a sub-lease. The Corporation accounted for its leases in accordance with IFRS 16 from the date of initial application.

d) Impact on financial statements
On transition to IFRS 16, the Corporation recognized the following changes (using its incremental borrowing rate calculated as of January 1, 2019 of 4.45%):

	As reported on December 31, 2018	Adjustments	Balance on Adoption January 1, 2019
Assets			
Right-of-use Asset	-	8.0	8.0
Property and Equipment	184.4	(0.6)	183.8
Liabilities			
Lease Liability	-	(11.2)	(11.2)
Unfavourable Lease Liability	(2.8)	2.8	-
Accounts Payable and Accrued Liabilities	(21.6)	0.5	(21.1)
Finance Lease Obligation	(0.5)	0.5	-
Total	**159.5**	**0.0**	**159.5**

Unfavourable Lease Liability and Finance Lease Obligation are replaced by Lease Obligation with the adoption of IFRS 16. The change in Accounts Payable and Accrued Liabilities relates to the current portion of the onerous and unfavourable lease liabilities.

The following is a reconciliation of the December 31, 2018 commitment note to the Corporation's lease liabilities as at January 1, 2019:

	January 1, 2019
Operating lease commitment at December 31, 2018 as disclosed in the Corporation's consolidated financial statements	14.5
Discount using the incremental borrowing rate at January 1, 2019	11.0
Fixed Payments for Non-lease Components	0.3
Short-term leases	(0.1)
Lease liability as of January 1, 2019	**11.2**

Evaluation of Disclosure Controls and Procedure and Internal Controls over Financial Reporting

There have been no changes in the Corporation's internal controls over financial reporting that occurred during the interim period ended September 30, 2019 that have materially affected or are reasonably likely to materially affect the Corporation's internal controls over financial reporting.

Business Risks and Uncertainties

In addition to the financial risks discussed above under "Financial Risk Management", below under "Forward Looking Statements" and elsewhere in this MD&A, High Arctic is exposed to a number of business risks and uncertainties that could have a material impact on the Corporation. Readers of the Corporation's MD&A should carefully consider the risks described under the heading "Risk Factors" in the Corporation's recently filed AIF for the year ended December 31, 2018, which are specifically incorporated by reference herein. The AIF is available on SEDAR at www.sedar.com, a copy of which can be obtained on request, without charge, from the Corporation.

Non-IFRS Measures

This MD&A contains references to certain financial measures that do not have a standardized meaning prescribed by IFRS and may not be comparable to the same or similar measures used by other companies. High Arctic uses these financial measures to assess performance and believes these measures provide useful supplemental information to shareholders and investors. These financial measures are computed on a consistent basis for each reporting period and include the following:

EBITDA

Management believes that, in addition to net earnings reported in the consolidated statement of earnings and comprehensive income, EBITDA (earnings before interest, taxes, depreciation and amortization) is a useful supplemental measure of the Corporation's performance prior to consideration of how operations are financed or how results are taxed or how depreciation and amortization affects results. EBITDA is not intended to represent net earnings calculated in accordance with IFRS.

Adjusted EBITDA

Adjusted EBITDA is calculated based on EBITDA (as referred to above) prior to the effect of share-based compensation, gains or losses on sales or purchases of assets or investments, business acquisition costs, other costs related to consolidating facilities, excess of insurance proceeds over costs and foreign exchange gains or losses. Management believes the addback for these items provides a more comparable measure of the Corporation's operational financial performance between periods. Adjusted EBITDA as presented is not intended to represent net earnings or other measures of financial performance calculated in accordance with IFRS.

The following tables provide a quantitative reconciliation of consolidated net earnings (loss) to EBITDA and Adjusted EBITDA for the three and nine months ended September 30, 2019 and 2018:

$ millions	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
Net earnings (loss) for the period	**(1.1)**	7.5	**(6.1)**	13.7
Add:				
Interest and finance expense	**0.3**	0.2	**0.7**	0.4
Income taxes	**0.5**	2.8	**2.1**	9.2
Depreciation	**7.2**	6.5	**21.0**	19.3
EBITDA	**6.9**	17.0	**17.7**	42.6
Adjustments to EBITDA:				
Other (income) expenses	**(0.4)**	0.2	**(1.1)**	0.8
Share-based compensation	**(0.1)**	0.3	**0.3**	1.2
Gain (loss) on sale of assets	**-**	0.1	**(0.8)**	(0.1)
Foreign exchange (gain) loss	**(0.1)**	(0.2)	**(0.3)**	0.5
Adjusted EBITDA	**6.3**	17.4	**15.8**	45.0

Adjusted Net Earnings (Loss)

Adjusted net earnings (loss) is calculated based on net earnings prior to the effect of costs not incurred in the normal course of business, such as consolidating facilities, gains and transaction costs incurred for acquisitions. Management utilizes Adjusted net earnings to present a measure of financial performance that is more comparable between periods. Adjusted net earnings (loss) as presented is not intended to represent net earnings (loss) or other measures of financial performance calculated in accordance with IFRS. Adjusted net earnings (loss) per share and Adjusted net earnings (loss) per share – diluted are calculated as Adjusted net earnings (loss) divided by the number of weighted average basic and diluted shares outstanding, respectively.

The following tables provide a quantitative reconciliation of net earnings (loss) to Adjusted net earnings (loss) for the three and nine months ended September 30, 2019 and 2018:

$ millions	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
Net earnings (loss) for the period	**(1.1)**	7.5	**(6.1)**	13.7
Adjustments to net earnings (loss):				
Other (income) expenses	(0.4)	0.2	(1.1)	0.8
Adjusted net earnings (loss)	**(1.5)**	7.7	**(7.2)**	14.5

Oilfield Services Operating Margin

Oilfield services operating margin is used by management to analyze overall operating performance. Oilfield services operating margin is not intended to represent operating income nor should it be viewed as an alternative to net earnings (loss) or other measures of financial performance calculated in accordance with IFRS. Oilfield services operating margin is calculated as revenue less oilfield services expense.

Oilfield Services Operating Margin %

Oilfield services operating margin % is used by management to analyze overall operating performance. Oilfield services operating margin % is calculated as oilfield services operating margin divided by revenue.

$ millions	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
Revenue	**49.6**	54.7	**142.7**	155.5
Less:				
Oilfield services expense	**39.0**	33.5	**114.8**	97.9
Oilfield Services Operating Margin	**10.6**	21.2	**27.9**	57.6
Oilfield Services Operating Margin (%)	**21%**	39%	**20%**	37%

Percent of Revenue

Certain figures are stated as a percent of revenue and are used by management to analyze individual components of expenses to evaluate the Corporation's performance from prior periods and to compare its performance to other companies.

Funds Provided from (used in) Operations

Management believes that, in addition to net cash generated from operating activities as reported in the consolidated statements of cash flows, cash flow from operating activities before working capital adjustments (funds provided from (used in) operations) is a useful supplemental measure as it provides an indication of the funds generated (used in) by High Arctic's principal business activities prior to consideration of changes in items of working capital.

This measure is used by management to analyze funds provided from (used in) operating activities prior to the net effect of changes in items of non-cash working capital and is not intended to represent net cash generated from (used in) operating activities as calculated in accordance with IFRS.

The following tables provide a quantitative reconciliation of net cash generated from operating activities to funds provided from (used in) operations for the three and nine months ended September 30:

$ millions	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
Net cash generated from operating activities	**2.6**	4.9	**11.5**	25.6
Less:				
Net changes in items of non-cash working capital	**2.7**	9.4	**0.7**	9.2
Funds provided from (used in) operations	**5.3**	14.3	**12.2**	34.8

Working capital
Working capital is used by management as another measure to analyze the operating liquidity available to the Corporation. It is defined as current assets less current liabilities and is calculated as follows:

	As At	
$ millions	September 30, 2019	December 31, 2018
Current assets	**62.4**	**80.4**
Less:		
Current liabilities	**24.2**	**23.6**
Working capital	**38.2**	**56.8**

Net cash
Net cash is used by management to analyze the amount by which cash and cash equivalents exceed the total amount of long-term debt and bank indebtedness or vice versa. The amount, if any, is calculated as cash and cash equivalents less total long-term debt. The following tables provide a quantitative reconciliation of cash and cash equivalents to net cash as follows:

	As At	
$ millions	September 30, 2019	December 31, 2018
Cash and cash equivalents	**12.1**	**31.5**
Less:		
Long-term debt	**-**	**-**
Net cash	**12.1**	**31.5**

Forward-Looking Statements

This MD&A contains forward-looking statements. When used in this document, the words “may”, “would”, “could”, “will”, “intend”, “plan”, “anticipate”, “believe”, “seek”, “propose”, “estimate”, “expect”, and similar expressions are intended to identify forward-looking statements. Such statements reflect the Corporation’s current views with respect to future events and are subject to certain risks, uncertainties and assumptions. Many factors could cause the Corporation’s actual results, performance or achievements to vary from those described in this MD&A. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this MD&A as intended, planned, anticipated, believed, estimated or expected. Specific forward-looking statements in this MD&A include, among others, statements pertaining to the following: general economic and business conditions which will, among other things, impact demand for and market prices for the Corporation’s services; expectations regarding the Corporation’s ability to raise capital and manage its debt obligations; commodity prices and the impact that they have on industry activity; estimated capital expenditure programs for fiscal 2019 and subsequent periods; projections of market prices and costs; factors upon which the Corporation will decide whether or not to undertake a specific course of operational action or expansion; the Corporation’s ongoing relationship with major customers; treatment under governmental regulatory regimes and political uncertainty and civil unrest; the Corporation’s ability to maintain a U.S. dollar bank account and conduct its business in U.S. dollars in PNG; and the Corporation’s ability to repatriate excess funds from PNG as approval is received from the Bank of PNG and the PNG Internal Revenue Commission.

With respect to forward-looking statements contained in this MD&A, the Corporation has made assumptions regarding, among other things, its ability to: obtain equity and debt financing on satisfactory terms; market successfully to current and new customers; the general continuance of current or, where applicable assumed industry conditions; activity and pricing; assumptions regarding commodity prices, in particular oil and gas; the Corporation’s primary objectives, and the methods of achieving those objectives; obtain equipment from suppliers; construct property and equipment according to anticipated schedules and budgets; remain competitive in all of its operations; and attract and retain skilled employees.

The Corporation’s actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth above and elsewhere in this MD&A, along with the risk factors set out in the most recent Annual Information Form filed on SEDAR at www.sedar.com.

The forward-looking statements contained in this MD&A are expressly qualified in their entirety by this cautionary statement. These statements are given only as of the date of this MD&A. The Corporation does not assume any obligation to update these forward-looking statements to reflect new information, subsequent events or otherwise, except as required by law.