Management's Discussion and Analysis
For the Three and Six Months Ended June 30, 2018 and 2017

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 August 9, 2018 and should be read in conjunction with the unaudited condensed consolidated interim financial statements for the three and six months ended June 30, 2018 and 2017 (the "Financial Statements") and the audited consolidated financial statements for the years ended December 31, 2017 and 2016. Additional information relating to the Corporation including the Corporation's Annual Information Form ("AIF") for the year ended December 31, 2017, 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. The definitions of certain non-IFRS financial measures are included on page 18 under the "Non-IFRS Measures" section.

Select Comparative Financial Information

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

	Three Months Ended June 30			Six Months Ended June 30		
$ millions (except per share amounts)	2018	2017	% Change	2018	2017	% Change
Revenue	**47.1**	51.1	(8%)	**100.8**	115.9	(13%)
EBITDA(1)	**12.9**	14.5	(11%)	**25.6**	35.5	(28%)
Adjusted EBITDA(1)	**13.9**	14.3	(3%)	**27.6**	35.3	(22%)
Adjusted EBITDA % of revenue	**30%**	28%	5%	**27%**	30%	(9%)
Operating earnings	**7.2**	7.8	(8%)	**13.9**	22.3	(38%)
Net earnings	**1.8**	5.0	(64%)	**6.2**	14.0	(56%)
per share (basic and diluted)(2)	**0.04**	0.09	(56%)	**0.12**	0.26	(54%)
Adjusted Net earnings(1)	**2.4**	5.0	(52%)	**6.8**	14.0	(51%)
per share (basic and diluted)(2)	**0.05**	0.09	(44%)	**0.13**	0.26	(50%)
Funds provided from operations(1)	**8.6**	9.1	(5%)	**20.5**	26.1	(21%)
per share (basic)(2)	**0.17**	0.17	0%	**0.39**	0.49	(20%)
per share (diluted)(2)	**0.16**	0.17	(6%)	**0.38**	0.49	(22%)
Dividends	**2.6**	2.7	(4%)	**5.2**	5.3	(2%)
per share(2)	**0.05**	0.05	0%	**0.10**	0.10	0%
Capital expenditures	**1.3**	1.8	(28%)	**3.9**	4.4	(11%)

	As at		
	June 30, 2018	December 31, 2017	% Change
Working capital(1)	**59.9**	53.7	12%
Total assets	**269.3**	267.0	1%
Total non-current financial liabilities	**3.3**	3.6	(8%)
Net cash, end of period(1)	**28.1**	22.1	27%
Shareholders' equity	**231.7**	230.8	0%
Shares outstanding(2)	**52.0**	53.3	(2%)

(1) Readers are cautioned that EBITDA, Adjusted EBITDA, Adjusted net earnings, Funds provided from operations, Net cash and Working capital do not have standardized meanings prescribed by IFRS – see "Non IFRS Measures" on page 18 for calculations of these measures.
(2) The number of shares used in calculating the net earnings per share and adjusted net earnings per share amounts is determined differently as explained in note 14 in the Financial Statements.

Corporate Profile

Headquartered in Calgary, Alberta, Canada, High Arctic provides oilfield services to exploration and production companies operating in Canada 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") 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.

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

The stability provided by High Arctic's Canadian well servicing operations has helped to offset lower activity levels in the Corporation's PNG business operations as well as reduced activity in the Corporation's snubbing operations which continue to face headwinds in light of prolonged low natural gas pricing in the WCSB. The Corporation continues to seek opportunities to leverage its financial position to pursue additional growth and diversification opportunities to further strengthen High Arctic's business operations.

Second Quarter 2018:

- High Arctic reported revenue of $47.1 million and Adjusted EBITDA of $13.9 million in the quarter.
- Utilization for High Arctic's 57 registered Concord Well Servicing rigs was 53% in the quarter versus industry utilization of 30% (source: Canadian Association of Oilwell Drilling Contractors "CAODC").
- The Corporation's PNG operations were impacted by a large earthquake in PNG on February 25, 2018, which resulted in some operating activities being suspended during the first quarter and the customer to invoke Force Majeure on the drilling activity involving Rig 405. After assessment of Rig 405 wellsite the customer decided to defer the well and Rig 405 has been demobilized to the port for inspection and export anticipated to occur in the third quarter.
- Consistent with prior quarters, High Arctic declared $2.6 million ($0.05 per share) in dividends during the quarter which represents 30% of funds provided from operations in the quarter. In addition, High Arctic repurchased and cancelled 1,097,019 shares with a value of $4.3 million under the Corporation's NCIB during the quarter resulting in a total of $6.9 million being returned to shareholders in the quarter via dividends and share repurchases.

Year to Date 2018:

- Year to date the Corporation reported revenue of $100.8 million and Adjusted EBITDA of $27.6 million.
- A total of $10.5 million has been returned to shareholders year to date through dividends and share buybacks. The Corporation maintained it's monthly dividend of $0.0165 per share resulting in year to date dividends declared of $5.2 million. The Corporation purchased and cancelled 1,367,427 shares for a total of $5.3 million under the Corporation's NCIB.
- High Arctic continues to maintain a strong balance sheet with $28.1 million in cash, for a total working capital balance of $59.9 million and no amounts outstanding on its debt.

Consolidated Results

	Three Months Ended June 30				Six Months Ended June 30			
($ millions)	2018	2017	Change	%	2018	2017	Change	%
Revenue	**47.1**	51.1	(4.0)	(8%)	**100.8**	115.9	(15.1)	(13%)
EBITDA(1)	**12.9**	14.5	(1.6)	(11%)	**25.6**	35.5	(9.9)	(28%)
Adjusted EBITDA(1)	**13.9**	14.3	(0.4)	(3%)	**27.6**	35.3	(7.7)	(22%)
Adjusted EBITDA % of Revenue	**30%**	**28%**	2%	5%	**27%**	**30%**	(3%)	(10%)
Net earnings	**1.8**	5.0	(3.2)	(64%)	**6.2**	14.0	(7.8)	(56%)
per share (basic and diluted)(2)	0.04	0.09	(0.1)	(56%)	0.12	0.26	(0.1)	(54%)
Adjusted net earnings(1)	**2.4**	5.0	(2.6)	(52%)	**6.8**	14.0	(7.2)	(51%)
per share (basic and diluted)(2)	0.05	0.09	(0.0)	(44%)	0.13	0.26	(0.1)	(50%)

(1) Readers are cautioned that EBITDA, Adjusted EBITDA and Adjusted net earnings do not have standardized meanings prescribed by IFRS – see "Non IFRS Measures" on page 18 for calculations of these measures.
(2) The number of shares used in calculating the net earnings per share and adjusted net earnings per share amounts is determined as explained in note 14 of the Financial Statements.

Second Quarter:

Activity for the Corporation's well servicing operations increased quarter over quarter due to a short spring break up contributing to a 14% increase in well servicing revenue in the quarter relative to the second quarter of 2017. This positive contribution was offset by lower drilling activity in PNG as well as lower Canadian nitrogen and snubbing activity, resulting in an 8% decline in consolidated revenue to $47.1 million in the quarter from $51.1 million in the second quarter of 2017.

The reduction in consolidated revenue, combined with the increased contribution from the Production Services segment, which has a lower operating margin, resulted in Adjusted EBITDA declining to $13.9 million in the quarter from $14.3 million in the second quarter of 2017. The reduced Adjusted EBITDA during the quarter combined with increased share-based compensation expense and foreign exchange losses resulted in a decline in net earnings to $1.8 million ($0.04 per share) in the quarter versus $5.0 million ($0.09 per share) in the second quarter of 2017. Impacting net earnings in 2016 and 2017 was the anticipated declaration of a dividend from PNG to Canada in 2017, which resulted in income tax expense for dividend withholdings recognized in 2016, as compared to the 2018 dividend which was declared, withholding tax recognized and paid in the same financial year.

Year to Date 2018:

- Consistent with the second quarter, increased activity from High Arctic's Production Services segment was offset by lower drilling activity in PNG and lower Canadian nitrogen and snubbing activity, resulting in a 13% decrease in revenue to $100.8 million year to date versus $115.9 million in the first six months of 2017.

- The decline in revenue relative to the comparable period in 2017, combined with a greater proportion of revenue contribution from lower margin Production Services resulted in a 22% decrease in Adjusted EBITDA to $27.6 million versus $35.3 million in the first six months of 2017.
- The Corporation generated $6.2 million ($0.12 per share) in net earnings year to date versus $14.0 million ($0.26 per share) in the first six months of 2017.
- A total of $5.2 million has been returned to shareholders year to date through dividends which represents 25% of funds provided from operations year to date.

Operating Segments

Drilling Services

	Three Months Ended June 30				Six Months Ended June 30			
($ millions)	**2018**	**2017**	**Change**	**%**	**2018**	**2017**	**Change**	**%**
Revenue	**23.2**	28.3	(5.1)	(18%)	**46.7**	62.6	(15.9)	(25%)
Oilfield services expense [(1)]	**12.6**	16.1	(3.5)	(22%)	**27.1**	34.7	(7.6)	(22%)
Oilfield services operating margin [(1)]	**10.6**	**12.2**	**(1.6)**	**(13%)**	**19.6**	**27.9**	**(8.3)**	**(30%)**
Operating margin (%)	**46%**	43%	3%	6%	**42%**	45%	(3%)	(7%)

[(1)] See 'Non-IFRS Measures' on page 18

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. In the fourth quarter of 2017, High Arctic added a fast-moving land based rig, Rig 405, to its PNG drilling fleet to complete a short-term drilling project. Due to the duration of this project, the rig was leased from a non-PNG third-party contractor. Following damage to the well site from the earthquake, the customer decided to terminate operations and Rig 405 has been moved to the port for inspection and is anticipated to return to Australia during the third quarter of 2018.

Second Quarter:

Drilling Services revenue declined 18% in the quarter to $23.2 million from $28.3 million in the second quarter of 2017. This decline was due to a combination of lower pricing and drilling activity in the quarter. In addition, the second quarter of 2017 benefitted from the higher rate take-or-pay contract contribution for Rig 115 which expired in June 2017. Drilling activity was negatively impacted during the quarter by a large earthquake in PNG on February 25, 2018, which continued to curtail some of the Corporation's operations in PNG.

The customer for Rig 405 invoked the Force Majeure clause following the earthquake which occurred in February. During this period of Force Majeure, the Corporation received its lower contracted Force Majeure rates which has largely been offset by lower operating costs. Based on initial assessments, only minor damage was incurred to some of the support equipment and no personnel injuries were incurred as a result of the earthquake. The customer decided to terminate operations at the wellsite and Rig 405 has been moved to the port for inspection and is anticipated to return to Australia during the third quarter.

Mobilization activity for Rig 104 was deferred by the customer while they focused resources on the earthquake response with the rig warm stacked awaiting its expected mobilization to its next well, Muruk 2, in the third quarter. Rig 103 commenced mobilization and rig up at a drilling location in Barikewa during the quarter with the well spudding in June. Rig 115 completed drilling at Kimu 2 in June and began demobilizing to Port Moresby where it will be stacked for maintenance activities to be conducted on it. Rig 116 continued to generate standby revenue under its take-or-pay contract.

Operating margin as a percentage of revenue increased quarter over quarter to 46% versus 43% in the second quarter of 2017. Consistent with prior quarters, the standby revenue generated on Rig 116 skewed margins higher due to minimal operating costs being incurred while the rig is on standby.

Year to Date 2018:

Consistent with the second quarter results, lower drilling activity combined with reduced contribution from take-or-pay contracted revenue from Rig 115 has contributed to a 25% decline in Drilling Services revenue to $46.7 million year to date versus $62.6 million generated in the first six months of 2017. The lower drilling activity in 2018 is a result of the major earthquake in the first quarter and resulting delays in drilling programs compared to the same period in 2017 when Rig 115 was under take-or-pay until June and Rig 104 was actively drilling.

Operating margin as a percentage of revenue decreased to 42% year to date versus 45% in the first six months of 2017. Consistent with the second quarter results, the first six months of 2017 benefitted from revenue generated from take-or-pay contracts on Rig 115.

Production Services

	Three Months Ended June 30				Six Months Ended June 30			
($ millions)	**2018**	**2017**	**Change**	**%**	**2018**	**2017**	**Change**	**%**
Revenue	**18.0**	16.8	1.2	7%	**41.3**	39.3	2.0	5%
Oilfield services expense (1)	**14.7**	14.4	0.3	2%	**33.9**	33.1	0.8	2%
Oilfield services operating margin (1)	**3.3**	**2.4**	**0.9**	**38%**	**7.4**	**6.2**	**1.2**	**19%**
Operating margin (%)	**18%**	14%	4%	28%	**18%**	16%	2%	14%
Operating Statistics:								
Service rigs								
Average Fleet (2)	57	55	2	4%	57	54	3	6%
Utilization (3)	53%	49%	4%	8%	58%	56%	2%	4%
Operating hours	27,420	24,514	2,906	12%	59,604	55,178	4,426	8%
Revenue per hour	600	587	13	2%	618	595	23	4%
Snubbing rigs								
Average Fleet (4)	8	9	(1)	(11%)	8	9	(1)	(11%)
Utilization (3)	14%	21%	(7%)	(33%)	20%	30%	(10%)	(33%)
Operating hours	996	1,752	(756)	(43%)	2,871	4,806	(1,935)	(40%)

(1) See 'Non-IFRS Measures' on page 18
(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.

High Arctic's well servicing and snubbing operations are provided through its Production Services segment. These operations are primarily conducted in the WCSB 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 2017 or 2018 and as such no revenue was generated or costs have been incurred associated with this rig during the periods presented.

Second Quarter:

Increased quarter over quarter activity and pricing for High Arctic's Concord Well Servicing rigs offset lower activity experienced from the Corporation's snubbing operations in the quarter resulting in a 7% increase in revenue for the Production Services segment to $18.0 million in the quarter versus $16.8 million in the second quarter of 2017. Operating hours for the Concord rigs increased 12% to 27,420 hours in the quarter from 24,514 hours in the second quarter of 2017. Consistent with prior quarters, the Concord rigs achieved above industry utilization of 53% versus the 30% utilization generated by the industry's registered well servicing rigs in the quarter (source: CAODC). The increase in activity has allowed for pricing increases in certain areas, however, pricing remains competitive. This increase in pricing combined with an increased exposure to higher rate operating areas allowed the average revenue per hour for the Concord rigs to increase to $600 per hour in the quarter from $587 per hour in the comparative quarter in 2017.

The positive contribution from the Concord rigs was partially offset by lower activity experienced in the Production Services snubbing operations which saw revenue decrease to $1.5 million in the quarter versus the $2.4 million generated in the second quarter of 2017. Operating hours for the snubbing rigs in the quarter were 996 versus 1,752 hours in the second quarter of 2017. Activity for the Corporation's snubbing operations has been hampered over recent quarters due to prolonged low natural gas prices which is curtailing snubbing activity on natural gas completions for the Corporation's customers.

Operating margin increased 4% since the comparative quarter in 2017, resulting in a 18% operating margin achieved in 2018 versus 14% achieved in the comparative quarter of 2017. The increase in margin is primarily due to a decrease in operating costs in the well servicing division combined with an increase in revenue. Operating costs in 2017 were negatively impacted by initial start-up costs associated with expanding the division into the Grande Prairie region that began to normalize in the second quarter of 2017 and onward.

Year to Date 2018:

The Production Services segment revenue increased to $41.3 million from $39.3 million in the first six months of 2017. Year to date the Concord rigs have generated 59,604 operating hours for a 58% utilization of the Corporation's 57 average CAODC registered service rigs versus 38% utilization achieved in the first six months for the industry's registered service rig fleet (source: CAODC). Year to date the Concord rigs have generated an average revenue rate of $618 per hour compared to an average revenue rate of $595 per hour for the same period in 2017.

Activity for the Corporation's snubbing rigs has declined 40% year to date versus the first six months of 2017. This decline in activity was due to the Corporation's core snubbing customers directing their efforts towards completing fracturing programs during the period.

As a result of the increased revenue, operating margin increased to $7.4 million year to date from $6.2 million in the first half of 2017. Operating margins as a percentage of revenue increased to 18% during the period from 16% in the first six months of 2017. The primary factors contributing to this increase are pricing increases in the industry combined with a decline in operating cost per hour resulting in higher field operating margins.

During the second quarter, the Corporation closed it's Blackfalds facility and re-located these operations to its Acheson facility in an effort to improve cost savings and better position these operations closer to areas of field activity. The consolidation of these operations is anticipated to result in approximately $0.6 million in annualized cost savings.

Ancillary Services

	Three Months Ended June 30				Six Months Ended June 30			
($ millions)	**2018**	**2017**	**Change**	**%**	**2018**	**2017**	**Change**	**%**
Revenue	**6.8**	6.8	0.0	0%	**14.6**	15.6	(1.0)	(6%)
Oilfield services expense (1)	**2.3**	2.7	(0.4)	(15%)	**5.2**	5.5	(0.3)	(5%)
Oilfield services operating margin (1)	**4.5**	**4.1**	**0.4**	**10%**	**9.4**	**10.1**	**(0.7)**	**(7%)**
Operating margin (%)	**66%**	60%	6%	10%	**64%**	65%	(1%)	(2%)

(1) Revenue includes inter-segment revenue charged to Production Services and Drilling Services from Ancillary Services division of $0.9 million for the quarter and $1.8 million year to date. In 2017 inter-segment revenue was $0.8 million for the quarter and $1.6 million year to date.
(2) See 'Non-IFRS Measures' on page 18

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

Second Quarter:

Growth in the segment's Canadian and PNG rental operations offset lower nitrogen services activity during the quarter. The growth in the Canadian rental operations over recent quarters has been due to a combination of increased well servicing operations which utilize certain rental equipment as well as successful efforts to expand the segment's rental opportunities with new and existing customers. The increase in PNG rental activity was due to an increase in equipment being utilized in recovery work after the earthquake. Nitrogen activity was lower due to reduced activity from core customers in the quarter as lower natural gas pricing in the WCSB curtailed natural gas fracturing activity which is an activity driver for the Corporation's nitrogen operations.

Operating margin as a percentage of revenue increased to 66% in the quarter versus 60% in the second quarter of 2017. This increase was due to the increased contribution from higher margin rental divisions in the quarter relative to the second quarter of 2017.

Year to Date 2018:

Increased rentals associated with higher activity for the Corporation's Concord Well Servicing partially offset lower equipment rental activity in PNG and lower nitrogen services year to date. The lower equipment rental activity was due to lower drilling activity experienced in 2018 versus 2017 as well as the expiry of the equipment rental contracts associated with Rig 115 during June 2017.

Operating margin as a percentage of revenue declined to 64% year to date from 65% in 2017. Higher margin rental divisions in PNG and Canada made up a greater proportion of revenue in 2018, which helped offset the decline in operating margin from the nitrogen services division.

General and Administration

	Three Months Ended June 30				Six Months Ended June 30			
($ millions)	**2018**	**2017**	**Change**	**%**	**2018**	**2017**	**Change**	**%**
General and administration	**4.5**	4.4	0.1	2%	**8.8**	8.9	(0.1)	(1%)
Percent of revenue	**10%**	9%	1%	11%	**9%**	8%	1%	13%

General and administrative costs increased $0.1 million from $4.4 million in the second quarter of 2017, however on a year to date basis general and administrative costs decreased $0.1 million to $8.8 million from $8.9 million in 2017. Due to the decline in revenue during the quarter and year to date, general and administrative costs as a percentage of revenue increased by 1% over the 2017 respective periods resulting in 10% in the second quarter and 9% year to date as a percentage of revenue.

Depreciation

Depreciation expense decreased to $6.4 million in the quarter from $6.5 million in the second quarter of 2017. The decrease is due to the Corporation disposing of redundant equipment combined with incurring limited capital expenditures subsequent to the second quarter of 2017. $1.7 million remains in capital under construction for items not yet placed into operational service for which depreciation has not yet commenced.

Share-based Compensation

The increase in share-based compensation to $0.3 million in the second quarter and $0.9 million year to date from nil and $0.1 million in the respective periods in 2017, is a result of a higher number of awards granted year to date in 2018 versus 2017. The amortization costs associated with the Corporation's option grants and deferred share units are higher in the first year subsequent to the grant versus future years.

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 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, as it increased during the second quarter compared to the first quarter, with an average exchange rate of $1.291 during the second quarter of 2018 (2017 – $1.345). The stronger U.S. dollar benefits the Corporation as the majority of the Corporation's PNG business is conducted in U.S. dollars.

As at June 30, 2018, the U.S. dollar exchange rate was 1.317 versus 1.255 as at December 31, 2017. This strengthening of the U.S. dollar has resulted in a translation gain of $7.0 million recorded in other comprehensive income for the six months ended June 30, 2018 ($3.1 million gain for the three months ended June 30, 2018).

The fluctuation in exchange rates year to date also resulted in a $0.7 million foreign exchange loss being recorded on various foreign exchange transactions (2017 - $0.3 million gain). The Corporation does not currently hedge its foreign exchange transactions or exposure.

Interest and Finance Expense

On a year to date basis, the Corporation did not have any long term debt outstanding but incurred $0.2 million in bank fees and other interest charges ($0.7 million for the six months ended June 30, 2017).

Income Taxes

	Three Months Ended June 30			Six Months Ended June 30		
($ millions)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Net earnings before income taxes	**6.4**	7.7	(1.3)	**12.6**	21.9	(9.3)
Current income tax expense	**4.4**	5.1	(0.7)	**6.0**	8.5	(2.5)
Deferred income tax expense (recovery)	**0.2**	(2.4)	2.6	**0.4**	(0.6)	1.0
Total income tax expense	**4.6**	2.7	1.9	**6.4**	7.9	(1.5)
Effective tax rate	**72%**	35%		**51%**	36%	

The Corporation's effective tax rate increased to 51% for the first six months of 2018 from 36% in the first half of 2017. The increase in effective tax rate is largely due to an increase in tax expense associated with tax withholdings on dividend payments from PNG. During the second quarter of 2018 the Corporation paid $2.2 million in withholding taxes on the payment of intercompany dividends from PNG to Canada versus $3.1 million paid out in the second quarter of 2017. The increase in effective tax rate quarter over quarter, despite a decrease in the amount of tax paid, is due to the Corporation recognizing income tax expense in a prior period, 2016, when a dividend was anticipated to be declared from PNG to Canada and paid out during the second quarter of 2017, versus the income tax expense on the dividend declared and paid in 2018 being recognized when declared and paid in 2018. The increase in income tax expense related to dividend withholding payments combined with the decrease in revenue resulted in the 37% increase in effective tax rate quarter over quarter.

As at June 30, 2018, High Arctic had $73.0 million in unrecognized tax pools, consisting of $35.1 million in non-capital loss pools and $37.9 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.

Other Comprehensive Income

As discussed above under Foreign Exchange Transactions, the Corporation recorded a $7.0 million foreign currency translation gain in other comprehensive income year to date due to the weakening of the Canadian dollar, as compared to the US dollar, at June 30, 2018 relative to December 31, 2017.

During the six months ended June 30, 2018, the Corporation also recognized a $0.5 million unrealized loss on its strategic investments, which increased $0.2 million during the three months ended June 30, 2018 due to fluctuations in investment share prices.

Liquidity and Capital Resources

	Three Months Ended June 30			Six Months Ended June 30		
($ millions)	2018	2017	Change	2018	2017	Change
Cash provided by (used in):						
Operating activities	**15.9**	31.4	(15.5)	**20.7**	26.5	(5.8)
Investing activities	**(1.0)**	(1.6)	0.6	**(3.7)**	(3.5)	(0.2)
Financing activities	**(6.9)**	(22.1)	15.2	**(11.5)**	(23.4)	11.9
Effect of exchange rate changes	**0.4**	(0.7)	1.1	**0.5**	(0.8)	1.3
Increase (decrease) in cash and cash equivalents	**8.4**	7.0	1.4	**6.0**	(1.2)	7.2

	As At		
	June 30, 2018	December 31, 2017	Change
Working capital[(1)]	59.9	57.6	2.3
Working capital ratio[(1)]	3.5:1	3.3:1	0.2:1
Net cash[(1)]	28.1	19.7	8.4
Undrawn availability under debt facilities	45.0	45.0	0.0

[(1)]See 'Non-IFRS Measures' on page 18

High Arctic continues to maintain a strong balance sheet with $28.1 million in cash and no debt outstanding on its credit facility as at June 30, 2018.

Management believes High Arctic's current capital resources, plus anticipated cash generated from operating activities in 2018, will be sufficient to meet its planned 2018 capital expenditure program of $13.3 million and anticipated dividends and share repurchases under the Corporation's Normal Course Issuer Bid ("NCIB") for 2018. Management will reassess the Corporation's capital resource needs as changes occur in its business operations and as future growth opportunities arise.

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 as well as extensions or amendments of its existing contracts with its key customer 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, 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

Funds provided from operations decreased to $8.6 million in the quarter from $9.1 million in the second quarter of 2017. This decrease was the result of a 3% decline in Adjusted EBITDA during the quarter as well as $2.2 million paid in withholding taxes related to the intercompany dividend paid in the quarter.

Year to date, funds provided from operations decreased 21% to $20.5 million from $26.1 million in the first six months of 2018, which is also due to lower Adjusted EBITDA and increased dividend withholding tax payments. After working capital adjustments, net cash generated from operating activities was $20.7 million compared to $26.5 million for the first six months of 2017.

Investing Activities

High Arctic incurred $1.3 million in capital expenditures during the second quarter and $3.9 million year to date (2017 - $4.4 million) 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. Further capital investment and rig enhancements will be made as driven by customer demand and operating requirements.

During the quarter, the Corporation generated $0.4 million in cash from the sale of redundant equipment and $0.5 million year to date (2017 - $0.1 million).

Financing Activities

Year to date the Corporation declared monthly dividends of $0.0165 per share, resulting in total dividends paid to shareholders of $5.2 million (2017 - $5.3 million). In addition, the Corporation purchased and cancelled 1,367,427 shares for a total of $5.3 million under its NCIB, resulting in a total of $10.5 million being returned to shareholders via dividends and share buybacks year to date.

Credit Facility

In the first quarter of 2017, High Arctic renewed its existing credit facility. As at June 30, 2018, High Arctic's credit facility consisted of a $45.0 million revolving loan facility which matures on August 31, 2019. 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 June 30, 2018, no amounts were drawn on the facility and total credit available to draw was $45.0 million.

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

Covenant	Required	June 30, 2018
Funded debt to EBITDA(1)(4)	2.50 : 1 Maximum	0.01 : 1
Current ratio(2)	1.25 : 1 Minimum	3.50 : 1
Fixed charge coverage ratio(3)	1.25 : 1 Minimum	34.57 : 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) Current ratio is defined as the ratio of consolidated current assets to consolidated current liabilities (excluding current portion of long-term debt and other debt, if any).
(3) Fixed charge coverage ratio is defined as EBITDA less cash taxes, dividends, distributions and unfunded capital expenditures divided by the total of principal payments on long-term debt and capital leases plus interest, in which principal payments means the total principal amount of the loan outstanding at the end of the quarter amortized over a 7-year period.
(4) 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), stock 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 June 30, 2018 and the Corporation remains in compliance with the financial covenants under its credit facility as at June 30, 2018.

Contractual Obligations and Contingencies

High Arctic's contractual financial obligations as at June 30, 2018 are summarized as follows:

($ millions)	1 Year	2-3 Years	4-5 Years	Beyond 5 Years	Total
Accounts payable	22.6	-	-	-	22.6
Dividends payable	0.9	-	-	-	0.9
Operating and financial lease commitments	1.7	2.6	1.9	8.3	14.5
Total	**25.2**	**2.6**	**1.9**	**8.3**	**38.0**

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 $9.0 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. The Corporation recorded a provision of $0.7 million during 2016 within accrued liabilities to account for a potential shortfall in inventory, which may require cash settlement.

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 August 9, 2018, there were 51,617,727 issued and outstanding common shares. In addition, 1,952,300 options were outstanding at an average exercise price of $3.98 as well as 382,819 units under the Corporation's Performance Share Unit Plan and 155,595 units under the Deferred Share Unit plan.

On September 15, 2017, the Corporation received approval from the Toronto Stock Exchange to acquire for cancellation up to 2,902,733 common shares, representing approximately 10 percent of the Corporation's public float, under a NCIB. The NCIB is valid for one year and expires on September 18, 2018. A total of 1,367,427 common shares have been purchased and cancelled under the NCIB as at June 30, 2018 at a cost of $5.3 million. Subsequent to quarter end, an additional 408,885 shares have been repurchased under the NCIB for total proceeds of $1.6 million. As at August 9, 2018 the Corporation has 1,126,421 million in shares remaining under its approved NCIB which can be repurchased prior to the expiry of the NCIB.

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:

	2018		2017				2016	
$ (millions, except per share amounts)	Q2[3]	Q1	Q4	Q3	Q2	Q1	Q4[2]	Q3[2]
Revenue	**47.1**	**53.7**	**51.5**	**42.8**	**51.1**	**64.8**	**62.3**	**47.5**
Adjusted EBITDA[1]	13.9	13.7	12.4	10.6	14.3	21.0	18.3	15.6
Net earnings	1.8	4.4	3.5	2.8	5.0	9.0	8.4	8.8
per share - basic	0.04	0.08	0.06	0.06	0.09	0.17	0.16	0.16
Adjusted net earnings[1][2][3]	2.4	4.4	3.5	2.8	5.0	9.0	7.5	20.1
per share - basic	0.05	0.08	0.06	0.06	0.09	0.17	0.14	0.38
Funds provided from operations[1]	8.6	11.9	9.3	9.8	9.1	17.0	15.9	11.6

(1) See 'Non-IFRS Measures' on page 18
(2) Adjusted net earnings in 2016 excludes the impact of a $12.7 million gain on acquisition and $2.3 million in transaction costs related to the Tervita Acquisition completed in 2016.
(3) Adjusted net earnings in 2018 excludes the impact of $0.6 million of expenses incurred during the second quarter related to the closing of the Corporation's Blackfalds facility.

Various factors have affected the quarterly profitability of the Corporation's operations. In response to customer demand in PNG, the Corporation added two drilling rigs, Rigs 115 and 116, and additional rental equipment to its fleet in 2015 under take-or-pay contract arrangements. These take-or-pay contract arrangements have provided a consistent revenue and earnings base for the Corporation's PNG operations and have helped to mitigate the impact of lower activity levels experienced in PNG subsequent to the first quarter of 2016. The take-or-pay contract for Rig 115 expired in June 2017 resulting in reduced revenue and EBITDA contribution subsequent to the second quarter of 2017. The take-or-pay contract for Rig 116 remains in effect and is scheduled to expire on November 2, 2018. The Corporation's results have also benefited from the acquisition of Tervita's Production Services Division (the "Tervita Acquisition") which closed on August 31, 2016. This acquisition has contributed to the increased revenue since the fourth quarter of 2016, as well as a gain on acquisition in the third quarter of 2016.

The decline in revenue subsequent to the first quarter of 2017 is due to the expiry of the take or pay contract for Rig 115 in June 2017 as well as the impact of seasonal conditions in the Corporation's Canadian operations whereby frozen ground during the winter months tends to provide an optimal environment for drilling activities and consequently the first quarter is typically the strongest. As warm weather returns in the spring, the winter's frost comes out of the ground rendering many secondary roads incapable of supporting the weight of heavy equipment until they have thoroughly dried out. This period is generally referred to as spring break-up. Road bans, which are generally imposed in the spring, restrict the transportation of heavy equipment onto customer locations which reduces demand for services in the Canadian operation and, therefore, the second quarter is generally the weakest quarter of the year for the Corporation's operations in Canada.

Changes in the value of the U.S. dollar as compared to the Canadian dollar have also contributed to fluctuations in revenues, earnings and funds provided from operations. The U.S. Dollar has strengthened relative to the Canadian dollar, peaking in the second quarter of 2017 and subsequently leveling off in the 1.25 to 1.30 range since the second quarter of 2017.

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.

	2018		2017				2016	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Oil and natural gas prices (Average for the period)								
Brent Crude Oil *(U.S. $/bbl)*	$75	$68	$61	$52	$51	$55	$51	$47
Japan LNG *(U.S. $/mmbtu)*	$9.40	$8.98	$7.76	$8.33	$8.40	$7.57	$7.15	$6.51
U.S./Canadian dollar exchange rate	1.29	1.26	1.27	1.25	1.34	1.32	1.33	1.30

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 Asian 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.

	2018		2017				2016	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Oil and natural gas prices Average for the period:								
West Texas Intermediate (U.S. $/bbl)	$68	$63	$55	$48	$48	$52	$49	$45
Canadian Light Sweet Oil (Cdn $/bbl)	$78	$70	$66	$57	$60	$65	$61	$54
AECO (C$/mmbtu)	$1.20	$2.06	$1.72	$1.61	$2.79	$2.69	$3.11	$2.36
Other industry indicators								
Total wells drilled in Western Canada(1)(2)	1,268	1,696	1,852	1,764	1,265	1,554	824	754
Average service rig utilization rates(1)	30%	47%	40%	39%	29%	45%	39%	32%
Average drilling rig utilization rates(1)	17%	41%	32%	30%	18%	39%	39%	32%

(1) Source: CAODC
(2) Source: Daily Oil Bulletin

Decreases in oil and natural gas prices 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

Activity for the Corporation's Concord well servicing operations continues to show strength after a shorter than normal second quarter slow down when weather and road bans impact operations, commonly referred to as spring breakup. Year to date, operating hours for the Concord service rigs are approximately 8% above the hours generated in the same period in 2017. This increase in hours demonstrates the strength of High Arctic's customer base and exposure to certain operating areas which are less impacted by seasonal spring breakup conditions.

Similar to prior quarters, attraction and retention of sufficient field staff to meet demand continues to remain an industry challenge and has resulted in the Corporation implementing various compensation initiatives in an effort to attract and retain staff. As seen in the second quarter results, these compensation programs have added additional costs to the Corporation's Canadian operations, however, management believes this investment in enhanced field compensation plans, which is beginning to show results through reduced field staff turnover rates, will improve High Arctic's ability to respond to activity demands while retaining High Arctic's strong safety and operational performance.

While activity levels for the Corporation's well servicing operations remain strong, low natural gas prices continue to hamper activity for the Corporation's snubbing and N2 operations. Management continues exploring opportunities to expand into markets with increased activity levels which may help to improve the financial contribution from these operations.

In PNG, Rig 405 and associated equipment has been moved off the well and has been mobilized to a yard in Port Moresby for non-destructive testing inspections on equipment, CAT IV inspection of pipe and preparation for hand back to its owner and export to Australia. The rig and equipment suffered superficial damage only in the earthquake. Rig 103 is drilling at Barikewa in place of Rig 115 which is being moved to Port Moresby to be stacked and undergo maintenance activities. Rig 104 has commenced mobilization with a skeleton crew to its next well in Muruk in anticipation of commencing drilling late in the third quarter. Rig 116 remains stacked under contract in Port Moresby until November 2, 2018.

High Arctic and its key customer in PNG have agreed to suspend any further discussion on the formation of a jointly owned drilling company, however they have not ruled-out revisiting discussion on a commercial arrangement regarding the ownership and operations management of the drilling rigs in PNG again in the future.

Financial Risk Management

Credit Risk

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 are 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 three large customers (2017 – four) which individually accounted for greater than 10% of its consolidated revenues during the six months ended June 30, 2018. Sales to these three customers were approximately $41.4 million, $13.6 million and $11.1 million for the six months ended June 30, 2018 (2017 - $30.4 million, $14.7 million and $9.6 million). As at June 30, 2018, these three customers represented 53%, 12% and 6%, respectively, of outstanding accounts receivable (December 31, 2017 – three customers represented a total of 60%). Management has assessed the three customers as creditworthy and the Corporation has had no history of collection issues with these customers.

The Corporation's accounts receivable are aged as follows:

Days outstanding:	June 30, 2018	December 31, 2017
Less than 31 days	27.3	18.0
31 to 60 days	4.2	13.7
61 to 90 days	4.4	5.7
Greater than 90 days	4.9	3.1
Allowance for doubtful accounts	(0.1)	(0.1)
Total	**40.7**	**40.4**

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 six months ended June 30, 2018, a $0.10 change in the value of the Canadian dollar relative to the U.S. dollar would have resulted in a $0.8 million change in net earnings for the quarter as a result of changes in foreign exchange.

The Corporation's financial instruments have the following foreign exchange exposure at June 30, 2018:

(millions)	U.S. Dollar(1) (in USD)	PNG Kina(2) (in Kina)	Australian Dollar(3) (in AUD)
Cash and cash equivalents	12.7	1.1	0.2
Trade and other receivables	20.5	3.7	-
Trade and other payables	(6.1)	(9.7)	(0.4)
Total	**27.1**	**(4.9)**	**(0.2)**

(1) As at June 30, 2018, one U.S. dollar was equivalent to 1.3168 Canadian dollars.
(2) As at June 30, 2018, one PNG Kina was equivalent to 0.4004 Canadian dollars.
(3) As at June 30, 2018, one Australian dollar was equivalent to 0.9733 Canadian dollars.

As at June 30, 2018 U.S. $7.3 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, however, if such approval is withdrawn 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 Judgments

Information on the Corporation's critical accounting policies and estimates can be found in the notes to the annual audited consolidated financial statements for the year ended December 31, 2017.

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, 2017.

The Corporation has adopted, as of January 1, 2018, all the requirements of IFRS 15, *Revenue from Contracts with Customers.* The Corporation has adopted the modified retrospective approach, recognizing the cumulative impact of adoption in retained earnings as of January 1, 2018. Comparative periods were not restated. Please see note 3 in the unaudited June 30, 2018 interim consolidated financial statements for further details on the adoption of this standard.

Future Accounting Pronouncements

Leases
On January 13, 2016, the IASB issued IFRS 16, *"Leases"* ("IFRS 16"), which requires entities to recognize lease assets and lease obligations on the balance sheet. For lessees, IFRS 16 removes the classification of leases as either operating leases or finance leases, effectively treating all leases as finance leases. Certain short-term leases (less than 12 months) and leases with low-value assets are exempt from the requirements and may continue to be treated as operating leases.

IFRS 16 is effective for years beginning on or after January 1, 2019. The standard may be applied retrospectively or using a modified retrospective approach. The Corporation is currently evaluating the impact of adopting IFRS 16 on the Financial Statements.

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 June 30, 2018 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, 2017, 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 to EBITDA and Adjusted EBITDA for the three and six months ended June 30:

$ millions	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Net earnings for the period	**1.8**	5.0	**6.2**	14.0
Add:				
Interest and finance expense	**0.1**	0.3	**0.2**	0.7
Income taxes	**4.6**	2.7	**6.4**	7.9
Depreciation	**6.4**	6.5	**12.8**	12.9
EBITDA	**12.9**	14.5	**25.6**	35.5
Adjustments to EBITDA:				
Other expenses	**0.6**	-	**0.6**	-
Share-based compensation	**0.3**	-	**0.9**	0.1
Gain on sale of assets	**(0.2)**	-	**(0.2)**	-
Foreign exchange (gain) loss	**0.3**	(0.2)	**0.7**	(0.3)
Adjusted EBITDA	**13.9**	14.3	**27.6**	35.3

Adjusted Net Earnings

Adjusted net earnings 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 as presented is not intended to represent net earnings or other measures of financial performance calculated in accordance with IFRS. Adjusted net earnings per share and Adjusted net earnings per share – diluted are calculated as Adjusted net earnings divided by the number of weighted average basic and diluted shares outstanding, respectively. The following tables provide a quantitative reconciliation of net earnings to Adjusted net earnings for the three and six months ended June 30:

$ millions	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Net earnings for the period	**1.8**	5.0	**6.2**	14.0
Adjustments to net earnings:				
Other expenses	0.6	-	0.6	-
Adjusted net earnings	**2.4**	5.0	**6.8**	14.0

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 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 June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Revenue	**47.1**	51.1	**100.8**	115.9
Less:				
Oilfield services expense	**28.7**	32.4	**64.4**	71.7
Oilfield Services Operating Margin	**18.4**	18.7	**36.4**	44.2
Oilfield Services Operating Margin (%)	**39%**	37%	**36%**	38%

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 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 operations) is a useful supplemental measure as it provides an indication of the funds generated 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 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 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 operations for the three and six months ended June 30:

$ millions	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Net cash generated from operating activities	**15.9**	31.4	**20.7**	26.5
Less:				
Net changes in items of non-cash working capital	**(7.3)**	(22.3)	**(0.2)**	(0.4)
Funds provided from operations	**8.6**	9.1	**20.5**	26.1

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	June 30, 2018	December 31, 2017
Current assets	**83.9**	77.1
Less:		
Current liabilities	**(24.0)**	(23.4)
Working capital	**59.9**	53.7

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	**June 30, 2018**	**December 31, 2017**
Cash and cash equivalents	**28.1**	22.1
Less:		
Long-term debt	**-**	-
Net cash	**28.1**	22.1

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; the Corporation’s ability to negotiate and execute agreements with its key customer in PNG related to a commercial arrangement regarding the ownership and operations management of the drilling rigs in PNG; future acquisitions and growth opportunities; commodity prices and the impact that they have on industry activity; estimated capital expenditure programs for fiscal 2018 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.