



Precision Drilling Corporation

Second Quarter Report for the three and six months ended June 30, 2018 and 2017

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's Discussion and Analysis for the three-month and six-month periods ended June 30, 2018 of Precision Drilling Corporation ("Precision" or the "Corporation") prepared as at July 25, 2018 focuses on the unaudited Interim Consolidated Financial Statements and related notes and pertains to known risks and uncertainties relating to the oilfield services sector. This discussion should not be considered all-inclusive as it does not include all changes regarding general economic, political, governmental and environmental events. This discussion should be read in conjunction with the Corporation's 2017 Annual Report, Annual Information Form, unaudited June 30, 2018 Interim Consolidated Financial Statements and related notes.

This report contains "forward-looking information and statements" within the meaning of applicable securities laws. For a full disclosure of the forward-looking information and statements and the risks to which they are subject, see the "Cautionary Statement Regarding Forward-Looking Information and Statements" on page 16 of this report. This report contains references to Adjusted EBITDA, Covenant EBITDA, Operating Earnings (Loss), Funds Provided by (Used in) Operations and Working Capital. These terms do not have standardized meanings prescribed under International Financial Reporting Standards (IFRS) and may not be comparable to similar measures used by other companies, see "Non-GAAP Measures" on page 15 of this report.

Precision Drilling announces 2018 second quarter financial results:

- Second quarter revenue of \$331 million was an increase of 14% over the prior year comparative quarter.
- Second quarter net loss of \$47 million (\$0.16 per share) compares to a net loss of \$36 million (\$0.12 per share) in the second quarter of 2017.
- Second quarter earnings before income taxes, loss on repurchase and redemption of unsecured senior notes, finance charges, foreign exchange and depreciation and amortization (adjusted EBITDA see "NON-GAAP MEASURES") of \$62 million was 10% higher than the second quarter of 2017.
- Funds provided by operations (see "NON-GAAP MEASURES") in the second quarter of \$50 million versus funds used in operations of \$15 million in the prior year comparative quarter.
- Second quarter ending cash balance was \$95 million.
- Second quarter capital expenditures were \$37 million.

SELECT FINANCIAL AND OPERATING INFORMATION

Adjusted EBITDA and funds provided by (used in) operations are Non-GAAP measures. See “NON-GAAP MEASURES.”

Financial Highlights

<i>(Stated in thousands of Canadian dollars, except per share amounts)</i>	Three months ended June 30,			Six months ended June 30,		
	2018	2017	% Change	2018	2017	% Change
Revenue ⁽¹⁾	330,716	290,860	13.7	731,722	659,533	10.9
Adjusted EBITDA ⁽²⁾	62,182	56,520	10.0	159,651	140,828	13.4
Net loss	(47,217)	(36,130)	30.7	(65,294)	(58,744)	11.2
Cash provided by operations	129,695	2,739	4,635.1	167,884	36,509	359.8
Funds provided by (used in) operations ⁽²⁾	50,225	(15,187)	(430.7)	154,251	70,472	118.9
Capital spending:						
Expansion	15,786	4,852	225.4	16,471	8,644	90.5
Upgrade	5,447	13,287	(59.0)	16,810	26,934	(37.6)
Maintenance and infrastructure	13,091	2,997	336.8	23,334	5,981	290.1
Intangibles	2,429	7,301	(66.7)	10,220	8,970	13.9
Proceeds on sale	(2,630)	(3,563)	(26.2)	(8,680)	(5,781)	50.1
Net capital spending	34,123	24,874	37.2	58,155	44,748	30.0
Net loss per share:						
Basic	(0.16)	(0.12)	33.3	(0.22)	(0.20)	10.0
Diluted	(0.16)	(0.12)	33.3	(0.22)	(0.20)	10.0

(1) Prior year comparatives have changed to reflect a recast of certain amounts previously netted against operating expense. See our 2017 Annual Report.

(2) See “NON-GAAP MEASURES”.

Operating Highlights

	Three months ended June 30,			Six months ended June 30,		
	2018	2017	% Change	2018	2017	% Change
Contract drilling rig fleet	257	256	0.4	257	256	0.4
Drilling rig utilization days:						
Canada	2,834	2,639	7.4	9,302	9,458	(1.6)
U.S.	6,588	5,331	23.6	12,383	9,521	30.1
International	728	728	-	1,448	1,448	-
Revenue per utilization day:						
Canada ⁽¹⁾⁽²⁾ (Cdn\$)	22,072	22,177	(0.5)	22,167	21,620	2.5
U.S. ⁽¹⁾⁽³⁾ (US\$)	21,795	19,826	9.9	21,237	20,147	5.4
International (US\$)	49,832	49,679	0.3	49,935	50,054	(0.2)
Operating cost per utilization day:						
Canada (Cdn\$)	16,712	16,368	2.1	14,361	13,815	4.0
U.S. (US\$)	14,026	14,248	(1.6)	14,026	14,695	(4.6)
Service rig fleet	210	210	-	210	210	-
Service rig operating hours	31,824	33,813	(5.9)	84,525	85,870	(1.6)
Revenue per operating hour (Cdn\$)	676	629	7.5	691	633	9.2

(1) Prior year comparatives have changed to reflect a recast of certain amounts previously netted against operating expense. See our 2017 Annual Report.

(2) Includes lump sum revenue from contract shortfall for the six months ended June 30, 2018 and prior year comparatives.

(3) 2017 comparative periods include revenue from idle but contracted rig days.

Financial Position

<i>(Stated in thousands of Canadian dollars, except ratios)</i>	June 30, 2018	December 31, 2017
Working capital ⁽¹⁾	196,149	232,121
Cash	94,669	65,081
Long-term debt ⁽²⁾	1,735,842	1,730,437
Total long-term financial liabilities	1,753,580	1,754,059
Total assets	3,858,221	3,892,931
Long-term debt to long-term debt plus equity ratio	0.50	0.49

(1) See “NON-GAAP MEASURES”.

(2) Net of unamortized debt issue costs.

Summary for the three months ended June 30, 2018:

- Revenue this quarter was \$331 million which is 14% higher than the second quarter of 2017. The increase in revenue is primarily the result of higher activity in our U.S. contract drilling business. Compared with the second quarter of 2017 our activity for the quarter, as measured by drilling rig utilization days, respectively increased 24% and 7% in the U.S. and Canada, respectively, and remained consistent internationally. Revenue from our Contract Drilling Services segment increased over the comparative prior year period by 16% while revenue in our Completion and Production Services segment was down 6%.
- Adjusted EBITDA (see “NON-GAAP MEASURES”) this quarter of \$62 million is an increase of \$6 million from the second quarter of 2017. Our adjusted EBITDA as a percentage of revenue was 19% this quarter in-line with the comparative quarter of 2017. Adjusted EBITDA this quarter was positively impacted by higher activity and day rates in the U.S. offset by higher share-based incentive compensation from an increase in the Corporation’s share price versus the comparative prior year. Total share-based incentive compensation expensed in the quarter was \$10 million compared to a recovery of \$3 million in the second quarter of 2017. See discussion on share-based incentive compensation under “Other Items” later in this report for additional details.
- Operating loss (see “NON-GAAP MEASURES”) this quarter was \$26 million compared with an operating loss of \$39 million in the second quarter of 2017. Operating results this quarter were positively impacted by the increase in activity in our U.S. contract drilling business and lower depreciation expense.
- General and administrative expenses this quarter were \$32 million, \$12 million higher than the second quarter of 2017. The increase is due to higher share-based incentive compensation expense tied to the price of our common shares partially offset by a strengthening of the Canadian dollar on our U.S. dollar denominated costs.
- Net finance charges were \$32 million, a decrease of \$2 million compared with the second quarter of 2017, primarily due to a reduction in interest expense related to debt retired in 2017, the impact of the strengthening of the Canadian dollar on our U.S. dollar denominated costs and higher interest income in the current quarter.
- During the quarter we redeemed US\$50 million, and repurchased and cancelled US\$8 million of our previously outstanding unsecured senior notes incurring a loss of \$1 million.
- In Canada, average revenue per utilization day for contract drilling rigs was \$22,072 in the second quarter compared to \$22,177 in the second quarter of 2017. Overall, shortfall payments received in the prior year comparative quarter and a greater number of rigs on long-term contracts at legacy pricing were largely offset by higher spot market day rates in the current quarter. During the quarter, we did not recognize any shortfall payments in revenue compared with \$4 million in the prior year comparative period. Excluding the impact of shortfall payment revenue, average day rates were up 7%. In the U.S., revenue per utilization day increased in the second quarter of 2018 to US\$21,795 from US\$19,826 in the prior year second quarter. The increase in the U.S. revenue rate was the result of higher spot market day rates and higher turnkey revenue offset by lower revenue from idle but contracted rigs and lower mobilization revenue. During the quarter, we had turnkey revenue of US\$10 million compared with US\$5 million in the 2017 comparative period and no revenue from idle but contracted rigs in the current quarter versus US\$2 million in the comparative period. On a sequential basis, revenue per utilization day excluding revenue from idle but contracted rigs increased by US\$1,192 due to higher fleet average day rates and higher turnkey revenue when compared to the first quarter of 2018.
- Average operating costs per utilization day for drilling rigs in Canada increased to \$16,712 compared with the prior year second quarter of \$16,368. The increase in average costs was due to larger average crew formations with increased pad rig activity in the quarter. On a sequential basis, operating costs per day increased by \$3,381 compared to the first quarter of 2018 due to lower fixed cost absorption from lower activity with spring break-up. In the U.S., operating costs for the quarter on a per day basis decreased to US\$14,026 in 2018 compared with US\$14,248 in 2017 due to lower lump sum move costs and fixed costs spread over a greater number of utilization days partially offset by increased turnkey activity. On a sequential basis, operating costs per day remain consistent with the first quarter of 2018.
- We realized revenue from international contract drilling of US\$36 million in the second quarter of 2018, in-line with the prior year period. Average revenue per utilization day in our international contract drilling business was US\$49,832, consistent with the comparable prior year quarter.

- Directional drilling services realized revenue of \$7 million in the second quarter of 2018 compared with \$12 million in the prior year period.
- Funds provided by operations (see “NON-GAAP MEASURES”) in the second quarter of 2018 were \$50 million, an increase of \$65 million from the prior year comparative quarter of funds used in operations of \$15 million. The increase was primarily the result of improved operating results, a \$28 million tax refund received in the quarter and the timing of interest paid.
- Capital expenditures were \$37 million in the second quarter, an increase of \$8 million over the same period in 2017. Capital spending for the quarter included \$21 million for upgrade and expansion capital, \$13 million for the maintenance of existing assets and infrastructure spending and \$3 million for intangibles related to a new ERP system.

Summary for the six months ended June 30, 2018:

- Revenue for the first half of 2018 was \$732 million, an increase of 11% from the 2017 period.
- Operating loss (see “NON-GAAP MEASURES”) was \$16 million, a decrease of \$36 million over the same period in 2017. Operating loss was 2% of revenue in 2018 compared with 8% of revenue in 2017. Operating results this year were positively impacted by increased activity in our North American businesses.
- General and administrative costs were \$61 million, an increase of \$16 million from 2017. The increase was due to higher share-based incentive compensation that is tied to the price of our common shares (see “Other Items” later in this report) partially offset by the strengthening of the Canadian dollar on our U.S. dollar denominated costs.
- Net finance charges were \$64 million, a decrease of \$4 million from 2017 primarily due to a reduction in interest expense related to debt retired in 2017 and the effect of a stronger Canadian dollar on our U.S. dollar denominated interest expense partially offset by higher interest income earned in the comparative period.
- Funds provided by operations (see “NON-GAAP MEASURES”) in the first half of 2018 were \$154 million, an increase of \$84 million from the prior year comparative period of \$70 million.
- Capital expenditures for the purchase of property, plant and equipment were \$67 million for the first half of 2018, an increase of \$16 million over the same period in 2017. Capital spending for 2018 to date includes \$33 million for upgrade and expansion capital, \$23 million for the maintenance of existing assets and infrastructure and \$10 million for intangibles related to a new ERP system.

STRATEGY

Precision’s strategic priorities for 2018 are as follows:

1. **Reduce debt by generating free cash flow while continuing to fund only the most attractive investment opportunities** – we generated \$154 million in funds provided by operations (see “NON-GAAP MEASURES”) in the first half of 2018, representing an \$84 million increase over the prior year comparative period. Utilizing cash generated in the second quarter, we reduced debt by \$75 million through a partial redemption of our 2021 unsecured senior notes and open market debt repurchases of our 2021 and 2024 notes. We communicated a firm goal to reduce debt by \$75 to \$125 million in 2018 and have successfully achieved the low end of that range in the first half of this year. In addition, we ended the second quarter with \$95 million of cash on the balance sheet.
2. **Reinforce Precision’s High Performance competitive advantage by deploying Process Automation Controls (PAC), Directional Guidance Systems (DGS) and Drilling Performance Apps (Apps) on a wide scale basis** – year to date in 2018 we have drilled over 70 wells using our DGS compared to 58 wells in all of 2017. In addition, approximately 60% of these jobs used a reduced crew compared to only 30% in 2017. We have 21 rigs currently running in the field with PAC and have drilled approximately 230 wells with this technology in 2018 compared to 154 in all of 2017. Earlier this year we also equipped our training rigs in Nisku and Houston with PAC technology. Customer adoption is rising, and we expect to be running a total of 31 systems by year end, continuing full scale deployment and commercialization. Additionally, we are deploying revenue generating Apps on several rigs and currently have 12 Apps in varying stages of commercial development showcasing the

open platform of our PAC system. Several Apps are customer-built and supported by Precision's PAC platform with specific hosting agreements in place.

3. **Enhance financial performance through higher utilization and improved operating margins** – in the first half of 2018 overall utilization days are 13% higher than the prior year comparative period while average operating margins (revenue less operating costs) are up 32%, 12% and 4% in our U.S., international and Canada contract drilling businesses, respectively.

OUTLOOK

For the second quarter of 2018, the average West Texas Intermediate price of oil was 41% higher than the prior year comparative period while the average Henry Hub gas price was 3% lower and the average AECO price was 55% lower.

	Three months ended June 30,		Year ended December 31,
	2018	2017	2017
Average oil and natural gas prices			
Oil			
West Texas Intermediate (per barrel) (US\$)	67.91	48.33	50.95
Natural gas			
Canada			
AECO (per MMBtu) (CDN\$)	1.20	2.69	2.16
United States			
Henry Hub (per MMBtu) (US\$)	2.86	2.94	2.98

Contracts

Year to date in 2018 we have entered into 38 term contracts. The following chart outlines the average number of drilling rigs by quarter that we had under contract for 2017, the first two quarters of 2018 and the average number of drilling rigs by quarter we have under contract for 2018 as of July 25, 2018.

	Average for the quarter ended 2017				Average for the quarter ended 2018			
	Mar. 31	June 30	Sept. 30	Dec. 31	Mar. 31	June 30	Sept. 30	Dec. 31
Average rigs under term contract as at July 25, 2018:								
Canada	27	23	19	12	8	9	9	9
U.S.	26	33	31	27	36	48	47	35
International	8	8	8	8	8	8	7	6
Total	61	64	58	47	52	65	63	50

The following chart outlines the average number of drilling rigs that we had under contract for 2017 and the average number of rigs we have under contract for 2018 as of July 25, 2018.

	Average for the year ended	
	2017	2018
Average rigs under term contract as at July 25, 2018:		
Canada	20	9
U.S.	29	42
International	8	7
Total	57	58

In Canada, term contracted rigs normally generate 250 utilization days per year because of the seasonal nature of well site access. In most regions in the U.S. and internationally, term contracts normally generate 365 utilization days per year.

Drilling Activity

The following chart outlines the average number of drilling rigs that we had working or moving by quarter for the periods noted.

	Average for the quarter ended 2017				2018	
	Mar. 31	June 30	Sept. 30	Dec. 31	Mar. 31	June 30
Average Precision active rig count:						
Canada	76	29	49	54	72	31
U.S.	47	59	61	58	64	72
International	8	8	8	8	8	8
Total	131	96	118	120	144	111

For the first half of 2018, drilling activity has increased relative to this time last year in the U.S. and is down slightly in Canada. According to industry sources, as of July 20, 2018, the U.S. active land drilling rig count was up approximately 11% from the same point last year and the Canadian active land drilling rig count was down approximately 2%. To date in 2018, approximately 63% of the Canadian industry's active rigs and 81% of the U.S. industry's active rigs were drilling for oil targets, compared with 53% for Canada and 80% for the U.S. at the same time last year.

Industry Conditions

We expect Tier 1 rigs to remain the preferred rigs of customers globally. The economic value created by the significant drilling and mobility efficiencies delivered by the most advanced XY pad walking rigs has been highlighted and widely accepted by our customers. The trend to longer-reach horizontal completions and importance of the rig delivering these complex wells consistently and efficiently has been well established by the industry. We expect demand for leading edge high efficiency Tier 1 rigs will continue to strengthen, as drilling rig capability has been a key economic facilitator of horizontal/unconventional resource exploitation. Development and field application of drilling equipment process automation coupled with closed loop drilling controls and de-manning of rigs will continue this technical evolution while creating further cost efficiencies and performance value for customers.

Capital Spending

Capital spending in 2018 is expected to be \$135 million and includes \$57 million for sustaining and infrastructure, \$63 million for upgrade and expansion and \$15 million on intangibles related to a new ERP system. We expect that the \$135 million will be split \$113 million in the Contract Drilling Services segment, \$6 million in the Completion and Production Services segment and \$16 million to the Corporate segment.

SEGMENTED FINANCIAL RESULTS

Precision's operations are reported in two segments: Contract Drilling Services, which includes the drilling rig, directional drilling, oilfield supply and manufacturing divisions; and Completion and Production Services, which includes the service rig, snubbing, rental, camp and catering and wastewater treatment divisions.

(Stated in thousands of Canadian dollars)	Three months ended June 30,			Six months ended June 30,		
	2018	2017	% Change	2018	2017	% Change
Revenue: ⁽¹⁾						
Contract Drilling Services	304,353	262,458	16.0	657,155	586,388	12.1
Completion and Production Services	27,706	29,381	(5.7)	77,748	75,730	2.7
Inter-segment eliminations	(1,343)	(979)	37.2	(3,181)	(2,585)	23.1
	330,716	290,860	13.7	731,722	659,533	10.9
Adjusted EBITDA: ⁽²⁾						
Contract Drilling Services	83,441	67,031	24.5	194,407	160,696	21.0
Completion and Production Services	(1,402)	336	(517.3)	3,242	4,923	(34.1)
Corporate and other	(19,857)	(10,847)	83.1	(37,998)	(24,791)	53.3
	62,182	56,520	10.0	159,651	140,828	13.4

(1) Prior year comparatives have changed to reflect a recast of certain amounts previously netted against operating expense. See our 2017 Annual Report.

(2) See "NON-GAAP MEASURES".

SEGMENT REVIEW OF CONTRACT DRILLING SERVICES

(Stated in thousands of Canadian dollars, except where noted)	Three months ended June 30,			Six months ended June 30,		
	2018	2017	% Change	2018	2017	% Change
Revenue: ⁽¹⁾	304,353	262,458	16.0	657,155	586,388	12.1
Expenses:						
Operating: ⁽¹⁾	211,008	188,080	12.2	444,156	408,897	8.6
General and administrative	9,904	7,347	34.8	18,592	16,795	10.7
Adjusted EBITDA: ⁽²⁾	83,441	67,031	24.5	194,407	160,696	21.0
Depreciation	80,179	85,065	(5.7)	157,879	171,254	(7.8)
Operating earnings (loss): ⁽²⁾	3,262	(18,034)	(118.1)	36,528	(10,558)	(446.0)
Operating earnings (loss): ⁽²⁾ as a percentage of revenue	1.1%	(6.9)%		5.6%	(1.8)%	

(1) Prior year comparatives have changed to reflect a recast of certain amounts previously netted against operating expense. See our 2017 Annual Report.

(2) See "NON-GAAP MEASURES".

Canadian onshore drilling statistics: ⁽¹⁾	Three months ended June 30,		2017	
	2018			
	Precision	Industry ⁽²⁾	Precision	Industry ⁽²⁾
Number of drilling rigs (end of period)	135	618	136	634
Drilling rig operating days (spud to release)	2,526	9,536	2,358	9,252
Drilling rig operating day utilization	21%	17%	19%	16%
Number of wells drilled	227	903	267	1,024
Average days per well	11.1	10.6	8.8	9.0
Number of metres drilled (000s)	731	2,756	758	2,928
Average metres per well	3,218	3,052	2,839	2,859
Average metres per day	289	289	321	316

Canadian onshore drilling statistics: ⁽¹⁾	Six months ended June 30,		2017	
	2018			
	Precision	Industry ⁽²⁾	Precision	Industry ⁽²⁾
Number of drilling rigs (end of period)	135	618	136	634
Drilling rig operating days (spud to release)	8,180	32,381	8,400	32,756
Drilling rig operating day utilization	34%	29%	34%	28%
Number of wells drilled	742	3,133	831	3,308
Average days per well	11.0	10.3	10.1	9.9
Number of metres drilled (000s)	2,228	9,201	2,229	9,088
Average metres per well	3,003	2,937	2,682	2,747
Average metres per day	272	284	265	277

(1) Canadian operations only.

(2) Canadian Association of Oilwell Drilling Contractors ("CAODC"), and Precision – excludes non-CAODC rigs and non-reporting CAODC members.

United States onshore drilling statistics: ⁽¹⁾		2018		2017	
		Precision	Industry ⁽²⁾	Precision	Industry ⁽²⁾
Average number of active land rigs for quarters ended:					
March 31		64	951	47	722
June 30		72	1,021	59	874
Year to date average		68	986	53	798

(1) United States lower 48 operations only.

(2) Baker Hughes rig counts.

Revenue from Contract Drilling Services was \$304 million this quarter, or 16% higher than the second quarter of 2017, while adjusted EBITDA increased by 24% to \$83 million. The increase in revenue was primarily due to higher utilization days in the United States. During the quarter we did not recognize any shortfall payments in our Canadian contract drilling business compared with \$4 million in the prior year comparative period. In the U.S. we recognized turnkey revenue of US\$10 million compared with US\$5 million in the comparative period and we did not recognize any idle but contracted revenue compared with US\$2 million in the comparative quarter of 2017.

Drilling rig utilization days in Canada (drilling days plus move days) were 2,834 during the second quarter of 2018, an increase of 7% compared to 2017 primarily due to increased Deep Basin activity with several customers working pad rigs through spring break-up. Drilling rig utilization days in the U.S. were 6,588, or 24% higher than the same quarter of 2017 as our U.S. activity was up with higher industry activity. Drilling rig utilization days in our international business were 728, in-line with the same quarter of 2017.

Compared with the same quarter in 2017, drilling rig revenue per utilization day in Canada was in-line with last year as increases in spot market rates in the current quarter offset lower shortfall revenue and a higher number of rigs under long-term contract in the prior period. Drilling rig revenue per utilization day for the quarter in the U.S. was up 10% compared to prior year as higher average day rates and higher turnkey revenue were partially offset by lower lump sum move revenue and lower idle but contract revenue. International revenue per utilization day was in-line with the prior year comparative period.

In Canada, 8% of our utilization days in the quarter were generated from rigs under term contract, compared with 31% in the second quarter of 2017. In the U.S., 67% of utilization days were generated from rigs under term contract as compared with 57% in the second quarter of 2017.

Operating costs were 69% of revenue for the quarter which was two percentage points lower than the prior year period. On a per utilization day basis, operating costs for the drilling rig division in Canada were slightly higher than the prior year period primarily driven by larger average crew sizes associated with increased pad rig activity in the quarter. In the U.S., operating costs for the quarter on a per day basis were slightly lower than the prior year period primarily due to higher lump sum move costs in the prior period and the impact of fixed costs spread over higher activity partially offset by higher costs associated with turnkey activity.

Depreciation expense in the quarter was 6% lower than in the second quarter of 2017. The decrease in depreciation expense was primarily due to the strengthening of the Canadian dollar on our U.S. dollar denominated costs and a lower capital asset base as assets become fully depreciated.

SEGMENT REVIEW OF COMPLETION AND PRODUCTION SERVICES

(Stated in thousands of Canadian dollars, except where noted)	Three months ended June 30,			Six months ended June 30,		
	2018	2017	% Change	2018	2017	% Change
Revenue	27,706	29,381	(5.7)	77,748	75,730	2.7
Expenses:						
Operating	26,814	27,231	(1.5)	70,078	67,099	4.4
General and administrative	2,294	1,814	26.5	4,428	3,708	19.4
Adjusted EBITDA ⁽¹⁾	(1,402)	336	(517.3)	3,242	4,923	(34.1)
Depreciation	5,012	7,094	(29.3)	11,887	14,497	(18.0)
Operating loss ⁽¹⁾	(6,414)	(6,758)	(5.1)	(8,645)	(9,574)	(9.7)
Operating loss ⁽¹⁾ as a percentage of revenue	(23.2)%	(23.0)%		(11.1)%	(12.6)%	
Well servicing statistics:						
Number of service rigs (end of period)	210	210	-	210	210	-
Service rig operating hours	31,824	33,813	(5.9)	84,525	85,870	(1.6)
Service rig operating hour utilization	17%	18%	(5.6)	22%	23%	(4.3)
Service rig revenue per operating hour	676	629	7.5	691	633	9.2

(1) See "NON-GAAP MEASURES".

Revenue from Completion and Production Services was down \$2 million or 6% compared with the second quarter of 2017 due to lower activity in our Canadian well servicing and rental businesses partially offset by higher camp activity. Our service rig operating hours in the quarter were down 6% from the second quarter of 2017 while rates increased an average of 7%. Approximately 98% of our second quarter Canadian service rig activity was oil related.

During the quarter, Completion and Production Services generated 88% of its revenue from Canadian operations and 12% from U.S. operations compared with the second quarter of 2017 where 86% of revenue was generated in Canada and 14% in the U.S.

Average service rig revenue per operating hour in the quarter was \$676 or \$47 higher than the second quarter of 2017. The increase was primarily the result of increased costs passed through to the customer.

Adjusted EBITDA was lower than the second quarter of 2017 primarily due to reorganization costs of \$1 million incurred in the current quarter.

Operating costs as a percentage of revenue was 97% compared with the prior year comparative quarter of 93%.

Depreciation in the quarter was \$2 million lower than the prior year comparative period. The lower depreciation is due to a lower asset base as assets become fully depreciated.

SEGMENT REVIEW OF CORPORATE AND OTHER

Our Corporate and Other segment provides support functions to our operating segments. The Corporate and Other segment had an adjusted EBITDA loss of \$20 million, a \$9 million increase compared with the second quarter of 2017 primarily due to higher share-based incentive compensation.

OTHER ITEMS

Share-based Incentive Compensation Plans

We have several cash-settled share-based incentive plans for non-management directors, officers, and other eligible employees. The fair values of the amounts payable under these plans are recognized as an expense with a corresponding increase in liabilities over the period that the participant becomes entitled to payment. The recorded liability is re-established at the end of each reporting period until settlement with the resultant change to fair value of the liability recognized in net earnings (loss) for the period.

We also have two equity-settled share-based incentive plans. Under the Executive Performance Share plan, which commenced in May 2017, the fair value of the PSUs granted is calculated at the date of grant using a Monte Carlo simulation, and that value is recorded as compensation expense over the grant's vesting period with an offset to contributed surplus. Upon redemption of the PSUs into common shares, the associated amount is reclassified from contributed surplus to shareholders' capital. The share option plan is treated similarly, except that the fair value of the share purchased options granted are valued using the Black-Scholes option pricing model and consideration paid by employees upon exercise of the equity purchase options are recognized in share capital.

A summary of the amounts expensed (recovered) under these plans during the reporting periods are as follows:

	Three months ended June 30,		Six months ended June 30,	
<i>(Stated in thousands of Canadian dollars)</i>	2018	2017	2018	2017
Cash settled share-based incentive plans	7,681	(4,452)	15,471	(2,314)
Equity settled share-based incentive plans				
Executive PSU	1,696	821	2,749	821
Stock option plan	901	587	1,718	1,720
Total share-based incentive compensation plan expense	10,278	(3,044)	19,938	227
Allocated:				
Operating	3,305	(944)	6,801	434
General and Administrative	6,973	(2,100)	13,137	(207)
	10,278	(3,044)	19,938	227

Cash settled shared-based compensation expense increased \$12 million in the current quarter to \$8 million compared to a recovery of \$4 million in the same quarter in 2017. The increase is primarily due to the increasing share price experienced in the current quarter compared to a declining share price in the comparative 2017 period.

Executive PSU share-based incentive compensation expense for the quarter was \$2 million compared to \$1 million in the same quarter in 2017. This increase is a result of the plan being implemented part way through the second quarter in 2017 and from additional grants in 2018.

Financing Charges

Net financial charges for the quarter were \$32 million, a decrease of \$2 million compared with the second quarter of 2017 primarily because of a stronger Canadian dollar on our U.S. dollar denominated interest expense, reduction in interest expense related to debt retired in 2017 and higher interest income in the current period.

Loss on Repurchase and Redemption of Unsecured Senior Notes

During the quarter we redeemed US\$50 million of our 6.5% unsecured senior notes due 2021 and repurchased and cancelled US\$3 million principal amount of our 2021 notes and US\$5 million principal amount of our 2024 notes incurring a net loss of \$1 million.

Income Tax

Income tax expense for the quarter was a recovery of \$13 million compared with a recovery of \$37 million in the same quarter in 2017. The recoveries are due to negative pretax earnings.

LIQUIDITY AND CAPITAL RESOURCES

The oilfield services business is inherently cyclical in nature. To manage this, we focus on maintaining a strong balance sheet so we have the financial flexibility we need to continue to manage our growth and cash flow, regardless of where we are in the business cycle. We maintain a variable operating cost structure so we can be responsive to changes in demand.

Our maintenance capital expenditures are tightly governed by and highly responsive to activity levels with additional cost savings leverage provided through our internal manufacturing and supply divisions. Term contracts on expansion capital for new-build rig programs provide more certainty of future revenues and return on our capital investments.

Liquidity

Amount	Availability	Used for	Maturity
Senior facility (secured)			
US\$500 million (extendible, revolving term credit facility with US\$250 million ⁽¹⁾ accordion feature)	Undrawn, except US\$28 million in outstanding letters of credit	General corporate purposes	November 21, 2021
Operating facilities (secured)			
\$40 million	Undrawn, except \$29 million in outstanding letters of credit	Letters of credit and general corporate purposes	
US\$15 million	Undrawn	Short term working capital requirements	
Demand letter of credit facility (secured)			
US\$30 million	Undrawn, except US\$13 million in outstanding letters of credit	Letters of credit	
Unsecured senior notes (unsecured)			
US\$196 million – 6.5%	Fully drawn	Capital expenditures and general corporate purposes	December 15, 2021
US\$350 million – 7.75%	Fully drawn	Debt redemption and repurchases	December 15, 2023
US\$395 million – 5.25%	Fully drawn	Capital expenditures and general corporate purposes	November 15, 2024
US\$400 million – 7.125%	Fully drawn	Debt redemption and repurchases	January 15, 2026

(1) Increases to US\$300 million at the end of the covenant relief period of March 31, 2019.

As at June 30, 2018, we had \$1,762 million outstanding under our unsecured senior notes. The current blended cash interest cost of our debt is approximately 6.6%.

Covenants

Following is a listing of our currently applicable financial covenants and the calculations as at June 30, 2018.

	Covenant	As at June 30, 2018
Senior Facility		
Consolidated senior debt to consolidated Covenant EBITDA ⁽¹⁾	< 2.50	0.08
Consolidated Covenant EBITDA to consolidated interest expense	> 2.00	2.98
Unsecured Senior Notes		
Consolidated interest coverage ratio	> 2.00	2.39

(1) For purposes of calculating the leverage ratio consolidated senior debt only includes secured indebtedness.

At June 30, 2018, we were in compliance with the covenants of our senior credit facility and unsecured senior notes.

Senior Facility

The senior credit facility requires that we comply with certain covenants including a leverage ratio of consolidated senior debt to consolidated Covenant EBITDA (see “NON-GAAP MEASURES”) of less than 2.5:1. For purposes of calculating the leverage ratio consolidated senior debt only includes secured indebtedness.

Under the senior credit facility, we are required to maintain a ratio of consolidated Covenant EBITDA to consolidated interest expense for the most recent four consecutive quarters, of greater than 2.0:1 for the periods ending June 30,

September 30, and December 31, 2018 and March 31, 2019. For periods ending after March 31, 2019 the ratio reverts to 2.5:1.

The senior credit facility prevents us from making distributions prior to April 1, 2019, after which, distributions are subject to a pro forma consolidated senior net leverage covenant of less than or equal to 1.75:1. The senior credit facility also limits the redemption and repurchase of junior debt subject to a pro forma consolidated senior net leverage covenant ratio of less than or equal to 1.75:1.

In addition, the senior credit facility contains certain covenants that place restrictions on our ability to incur or assume additional indebtedness; dispose of assets; pay dividends, undertake share redemptions or other distributions; change our primary business; incur liens on assets; engage in transactions with affiliates; enter into mergers, consolidations or amalgamations; and enter into speculative swap agreements.

Unsecured Senior Notes

The senior notes require that we comply with financial covenants including an incurrence based consolidated interest coverage ratio test of consolidated cash flow, as defined in the senior note agreements, to consolidated interest expense of greater than 2.0:1 for the most recent four consecutive fiscal quarters. In the event that our consolidated interest coverage ratio is less than 2.0:1 for the most recent four consecutive fiscal quarters the senior notes restrict our ability to incur additional indebtedness.

The senior notes contain a restricted payments covenant that limits our ability to make payments in the nature of dividends, distributions and for repurchases from shareholders. This restricted payment basket grows from a starting point of October 1, 2010 for the 2021 and 2024 senior notes, from October 1, 2016 for the 2023 senior notes and October 1, 2017 for the 2026 senior notes by, among other things, 50% of consolidated cumulative net earnings and decreases by 100% of consolidated cumulative net losses, as defined in the note agreements, and payments made to shareholders. Beginning with the December 31, 2015 calculation the governing net restricted payments basket was negative and as of that date we were no longer able to declare and make dividend payments until such time as the restricted payments baskets once again become positive. For further information, please see the senior note indentures which are available on SEDAR and EDGAR.

In addition, the senior notes contain certain covenants that limit our ability, and the ability of certain subsidiaries, to incur additional indebtedness and issue preferred shares; create liens; create or permit to exist restrictions on our ability or certain subsidiaries to make certain payments and distributions; engage in amalgamations, mergers or consolidations; make certain dispositions and engage in transactions with affiliates.

Hedge of investments in foreign operations

We utilize foreign currency long-term debt to hedge our exposure to changes in the carrying values of our net investment in certain foreign operations as a result of changes in foreign exchange rates.

We have designated our U.S. dollar denominated long-term debt as a net investment hedge in our U.S. operations and other foreign operations that have a U.S. dollar functional currency. To be accounted for as a hedge, the foreign currency denominated long-term debt must be designated and documented as such and must be effective at inception and on an ongoing basis. We recognize the effective amount of this hedge (net of tax) in other comprehensive income. We recognize ineffective amounts (if any) in net earnings (loss).

QUARTERLY FINANCIAL SUMMARY

(Stated in thousands of Canadian dollars, except per share amounts)

	2017		2018	
Quarters ended	September 30	December 31	March 31	June 30
Revenue	314,504	347,187	401,006	330,716
Adjusted EBITDA ⁽²⁾	73,239	90,914	97,469	62,182
Net loss	(26,287)	(47,005)	(18,077)	(47,217)
Net loss per basic and diluted share	(0.09)	(0.16)	(0.06)	(0.16)
Funds provided by (used in) operations ⁽²⁾	85,140	28,323	104,026	50,225
Cash provided by (used in) operations	56,757	23,289	38,189	129,695

(Stated in thousands of Canadian dollars, except per share amounts)

	2016		2017	
Quarters ended	September 30	December 31	March 31	June 30
Revenue ⁽¹⁾	213,668	302,653	368,673	290,860
Adjusted EBITDA ⁽²⁾	41,411	65,000	84,308	56,520
Net loss	(47,377)	(30,618)	(22,614)	(36,130)
Net loss per basic and diluted share	(0.16)	(0.10)	(0.08)	(0.12)
Funds provided by (used in) operations ⁽²⁾	31,688	11,466	85,659	(15,187)
Cash provided by (used in) operations	17,515	(27,846)	33,770	2,739

(1) Prior year comparatives have changed to reflect a recast of certain amounts previously netted against operating expense. See our 2017 Annual Report.

(2) See "NON-GAAP MEASURES".

CRITICAL ACCOUNTING JUDGEMENTS AND ESTIMATES

Because of the nature of our business, we are required to make judgments and estimates in preparing our Consolidated Interim Financial Statements that could materially affect the amounts recognized. Our judgments and estimates are based on our past experiences and assumptions we believe are reasonable in the circumstances. The critical judgments and estimates used in preparing the Interim Financial Statements are described in our 2017 Annual Report and there have been no material changes to our critical accounting judgments and estimates during the three and six month periods ended June 30, 2018 except for those impacted by the adoption of new accounting standards.

CHANGES IN ACCOUNTING POLICY

New standards adopted

The following standards became effective on January 1, 2018:

- IFRS 9 *Financial Instruments*
- IFRS 15 *Revenue from Contracts with Customers*

The Corporation adopted these standards using the cumulative-effect method with no material impact or adjustment to the consolidated financial statements on the date of adoption. Please see the unaudited June 30, 2018 Interim Consolidated Financial Statements and related notes for further details on the adoption of these standards.

New standards not yet adopted

IFRS 16 Leases

IFRS 16 introduces a comprehensive model for the identification of lease arrangements and accounting treatments for both lessors and lessees. It replaces existing lease guidance including IAS 17 *Leases* and IFRIC 4 *Determining whether an Arrangement contains a lease*. The new standard is effective for annual periods beginning on or after January 1, 2019, with earlier application permitted for entities that apply IFRS 15 at or before the date of initial adoption of IFRS 16.

IFRS 16 brings most leases on-balance sheet for lessees under a single model, eliminating the distinction between operating and finance leases. A right-of use asset and a corresponding liability will be recognized for all leases by the lessee except for short-term leases and leases of low value assets.

The Corporation's initial assessment indicates that many of the operating lease arrangements will meet the definition of a lease under IFRS 16 and thus be recognized in the Statement of Financial Position as a right-of-use asset with a corresponding liability. In addition, the nature of expenses related to these arrangements will change as the current presentation of lease expense will be replaced with a depreciation charge for the right-of use asset and interest expense on the lease liabilities. As well, the classification of cash flows will be impacted as the current presentation of lease payments as operating cash flows will be split into financing (principal portion) and operating (interest portion) cash flows under IFRS 16.

Lessor accounting will not significantly change under the new standard. However, some differences may arise as a result of new guidance on the definition of a lease. Under IFRS 16 a contract is, or contains a lease if the contract conveys control of the use of an identified asset for a period of time in exchange for some form of consideration. Precision is assessing whether this new guidance will impact the treatment of its drilling rigs under long term contracts.

Additional disclosures will also be required under IFRS 16.

Precision plans to apply IFRS 16 initially on January 1, 2019 using the cumulative effect method whereby the cumulative impact of adopting the standard will be recognized in retained earnings as of January 1, 2019 and the comparative periods will not be restated.

IFRIC 23 Uncertainty over Income Tax Treatments

IFRIC 23 clarifies the accounting for uncertainties in income taxes. The interpretation requires the entity to use the most likely amount or the expected value of the tax treatment if it concludes that it is not probable that a particular tax treatment will be accepted. It requires an entity to assume that a taxation authority with the right to examine any amounts reported to it will examine those amounts and will have full knowledge of all relevant information when doing so.

IFRIC 23 is effective for annual reporting periods beginning on or after 1 January 2019. Earlier application is permitted. The requirements are applied by recognizing the cumulative effect of initially applying them in retained earnings, or in other appropriate components of equity, at the start of the reporting period in which an entity first applies them, without adjusting comparative information. Full retrospective application is permitted, if an entity can do so without using hindsight. The Corporation has yet to determine the impact this standard will have on its consolidated financial statements.

NON-GAAP MEASURES

In this press release we reference non-GAAP (Generally Accepted Accounting Principles) measures. Adjusted EBITDA, Covenant EBITDA, Operating Earnings (Loss), Funds Provided by (Used in) Operations and Working Capital are terms used by us to assess performance as we believe they provide useful supplemental information to investors. These terms do not have standardized meanings prescribed under International Financial Reporting Standards (IFRS) and may not be comparable to similar measures used by other companies.

Adjusted EBITDA

We believe that adjusted EBITDA (earnings before income taxes, loss on repurchase and redemption of unsecured senior notes, finance charges, foreign exchange, and depreciation and amortization), as reported in the Interim Consolidated Statement of Loss, is a useful measure, because it gives an indication of the results from our principal business activities prior to consideration of how our activities are financed and the impact of foreign exchange, taxation and depreciation and amortization charges.

Covenant EBITDA

Covenant EBITDA, as defined in our senior credit facility agreement, is used in determining the Corporation's compliance with its covenants. Covenant EBITDA differs from Adjusted EBITDA by the exclusion of bad debt expense, restructuring costs and certain foreign exchange amounts.

Operating Earnings (Loss)

We believe that operating earnings (loss), as reported in the Interim Consolidated Statements of Loss, is a useful measure because it provides an indication of the results of our principal business activities before consideration of how those activities are financed and the impact of foreign exchange and taxation.

Funds Provided By (Used In) Operations

We believe that funds provided by (used in) operations, as reported in the Interim Consolidated Statements of Cash Flow, is a useful measure because it provides an indication of the funds our principal business activities generate prior to consideration of working capital, which is primarily made up of highly liquid balances.

Working Capital

We define working capital as current assets less current liabilities as reported on the Interim Consolidated Statement of Financial Position.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION AND STATEMENTS

Certain statements contained in this report, including statements that contain words such as "could", "should", "can", "anticipate", "estimate", "intend", "plan", "expect", "believe", "will", "may", "continue", "project", "potential" and similar expressions and statements relating to matters that are not historical facts constitute "forward-looking information" within the meaning of applicable Canadian securities legislation and "forward-looking statements" within the meaning of the "safe harbor" provisions of the United States Private Securities Litigation Reform Act of 1995 (collectively, "forward-looking information and statements").

In particular, forward looking information and statements include, but are not limited to, the following:

- our strategic priorities for 2018;
- our capital expenditure plans for 2018;
- anticipated activity levels in 2018 and our scheduled infrastructure projects;
- anticipated demand for Tier 1 rigs; and
- the average number of term contracts in place for 2018.

These forward-looking information and statements are based on certain assumptions and analysis made by Precision in light of our experience and our perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate under the circumstances. These include, among other things:

- the fluctuation in oil prices may pressure customers into reducing or limiting their drilling budgets;
- the status of current negotiations with our customers and vendors;
- customer focus on safety performance;
- existing term contracts are neither renewed nor terminated prematurely;
- our ability to deliver rigs to customers on a timely basis; and
- the general stability of the economic and political environments in the jurisdictions where we operate.

Undue reliance should not be placed on forward-looking information and statements. Whether actual results, performance or achievements will conform to our expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results to differ materially from our expectations. Such risks and uncertainties include, but are not limited to:

- volatility in the price and demand for oil and natural gas;
- fluctuations in the demand for contract drilling, well servicing and ancillary oilfield services;
- our customers' inability to obtain adequate credit or financing to support their drilling and production activity;
- changes in drilling and well servicing technology which could reduce demand for certain rigs or put us at a competitive disadvantage;
- shortages, delays and interruptions in the delivery of equipment supplies and other key inputs;
- the effects of seasonal and weather conditions on operations and facilities;
- the availability of qualified personnel and management;
- a decline in our safety performance which could result in lower demand for our services;
- changes in environmental laws and regulations such as increased regulation of hydraulic fracturing or restrictions on the burning of fossil fuels and greenhouse gas emissions, which could have an adverse impact on the demand for oil and gas;
- terrorism, social, civil and political unrest in the foreign jurisdictions where we operate;
- fluctuations in foreign exchange, interest rates and tax rates; and
- other unforeseen conditions which could impact the use of services supplied by Precision and Precision's ability to respond to such conditions.

Readers are cautioned that the forgoing list of risk factors is not exhaustive. Additional information on these and other factors that could affect our business, operations or financial results are included in reports on file with applicable securities regulatory authorities, including but not limited to Precision's Annual Information Form for the year ended December 31, 2017, which may be accessed on Precision's SEDAR profile at www.sedar.com or under Precision's EDGAR profile at www.sec.gov. The forward-looking information and statements contained in this news release are made as of the date hereof and Precision undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, except as required by law.

SHAREHOLDER INFORMATION

STOCK EXCHANGE LISTINGS

Shares of Precision Drilling Corporation are listed on the Toronto Stock Exchange under the trading symbol PD and on the New York Stock Exchange under the trading symbol PDS.

TRANSFER AGENT AND REGISTRAR

Computershare Trust Company of Canada
Calgary, Alberta

TRANSFER POINT

Computershare Trust Company NA
Canton, Massachusetts

Q2 2018 TRADING PROFILE

Toronto (TSX: PD)
High: \$5.33
Low: \$3.36
Close: \$4.35
Volume Traded: 134,364,802

New York (NYSE: PDS)
High: US\$4.14
Low: US\$2.60
Close: US\$3.32
Volume Traded: 108,335,004

ACCOUNT QUESTIONS

Precision's Transfer Agent can help you with a variety of shareholder related services, including:

- change of address
- lost unit certificates
- transfer of shares to another person
- estate settlement

Computershare Trust Company of Canada
100 University Avenue
9th Floor, North Tower
Toronto, Ontario M5J 2Y1
Canada

1-800-564-6253 (toll free in Canada and the United States)
1-514-982-7555 (international direct dialing)
Email: service@computershare.com

ONLINE INFORMATION

To receive news releases by email, or to view this interim report online, please visit Precision's website at www.precisiondrilling.com and refer to the Investor Relations section. Additional information relating to Precision, including the Annual Information Form, Annual Report and Management Information Circular has been filed with SEDAR and is available at www.sedar.com and on the EDGAR website www.sec.gov

CORPORATE INFORMATION

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Brian J. Gibson
Allen R. Hagerman, FCA
Steven W. Krablin
Susan M. MacKenzie
Kevin O. Meyers
Kevin A. Neveu

OFFICERS

Kevin A. Neveu
President and Chief Executive Officer

Douglas B. Evasiuk
Senior Vice President, Sales and Marketing

Veronica H. Foley
Senior Vice President, General Counsel and Corporate Secretary

Carey T. Ford
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