Precision Drilling Corporation Announces 2017 Third Quarter Financial Results

27.10.2017 | Marketwired

CALGARY, ALBERTA--(Marketwired - Oct 27, 2017) -

(Canadian dollars except as indicated)

This news release contains "forward-looking information and statements" within the meaning of applicable securities la of the forward-looking information and statements and the risks to which they are subject, see the "Cautionary Stateme Forward-Looking Information and Statements" later in this news release. This news release contains references to Adju Earnings (Loss) and Funds Provided by (Used In) Operations. These terms do not have standardized meanings prescr Financial Reporting Standards (IFRS) and may not be comparable to similar measures used by other companies, see " later in this news release.

Precision Drilling (TSX:PD)(NYSE:PDS) announces 2017 third quarter financial results:

- Third quarter revenue of $315 million was an increase of 47% over the prior year comparative quarter.
- Third quarter earnings before income taxes, gain on repurchase of unsecured senior notes, finance charges, fore depreciation and amortization (adjusted EBITDA see "NON-GAAP MEASURES") of $73 million was 77% higher t 2016.
- Third quarter net loss of $26 million ($0.09 per share) compared with a net loss of $47 million ($0.16 per share) ir
- Third quarter capital expenditures were $23 million, with full year capital spending expected to be $104 million.

Kevin Neveu, Precision's President and Chief Executive Officer, stated: "I am pleased with our reported third quarter re cash flow generation driving a $37 million increase in our quarter end cash balance, and the first sequential increase in average day rates (excluding idle but contracted revenue) and margins since early in 2015. Despite commodity price vo anticipated WTI and Canadian AECO prices during the third quarter, demand and pricing for Precision's Super Series r through the quarter. We anticipate demand to further strengthen as our customers initiate their 2018 drilling programs."

"As our customers across the U.S. and Canada have learned to operate in a "lower for longer" commodity price enviror on drilling and completion efficiency utilizing long or extended-reach horizontal wells and adopted large-scale industrial as multi-well pads and high efficiency rig systems. Precision's Super Triple rigs are configured to optimize long reach d combined with pad walking capability, and are active in virtually every resource play in North America."

"During the third quarter we continued to demonstrate the "next tier" of drilling efficiency improvement with Process Aut and other technology initiatives we are implementing in our beta testing program. Precision has drilled approximately 7(technology, which is currently installed on 20 Super Triple rigs, and the results continue to show improved efficiency, co repeatability, exactly what our customers desire. Precision along with its partner have made significant strides towards a commercial success in 2018 as outlined as one of our three key priorities for the year. We believe these initiatives wil competitive positioning of Precision's Super Triple fleet while driving additional revenue streams for each of our technol

"We are encouraged by the improvement in commodity fundamentals as the global oil supply and demand balance tigh strip has returned to above US$50 per barrel. We believe these fundamentals form a constructive environment as our c drilling budgets, with customer bookings for additional rig deployments in late Q4 and Q1 2018 supporting this view."

"In the U.S. we signed three term contracts in the third quarter and have signed an additional three contracts quarter to than anticipated commodity prices caused industry rig activity to retract mid-Q3 with the trend continuing in recent wee a modest reduction in our active rig count with 55 rigs currently active, but overall demand for our Pad Walking Super T strong and we expect utilization in the high spec rig market to remain tight and pricing to remain firm. We expect our ac 2017 peak levels later this year and into the first quarter of 2018 with the potential for additional utilization improvemen should commodity prices hold in the low-to-mid $50's."

"Our third quarter activity in Canada was slightly lower than expected as a result of weather delays and a lack of urgen driven by soft commodity prices, particularly seasonally depressed AECO gas prices which resulted in lower cash flows customers. Precision's rig count rose to 57 rigs in the third quarter, with the expectation that activity continues to trend into the 2018 winter drilling season. Canadian activity has trended upwards into Q4 hitting 62 rigs last week but has sin as weather slowed some rig moves. While customer budgets have yet to firm up, early indications point to Q1 peak de levels with a potential for activity to exceed those levels should commodity prices remain firm."

"Operational performance from our international business continues to be strong with zero recordable incidents in the q year-over-year improvement in downtime. We expect robust cash flow from the division throughout the year with eight a East on contract and no rollovers in 2017. Additionally, we are actively bidding our four idle rigs to attractive opportuniti

"Precision, as published in 2017 objectives, manages its capital spending based on activity. As such we have reduced spending program by $34 million to $104 million. The reduction relates primarily to upgrade and maintenance capital. W $39 million in upgrade capital which includes approximately 30 rig upgrades. Precision practices tight capital discipline on debt reduction until customer demand translates to economics that warrant additional upgrade spending" concluded

SELECT FINANCIAL AND OPERATING INFORMATION

Adjusted EBITDA and funds provided by operations are Non-GAAP measures. See "NON-GAAP MEASURES."

Financial Highlights

	Three months ended September 30,			Nine mont
(Stated in thousands of Canadian dollars, except per share amounts)	2017	2016	% Change	2017
Revenue[(1)]	314,504	213,668	47.2	974,037
Adjusted EBITDA[(2)]	73,239	41,411	76.9	214,067
Adjusted EBITDA[(2)] % of revenue	23.3%	19.4%		22.0
Net loss	(26,287)	(47,377)	(44.5)	(85,031)
Cash provided by operations	56,757	17,515	224.0	93,266
Funds provided by operations	85,140	31,688	168.7	155,612
Capital spending:				
Expansion	2,336	67,672	(96.5)	10,980
Upgrade	7,168	4,902	46.2	34,102
Maintenance and infrastructure	13,014	5,588	132.9	27,965
Proceeds on sale	(4,273)	(2,125)	101.1	(10,054)
Net capital spending	18,245	76,037	(76.0)	62,993
Loss per share:				
Basic and diluted	(0.09)	(0.16)	(43.8)	(0.29)

(1) Prior year comparatives have changed to conform to current year presentation. For detail see "RECAST OF COMPARATIVE FINANCIAL INFORMATION."

(2) See "NON-GAAP MEASURES."

Operating Highlights

	Three months ended September 30,			Nine months ended September 30,		
	2017	2016	% Change	2017	2016	% Change
Contract drilling rig fleet	256	253	1.2	256	253	1.2
Drilling rig utilization days:						
Canada	4,487	2,853	57.3	13,945	8,050	73.2
U.S.	5,593	2,689	108.0	15,114	7,773	94.4
International	736	644	14.3	2,184	2,044	6.8
Revenue per utilization day:						
Canada [(1)(2)] *(Cdn$)*	19,980	21,046	(5.1)	21,092	25,214	(16.3)
U.S.[(1)(3)] *(US$)*	19,026	24,343	(21.8)	19,732	28,374	(30.5)
International *(US$)*	50,528	43,879	15.2	50,214	43,191	16.3
Operating cost per utilization day:						
Canada[(1)] *(Cdn$)*	13,656	14,107	(3.2)	13,764	14,815	(7.1)
U.S. [(1)] *(US$)*	12,591	15,456	(18.5)	13,917	16,097	(13.5)
Service rig fleet	210	163	28.8	210	163	28.8
Service rig operating hours	42,653	26,588	60.4	128,523	66,281	93.9
Revenue per operating hour *(Cdn$)*	638	599	6.5	635	654	(2.9)

(1) Prior year comparatives have changed to conform to current year presentation. For detail see "RECAST OF COMPARATIVE FINANCIAL INFORMATION."
(2) Includes lump sum revenue from contract shortfall.
(3) Comparatives and nine month period ended September 30, 2017 includes revenue from idle but contracted rig days.

Financial Position

(Stated in thousands of Canadian dollars, except ratios)	September 30, 2017	December 31, 2016
Working capital	266,159	230,874
Cash	131,742	115,705
Long-term debt[(1)]	1,777,667	1,906,934
Total long-term financial liabilities	1,801,212	1,946,742
Total assets	3,967,987	4,324,214
Long-term debt to long-term debt plus equity ratio[(1)]	0.49	0.49

(1) Net of unamortized debt issue costs.

RECAST OF COMPARATIVE FINANCIAL INFORMATION

During the third quarter of 2017, we changed our treatment of how certain amounts that were historically netted agains should be classified. In particular, certain amounts that were historically netted against operating expenses are now tre corresponding increase to operating expenses. The primary nature of these amounts related to additional labour above crew configuration, subsistence allowances paid to the drilling crew which varies depending on whether the crews were hotel and equipment rental. As a result, previously reported revenues and operating expenses were understated by eq

To conform to current year presentation, certain immaterial reclassifications between operating and general administra been made in the comparative periods.

As a result of these reclassifications, we have recast prior year's comparative amounts as follows:

Three months ended September 30, 2016 *(Stated in thousands of Canadian dollars except per day amounts)*	As previously reported	Revenue recast	Expense recast	As rec
Revenue	201,802	11,866	-	213,6
Expenses:				
Operating	137,935	11,866	576	150,3
General and administrative	21,748	-	(576)	21,17
Restructuring	708	-	-	708
Adjusted EBITDA[(1)]	41,411	-	-	41,41
(1) See "NON-GAAP MEASURES."				
Revenue per utilization day:				
Canada (Cdn$)	17,523	3,523	-	21,04
U.S. (US$)	23,826	517	-	24,34
International (US$)	43,879	-	-	43,87
Operating cost per utilization day:				
Canada (Cdn$)	10,584	3,523	-	14,10
U.S. (US$)	14,939	517	-	15,45

Nine months ended September 30, 2016 *(Stated in thousands of Canadian dollars except per day amounts)*	As previously reported	Revenue recast	Expense recast	As rec
Revenue	667,508	33,072	-	700,5
Expenses:				
Operating	419,914	33,072	2,146	455,1
General and administrative	78,765	-	(2,146)	76,61
Restructuring	5,754	-	-	5,754

Adjusted EBITDA[1]	163,075	-	-	163,0
(1) See "NON-GAAP MEASURES."				
Revenue per utilization day:				
Canada (Cdn$)	21,792	3,422	-	25,21
U.S. (US$)	27,842	532	-	28,37
International (US$)	43,191	-	-	43,19
Operating cost per utilization day:				
Canada (Cdn$)	11,393	3,422	-	14,81
U.S. (US$)	15,565	532	-	16,09

The tables below reflect our recast of day rates and operating costs per day for each of the previous six quarters:

As recast	2016				2017		
Quarters ended	March 31	June 30	September 30	December 31	March 31	June 30	September 3
Revenue per utilization day:							
Canada (Cdn$)	26,966	29,283	21,046	23,298	21,405	22,177	19,980
U.S. (US$)	32,442	27,962	24,343	21,293	20,554	19,826	19,026
International (US$)	41,609	44,391	43,879	52,816	50,434	49,679	50,528
Operating cost per utilization day:							
Canada (Cdn$)	13,985	19,257	14,107	13,298	12,828	16,368	13,656
U.S. (US$)	17,268	15,342	15,456	14,350	15,264	14,248	12,591

There is no impact on net loss or comprehensive loss and the consolidated statement of financial position, consolidated equity and the consolidated statement of cash flows remain unchanged as a result of this recast.

Summary for the three months ended September 30, 2017

- Revenue this quarter was $315 million which is 47% higher than the third quarter of 2016. The increase in revenu of higher activity in all of our North American based businesses and higher average day rates from our internatio business, partially offset by lower contract short-fall payments, a decrease in average day rate in all of our North businesses and no utilization in our Mexico based contract drilling business. Compared with the third quarter of 2 measured by drilling rig utilization days, increased 57% in Canada, 108% in the U.S. and 14% internationally. Re Drilling Services and Completion and Production Services segments both increased over the comparative prior y 57%, respectively.

- Adjusted EBITDA this quarter was $73 million, an increase of $32 million from the third quarter of 2016. Our adju percentage of revenue was 23% this quarter, compared with 19% in the third quarter of 2016. The increase in ad percent of revenue was mainly due to fixed costs spread over higher activity in our North American business part average pricing.

- Operating loss (see "NON-GAAP MEASURES") this quarter was $17 million compared with an operating loss of quarter of 2016. Operating results this quarter were positively impacted by increased activity in our North Americ offset by lower average pricing.

- General and administrative expenses this quarter were $22 million, $1 million higher than the third quarter of 201 higher share based compensation expense that is tied to our common shares, partially offset by a moderate stre dollar on our U.S. dollar denominated costs. As at September 30, 2017 we have a total share based incentive co million compared with $23 million at June 30, 2017 after having paid out $0.2 million in the quarter.

- Net finance charges were $32 million, a decrease of $2 million compared with the third quarter of 2016 primarily stronger Canadian dollar on our U.S. dollar denominated interest expense and a reduction in interest expense re 2016.

- In Canada, average revenue per utilization day for contract drilling rigs decreased in the third quarter of 2017 to $ the prior year third quarter as a result of fewer rigs working under legacy contracts and a higher proportion of reve drilling activity, partially offset by higher contract shortfall payments relative to the 2016 comparative period. Durin recognized $5 million in revenue associated with contract shortfall payments in Canada which was an increase of year period. On a sequential basis, revenue per utilization day in Canada decreased by $2,197 as a result of rig r payments and lower boiler revenue when compared to the second quarter of 2017. In the U.S. revenue per utiliza US$19,026 from US$24,343 over the same period. The decrease in the U.S. revenue rate was the result of long- rigs contracting at lower spot market rates, lower revenue from idle but contracted rigs and no turnkey activity in t the quarter we had no turnkey revenue compared with US$3 million in the 2016 comparative period and had no r contracted rigs in the current quarter versus US$6 million in the comparative period. On a sequential basis, reven excluding revenue from idle but contracted rigs increased by US$287 as higher fleet average day rates was partia turnkey revenue when compared to the second quarter of 2017.

- Average operating costs per utilization day for drilling rigs in Canada decreased to $13,656 compared with the pr $14,107. The decrease in average costs was due to improved absorption of fixed costs with higher utilization. In t for the quarter on a per day basis decreased to US$12,591 in 2017 compared with US$15,456 in 2016 due to fixe higher utilization, no regional repositioning of rigs and no turnkey work in the quarter.

- Average operating margin per utilization day excluding revenue from idle but contracted rigs in the third quarter o in Canada and increased by US$1,252 in the U.S. when compared to the second quarter of 2017. In Canada, the higher fixed cost absorption more than offsetting a reduction in revenue per utilization day. In the U.S., the seque primarily a result of higher fleet average day rates.

- We realized revenue from international contract drilling of US$37 million in the third quarter of 2017, a US$9 milli year period. The increase was due to the startup of two new rigs in Kuwait in the fourth quarter of 2016, partially c activity in our Mexico operations. Average revenue per utilization day in our international contract drilling busines increase of 15% over the comparable prior year quarter primarily due to rig mix as we had fewer rigs working in th jurisdictions.

- Directional drilling services realized revenue of $6 million in the third quarter of 2017 in line with the prior year pe

- Funds provided by operations in the third quarter of 2017 were $85 million, an increase of $53 million from the pr quarter and an increase of $100 million from the second quarter of 2017. The increases were primarily the result results.

- Capital expenditures for the purchase of property, plant and equipment were $23 million in the third quarter, a de the same period in 2016. Capital spending for the quarter included $2 million for expansion capital, $7 million for million for the maintenance of existing assets and infrastructure.

Summary for the nine months ended September 30, 2017:

- Revenue for the nine months of 2017 was $974 million, an increase of 39% from the 2016 period.

- Operating loss was $69 million, a decrease of $56 million over the same period in 2016. Operating loss was 7% c compared to 18% of revenue in 2016. Operating results this year were positively impacted by increased activity i businesses partially offset by lower average pricing.

- General and administrative costs were $68 million, a decrease of $9 million over the first nine months of 2016. Th fixed cost reductions implemented through the downturn and lower share based incentive compensation that is ti common shares.

- Net finance charges were $100 million, a decrease of $4 million from the first nine months of 2016 primarily due t expense related to debt retired in 2016 and the effect of a stronger Canadian dollar on our U.S. dollar denominate partially offset by higher interest income earned in the comparative period.

- Funds provided by operations (see "NON-GAAP MEASURES") in the first nine months of 2017 were $156 million million from the prior year comparative period of $94 million.

- Capital expenditures for the purchase of property, plant and equipment were $73 million in the first nine months o million over the same period in 2016. Capital spending for 2017 to date included $11 million for expansion capital capital and $28 million for the maintenance of existing assets and infrastructure.

STRATEGY

Precision's strategic priorities for 2017 are as follows:

1. Deliver High Performance, High Value service offering in an improving demand environment while demonstrating the U.S., we grew our active rig count by 58% throughout the nine months of 2017. In Canada, we began the yea reached a seasonal peak of 91 rigs. Year-over-year in the first nine months of 2017 our utilization days were up 8 American drilling operations and was achieved without any material increase in fixed costs. In addition, we are up system to increase operating efficiencies, improve our fixed cost leverage and position the organization to better flows associated with our business.
2. Commercialize rig automation and efficiency-driven technologies across our Super Series fleet - Beta-style field t automation technologies, including Process Automation Control (PAC), Directional Guidance System and High S ongoing and we expect to progress the commercialization of these automation features during 2017. We have dri wells utilizing PAC technology which is installed on 20 Super Triple Rigs.
3. Maintain strict financial discipline in pursuing growth opportunities with a focus on free cash flow and debt reducti upgrade capital spending is supported by take-or-pay term contracts priced at a level that allows for attractive rat reduced 2017 capital expenditures by approximately $34 million with the reduction relating primarily to upgrade a Our revised 2017 capital plan brings spending in line with expected activity levels while continuing to focus on fre reduction. In the first nine months of 2017, we generated funds from operations of $156 million - see "NON-GAAI

OUTLOOK

For the third quarter of 2017, the average West Texas Intermediate price of oil was 7% higher than the prior year comp average Henry Hub natural gas price was 3% higher. The average AECO price was 29% lower than the prior year com result of infrastructure constraints due to planned maintenance and high storage levels.

	Three months ended September 30,		Year ended December 31,
	2017	2016	2016
Average oil and natural gas prices			
Oil			
West Texas Intermediate *(per barrel)* (US$)	48.03	44.97	43.30
Natural gas			
Canada			
AECO *(per MMBtu)* (CDN$)	1.66	2.34	2.14
United States			
Henry Hub *(per MMBtu)* (US$)	2.93	2.85	2.48

Contracts

The following chart outlines the average number of drilling rigs that we have under contract as of October 26, 2017 for t 2017 and the full years 2017 and 2018.

	Average for the quarter ended				Average
	March 31	June 30	September 30	December 31	2017
Average rigs under term contract as at October 26, 2017:					
Canada	27	23	19	12	20
U.S.	26	33	31	28	29
International	8	8	8	8	8
Total	61	64	58	48	57

In Canada, term contracted rigs normally generate 250 utilization days per year because of the seasonal nature of well regions in the U.S. and internationally, term contracts normally generate 365 utilization days per year. Year to date as o have added 22 term contracts with durations of six months or longer.

Drilling Activity

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

	2016		2017		
Quarter ended	September 30	December 31	March 31	June 30	September 30

Average Precision active rig count:					
Canada	31	51	76	29	49
U.S.	29	39	47	59	61
International	7	8	8	8	8
Total	67	98	131	96	118

With improved commodity prices and increasing activity levels, earlier this year we were able to increase prices on spot majority of our fleet. Should commodity prices continue to improve, we expect sequential improvements in pricing in the Basin in Canada. We expect pricing improvements in the shallower parts of the Canadian market; however, the increas be of the same magnitude as other North American markets in which we operate.

Industry Conditions

In 2017, drilling activity has increased relative to this time last year for both Canada and the U.S. According to industry 20, 2017, the U.S. active land drilling rig count was up approximately 68% from the same point last year and the Canad count was up approximately 41%.

In Canada there has been a strengthening in natural gas and gas liquids drilling activity related to the Deep Basin in no northeastern British Columbia although recent weakness in AECO pricing has caused some producers to delay work pr related to dry gas. In the U.S., the trend towards oil-directed drilling continues. To date in 2017, approximately 53% of t active rigs and 80% of the U.S. industry's active rigs were drilling for oil targets, compared with 48% for Canada and 80 same time last year.

We expect Tier 1 rigs to remain the preferred rigs of customers globally. The economic value created by the significant efficiencies delivered by the most advanced XY pad walking rigs has been highlighted and widely accepted by our cust longer-reach horizontal completions and the importance of the rig delivering these complex wells consistently and effici established by the industry. We expect that demand for leading edge high efficiency Tier 1 rigs will continue to strength capability has been a key economic facilitator of horizontal/unconventional resource exploitation. Development and fiel equipment process automation coupled with closed loop drilling controls and de-manning of the rigs will continue this te creating further cost efficiencies and performance value for customers and further differentiating the specific capabilities 1 rigs and those rig contractors capable of widely deploying those technologies.

Capital Spending

Capital spending in 2017 is expected to be $104 million:

- The 2017 capital expenditure plan includes $13 million for expansion capital, $52 million for sustaining and infrast $39 million to upgrade existing rigs. We expect that the $104 million will be split $99 million in the Contract Drilling $5 million in the Completion and Production Services segment.

SEGMENTED FINANCIAL RESULTS

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

	Three months ended September 30,			Nine months ended September 30,		
(Stated in thousands of Canadian dollars)	2017	2016	% Change	2017	2016	% Change
Revenue:						
Contract Drilling Services(1)	278,569	190,329	46.4	864,957	634,152	36.4
Completion and Production Services	37,816	24,158	56.5	113,546	69,343	63.7
Inter-segment eliminations	(1,881)	(819)	129.7	(4,466)	(2,915)	53.2
	314,504	213,668	47.2	974,037	700,580	39.0
Adjusted EBITDA:(2)						
Contract Drilling Services	81,994	52,180	57.1	242,690	210,300	15.4

Completion and Production Services	4,251	736	477.6	9,174	(4,039)	(327.1)
Corporate and other	(13,006)	(11,505)	13.0	(37,797)	(43,186)	(12.5)
	73,239	41,411	76.9	214,067	163,075	31.3

(1) Prior year comparatives have changed to conform to current year presentation. For detail see "RECAST OF COMPARATIVE FINANCIAL INFORMATION."

(2) See "NON-GAAP MEASURES".

SEGMENT REVIEW OF CONTRACT DRILLING SERVICES

	Three months ended September 30,			Nine months enc	
(Stated in thousands of Canadian dollars, except where noted)	2017	2016	% Change	2017	2016
Revenue[1]	278,569	190,329	46.4	864,957	634,1
Expenses:					
Operating[1]	189,143	129,457	46.1	598,040	393,9
General and administrative[1]	7,432	8,069	(7.9)	24,227	26,83
Restructuring	-	623	(100.0)	-	3,040
Adjusted EBITDA[2]	81,994	52,180	57.1	242,690	210,3
Depreciation	80,653	86,643	(6.9)	251,907	257,3
Operating earnings (loss)[2]	1,341	(34,463)	(103.9)	(9,217)	(47,0
Operating earnings (loss) as a percentage of revenue	0.5%	(18.1%)		(1.1%)	(7.4%

(1) Prior year comparatives have changed to conform to current year presentation. For detail see "RECAST OF COMPARATIVE FINANCIAL INFORMATION."

(2) See "NON-GAAP MEASURES".

	Three months ended September 30,			
Canadian onshore drilling statistics:[1]	2017		2016	
	Precision	Industry[2]	Precision	Industry[2]
Number of drilling rigs (end of period)	136	634	135	672
Drilling rig operating days (spud to release)	3,998	16,288	2,538	10,401
Drilling rig operating day utilization	32%	28%	20%	17%
Number of wells drilled	451	1,977	269	1,115
Average days per well	8.9	8.2	9.4	9.3
Number of metres drilled (000s)	1,123	5,179	627	2,568
Average metres per well	2,490	2,620	2,330	2,303
Average metres per day	281	318	247	247

	Nine months ended September 30,			
Canadian onshore drilling statistics:[1]	2017		2016	
	Precision	Industry[2]	Precision	Industry[2]
Number of drilling rigs (end of period)	136	634	135	672
Drilling rig operating days (spud to release)	12,398	49,889	7,183	27,833
Drilling rig operating day utilization	34%	29%	19%	15%
Number of wells drilled	1,282	5,285	607	2,490
Average days per well	9.7	9.4	11.8	11.2
Number of metres drilled (000s)	3,352	14,267	1,616	6,328
Average metres per well	2,615	2,700	2,663	2,542
Average metres per day	270	286	225	227

(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]	2017		2016	
	Precision	Industry[2]	Precision	Industry[2]
Average number of active land rigs for quarters ended:				
March 31	47	722	32	516

June 30	59	874	24	397
September 30	61	927	29	465
Year to date average	55	841	28	459

(1) United States lower 48 operations only.
(2) Baker Hughes rig counts.

Revenue from Contract Drilling Services was $279 million this quarter, or 46% higher than the third quarter of 2016, wh increased by 57% to $82 million. The increase in revenue was primarily due to higher utilization days in Canada and th average day rates for international contracts. During the quarter we recognized $5 million in shortfall payments in our C business, which was $3 million higher than in the prior year. During the quarter in the U.S. we did not recognize any idl turnkey revenue compared with US$6 million and US$3 million, respectively, in the comparative quarter of 2016.

Drilling rig utilization days in Canada (drilling days plus move days) were 4,487 during the third quarter of 2017, an incr to 2016 primarily due to the increase in industry activity resulting from higher oil prices. Drilling rig utilization days in the 108% higher than the same quarter of 2016 as U.S. activity was up with higher industry activity. Drilling rig utilization da business were 736 or 14% higher than the same quarter of 2016 due to the addition of two rigs in Kuwait during the fou partially offset by no activity in Mexico.

Compared with the same quarter in 2016, drilling rig revenue per utilization day was down 5% in Canada due to fewer l rig revenue per utilization day for the quarter in the U.S. was down 22% from the prior comparative period, while interna utilization day was up 15%. The decrease in the U.S. average rate was due to long-term contracts ending and rigs bein spot market rates, no idle but contracted revenue and no turnkey activity in the current quarter. International revenue pe due to rig mix with a higher proportion of days from Kuwait during the quarter and no activity in Mexico.

In Canada, 18% of our utilization days in the quarter were generated from rigs under term contract, compared with 33% 2016. In the U.S., 55% of utilization days were generated from rigs under term contract as compared with 53% in the th

Operating costs were 68% of revenue for the quarter which was in line with the prior year period. On a per utilization da for the drilling rig division in Canada were lower than the prior year period primarily because of improved absorption of f utilization. In the U.S., operating costs for the quarter on a per day basis were lower than the prior year period primarily activity in the current year quarter and the impact of fixed costs spread over higher activity. Both Canada and U.S. oper from cost saving initiatives taken in 2015 and 2016.

Depreciation expense in the quarter was 7% lower than in the third quarter of 2016.

SEGMENT REVIEW OF COMPLETION AND PRODUCTION SERVICES

	Three months ended September 30,			Nine months end	
(Stated in thousands of Canadian dollars, except where noted)	2017	2016	% Change	2017	2016
Revenue	37,816	24,158	56.5	113,546	69,34
Expenses:					
Operating[1]	31,674	21,739	45.7	98,773	64,06
General and administrative[1]	1,891	1,629	16.1	5,599	7,293
Restructuring	-	54	(100.0)	-	2,021
Adjusted EBITDA[2]	4,251	736	477.6	9,174	(4,03
Depreciation	6,731	6,759	(0.4)	21,228	20,53
Operating loss[2]	(2,480)	(6,023)	(58.8)	(12,054)	(24,5
Operating loss as a percentage of revenue	(6.6%)	(24.9%)		(10.6%)	(35.4
Well servicing statistics:					
Number of service rigs (end of period)	210	163	28.8	210	163
Service rig operating hours	42,653	26,588	60.4	128,523	66,28
Service rig operating hour utilization	22%	18%		22%	15%
Service rig revenue per operating hour	638	599	6.5	635	654

(1) Certain expenses in the prior year comparative have been reclassified to conform to current year presentation.

(2) See "NON-GAAP MEASURES".

Revenue from Completion and Production Services was up $14 million or 57% compared with the third quarter of 2016
levels in all service lines. As oil prices have recovered, customers have increased spending and activity in well complet
programs. Our well servicing activity in the quarter was up 60% from the third quarter of 2016 as a result of improved in
a larger fleet following the acquisition of service rigs late in the fourth quarter of 2016. Approximately 97% of our third q
rig activity was oil related.

During the quarter, Completion and Production Services generated 90% of its revenue from Canadian operations and 1
which is in line with the third quarter of 2016.

Average service rig revenue per operating hour in the quarter was $638 or $39 higher than the third quarter of 2016. Th
the result of increased labour costs which are passed through to the customer.

Adjusted EBITDA was $4 million higher than the third quarter of 2016 due to increased activity in all divisions.

Operating costs as a percentage of revenue decreased to 84% in the third quarter of 2017, from 90% in the third quarte
is the result of the impact of fixed costs spread across greater activity combined with our reduced cost structure.

Depreciation in the quarter was $7 million in line with the previous year comparative period. The added depreciation co
associated with additional well service units was offset by assets becoming fully depreciated.

SEGMENT REVIEW OF CORPORATE AND OTHER

Our Corporate and Other segment provides support functions to our operating segments. The Corporate and Other seg
EBITDA loss of $13 million an increase of $2 million compared with the third quarter of 2016 primarily due to higher sha
compensation.

OTHER ITEMS

Net financial charges for the quarter were $32 million, a decrease of $2 million compared with the third quarter of 2016
effect of a stronger Canadian dollar on our U.S. dollar denominated interest expense and a reduction in interest expens
in 2016. For the current quarter we incurred a foreign exchange gain of $1 million in line with the third quarter of 2016.

Income tax expense for the quarter was a recovery of $23 million compared with a recovery of $36 million in the same c
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
financial flexibility we need to continue to manage our growth and cash flow, regardless of where we are in the busines

We apply a disciplined approach to managing and tracking results of our operations to keep costs down. We maintain a
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 co
provided through our internal manufacturing and supply divisions. Term contracts on expansion capital for new-build rig
certainty of future revenues and return on our capital investments.

Liquidity

Amount	Availability

Senior facility (secured)	
US$525 million (extendible, revolving term credit facility with US$250 million[(1)] accordion feature)	Undrawn, except US
Operating facilities (secured)	
$40 million	Undrawn, except $2
US$15 million	Undrawn
Demand letter of credit facility (secured)	
US$30 million	Undrawn, except US
Senior notes (unsecured)	
US$372 million - 6.625%	Fully drawn
US$319 million - 6.5%	Fully drawn
US$350 million - 7.75%	Fully drawn
US$400 million - 5.25%	Fully drawn

(1) Increases to US$275 million at the end of the covenant relief period of March 31, 2018.

In January, 2017 we agreed with our lending group to the following amendments to our senior credit facility:

- Reduce the consolidated Adjusted EBITDA (as defined in the debt agreement) to consolidated interest expense r for the periods ending March 31, June 30 and September 30, 2017. For the periods ending December 31, 2017 a ratio is 1.5:1 reverting to 2.5:1 thereafter.
- Reduce the size of the facility to US$525 million and suspended the increase in the accordion feature from US$25 million until the end of covenant relief period.

As at September 30, 2017 we had $1,802 million outstanding under our senior unsecured notes. The current blended c debt is approximately 6.5%.

Covenants

Senior Facility

The senior credit facility requires that we comply with certain covenants including a leverage ratio of consolidated senio interest, taxes, depreciation and amortization as defined in the agreement (Adjusted EBITDA) of less than 2.5:1. For pu leverage ratio consolidated senior debt only includes secured indebtedness. Adjusted EBITDA, as defined in our revolv agreement differs from Adjusted EBITDA as defined under Non-GAAP Measures by the exclusion of bad debt expense certain foreign exchange amounts. As at September 30, 2017 our consolidated senior debt to Adjusted EBITDA ratio w

Effective January 20, 2017, under the senior credit facility, we are required to maintain a ratio of consolidated Adjusted interest expense for the most recent four consecutive quarters, of greater than 1.25:1 for the periods ending March 31, 30, 2017. For the periods ending December 31, 2017 and March 31, 2018 the ratio is 1.5:1 reverting to 2.5:1 thereafter 2017 our senior credit facility consolidated Adjusted EBITDA to consolidated interest expense ratio was 2.04:1.

The senior credit facility also prevents us from making distributions prior to April 1, 2018 and restricts our ability to repu senior notes subject to a pro forma liquidity test of US$500 million.

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

At September 30, 2017, we were in compliance with the covenants of the senior credit facility.

Senior Notes

The senior notes require that we comply with financial covenants including an incurrence based consolidated interest c consolidated cashflow, as defined in the senior note agreements, to consolidated interest expense of greater than 2.0:1 consecutive fiscal quarters. In the event that our consolidated interest coverage ratio is less than 2.0:1 for the most rec fiscal quarters the senior notes restrict our ability to incur additional indebtedness. As at September 30, 2017, our senic interest coverage ratio was 1.89:1 which limits our ability to incur additional indebtedness, except as permitted under th time as we are in compliance with the ratio test, but would not restrict our access to available funds under the senior cr our existing debt. Furthermore, it does not give rise to any cross-covenant violations, give the lenders the right to dema outstanding portion of the senior notes prior to the stated maturity dates, or provide any other forms of recourse to the l

The senior notes contain a restricted payments covenant that limits our ability to make payments in the nature of divide repurchases from shareholders. This restricted payment basket grows from a starting point of October 1, 2010 for the 2 Senior Notes and from October 1, 2016 for the 2023 Senior Notes by, among other things, 50% of cumulative net earni 100% of cumulative net losses, as defined in the note agreements, and payments made to shareholders. Beginning wit 2015 calculation the governing net restricted payments basket was negative and as of that date we were no longer able dividend payments until such time as the restricted payments baskets once again become positive. For further informat 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 incu indebtedness and issue preferred shares; create liens; create or permit to exist restrictions on our ability or certain subs payments and distributions; engage in amalgamations, mergers or consolidations; make certain dispositions and engag 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 investme 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 that have a U.S. dollar functional currency. To be accounted for as a hedge, the foreign currency denominated long-ter designated and documented as such and must be effective at inception and on an ongoing basis. We recognize the eff hedge (net of tax) in other comprehensive income. We recognize ineffective amounts (if any) in net earnings (loss).

Average shares outstanding

The following table reconciles the weighted average shares outstanding used in computing basic and diluted net loss p

	Three months ended September 30,		Nine months ended	
(Stated in thousands)	2017	2016	2017	2
Weighted average shares outstanding - basic	293,239	293,238	293,239	2
Effect of stock options and other equity compensation plans	-	-	-	-
Weighted average shares outstanding - diluted	293,239	293,238	293,239	2

QUARTERLY FINANCIAL SUMMARY

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

	2016	2017		
Quarters ended	December 31	March 31	June 30	September 30
Revenue[1]	302,653	368,673	290,860	314,504
Adjusted EBITDA[2]	65,000	84,308	56,520	73,239
Net loss:	(30,618)	(22,614)	(36,130)	(26,287)
Per basic and diluted share	(0.10)	(0.08)	(0.12)	(0.09)
Funds provided by (used in) operations[2]	11,466	85,659	(15,187)	85,140
Cash provided by (used in) operations	(27,846)	33,770	2,739	56,757

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

	2015	2016

Quarters ended	December 31	March 31	June 30	September 30
Revenue[1]	362,117	316,505	170,407	213,668
Adjusted EBITDA[2]	111,095	99,264	22,400	41,411
Net loss:	(270,952)	(19,883)	(57,677)	(47,377)
Per basic and diluted share	(0.93)	(0.07)	(0.20)	(0.16)
Funds provided by (used in) operations[2]	49,503	93,593	(31,372)	31,688
Cash provided by operations	70,952	112,174	20,665	17,515
Dividends paid per share	0.07	-	-	-

(1) Prior year comparatives have changed to conform to current year presentation. For detail see "RECAST OF COMPARATIVE FINANCIAL INFORMATION."

(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 Consolidate Statements that could materially affect the amounts recognized. Our judgments and estimates are based on our past e assumptions we believe are reasonable in the circumstances. The critical judgments and estimates used in preparing t Statements are described in our 2016 Annual Report and there have been no material changes to our critical accountin estimates during the three and nine month periods ended September 30, 2017.

NON-GAAP MEASURES

In this press release we reference non-GAAP (Generally Accepted Accounting Principles) measures. Adjusted EBITDA (Loss) and Funds Provided by (Used In) Operations are terms used by us to assess performance as we believe they p supplemental information to investors. These terms do not have standardized meanings prescribed under International 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, gain on repurchase of unsecured senior notes, finan exchange and depreciation and amortization), as reported in the Interim Consolidated Statement of Loss, is a useful m an indication of the results from our principal business activities prior to consideration of how our activities are financed exchange, taxation and depreciation and amortization charges.

Operating Earnings (Loss)

We believe that operating earnings (loss), as reported in the Interim Consolidated Statements of Loss, is a useful meas an indication of the results of our principal business activities before consideration of how those activities are financed a 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 Fl because it provides an indication of the funds our principal business activities generate prior to consideration of workin primarily made up of highly liquid balances.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION AND STATEMENTS

Certain statements contained in this report, including statements that contain words such as "could", "should", "can", "a "intend", "plan", "expect", "believe", "will", "may", "continue", "project", "potential" and similar expressions and statemen are not historical facts constitute "forward-looking information" within the meaning of applicable Canadian securities leg "forward-looking statements" within the meaning of the "safe harbor" provisions of the United States Private Securities 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 2017;
- our capital expenditure plans for 2017 and our scheduled ERP upgrade;
- anticipated activity levels in 2017;
- anticipated demand for Tier 1 rigs; and
- the average number of term contracts in place for 2017 and 2018.

These forward-looking information and statements are based on certain assumptions and analysis made by Precision i and our perception of historical trends, current conditions, expected future developments and other factors we believe a 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, performar conform to our expectations and predictions is subject to a number of known and unknown risks and uncertainties whic 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 compe
- 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 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 t conditions.

Readers are cautioned that the forgoing list of risk factors is not exhaustive. Additional information on these and other f our business, operations or financial results are included in reports on file with applicable securities regulatory authoritie limited to Precision's Annual Information Form for the year ended December 31, 2016, which may be accessed on Prec www.sedar.com or under Precision's EDGAR profile at www.sec.gov. The forward-looking information and statements c release are made as of the date hereof and Precision undertakes no obligation to update publicly or revise any forward information, whether as a results of new information, future events or otherwise, except as required by law.

INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION (UNAUDITED)

(Stated in thousands of Canadian dollars)	*September 30, 2017*	*December 31, 2016*
ASSETS		
Current assets:		
Cash	$ 131,742	$ 115,705
Accounts receivable	298,016	293,682
Income tax recoverable	29,913	38,087
Inventory	25,282	24,136
Total current assets	484,953	471,610
Non-current assets:		
Property, plant and equipment	3,275,629	3,641,889
Intangibles	2,403	3,316
Goodwill	205,002	207,399

Total non-current assets		3,483,034			3,852,604	
Total assets	$	3,967,987		$	4,324,214	
LIABILITIES AND EQUITY						
Current liabilities:						
Accounts payable and accrued liabilities	$	218,794		$	240,736	
Total current liabilities		218,794			240,736	
Non-current liabilities:						
Share based compensation		12,213			27,387	
Provisions and other		11,332			12,421	
Long-term debt		1,777,667			1,906,934	
Deferred tax liabilities		90,599			174,618	
Total non-current liabilities		1,891,811			2,121,360	
Shareholders' equity:						
Shareholders' capital		2,319,293			2,319,293	
Contributed surplus		42,841			38,937	
Deficit		(637,599	)		(552,568	)
Accumulated other comprehensive income		132,847			156,456	
Total shareholders' equity		1,857,382			1,962,118	
Total liabilities and shareholders' equity	$	3,967,987		$	4,324,214	

INTERIM CONSOLIDATED STATEMENTS OF LOSS (UNAUDITED)

	Three months	
(Stated in thousands of Canadian dollars, except per share amounts)	2017	
Revenue	$	314,504
Expenses:		
Operating		218,936
General and administrative		22,329
Restructuring		-
Earnings before income taxes, gain on repurchase of unsecured senior notes, finance charges, foreign exchange and depreciation and amortization		73,239
Depreciation and amortization		90,555
Operating loss		(17,316
Foreign exchange		(685
Finance charges		32,218
Gain on repurchase of unsecured senior notes		-
Loss before income taxes		(48,849
Income taxes:		
Current		89
Deferred		(22,651
		(22,562
Net loss	$	(26,287
Net loss per share:		
Basic	$	(0.09
Diluted	$	(0.09

INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS (UNAUDITED)

	Three mon	
(Stated in thousands of Canadian dollars)	2017	
Net loss	$	(26,287
Unrealized gain (loss) on translation of assets and liabilities of operations denominated in foreign currency		(79,729

Foreign exchange gain (loss) on net investment hedge with U.S. denominated debt, net of tax	68,057
Comprehensive loss	$ (37,959

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOW (UNAUDITED)

	Three months ended September 30,		Nine months e
(Stated in thousands of Canadian dollars)	2017	2016	2017
Cash provided by (used in):			
Operations:			
Net loss	$ (26,287)	$ (47,377)	$ (85,031
Adjustments for:			
Long-term compensation plans	1,945	983	4,276
Depreciation and amortization	90,555	96,998	283,517
Gain on repurchase of unsecured senior notes	-	(5,108)	-
Foreign exchange	(239)	(2,563)	(1,593
Finance charges	32,218	34,673	99,732
Income taxes	(22,562)	(36,373)	(82,715
Other	72	425	(705
Income taxes paid	(539)	(2,512)	(3,300
Income taxes recovered	11,600	536	11,932
Interest paid	(1,877)	(8,685)	(72,136
Interest received	254	691	1,635
Funds provided by operations	85,140	31,688	155,612
Changes in non-cash working capital balances	(28,383)	(14,173)	(62,346
	56,757	17,515	93,266
Investments:			
Purchase of property, plant and equipment	(22,518)	(78,162)	(73,047
Proceeds on sale of property, plant and equipment	4,273	2,125	10,054
Income taxes recovered	-	-	-
Changes in non-cash working capital balances	(150)	9,394	(10,716
	(18,395)	(66,643)	(73,709
Financing:			
Repurchase of unsecured senior notes	-	(55,916)	-
Debt issue costs	-	(59)	(341
Issuance of common shares on the exercise of options	-	12	-
	-	(55,963)	(341
Effect of exchange rate changes on cash and cash equivalents	(1,684)	1,606	(3,179
Increase (decrease) in cash and cash equivalents	36,678	(103,485)	16,037
Cash and cash equivalents, beginning of period	95,064	455,679	115,705
Cash and cash equivalents, end of period	$ 131,742	$ 352,194	$ 131,742

INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY (UNAUDITED)

(Stated in thousands of Canadian dollars)	Share-holders' capital	Contri-buted surplus	Accumu-lated other compre-hensive income	Deficit	Total equity
Balance at January 1, 2017	$ 2,319,293	$ 38,937	$ 156,456	$ (552,568)	$ 1,962,118
Net loss for the period	-	-	-	(85,031)	(85,031)
Other comprehensive loss for the period	-	-	(23,609)	-	(23,609)
Share based compensation expense	-	3,904	-	-	3,904
Balance at September 30, 2017	$ 2,319,293	$ 42,841	$ 132,847	$ (637,599)	$ 1,857,382

(Stated in thousands of Canadian dollars)	Share-holders' capital	Contri-buted surplus	Accumu-lated other compre-hensive income	Deficit	Total equity
Balance at January 1, 2016	$ 2,316,321	$ 35,800	$ 166,101	$ (397,013)	$ 2,121,209
Net loss for the period	-	-	-	(124,937)	(124,937)
Other comprehensive loss for the period	-	-	(25,563)	-	(25,563)
Share options exercised	2,972	(1,046)	-	-	1,926
Share based compensation expense	-	3,065	-	-	3,065
Balance at September 30, 2016	$ 2,319,293	$ 37,819	$ 140,538	$ (521,950)	$ 1,975,700

THIRD QUARTER 2017 EARNINGS CONFERENCE CALL AND WEBCAST

Precision Drilling Corp. has scheduled a conference call and webcast to begin promptly at 12:00 noon MT (2:00 p.m. E
2017.

The conference call dial in numbers are 1-844-515-9176 or 614-999-9312.

A live webcast of the conference call will be accessible on Precision's website at www.precisiondrilling.com by selecting
then "Webcasts & Presentations". Shortly after the live webcast, an archived version will be available for approximately

An archived recording of the conference call will be available approximately one hour after the completion of the call un
dialing 1-855-859-2056 or 404-537-3406, pass code 93161565.

About Precision

Precision is a leading provider of safe and *High Performance, High Value* services to the oil and gas industry. Precision
access to an extensive fleet of contract drilling rigs, directional drilling services, well service and snubbing rigs, camps,
water treatment units backed by a comprehensive mix of technical support services and skilled, experienced personnel

Precision is headquartered in Calgary, Alberta, Canada. Precision is listed on the Toronto Stock Exchange under the tr
on the New York Stock Exchange under the trading symbol "PDS".

Contact

Carey Ford
Senior Vice President and Chief Financial Officer
403.716.4566
Ashley Connolly, CFA
Manager, Investor Relations
403.716.4725
Precision Drilling Corp.
800, 525 - 8th Avenue S.W.
Calgary, Alberta, Canada T2P 1G1
Website: www.precisiondrilling.com