First Quarter Interim Report

Date: April 28, 2016

The following discussion of the financial condition, changes in financial condition and results of operations of Western Energy Services Corp. (the "Company" or "Western") should be read in conjunction with the audited consolidated financial statements and accompanying notes of the Company for the years ended December 31, 2015 and 2014, the Company's management discussion and analysis ("MD&A") for the year ended December 31, 2015, as well as the condensed consolidated financial statements and notes as at and for the three months ended March 31, 2016 and 2015. This Management Discussion and Analysis ("MD&A") is dated April 28, 2016. All amounts are denominated in Canadian dollars (CDN$) unless otherwise identified.

Financial Highlights	**Three months ended March 31**		
(stated in thousands, except share and per share amounts)	**2016**	**2015**	**Change**
Revenue	33,937	105,850	(68%)
Operating Revenue[1]	32,200	100,958	(68%)
Gross Margin[1]	8,867	47,891	(81%)
Gross Margin as a percentage of Operating Revenue	28%	47%	(40%)
Adjusted EBITDA[1]	3,364	40,637	(92%)
Adjusted EBITDA as a percentage of Operating Revenue	10%	40%	(75%)
Cash flow from operating activities	8,604	39,337	(78%)
Capital expenditures	921	17,863	(95%)
Net income (loss)	(6,319)	15,294	(141%)
-basic net income (loss) per share	(0.09)	0.20	(145%)
-diluted net income (loss) per share	(0.09)	0.20	(145%)
Weighted average number of shares			
-basic	73,646,292	74,686,828	(1%)
-diluted	73,646,292	74,702,482	(1%)
Outstanding common shares as at period end	73,646,292	74,578,128	(1%)
Dividends declared	-	5,593	(100%)
Dividends declared per common share	-	0.075	(100%)
Operating Highlights			
Contract Drilling			
Canadian Operations			
Average contract drilling rig fleet	52	49	6%
Operating Revenue per Revenue Day[1]	19,437	25,947	(25%)
Operating Revenue per Operating Day[1]	21,970	28,707	(23%)
Drilling rig utilization - Revenue Days[1]	21%	54%	(62%)
Drilling rig utilization - Operating Days[1]	18%	49%	(63%)
CAODC industry average utilization[1][2]	20%	35%	(43%)
United States Operations			
Average contract drilling rig fleet	5	5	-
Operating Revenue per Revenue Day (US$)[1]	27,097	29,645 [3]	(9%)
Operating Revenue per Operating Day (US$)[1]	31,504	33,738 [3]	(7%)
Drilling rig utilization - Revenue Days[1]	20%	54%	(63%)
Drilling rig utilization - Operating Days[1]	17%	48%	(64%)
Production Services			
Average well servicing rig fleet	66	65	2%
Service rig Operating Revenue per Service Hour[1]	740	858	(14%)
Service rig utilization[1]	17%	42%	(59%)

(1) See "Non-IFRS measures" on page 14 of this MD&A.

(2) Source: The Canadian Association of Oilwell Drilling Contractors ("CAODC"). The CAODC industry average is based on Operating Days divided by total available days.

(3) Excludes shortfall commitment and standby revenue from take or pay contracts of US$3.8 million for the three months ended March 31, 2015.

Financial Position at (stated in thousands)	March 31, 2016	March 31, 2015	December 31, 2015
Working capital	68,145	92,300	70,679
Property and equipment	759,205	841,576	773,647
Total assets	842,492	1,049,145	876,608
Long term debt	264,118	264,207	264,155

Overall Performance and Results of Operations

Western is an oilfield service company focused on three core business lines: contract drilling, well servicing and oilfield rental equipment services. Western provides contract drilling services through its division, Horizon Drilling ("Horizon") in Canada, and its wholly owned subsidiary, Stoneham Drilling Corporation ("Stoneham"), in the United States ("US"). On December 28, 2015, Western wound up its partnership, Western Energy Services Partnership (the "Partnership") and rolled all of the Partnership's assets into IROC Drilling and Production Services Corp., which then changed its name to Western Production Services Corp. ("Western Production Services"). As a result, Western now provides well servicing operations in Canada through Western Production Services' division, Eagle Well Servicing ("Eagle") and oilfield rental equipment services in Canada through Western Production Services' division, Aero Rental Services ("Aero"). Financial and operating results for Horizon and Stoneham are included in Western's contract drilling segment, while Eagle and Aero's financial and operating results are included in Western's production services segment. Non-International Financial Reporting Standards ("Non-IFRS") measures are defined on page 14 of this MD&A. Abbreviations for standard industry terms are included on page 16 of this MD&A.

Western currently has a drilling rig fleet of 57 rigs specifically suited for drilling horizontal wells of increased complexity. Western is the sixth largest drilling contractor in Canada with a fleet of 52 rigs operating through Horizon. Of the Canadian fleet, 25 are classified as Cardium rigs, 19 as Montney rigs and eight as Duvernay rigs. As compared to the Cardium classified rigs, the Montney class rigs have a larger hookload, while the Duvernay class rigs have the largest hookload. Additionally, Western has five Duvernay class triple drilling rigs deployed in the United States operating through Stoneham. Western is also the fourth largest well servicing company in Canada with a fleet of 66 rigs operating through Eagle. Western's oilfield rental equipment division, which operates through Aero, provides oilfield rental equipment for frac services, well completions and production work, coil tubing and drilling services.

Crude oil and natural gas prices impact the cash flow of Western's customers, which in turn impacts the demand for Western's services. Overall performance of the Company was affected by the continued decline in crude oil and natural gas prices throughout 2015 and into the first quarter of 2016, when prices were at their lowest levels in over a decade. The following table summarizes the average oil and natural gas prices, as well as the average foreign exchange rates for the three months ended March 31, 2016 and 2015.

	Three months ended March 31		
	2016	**2015**	**Change**
Average oil and natural gas prices(1)			
Oil			
West Texas Intermediate (US$/bbl)	33.45	48.63	(31%)
Western Canadian Select (CDN$/bbl)	26.29	42.13	(38%)
Natural Gas			
30 day Spot AECO (CDN$/mcf)	1.83	2.75	(34%)
Average foreign exchange rates			
US dollar to Canadian dollar	1.37	1.24	10%

(1) See "Abbreviations" on page 16 of this MD&A.

The significant reduction in commodity prices led to a corresponding decrease in the demand for oilfield services in both Canada and the United States. As a result, first quarter drilling rig counts in both Canada and the United States were at or near 30 year lows in 2016. The Canadian Association of Oilwell Drilling Contractors ("CAODC") reported that for drilling in Canada, the total number of Operating Days in the Western Canadian Sedimentary Basin ("WCSB") decreased approximately 44% for the three months ended March 31, 2016, as compared to the same period in 2015. Similarly, as reported by Baker Hughes Incorporated, the number of active drilling rigs in the United States decreased approximately 60% for the three months ended March 31, 2016, as compared to the same period in the prior year. Well servicing hours were also impacted by the decline in demand, as the CAODC reported that Service Hours in the WCSB decreased approximately 34% in the first quarter of 2016, as compared to the first quarter of 2015.

Operational results for the three months ended March 31, 2016 include:

- First quarter Operating Revenue decreased by $68.8 million (or 68%) to $32.2 million in 2016 as compared to $101.0 million in 2015. In the contract drilling segment, Operating Revenue decreased by $53.3 million (or 70%) to $22.3 million in the first quarter of 2016 as compared to $75.6 million in the first quarter of 2015; while in the production services segment, Operating Revenue decreased by $15.7 million (or 61%) to $9.9 million as compared to $25.6 million in the first quarter of 2015. Operating Revenue was impacted by decreased commodity prices, such as West Texas Intermediate ("WTI") crude oil, which dropped to its lowest level in over a decade in the first quarter of 2016, resulting in a dramatic decrease in customer spending in the period. The lower utilization and pricing in both the contract drilling and production services segments is described below:
    - Drilling rig utilization – Operating Days in Canada decreased to 18% in the first quarter of 2016 as compared to 49% in the first quarter of 2015, reflecting a 63% decrease. Utilization for Western's Cardium class rigs was most impacted in the period, averaging 13%, as these rigs typically operate in highly competitive conventional resource plays, whereas utilization for Western's Montney and Duvernay class rigs were impacted to a lesser extent, averaging 22% and 26% respectively, in the first quarter of 2016. First quarter 2016 drilling rig utilization – Operating Days of 18% represented a discount of 200 basis points ("bps") to the CAODC industry average, as compared to the 1,400 bps premium to the industry average realized in the first quarter of 2015. The CAODC industry average utilization of 20% for the three months ended March 31, 2016 was the lowest first quarter industry utilization on record. The change in the Company's utilization relative to the CAODC industry average is partially due to a number of Western's customers, who typically have substantial drilling programs, significantly cutting their capital spending in 2016. Additionally, changes in the industry rig mix, as competitors continue to decommission older and shallower rigs in the WCSB, and add rigs that directly compete with Western's drilling rig fleet, impacts Western's relative utilization as compared to the CAODC industry average. Additionally, lower activity and increased competition in the first quarter of 2016 resulted in downward pricing pressure on all drilling rig classes, which reduced Operating Revenue per Revenue Day in the contract drilling segment in Canada by 25%, as compared to the first quarter of 2015;
    - In the United States, drilling rig utilization – Operating Days decreased to 17% in the first quarter of 2016, as compared to 48% in the same period of the prior year, while Operating Revenue per Revenue Day in the United States decreased by 9% in the first quarter of 2016 due to the decreased commodity price environment; and
    - Well servicing utilization decreased to 17% in the first quarter of 2016 as compared to 42% in the same period of the prior year. Reduced activity, coupled with a 14% decrease in well servicing hourly rates, due to pricing pressure in all areas, resulted in a $13.5 million (or 64%) decrease in well servicing Operating Revenue in the period.
- First quarter Adjusted EBITDA totaled $3.4 million in 2016, a $37.2 million (or 92%) decrease, as compared to $40.6 million in the first quarter of 2015. The year over year decrease in Adjusted EBITDA is due to lower utilization and pricing in both the contract drilling and production services segments, offset by cost reduction measures including an approximate one third reduction to salaried headcount, wage reductions to all employees and other cost control measures.
- Administrative expenses, excluding depreciation and stock based compensation, in the first quarter of 2016 decreased by $1.8 million (or 25%) to $5.5 million as compared to $7.3 million in the first quarter of 2015. The decrease in administrative expenses is due to a reduced employee headcount, a 10% rollback to all employee wages and directors' fees implemented in the first quarter of 2016, coupled with additional cost control measures.
- Net income decreased by $21.6 million to a loss of $6.3 million in the first quarter of 2016 (a loss of $0.09 per basic common share) as compared to net income of $15.3 million in the same period in 2015 ($0.20 per basic common share). The decrease in net income in 2016 can be attributed to the following:
    - A $37.2 million decrease in Adjusted EBITDA due to lower utilization and pricing in both the contract drilling and production services segments; and
    - A $0.7 million increase in finance costs, due to lower capitalized interest;

  Offsetting the above mentioned items are the following:
    - A decrease in depreciation expense of $6.1 million due to lower activity levels;
    - A $1.5 million increase in other items, mainly relating to foreign exchange gains; and
    - An $8.9 million decrease in income tax expense due to lower taxable income.

- First quarter 2016 capital expenditures of $0.9 million included $0.4 million of expansion capital and $0.5 million of maintenance capital. In total, capital spending in the first quarter of 2016 decreased by 95% from the $17.9 million incurred in the first quarter of 2015. The majority of first quarter 2016 capital expenditures relate to the production services segment, which incurred $0.6 million in capital. These expenditures mainly relate to the purchase of additional oilfield rental equipment. Additionally, $0.3 million was incurred in the contract drilling segment relating to maintenance capital.

Credit Facility and Covenant Amendments

On April 27, 2016, the Company amended the covenants and elected to reduce its syndicated revolving credit facility (the “Revolving Facility”) from $175.0 million to $40.0 million and has reduced its previously uncommitted operating demand revolving loan of $20.0 million to a committed operating line (the “Operating Facility”) totaling $10.0 million. Western’s decision to reduce its Revolving Facility and Operating Facility (the “Credit Facilities”) is estimated to save the Company $1.5 million in standby fees annually. The interest coverage ratio, which previously required EBITDA to exceed interest expense by 2.0x or more, has been permanently removed and the senior debt to EBITDA ratio has been increased. The revised facility now includes a borrowing base calculation, based on the value of Western’s accounts receivable and property and equipment, and a current ratio covenant of 1.15x. The Revolving Facility includes an accordion feature, whereby an incremental $60.0 million of borrowing would become available, subject to approval of the lenders. The Company believes the amended Credit Facilities provide the financial flexibility to effectively manage through the current slowdown in oilfield service activity.

Outlook

Currently, 7 of Western’s 57 drilling rigs (or 12%) are operating under long term take-or-pay contracts providing a base level of future revenue, with 3 of these contracts expected to expire in each of 2016 and 2017, and 1 expected to expire in 2018. These contracts each typically generate between 250 and 350 Revenue Days per year.

Western’s revised capital budget for 2016 of $7 million remains unchanged, and is comprised of $2 million of expansion capital and $5 million of maintenance capital. Western believes the revised 2016 capital budget provides a prudent use of cash resources and will allow it to maintain its premier drilling and well servicing rig fleets, while remaining responsive to customer requirements. Western will continue to manage its operations in a disciplined manner and make any required adjustments to its capital program as customer demand changes.

The continued pressure on commodity prices in 2016 has resulted in significant year-over-year reductions to the capital spending plans for the majority of Western’s customers. As a result, active drilling rig counts in both Canada and the United States are expected to be at or near 30 year lows for the remainder of 2016. Activity levels throughout the oilfield service industry in the second quarter of 2016 are expected to be extremely low. Lower activity and pricing pressure will continue to impact Western’s Adjusted EBITDA and cash flow from operating activities. The Company has taken a proactive approach to reducing administrative and fixed overhead costs including reducing fixed headcount since the beginning of 2015 by a third and implementing a 10% company-wide wage rollback to salaried employees and directors’ fees, as well as reducing various other office related costs. In addition, Western’s variable cost structure, under which approximately 80% of operating and administrative costs are variable, the previously announced suspension of the Company’s quarterly dividend and a prudent capital budget will aid in preserving balance sheet strength. In addition to $50 million in cash and cash equivalents at March 31, 2016, Western has $50 million undrawn on the Company’s Credit Facilities, which do not mature until December 17, 2018 and no principal repayments due on the $265 million Senior Notes until they mature on January 30, 2019.

Oilfield service activity in Canada will be impacted by the development of resource plays in Alberta and northeast British Columbia including those related to liquefied natural gas projects, increased crude oil transportation capacity through rail and pipeline development and foreign investment into Canada. Currently, the largest challenge facing the oilfield service industry is customer spending constraints as a result of lower commodity prices. Western’s view is that its modern drilling and well servicing rig fleets, reputation, and disciplined cash management provide a competitive advantage which will enable the Company to manage through the current slowdown in oilfield services activity.

Segmented Information

Western operates in the contract drilling segment in both Canada and the United States as well as in the production services segment in Canada. Contract drilling includes drilling rigs along with related equipment. Production services includes well servicing rigs and related equipment as well as oilfield rental equipment.

Contract Drilling

Financial Highlights	**Three months ended March 31**		
(stated in thousands)	**2016**	**2015**	**Change**
Revenue			
Operating Revenue[1]	22,324	75,607	(70%)
Third party charges	1,001	3,505	(71%)
Total revenue	23,325	79,112	(71%)
Expenses			
Operating			
Cash operating expenses	16,568	40,500	(59%)
Depreciation	5,336	10,099	(47%)
Stock based compensation	38	115	(67%)
Total operating expenses	21,942	50,714	(57%)
Administrative			
Cash administrative expenses	2,837	3,895	(27%)
Depreciation	86	80	8%
Stock based compensation	82	102	(20%)
Total administrative expenses	3,005	4,077	(26%)
Gross Margin[1]	6,757	38,612	(83%)
Gross Margin as a percentage of Operating Revenue	30%	51%	(41%)
Adjusted EBITDA[1]	3,920	34,717	(89%)
Adjusted EBITDA as a percentage of Operating Revenue	18%	46%	(61%)
Operating Earnings[1]	(1,502)	24,538	(106%)
Capital expenditures	314	15,029	(98%)

	Three months ended March 31		
Operating Highlights	**2016**	**2015**	**Change**
Canadian Operations			
Contract drilling rig fleet:			
Average	52	49	6%
End of period	52	49	6%
Operating Revenue per Revenue Day[1]	19,437	25,947	(25%)
Operating Revenue per Operating Day[1]	21,970	28,707	(23%)
Operating Days[1]	861	2,154	(60%)
Number of meters drilled	172,573	400,631	(57%)
Number of wells drilled	57	115	(50%)
Average Operating Days per well	15.1	18.7	(19%)
Drilling rig utilization - Revenue Days[1]	21%	54%	(62%)
Drilling rig utilization - Operating Days[1]	18%	49%	(63%)
CAODC industry average utilization[1][2]	20%	35%	(43%)
United States Operations			
Contract drilling rig fleet:			
Average	5	5	-
End of period	5	5	-
Operating Revenue per Revenue Day (US$)[1]	27,097	29,645 [3]	(9%)
Operating Revenue per Operating Day (US$)[1]	31,504	33,738 [3]	(7%)
Operating Days[1]	78	214	(64%)
Number of meters drilled	23,833	60,858	(61%)
Number of wells drilled	5	11	(55%)
Average Operating Days per well	15.6	19.5	(20%)
Drilling rig utilization - Revenue Days[1]	20%	54%	(63%)
Drilling rig utilization - Operating Days[1]	17%	48%	(64%)

(1) See "Non-IFRS measures" on page 14 of this MD&A.

(2) Source: The Canadian Association of Oilwell Drilling Contractors ("CAODC"). The CAODC industry average is based on Operating Days divided by total available days.

(3) Excludes shortfall commitment and standby revenue from take or pay contracts of US$3.8 million for the three months ended March 31, 2015.

For the first quarter of 2016, Operating Revenue in the contract drilling segment totalled $22.3 million, a $53.3 million decrease (or 70%), as compared to the first quarter of 2015. Reduced demand for contract drilling services in both Canada and the United States, due to the decreased commodity price environment, led to significantly lower year over year activity and has put downward pressure on day rates in Canada and the United States.

During the three months ended March 31, 2016, Adjusted EBITDA in the contract drilling segment decreased by $30.8 million (or 89%) to $3.9 million, as compared to $34.7 million in the same period of 2015, mainly due to the decrease in Operating Days in both Canada and the United States, coupled with a 25% decrease in Operating Revenue per Revenue Day in Canada and a 9% decrease in Operating Revenue per Revenue Day in the United States. The decrease in activity was partially offset by cost control measures implemented throughout the Company.

For the first quarter of 2016, cash administrative expenses, which exclude depreciation and stock based compensation, decreased 27% to $2.8 million, compared to $3.9 million in the prior year, mainly due to lower employee costs and effective cost control measures.

Depreciation expense for the quarter ended March 31, 2016 decreased by $4.7 million to $5.4 million due to the decrease in Operating Days in 2016 as compared to the same period of 2015, as the majority of depreciation expense is calculated on a per Operating Day basis.

Capital expenditures in the contract drilling segment totalled $0.3 million in the first quarter of 2016 and relate entirely to maintenance capital, representing a 98% decrease from the $15.0 million incurred in the first quarter of 2015.

Canadian Operations

During the quarter ended March 31, 2016, drilling rig utilization – Operating Days in Canada decreased to 18% as compared to 49% in 2015. The decrease in utilization is due to lower demand, resulting in a 60% decrease in the Company's Operating Days to 861 days in 2016, as compared to 2,154 days in the same period of 2015. Utilization for Western's Cardium class rigs were most impacted in the period averaging 13%, as these rigs typically operate in highly competitive conventional resource plays, whereas utilization for Western's Montney and Duvernay class rigs were impacted to a lesser extent averaging 22% and 26% respectively, in the period.

The Company's drilling rig utilization – Operating Days in Canada of 18% for the first quarter of 2016 reflects an approximate 200 bps discount to the CAODC industry average of 20%, as compared to the 1,400 bps premium realized in the same period of 2015. The decrease in the Company's utilization premium from 2015 is partially due to an 11% reduction in the industry rig count from 757 rigs at March 31, 2015 to 671 rigs at March 31, 2016 as competitors continue to decommission older shallower rigs given the current market conditions. From March 31, 2015 to March 31, 2016, 26 drilling rigs were added to the industry fleet while 112 drilling rigs were removed by decommissioning or movement out of the WCSB year over year. Of the rigs added year over year, the majority of new additions directly compete with Western's Montney and Duvernay class rig fleet, which impacts Western's utilization premium to the industry average. Additionally, the change relative to the CAODC industry average is partially due to a number of Western's customers, who typically have substantial drilling programs, significantly cutting their capital spending in 2016.

For the quarter ended March 31, 2016, Operating Revenue per Revenue Day in Canada totalled $19,437 compared to $25,947 in the prior year, a 25% decrease mainly due to downward pricing pressure decreasing day rates in all rig categories in Canada. Third party charges per Revenue Day decreased for the quarter ended March 31, 2016 to approximately $1,000 per Revenue Day as compared to approximately $1,300 per Revenue Day for the same period of 2015, mainly due to lower fuel prices.

United States Operations

For the quarter ended March 31, 2016, Operating Days decreased by 136 days (or 64%) resulting in drilling rig utilization – Operating Days decreasing to 17% compared to 48% in the same period of the prior year. Additionally, first quarter 2016 Operating Revenue per Revenue Day in the United States decreased by 9% to US$27,097. The decrease in both activity and pricing in the first quarter of 2016 is due to the decreased commodity price environment. In the Williston basin in North Dakota where the Company operates in the United States, drilling rig counts decreased by approximately 70% to 29 active drilling rigs at March 31, 2016, as compared to 97 active drilling rigs at March 31, 2015.

Production Services

(stated in thousands)	Three months ended March 31 2016	2015	Change
Revenue			
Operating Revenue[1]	9,886	25,573	(61%)
Third party charges	736	1,387	(47%)
Total revenue	10,622	26,960	(61%)
Expenses			
Operating			
Cash operating expenses	8,510	17,681	(52%)
Depreciation	1,975	3,266	(40%)
Stock based compensation	71	36	97%
Total operating expenses	10,556	20,983	(50%)
Administrative			
Cash administrative expenses	1,566	1,797	(13%)
Depreciation	113	104	9%
Stock based compensation	101	54	87%
Total administrative expenses	1,780	1,955	(9%)
Gross Margin[1]	2,112	9,279	(77%)
Gross margin as a percentage of Operating Revenue	21%	36%	(42%)
Adjusted EBITDA[1]	546	7,482	(93%)
Adjusted EBITDA as a percentage of Operating Revenue	6%	29%	(79%)
Operating Earnings[1]	(1,542)	4,112	(138%)
Capital expenditures	606	2,809	(78%)
Well servicing rig fleet:			
Average	66	65	2%
End of period	66	65	2%
Service rig Operating Revenue per Service Hour[1]	740	858	(14%)
Service Hours[1]	10,386	24,712	(58%)
Service rig utilization [1]	17%	42%	(59%)

(1) See "Non-IFRS measures" on page 14 of this MD&A.

The Company's production services segment includes Eagle's well servicing fleet, which currently totals 66 rigs, as well as Aero's oilfield rental equipment. For the quarter ended March 31, 2016, Operating Revenue decreased by $15.7 million (or 61%) to $9.9 million, compared to $25.6 million in the same period of the prior year. For 2016, Eagle's contribution to Operating Revenue in the production services segment decreased by $13.5 million (or 64%) to $7.7 million as compared to $21.2 million in the prior year, whereas Aero's contribution to Operating Revenue in the production services segment decreased by $2.2 million (or 50%) to $2.2 million, compared to $4.4 million in the prior year. The decrease in Operating Revenue for both Eagle and Aero for the first quarter of 2016, as compared to the first quarter of 2015, is due to reduced customer spending resulting from the decreased commodity price environment, leading to lower pricing and activity.

Eagle's Service Hours decreased by 58% in the quarter ended March 31, 2016 to 10,386 (17% utilization) as compared to 24,712 (42% utilization) in the same period of the prior year, as a result of lower demand across all geographic areas. Operating Revenue per Service Hour decreased by 14% for the quarter ended March 31, 2016 to $740 compared to $858 in the same period of the prior year due to pricing pressure across all operating areas.

Adjusted EBITDA decreased by 93% to $0.5 million during the first quarter of 2016 from $7.5 million in the same period of 2015. The lower EBITDA in 2016 was due to the decreased commodity price environment which impacted the demand and pricing for the Company's services and was partially offset by lower employee costs and cost control measures. During the first quarter of 2016, cash administrative expenses, which exclude depreciation and stock based compensation, decreased by 13% to $1.6 million as compared to $1.8 million in the same period of the prior year.

Depreciation expense in the first quarter of 2016 decreased by 38%, to $2.1 million, reflecting fewer Service Hours compared to the prior year as the majority of Eagle's depreciation expense is calculated on a per Service Hour basis.

During the quarter ended March 31, 2016, capital expenditures in the production services segment totalled $0.6 million and included expansion capital of $0.4 million mainly related to the purchase of additional oilfield rental equipment. Additionally, maintenance capital of $0.2 million was incurred in the first quarter of 2016. Total capital expenditures of $0.6 million in the first quarter of 2016 represent a 78% decrease from the $2.8 million incurred in the first quarter of 2015.

Corporate

	Three months ended March 31		
(stated in thousands)	**2016**	**2015**	**Change**
Administrative			
Cash administrative expenses	1,102	1,562	(29%)
Depreciation	221	245	(10%)
Stock based compensation	746	656	14%
Total administrative expenses	2,069	2,463	(16%)
Finance costs	5,538	4,758	16%
Other items	(2,130)	(594)	259%
Income taxes			
Current tax (recovery) expense	(419)	(1,485)	(72%)
Deferred tax (recovery) expense	(2,076)	7,907	(126%)
Total income taxes	(2,495)	6,422	(139%)
Operating earnings(1)	(1,323)	(1,807)	(27%)
Capital expenditures	1	25	(96%)

(1) See "Non-IFRS measures" on page 14 of this MD&A.

Corporate cash administrative expenses, which exclude depreciation and stock based compensation, for the quarter ended March 31, 2016 decreased by 29% to $1.1 million as compared to the same period in the prior year, mainly due to lower employee related costs.

For the quarter ended March 31, 2016, finance costs on a consolidated basis increased by $0.7 million to $5.5 million, mainly due to $0.7 million in capitalized interest recorded in the first quarter of 2015. The Company had an effective interest rate on its borrowings of 8.4% in both the first quarter of 2016 and 2015.

Other items for the first quarter of 2016 reflect net gains of $2.1 million consisting of gains and losses on foreign exchange, asset sales and derivatives.

For the first quarter of 2016, income taxes on a consolidated basis totalled a recovery of $2.5 million representing an effective tax rate of 28.2% as compared to a tax rate of 29.6% in the same period of 2015. The reduction in the effective tax rate is due to a lower proportion of taxable income, as compared to the same period of the prior year, earned in the United States which has higher corporate tax rates. The current tax recovery for 2016 of $0.4 million is due to the recognition of tax losses during the period, expected to be carried back to prior taxation years.

Liquidity and Capital Resources

The Company's liquidity needs in the short term and long term can be sourced in several ways including: available cash balances, funds from operations, borrowing against existing credit facilities, new debt instruments, equity issuances and proceeds from the sale of assets. As at March 31, 2016, Western had cash and cash equivalents of $49.9 million, a decrease of $8.5 million from December 31, 2015. As a result, Western's consolidated Net Debt balance at March 31, 2016 was $215.0 million, an increase of $8.5 million as compared to December 31, 2015. During the first quarter of 2016, Western had Adjusted EBITDA of $3.4 million, a positive change in non-cash working capital of $2.6 million mainly due to the collection of prior year receivables, $2.5 million in foreign exchange gains, and proceeds on the sale of property and equipment of $0.4 million, which was offset by cash interest payments of $10.6 million, dividend payments of $3.7 million, income tax payments of $1.7 million, and capital expenditures of $0.9 million.

As at March 31, 2016, Western had a working capital balance of $68.1 million, a $2.6 million decrease as compared to December 31, 2015. Currently, the Company has $265.0 million in Senior Notes outstanding. On April 27, 2016, the Company elected to reduce its syndicated Revolving Facility from $175.0 million to $40.0 million and has reduced its previously uncommitted operating demand revolving loan of $20.0 million to a committed Operating Facility totalling $10.0 million. In addition to the $50.0 million of available credit under the Credit Facilities, Western has access to an accordion feature whereby an incremental $60.0 million of borrowing would become available, subject to the approval of the lenders. The Credit Facilities include a covenant relief period from January 1, 2016 to December 31, 2017. During the covenant relief period, there are restrictions on exercising the accordion and on certain payments made by the Company, including dividends, normal course issuer bid purchases and capital expenditures in excess of Western's approved budget. The Credit Facilities maturity date of December 17, 2018 remains unchanged.

Additionally, advances under the Credit Facilities will be limited by the Company's borrowing base. The borrowing base is determined as follows:

- 85% of eligible investment grade accounts receivable; plus
- 75% of eligible non-investment grade accounts receivable; plus
- 25% of the net book value of property and equipment (to a maximum of $40.0 million, with a seasonal increase to $50.0 million each quarter ending June 30).

Amounts borrowed under the Credit Facilities bear interest at the bank's Canadian prime rate, US base rate, LIBOR or the banker's acceptance rate plus an applicable margin depending, in each case, on the ratio of Consolidated Debt to Consolidated EBITDA as defined by the Revolving Facility agreement.

The Credit Facilities are secured by the assets of Western and its subsidiaries. As at March 31, 2016, the Revolving Facility and the Operating Facility were undrawn.

The reduction of the Credit Facilities included a revised covenant package. The revised covenant package permanently removed the Consolidated EBITDA to Consolidated Interest Expense ratio, increased the Consolidated Senior Debt to Consolidated EBITDA ratio and now includes a current ratio. A summary of the previous and revised financial covenants is as follows:

	Previous Covenant	Revised Covenant
Maximum Consolidated Senior Debt to Consolidated EBITDA Ratio (1)(2)	2.5:1.0 or less	4.0:1.0 or less
Maximum Consolidated Debt to Consolidated Capitalization Ratio (1)	0.6:1.0 or less	0.6:1.0 or less
Minimum Consolidated EBITDA to Consolidated Interest Expense Ratio (1)	2.0:1.0 or more	Not applicable
Minimum Current Ratio (1)	Not applicable	1.15:1.0 or more

(1) See covenant definitions in Note 6 of the March 31, 2016 interim financial statements.

(2) Consolidated Senior Debt to Consolidated EBITDA adjusts to 3.0:1.0 or less subsequent to January 1, 2018.

At March 31, 2016, Western is in compliance with all debt covenants under its revised Credit Facilities and has no scheduled long term debt repayments until January 2019. As such, cash from operations coupled with Western's working capital, including cash balances, and available Credit Facilities are expected to be sufficient to cover Western's financial obligations including the revised 2016 capital budget.

For the three months ended March 31, 2016 the Company had two significant customers comprising 11.9% and 10.2% respectively, of the Company's total revenue. For the three months ended March 31, 2015, the Company had one customer comprising 11.7% of the Company's total revenue. As at March 31, 2016, there was no trade receivable balance owing relating to one of the significant customers, while the other significant customer's trade receivable balance was 6.7% of the Company's total trade and other receivables balance. The Company's significant customers may change from period to period.

Summary of Quarterly Results

In addition to other market factors, quarterly results of Western are markedly affected by weather patterns throughout its operating areas. Historically, the first quarter of the calendar year is very active, followed by a much slower second quarter due to what is known in the Canadian oilfield service industry as "spring breakup", where due to the spring thaw, provincial and county road bans restrict movement of heavy equipment. As a result of this, the variation of Western's results on a quarterly basis, particularly in the first and second quarters, can be significant quarter over quarter independent of other demand factors.

The following is a summary of selected financial information of the Company for the last eight completed quarters.

Three months ended (stated in thousands, except per share amounts)	Mar 31, 2016	Dec 31, 2015	Sep 30, 2015	Jun 30, 2015	Mar 31, 2015	Dec 31, 2014	Sep 30, 2014	Jun 30, 2014
Revenue	33,937	42,678	46,959	32,037	105,850	139,210	125,225	81,981
Operating Revenue[(1)]	32,200	40,458	44,350	30,719	100,958	129,181	117,960	77,352
Gross Margin[(1)]	8,867	13,372	14,285	10,403	47,891	57,826	50,570	31,206
Adjusted EBITDA[(1)]	3,364	7,573	8,080	4,255	40,637	50,419	42,782	24,028
Cash flow from operating activities	8,604	11,139	(530)	41,009	39,337	47,830	22,975	71,912
Net income (loss)	(6,319)	(55,010)	(76,816)	(12,607)	15,294	(8,164)	14,718	4,396
per share - basic	(0.09)	(0.75)	(1.04)	(0.17)	0.20	(0.11)	0.20	0.06
per share - diluted	(0.09)	(0.75)	(1.04)	(0.17)	0.20	(0.11)	0.19	0.06
Total assets	842,492	876,608	947,137	1,025,776	1,049,145	1,057,118	1,040,973	1,016,112
Long term debt	264,118	264,155	264,219	264,234	264,207	264,165	263,624	263,293
Dividends declared	-	3,682	5,526	5,591	5,593	5,614	5,615	5,609

(1) See "Non-IFRS measures" on page 14 of this MD&A.

Revenue and EBITDA were impacted by lower commodity prices in 2015 and 2016, declining throughout the second half of 2015 and in the first quarter of 2016. Prior to the first quarter of 2015, revenue was significantly higher due to greater activity levels in both the contract drilling and production services segments throughout 2014 as WTI averaged US$99/bbl, US$103/bbl, US$97/bbl and US$73/bbl respectively, in the first, second, third and fourth quarters of 2014, and AECO averaged approximately $6/mcf, $5/mcf, $4/mcf, and $4/mcf respectively, in the first, second, third and fourth quarters of 2014.

Net income has fluctuated throughout the last eight quarters in part due to the seasonal nature of the oilfield service industry in Canada. In addition, the Company recorded impairments in the fourth quarter of 2014 totaling $29.9 million, $71.3 million in the third quarter of 2015 and $68.5 million in the fourth quarter of 2015, which significantly impacted net income in each of the respective periods.

With the exception of the impairments noted above, total assets of the Company have remained relatively constant throughout the last eight quarters as capital spending has been largely offset by depreciation.

Contractual Obligations

In the normal course of business the Company incurs contractual obligations. The expected maturities of the Company's contractual obligations as at March 31, 2016 are as follows:

(stated in thousands)	2016	2017	2018	2019	2020	Thereafter	Total
Senior Notes	$ -	$ -	$ -	$ 265,000	$ -	$ -	$ 265,000
Senior Notes interest	10,349	20,869	20,869	10,519	-	-	62,606
Trade payables and other current liabilities [(1)]	10,300	-	-	-	-	-	10,300
Operating leases	3,238	3,877	3,706	3,550	3,525	10,632	28,528
Purchase commitments	157	-	-	-	-	-	157
Other long term debt	571	711	84	-	-	-	1,366
Total	$ 24,615	$ 25,457	$ 24,659	$ 279,069	$ 3,525	$ 10,632	$ 367,957

(1) Trade payables and other current liabilities exclude the Company's interest accrued as at March 31, 2016 on the Senior Notes.

There have been no material changes in the contractual obligations detailed above, other than in the normal course of business, during the three months ended March 31, 2016.

Outstanding Share Data

	April 28, 2016	March 31, 2016	December 31, 2015
Common shares outstanding	73,648,484	73,646,292	73,646,292
Restricted share units outstanding	744,894	744,833	759,504
Stock options outstanding	5,868,712	5,950,409	6,058,906

Off Balance Sheet Arrangements

As at March 31, 2016, Western had no off balance sheet arrangements in place.

Transactions with Related Parties

During the three months ended March 31, 2016 and 2015, the Company had no transactions with related parties.

Financial Instruments

Fair Values

All financial instruments are measured at fair value upon initial recognition of the transaction. Measurement in subsequent periods is dependent on whether the instrument is classified as a "financial asset or financial liability at fair value through profit or loss", "available-for-sale financial assets", "held-to-maturity investments", "loans and receivables", or "other financial liabilities".

The Company derecognizes a financial asset when the contractual right to the cash flows from the asset expires, or it transfers the right to receive the contractual cash flows on the financial asset in a transaction in which substantially all the risks and rewards of ownership of the financial asset are transferred. The Company derecognizes a financial liability when its contractual obligations are discharged, cancelled or expired.

Financial assets and liabilities are offset and the net amount presented in the balance sheet when the Company has a legal right to offset the amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously.

Derivatives embedded in other instruments or host contracts are separated from the host contract and accounted for separately when their economic characteristics and risks are not closely related to the host contract. Embedded derivatives are recorded on the balance sheet at their estimated fair value and changes in the fair value are recorded through net income. The asset is recognized in other assets on the balance sheet while a change in the value of the embedded derivative is included in other items within net income.

The Company has the following non-derivative financial assets:

(i) Financial assets at fair value through profit or loss:

Cash and cash equivalents are classified as held for trading within the fair value through profit or loss category. Financial assets at fair value through profit or loss are measured at fair value, and changes therein are recognized in net income.

(ii) Loans and receivables:

The Company's trade and other receivables are classified as loans and receivables. Loans and receivables are financial assets with fixed or determinable payments that are not quoted in an active market. Such assets are recognized initially at fair value adjusted for any directly attributable transaction costs. Subsequent to initial recognition, loans and receivables are measured at amortized cost using the effective interest method, less any impairment losses.

(iii) Available for sale:

From time to time, the Company may have certain equity investments in publicly traded entities. Investments that have a quoted price in an active market are measured at fair value with changes in fair value recognized in other comprehensive income. When the investment is ultimately sold, any gains or losses are recognized in net income and any unrealized gains or losses previously recognized in other comprehensive income are reversed.

The Company has the following non-derivative financial liabilities:

(i) Other financial liabilities:

Trade and other payables, finance lease obligations, the Senior Notes and credit facilities are classified as "other financial liabilities". Other financial liabilities are recognized initially at fair value net of any directly attributable transaction costs. Other financial liabilities, including the Senior Notes, are subsequently measured at amortized cost using the effective interest method. Transaction costs incurred with respect to the credit facilities are deferred and amortized using the straight-line method over the term of the facility. The asset is recognized in other assets on the balance sheet while the amortization is included in finance costs within net income.

(ii) Equity instruments:

Common shares are classified as equity. Incremental costs directly attributable to the issuance of common shares are recognized as a deduction from equity, net of any tax effects.

Credit Risk

The Company's trade receivables are with customers in the oil and gas industry and are subject to normal industry credit risk. The Company's practice is to manage credit risk by performing a detailed analysis of the credit worthiness of new customers before the Company's standard payment terms are offered. Additionally, the Company constantly reviews individual customer trade receivables, taking into consideration payment history and the aging of the trade receivable to monitor collectability. The Company records an allowance for doubtful accounts if an account is determined to be uncollectible. Any provisions recorded by the Company are reviewed regularly to determine if any of the balances provided for should be written off. The allowance for doubtful accounts could materially change as a result of fluctuations in the financial position of the Company's customers.

Interest Rate Risk

The Company is exposed to interest rate risk on debt subject to floating interest rates, such as the Company's Credit Facilities, which are currently undrawn. Other long term debt, such as the Senior Notes and the Company's finance leases have fixed interest rates, however they are subject to interest rate fluctuations relating to refinancing as required.

Foreign Exchange Risk

The Company is exposed to foreign exchange fluctuations in relation to its US dollar capital expenditures and US operations. The Company ensures that its net exposure is kept to an acceptable level by buying or selling foreign currencies at spot rates when necessary. From time-to-time the Company may use forward foreign currency contracts to hedge against these fluctuations.

Liquidity Risk

Liquidity risk is the exposure of the Company to the risk of not being able to meet its financial obligations as they become due. To manage liquidity risk, the Company forecasts operational results and capital spending on a regular basis. Variances between actual results and forecast are continually monitored to assess the Company's ability to meet its financial obligations.

Disclosure Controls and Procedures and Internal Controls Over Financial Reporting

As Western's common shares trade on the Toronto Stock Exchange, per National Instrument 52-109, CERTIFICATION OF DISCLOSURE IN ISSUERS' ANNUAL AND INTERIM FILINGS, the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") of the Company have certified as at March 31, 2016 that they have designed or caused to be designed under their supervision, disclosure controls and procedures ("DC&P") to provide reasonable assurance that: (i) material information relating to the Company, including its consolidated subsidiaries, is made known to the CEO and the CFO by others within those entities, particularly during the periods in which the interim filings of the Company are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The CEO and CFO do not expect that the DC&P will prevent or detect all errors, misstatements and fraud but are designed to provide reasonable assurance of achieving their objectives. A control system, no matter how well designed or operated, can only provide reasonable, but not absolute, assurance that the objectives of the control system are met. In addition to DC&P, the CEO and CFO have designed internal controls over financial reporting, or caused them to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with International Financial Reporting Standards ("IFRS").

During the three months ended March 31, 2016, there were no changes in internal control over financial reporting that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Critical Accounting Estimates

This MD&A of the Company's financial condition and results of operations is based on the condensed consolidated financial statements for the three months ended March 31, 2016, which were prepared in accordance with IFRS. The presentation of these financial statements in conformity with IFRS requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of provisions at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. These estimates and judgements are based on historical experience and on various assumptions that are believed to be reasonable under the circumstances. Anticipating future events cannot occur with absolute certainty, therefore these estimates may change as new events occur, more experience is acquired and as the Company's operating environment changes. The Company's key accounting estimates relate to impairment, depreciation, current and deferred taxes and the determination of the fair value of share based payments.

The accounting estimates believed to be the most difficult, subjective or require complex judgements and which are the most critical to the reporting of results of operations and financial positions of the Company are as follows:

Impairment

The Company assesses impairment at each reporting date by evaluating conditions specific to the organization that may lead to impairment of assets. Where an impairment indicator exists, or annually in the case of goodwill, the recoverable amount of the asset or cash generating unit ("CGU") is determined using a value-in-use calculation, where estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset or CGU. The application of judgement is required in determining if an impairment test is required. If indicators conclude that the asset is no longer impaired, the Company will reverse impairment losses on assets. Impairment losses on goodwill are not reversed. Similar to determining if an impairment exists, judgment is required in assessing if a reversal of an impairment loss is required. Value-in-use and fair value less cost to sell calculations performed in assessing the recoverable amounts incorporate a number of key estimates. As at March 31, 2016, the Company completed its assessments of impairment and determined there were no indicators of property and equipment impairment. There were no reversals of previous property and equipment impairment losses during the three months ended March 31, 2016.

Depreciation

The Company's property and equipment is depreciated based upon estimates of useful lives and salvage values. These estimates are based on industry practice and the Company's own experience and may change as more experience is gained, market conditions shift or new technological advancements are made.

The componentization of the Company's property and equipment, specifically drilling rig equipment and well servicing rig equipment, is based on management's judgment as to which components constitute a significant cost in relation to the entire item. The componentization process also requires management's judgement in assessing whether individual components have similar consumption patterns and useful lives.

Income taxes

Preparation of the consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which the Company operates. The process also involves making an estimate of taxes currently payable and taxes expected to be payable or recoverable in future periods, referred to as deferred taxes. Deferred taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the consolidated balance sheet as deferred tax assets and liabilities. An assessment must also be made to determine the likelihood that the Company's future taxable income will be sufficient to permit the recovery of deferred tax assets. To the extent that such recovery is not probable, recognized deferred tax assets must be reduced to the recoverable amount. Judgement is required in determining the provision for income taxes and recognition of deferred tax assets and liabilities. Management must also exercise judgement in its assessment of continually changing tax interpretations, regulations and legislation, to ensure deferred tax assets and liabilities are complete and fairly presented. The effects of differing assessments and applications could be material.

Share based payments

Stock based compensation expense associated with stock options and equity settled restricted share units is based on various assumptions, using a Black-Scholes option pricing model to calculate an estimate of fair value. The inputs into the model include interest rates, expected life, expected volatility, expected forfeitures, expected dividends and share prices which all affect the estimated fair value calculated. Determining the estimated expected life, volatility, forfeitures and expected dividends requires management's judgement.

Business Risks

For a comprehensive listing of the Company's business risks please see the most recent Annual Information Form for the year ended December 31, 2015 as filed on SEDAR at www.sedar.com. The Company's primary business risks as at March 31, 2016 are as follows:

- The Company's business relies on the oil and gas exploration and production industry which is subject to a number of risks including general economic conditions, fluctuations in demand and supply of oil and gas production, fluctuations in commodity prices, competition and increases in operating costs. In addition, changes may occur in government regulations, including regulations relating to foreign acquisitions, prices, taxes, royalties, land tenure, allowable production, importing and exporting of oil and natural gas and environmental protection for the oil and gas industry as a whole. Risks impacting the oil and gas exploration and production industry, including the ability of oil and gas companies to accumulate capital or variations in their exploration and development budgets, may also affect the Company's business. The exact impact of these risks cannot be accurately predicted.
- The current low commodity price environment is expected to continue throughout 2016. If a low commodity price environment persists as expected, the demand for the Company's equipment and services will remain lower than normal and the Company's utilization rates and revenue will continue to be adversely affected during such time. In addition, lower utilization and revenue could result in the Company not being in compliance with certain covenants in its credit facility and under its long term note indenture, which in turn could restrict the Company's ability to access its credit facility, pay distributions and incur additional debt in the future.

- The Company's exploration and production customer's facilities and other operations emit greenhouse gases and require them to comply with legislation in those provinces and states where they operate. On November 22, 2015, the Alberta government announced new emissions regulations, including an economy wide price on carbon emissions effective January 1, 2017 and methane emission reductions. The direct or indirect costs of greenhouse gas emission reduction regulations may have a material adverse effect on the Company's business, financial condition and results of operations and cash flows, as well as impacting the Company's customer's operations.
- In addition to global economic events and uncertainty, the capacity within North America to ship commodities to market introduces uncertainties in levels of activity and pricing for oil and natural gas production.
- The Company is vulnerable to market prices. Fixed costs, including costs associated with operations, leases, and labour costs account for a significant portion of the Company's expenses. As a result, reduced productivity resulting from reduced demand, equipment failure, or other factors could significantly affect its financial results.
- Competition among oilfield service companies offering related services is significant. Some competitors are larger and have greater revenue than the Company and overall greater financial resources. The Company's ability to generate revenue depends on its ability to attract and win contracts and to perform services.
- Currently, the Company is focused on providing services in the WCSB as well as certain geographic areas in the United States, which may expose the Company to more extreme market fluctuations relating to items such as weather and general economic conditions which may be more extreme than the broader industry conditions.
- The success of the Company is dependent upon the efforts and abilities of its management team. The loss of any member of the management team could have a material adverse effect upon the business and prospects of the Company.
- The Company's business is subject to the operating risks inherent to the oilfield service industry. On occasion, substantial liabilities to third parties may be incurred. The Company will have the benefit of insurance maintained by it and industry standard contracts, however, it may become liable for damages against which it cannot adequately insure or against which it may elect not to insure because of high costs or other reasons.
- The oilfield service industry has experienced a high degree of invention and innovation. It is possible that new technology will be developed which will compete with the Company's products and services.
- A portion of the operations of the Company are in the United States which subject the Company to currency fluctuations and different tax and regulatory laws.
- The loss of a significant customer or customers, or any decrease in services provided or prices charged to a significant customer or customers.

Non-IFRS Measures

Western uses certain measures in this MD&A which do not have any standardized meaning as prescribed by IFRS. These measures which are derived from information reported in the condensed consolidated financial statements may not be comparable to similar measures presented by other reporting issuers. These measures have been described and presented in this MD&A in order to provide shareholders and potential investors with additional information regarding the Company. These Non-IFRS measures are identified and defined as follows:

Operating Revenue

Management believes that in addition to revenue, Operating Revenue is a useful supplemental measure as it provides an indication of the revenue generated by Western's principal operating activities, excluding flow through third party charges such as rig fuel, which at the customer's request may be paid for initially by Western, then recharged in its entirety to Western's customers.

Gross Margin

Management believes that in addition to net income, Gross Margin is a useful supplemental measure as it provides an indication of the results generated by Western's principal operating activities prior to considering administrative expenses, depreciation and amortization, how those activities are financed, the impact of foreign exchange, how the results are taxed, how funds are invested, and how non-cash items and one-time gains and losses affect results.

The following table provides a reconciliation of revenue under IFRS, as disclosed in the condensed consolidated statements of operations and comprehensive income, to Operating Revenue and Gross Margin:

	Three months ended March 31	
(stated in thousands)	**2016**	**2015**
Operating Revenue		
Drilling	22,324	75,607
Production services	9,886	25,573
Less: inter-company eliminations	(10)	(222)
	32,200	**100,958**
Third party charges	1,737	4,892
Revenue	**33,937**	**105,850**
Less: operating expenses	(32,489)	(71,475)
Add:		
Depreciation - operating	7,311	13,365
Stock based compensation - operating	108	151
Gross Margin	**8,867**	**47,891**

Adjusted EBITDA

Management believes that in addition to net income, earnings before interest and finance costs, taxes, depreciation and amortization, other non-cash items and one-time gains and losses ("Adjusted EBITDA") is a useful supplemental measure as it provides an indication of the results generated by the Company's principal operating activities similar to Gross Margin but also factors in the cash administrative expenses incurred in the period.

Operating Earnings

Management believes that in addition to net income, Operating Earnings is a useful supplemental measure as it provides an indication of the results generated by the Company's principal operating activities similar to Adjusted EBITDA but also factors in the depreciation expense incurred in the period.

The following table provides a reconciliation of net income under IFRS, as disclosed in the condensed consolidated statements of operations and comprehensive income, to earnings before interest and finance costs, taxes, depreciation and amortization ("EBITDA"), Adjusted EBITDA and Operating Earnings:

	Three months ended March 31	
(stated in thousands)	**2016**	**2015**
Net income (loss)	**(6,319)**	**15,294**
Add:		
Finance costs	5,538	4,758
Income tax (recovery) expense	(2,495)	6,422
Depreciation - operating	7,311	13,365
Depreciation - administrative	420	429
EBITDA	**4,455**	**40,268**
Add:		
Stock based compensation - operating	108	151
Stock based compensation - administrative	931	812
Other items	(2,130)	(594)
Adjusted EBITDA	**3,364**	**40,637**
Subtract:		
Depreciation - operating	(7,311)	(13,365)
Depreciation - administrative	(420)	(429)
Operating Earnings (Loss)	**(4,367)**	**26,843**

Net Debt

The following table provides a reconciliation of long term debt under IFRS, as disclosed in the condensed consolidated balance sheets to Net Debt:

(stated in thousands)	March 31, 2016	December 31, 2015
Long term debt	264,118	264,155
Current portion of long term debt	709	761
Less: cash and cash equivalents	(49,852)	(58,445)
Net Debt	**214,975**	**206,471**

Drilling rig utilization – Operating Days: Calculated based on Operating Days divided by total available days.

Drilling rig utilization – Revenue Days: Calculated based on Revenue Days divided by total available days.

Operating Days: Defined as contract drilling days, calculated on a spud to rig release basis.

Revenue Days: Defined as Operating Days plus rig mobilization days.

Service Hours: Defined as well servicing hours completed.

Service rig utilization: Calculated based on Service Hours divided by available hours, being 10 hours per day, per well servicing rig, 365 days per year.

Contract Drilling Rig Classifications

Cardium class rig: Defined as any contract drilling rig which has a total hookload of less than or equal to 399,999 lbs (or 177,999 daN).

Montney class rig: Defined as any contract drilling rig which has a total hookload between 400,000 lbs (or 178,000 daN) and 499,999 lbs (or 221,999 daN).

Duvernay class rig: Defined as any contract drilling rig which has a total hookload equal to or greater than 500,000 lbs (or 222,000 daN).

Abbreviations:

- Barrel (“bbl”);
- Basis point (“bps”): A 1% change equals 100 basis points and a 0.01% change is equal to one basis point;
- Canadian Association of Oilwell Drilling Contractors (“CAODC”);
- DecaNewton (“daN”);
- International Financial Reporting Standards (“IFRS”);
- Pounds (“lbs”);
- Thousand cubic feet (“mcf”);
- West Texas Intermediate (“WTI”);
- Western Canadian Sedimentary Basin (“WCSB”); and
- Western Canadian Select (“WCS”).

Forward-Looking Statements and Information

This MD&A contains certain statements or disclosures relating to Western that are based on the expectations of Western as well as assumptions made by and information currently available to Western which may constitute forward-looking information under applicable securities laws. All such statements and disclosures, other than those of historical fact, which address activities, events, outcomes, results or developments that Western anticipates or expects may, or will occur in the future (in whole or part) should be considered forward-looking information. In some cases forward-looking information can be identified by terms such as “forecast”, “future,” “may”, “will”, “expect”, “anticipate,”, “believe”, “potential”, “enable”, “plan”, “continue”, “contemplate”, “pro forma”, or other comparable terminology.

In particular, forward-looking information in this MD&A includes, but is not limited to, statements relating to future declaration of dividends; commodity pricing; the future demand for and utilization of the Company’s services and equipment; the terms of existing and future drilling contracts in Canada and the US and the revenue resulting therefrom (including the number of Operating Days typically generated from the Company’s contracts); the Company’s expansion and maintenance capital plans for 2016, including the ability of current capital resources to cover Western’s financial obligations and the 2016 capital budget; the Company’s expected sources of funding to support such capital plans and the Company’s ability to adjust capital spending in the remainder of 2016 if market conditions, including customer demand, continue to change; the expected benefits from cost control measures; the use and availability of the Company's Credit Facilities; the Company's ability to maintain certain covenants under its Credit Facility; expectations as to the increase in crude oil transportation capacity through rail and pipeline development; expectations as to the necessary approvals for liquefied natural gas projects being obtained; the expectation of continued foreign investment into the Canadian oilfield industry; the expectation that producer spending constraints will continue to be a large challenge facing the Company in 2016; and forward-looking statements under the heading "Critical Accounting Estimates".

The material assumptions in making the forward-looking statements in this MD&A include, but are not limited to, assumptions relating to, demand levels and pricing for oilfield services; fluctuations in the price and demand for oil and natural gas; the current low levels of, and pressures on, commodity pricing; the continued business relationship between the Company and its significant customers; general economic and financial market conditions; the development of liquefied natural gas projects, crude oil transport and pipeline approval and development; the Company's ability to finance its operations; the effects of seasonal and weather conditions on operations and facilities; the competitive environment to which the various business segments are, or may be, exposed in all aspects of their business; the ability of the Company's various business segments to access equipment (including spare parts and new technologies); changes in laws or regulations; currency exchange fluctuations; the ability of the Company to attract and retain skilled labour and qualified management; the ability to retain and attract significant customers; and other unforeseen conditions which could impact the use of services supplied by Western including Western's ability to respond to such conditions.

Although Western believes that the expectations and assumptions on which such forward-looking statements and information are based on are reasonable, undue reliance should not be placed on the forward-looking statements and information as Western cannot give any assurance that they will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risk that the demand for oilfield services will not improve for the remainder of 2016 and that commodity prices will remain low, and other general industry, economic, market and business conditions. Readers are cautioned that the foregoing list of risks, uncertainties and assumptions are not exhaustive. Additional information on these and other risk factors that could affect Western's operations and financial results are included in Western's annual information form which may be accessed through the SEDAR website at www.sedar.com. The forward-looking statements and information contained in this MD&A are made as of the date hereof and Western does not undertake any obligation to update publicly or revise any forward-looking statements and information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

Additional data

The Annual Information Form containing additional information relating to the Company is filed on SEDAR at www.sedar.com.