interim report Q1 2016

first quarter ending March 31, 2016

crew energy inc.

Crew Energy Inc. (TSX: CR) ("Crew" or the "Company") is pleased to announce our operating and financial results for the three month period ended March 31, 2016, along with an updated independent Montney Resource Evaluation.

FIRST QUARTER HIGHLIGHTS

- Increased production to 23,832 boe per day, an increase of 15% over the previous quarter and an increase of 25% over the same period in 2015. The year-over-year production growth is highlighted by a 97% increase in condensate production from the continued strong performance of wells drilled at our Northeast British Columbia ("NE BC") Montney areas;
- Realized a 15% improvement in natural gas pricing over the previous quarter despite a 26% decline quarter over quarter in AECO benchmark pricing, as a result of Crew's firm transportation arrangement on the Alliance Pipeline system ("Alliance") and further supported by our ongoing efforts to secure natural gas sales contracts into diversified markets;
- Reduced operating costs per boe by 30% year over year and 6% quarter over quarter to $6.45 per boe with our liquids-rich Montney Septimus / West Septimus operating costs now at $4.43 per boe;
- Lowered total cash costs per boe by 24% over the same period in 2015 and continued to benefit from capital cost reductions achieving all-in drilling, completion and tie-in costs of approximately $3.5 million per well;
- Generated funds from operations of $11.7 million ($0.08 per diluted share), supported by stronger production volumes, improved natural gas pricing and lower cash costs;
- Invested $18.7 million in capital expenditures in the quarter, 24% less than budgeted, directed at drilling the last four wells of an eight well pad, completing three liquids-rich wells at West Septimus and concluding construction of a pipeline beneath the Pine River which connects our West Septimus and Septimus facilities;
- Increased sand loading by 40% on two Upper Montney wells which tested at an average 12 mmcf per day at a flowing casing pressure of 1,135 psi, a 114% increase from the three wells completed on the same pad in Q4 2015, at a drill, complete and tie-in cost of $3.5 million per well;
- Maintained a strong balance sheet with significant liquidity supported by a 51% increase in our proved developed producing reserves and a newly approved $235 million credit facility, which was 58% undrawn at March 31, 2016; and
- Updated our independent Montney Resource Evaluation which reflected an 8% increase to the Best Estimate Economic Contingent Resource ("ECR") assessment to 9.0 TCFE and a modest increase to the Total Petroleum Initially In Place ("TPIIP") estimate to 111.7 TCFE, primarily due to the improved liquid yields on our developed lands. The year-over-year increase in our resource estimate underpins Crew's ongoing Montney-focused drilling strategy designed to develop this massive resource and realize significant long-term value through reserves additions.

FINANCIAL & OPERATING HIGHLIGHTS

FINANCIAL ($ thousands, except per share amounts)	**Three months ended March 31, 2016**	Three months ended March 31, 2015
Petroleum and natural gas sales	**36,343**	39,940
Funds from operations[1]	**11,714**	20,720
Per share - basic	**0.08**	0.16
- diluted	**0.08**	0.16
Net loss	**(6,795)**	(15,770)
Per share - basic	**(0.05)**	(0.12)
- diluted	**(0.05)**	(0.12)
Exploration and Development expenditures	**17,763**	91,092
Property acquisitions (net of dispositions)	**956**	258
Net capital expenditures	**18,719**	91,350

Capital Structure ($ thousands)	**As at March 31, 2016**	As at Dec. 31, 2015
Working capital deficiency[2]	**858**	10,737
Bank loan	**98,108**	80,980
	98,966	91,717
Senior Unsecured Notes	**146,854**	146,679
Total Net Debt	**245,820**	238,396
Current Debt Capacity[3]	**385,000**	400,000
Common Shares Outstanding (thousands)	**141,073**	141,067

Notes:

(1) Funds from operations is calculated as cash provided by operating activities, adding the change in non-cash working capital, decommissioning obligation expenditures and accretion of deferred financing costs. Funds from operations is used to analyze the Company's operating performance and leverage. Funds from operations does not have a standardized measure prescribed by International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures for other companies.

(2) Working capital deficiency includes cash and cash equivalents plus accounts receivable less accounts payable and accrued liabilities.

(3) Current Debt Capacity reflects the newly approved bank facility of $235 million plus $150 million in senior unsecured notes outstanding.

Operations	**Three months ended March 31, 2016**	Three months ended March 31, 2015
Daily production		
Light crude oil (bbl/d)	**303**	657
Heavy crude oil (bbl/d)	**2,799**	4,735
Natural gas liquids (bbl/d)	**3,359**	2,060
Natural gas (mcf/d)	**104,224**	69,498
Total (boe/d @ 6:1)	**23,832**	19,035
Average prices [1]		
Light crude oil ($/bbl)	**37.34**	49.28
Heavy crude oil ($/bbl)	**20.45**	36.63
Natural gas liquids ($/bbl)	**25.95**	27.17
Natural gas ($/mcf)	**2.34**	2.62
Oil equivalent ($/boe)	**16.76**	23.31

Notes:

(1) Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments.

	Three months ended March 31, 2016	Three months ended March 31, 2015
Netback ($/boe)		
Revenue	**16.76**	23.31
Realized commodity hedging gain	**2.21**	6.61
Royalties	**(0.88)**	(2.00)
Operating costs	**(6.45)**	(9.28)
Transportation costs	**(2.51)**	(1.96)
Operating netback [(1)]	**9.13**	16.68
G&A	**(1.76)**	(2.18)
Interest on long-term debt	**(1.98)**	(2.40)
Funds from operations	**5.39**	12.10
Drilling Activity		
Gross wells	**4**	6
Working interest wells	**4.0**	6.0
Success rate, net wells (%)	**100%**	100%

Notes:

(1) Operating netback equals petroleum and natural gas sales including realized hedging gains and losses on commodity contracts less royalties, operating costs and transportation costs calculated on a boe basis. Operating netback and funds from operations netback do not have a standardized measure prescribed by International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures for other companies.

OVERVIEW

Crew realized a successful first quarter of 2016 and effectively navigated through persistently challenging market conditions. The Company realized production growth of 15% quarter over quarter and 25% year over year, attributable to our successful Montney drilling and development program, as well as the ramp-up of volumes processed through our West Septimus facility that occurred with the commencement of our Alliance pipeline service on December 1, 2015.

The first quarter of 2016 was Crew's first full reporting period with the Alliance transportation service which facilitates the sale of a portion of our natural gas into markets priced off of the Chicago City Gate hub, realizing a premium to AECO benchmark pricing during the quarter. Crew's actively-managed portfolio approach to transportation and gas marketing has positioned the Company well to mitigate risk through diversifying sales points and pricing optionality for our gas. We added incremental marketing arrangements in late 2015 which further strengthen our position for 2016 and beyond.

Crew continues to focus on maintaining our strong balance sheet, exiting the quarter with more than $136 million of capacity available on our newly approved $235 million credit facility. We were very pleased with our lending review, which due to Crew's strong underlying asset base, resulted in a modest 6% reduction to our borrowing base. The significant portion of undrawn capacity provides Crew with substantial financial flexibility that we plan to maintain by aligning 2016 capital investments with our cash flow. As a result of taking this conservative approach, we are confident in Crew's ability to withstand the ongoing market volatility while advancing our Montney development.

MONTNEY RESOURCE EVALUATION UPDATE

Crew is pleased to report the results of its annual updated independent Montney resource evaluation conducted by Sproule Associates Ltd. ("Sproule") on our principal NE BC Montney lands including Septimus, West Septimus, Groundbirch / Monias, Attachie and Tower, effective December 31, 2015 (the "Resource Evaluation"). Sproule performed detailed mapping across the evaluated areas which included section by section estimates of reservoir parameters, such as pressure, temperature, porosity, and water saturation, which make up the TPIIP determination. At 111.7 TCFE, Crew's TPIIP estimate provides the Company with significant opportunities to continue increasing the current ECR estimates plus add reserves with further drilling. Crew's risked best estimate ECR on natural gas increased 5% to 7.5 Tcf, natural gas liquids ("NGL") ECR was 32% higher at 225 mmbbls, a result of our highly successful West Septimus drilling program, while our crude oil ECR remained stable at 23 million bbls.

The updated Resource Evaluation demonstrates the significant potential of our lands, offering multiple years of future running room and significant value creation opportunities. Although the play remains in its early stages of development, with new and enhanced drilling and completions techniques, Crew and other area operators continue to further delineate and de-risk the potential of this massive play, demonstrating results from the Montney that continue to improve.

FINANCIAL

Crew's strong financial position, operational and market optionality, and ongoing focus on preserving balance sheet strength enable the Company to make decisions that are in the long-term interests of our shareholders. Given the high quality nature of our asset base, we continue to generate compelling long-term returns from our projects despite persistent commodity price weakness. Crew's historical commitment to maintaining diversity in our long-term funding strategy has afforded the Company financial flexibility provided by our credit facility which remained 58% undrawn at quarter end. Total net debt at the end of the quarter was $245.8 million, including working capital deficiency and $150 million ($146.9 million net of deferred financing costs) of senior unsecured notes that are not due for repayment until the fourth quarter of 2020. Given that the Company has no near-term debt maturities and has maintained substantial liquidity in a challenging market, Crew is well positioned to manage through sustained weak commodity prices.

During the quarter, commodity prices remained weak and declined further. Crude oil prices reached their lowest level since 2003 due to continued oversupply and uncertain global demand. North American natural gas was also weaker, driven lower by the warmest North American winter in over 100 years and a prolonged supply glut, with Western Canadian natural gas prices at AECO and Station 2 trading below $1 per mcf during the quarter. With the onset of Crew's arrangements on the Alliance pipeline in early December, the Company accessed new markets, including selling approximately 40% of our natural gas at Chicago City Gate prices, which realized a significant premium to AECO benchmark pricing and helped support our funds from operations in the quarter. Although Crew was able to access better markets, significantly increase production and reduce costs, first quarter funds from operations was $11.7 million ($0.08 per diluted share), 43% lower than the first quarter of 2015.

Net capital expenditures during the first quarter totaled $18.7 million, including exploration and development expenditures of $17.8 million, with $0.9 million spent on a minor acquisition. Net expenditures are inclusive of the $10.8 million Government of British Columbia infrastructure credit earned for construction of the Pine River Pipeline which concluded in first quarter and started flowing subsequent to the end of the quarter. At West Septimus, Crew also drilled four (4.0 net) wells and completed three (3.0 net) wells. First quarter 2016 capital expenditures were 24% under our quarterly budget as capital cost savings continued to be realized and we undertook fewer well completions due to the strong performance of the three West Septimus wells which were completed during the quarter.

NE BC MONTNEY – SEPTIMUS / WEST SEPTIMUS OVERVIEW

Operations

During the quarter, Crew achieved record average production at Septimus and West Septimus of 18,149 boe per day representing approximately 76% of the Company's total production volumes. This is a 27% increase over the previous quarter, and a 79% increase over the same period in 2015, highlighted by a 97% increase in condensate production due to strong well performance, particularly at West Septimus. Crew's operating costs per unit for the Septimus/West Septimus complex declined 23% from the previous quarter to $4.43 per boe on increased throughput and continuing cost reduction initiatives.

Montney Liquids-Rich Natural Gas

Production & Drilling	**First Quarter 2016**	Fourth Quarter 2015
Average Daily Production (boe/d)	**18,149**	14,321
Wells drilled (gross / net)	**4 / 4.0**	5 / 5.0
Wells completed	**3**	6

Operating Netback ($ per boe)	**First Quarter 2016**	Fourth Quarter 2015
Revenue	**16.69**	16.55
Royalties	**(0.78)**	(0.72)
Operating costs	**(4.43)**	(5.75)
Transportation costs	**(2.27)**	(1.65)
Operating netback	**9.21**	9.15

Crew completed and brought into service the Pine River sales gas pipeline connecting our West Septimus and Septimus facilities. This commissioning facilitated the conversion of an existing six inch gas pipeline into a condensate transportation line between the two facilities. With both of these pipelines now in service, Crew's immediate realized cost savings are approximately $3 to $4 per bbl of condensate with the elimination of trucking from the West Septimus facility. The Company now has the necessary infrastructure in place to handle sales volumes associated with a future expansion of our West Septimus facility to 120 mmcf per day. With the successful drilling program at West Septimus through the latter part of 2015 and into 2016, Crew has increased production and reduced costs while realizing improved pricing due to marketing arrangements that commenced in December of 2015.

During the first quarter, the Company drilled the last four wells of an eight well pad, and completed three wells at West Septimus. The eight well pad is expected to be completed in the third quarter including Crew's second Lower Montney well. Crew's initial Lower Montney well continues to exhibit a positive production trend averaging 3.6 mmcf per day of raw gas production over a 125 day period with average wellhead condensate of 46 bbls per mmcf.

Crew continues to optimize completion practices in West Septimus which has contributed to a significant improvement in well performance over time. Early in the second quarter, Crew completed the last two wells of a five well pad at West Septimus, utilizing 40% higher sand loading on a per meter basis than the previous three wells. The two wells were production tested over a 6 day period and achieved a final raw gas rate of 12 mmcf per day, each at an average flowing casing pressure of 1,135 psi. This rate is an increase of 114% from the initial average raw gas rate of the original three wells completed in Q4 2015. With lower costs for completions, and factoring in our current drilling and tie-in costs, projected all-in well costs at Crew's West Septimus Montney area are coming in at a very attractive $3.5 million including the higher sand loading. Although the commodity price environment continues to be weak, the project economics at West Septimus and Septimus remain compelling, supported by continued costs reductions, particularly on completions and improved pricing through diversified markets.

Transportation and Marketing

The firm Alliance transportation service Crew contracted beginning in December 2015 has allowed the Company to diversify our gas marketing arrangements leading to stronger realized gas pricing. This contract diversification, combined with Crew's Montney gas that has a heat content 18% higher than the Alliance standard, contributed to higher first quarter realized natural gas prices, which averaged $0.51 per mcf or 28% higher than the quarterly AECO daily spot average of $1.83 per mcf. Crew currently has approximately 40% of our natural gas volumes priced off of Chicago City Gate prices, 22% priced off of AECO, 30% priced off of ATP (Alliance Trading Pool), 4% priced at Sumas, WA and only 4% priced off of Station 2. Optionality in our marketing and sales points affords Crew significant flexibility to respond to changing market conditions, and focus on projects or markets offering the best returns and pricing.

NE BC MONTNEY – TOWER OVERVIEW

Crew's Montney Tower area continues to represent significant future development opportunity for the Company as crude oil prices strengthen. With an inventory of four drilled and uncompleted wells at Tower, Crew is preparing to implement improvements in completion techniques which have resulted in increased initial production rates and ultimate recoveries from area wells. With an improvement in commodity prices, Crew may elect to complete these wells in 2016, which would substantially increase our light oil production.

LLOYDMINSTER, AB/SK OVERVIEW

Production at our Lloydminster heavy oil property averaged 2,837 boe per day in the first quarter of 2016, which reflects an additional 235 boe per day of production that was taken offline at the end of the first quarter due to low commodity prices. In aggregate Crew has approximately 700 boe per day of heavy oil shut-in at present. Our heavy oil team continues to strive to improve the economics of our operations through the rationalization of higher cost production and a focus on optimizing operating efficiencies. Total cash costs per unit for our heavy oil operations have decreased 17% in the first quarter of 2016 compared to the same period in 2015 including operating expenses decreasing 7% to average $16.06 per boe during the quarter.

OUTLOOK

Crew continues to focus on the prudent and measured development of our high-quality asset base and successful execution of our value creation strategy. Over the past few years we have taken steps to ensure the Company is well positioned for a low commodity price environment. These actions have served us well during the past 18 months of price weakness. We have assembled a sizeable and ideally situated land base of 474 net sections in the Montney with resource of 111.7 TCFE of Total Petroleum Initially In Place. This resource is comprised of 7.9 billion bbls of light oil and 64.3 TCF of natural gas that offers significant exposure to both commodities. Access to owned and operated facilities and infrastructure, firm transportation arrangements and a diversified marketing strategy have enabled the Company to optimize Crew's realized product prices in the current commodity price environment.

In light of continued commodity price uncertainty and volatility, we have taken a very conservative approach to our capital expenditures this year. Following increased activity through 2015, we have built an inventory of 14 drilled but uncompleted wells that we can complete to maintain or increase production volumes. Further, with continued reductions in drilling and completions costs, there may be opportunities to undertake projects that weren't included in our original 2016 plans within our existing capital budget. Our ability to invest capital and achieve better results continues to improve with cost reductions and evolving drilling and completions practices. We are excited about recent improvements in well results through enhanced completions, as increased sand loading is yielding materially improved results. We intend to continue increasing our proppant per stage with the completion of our next wells at West Septimus. As a result of drilling, Crew has also identified specific areas of our West Septimus acreage which are generating stronger liquids yields, better initial production rates and greater estimated recoveries per well. We will continue to assess the cost-benefit analysis of enhanced completions in our 2016 program.

In addition to the approximately 700 boe per day of shut-in Lloydminster volumes mentioned above, the low commodity prices have impacted a number of other minor non–operated properties which have experienced shut-in volumes. Most notably, Crew had working interest volumes at properties in NE BC associated with an operating company that served notice of receivership and the shut-in of all of its production on March 18, 2016. Combined with other minor properties, Crew has approximately 700 boe per day of shut-in volumes from these NE BC areas that were generating minimal funds from operations and are not expected to return to production in the near future. The Company plans to make up these volumes from Montney wells that have outperformed expectations, which will also contribute to higher netbacks. Our 2016 annual production guidance remains at 23,000 to 25,000 boe per day on a capital budget of $70 million. Capital expenditures will be adjusted with expected funds from operations, with a priority to maintain total net debt between $235 and $250 million at year end 2016.

Longer term, Crew plans to continue developing our massive Montney resource converting prospective resource to Economic Contingent Resource ("ECR"), to reserves and ultimately, to production and cash flow. Our priorities remain on preserving balance sheet strength while investing capital prudently to maintain production while positioning the Company to ramp up activity levels at the appropriate time. Crew has the option to increase our interest in both the Septimus and West Septimus facilities starting in 2017, which would further improve our cost structure. Longer term, we have the option to buy out the remaining partner in the facilities in 2020 which would further reduce operating costs, and advance Crew's goal of becoming one of the Montney's lowest cost operators. Crew will continue to actively manage our marketing and transportation arrangements, making adjustments to optimize our sales points in order to achieve the strongest price for our products.

We are pleased to be moving forward in 2016 with financial flexibility, significant liquidity, and a high quality asset base that is constantly improving. We would like to thank our employees and Board of Directors for their commitment to Crew, and our shareholders for their ongoing support through a challenging market environment.

DECEMBER 31, 2015 RESOURCE EVALUATION

The following discussion in "Northeast British Columbia Montney Resource Evaluation" is subject to a number of cautionary statements, assumptions and risks as set forth therein. See "Information Regarding Disclosure on Oil and Gas Reserves, Resources and Operational Information" at the end of this release for additional cautionary language, explanations and discussion, and see "Forward-looking Information and Statements" for a statement of principal assumptions and risks that may apply. See also "Definitions of Oil and Gas Resources and Reserves" in this news release. The discussion includes reference to TPIIP, DPIIP and ECR as per the Resource Evaluation as at December 31, 2015, prepared in accordance with the current COGE Handbook guidelines. Unless otherwise indicated in this news release, all references to ECR and prospective volumes are Best Estimate ECR and Best Estimate prospective volumes, respectively.

Amendments to NI 51-101 that came into effect on July 1, 2015 require significant changes to the way resources are disclosed relative to prior years. The most significant changes require:

- *The sub-classification of contingent resources into specified project maturity subclasses. Those that apply to Crew's resources include:*
  - *Development Pending*
  - *Development on Hold*
  - *Development not Viable*

Sproule considers the 'development pending' and 'development on hold' project maturity subclasses to be economic and are therefore included in ECR. The economic status of the 'development not viable' project maturity subclass is undetermined and is therefore not included in the ECR reported. The "development not viable" sub-classification represented less than 2% of the sum of all three sub-classifications on a BOE basis.

- *Changes to the product types, including the addition of new product types and providing new definitions for some existing product types;*
- *The disclosure of the risked, best estimate of the contingent resources volumes for each product type;*
- *The disclosure of the risked NPV of future net revenues for any disclosed development pending contingent resources, calculated using forecast prices and costs for each product type, on a before tax basis using discount rates of zero %, five %, 10 %, 15 % and 20 %;*
- *The disclosure of the chance of development risk for each project maturity sub-class the issuer discloses; and*
- *The disclosure of the estimated total cost to achieve commercial production, the estimated date of first commercial production and the recovery technology to be used.*

CREW NORTHEAST BRITISH COLUMBIA MONTNEY RESOURCE EVALUATION

The Montney formation in NE BC has been identified as a world-class unconventional resource play with the potential for significant volumes of recoverable resources. The area includes dry gas, liquids-rich gas and light oil development opportunities, with Crew having access to all three hydrocarbon windows. It is one of the largest and lowest cost natural gas resource plays in North America and Crew's land base comprises 474 net sections, ideally situated in some of the most prospective parts of the play, with good access to infrastructure and multiple egress options.

Sproule was engaged to conduct an updated independent Montney resource evaluation of Crew's principal lands in the NE BC Montney region including Septimus, West Septimus, Groundbirch/Monias, Attachie and Tower (the "Evaluated Areas") effective as of December 31, 2015, and based on Sproule's forecast price deck as at December 31, 2015 (the "Resource Evaluation"). The Resource Evaluation highlights the development potential on the Company's undeveloped land base providing Crew with significant opportunities to progress conversion of Resource to ECR and ultimately to increased reserve bookings over time. . Further, the diversity of Crew's NE BC Montney assets with exposure to liquids rich gas, crude oil and dry natural gas allows us to effectively navigate through commodity price cycles.

TPIIP for the natural gas-bearing lands in the Evaluated Areas remains unchanged relative to year end 2014 at 64.3 Tcf. Crew achieved a 15% increase in DPIIP for the Evaluated Areas to 35.2 Tcf, primarily attributed to the 2015 petroleum and natural gas rights exchange with the Province of British Columbia announced in July of 2015.

Natural gas ECR was evaluated on an unrisked and risked basis in the Resource Evaluation and was subdivided into the Maturity Subclasses of 'development pending' and 'development on hold'. The risked 'development pending' natural gas ECR totaled 7.1 Tcf and the risked 'development on hold' ECR totaled 0.4 Tcf. Total risked natural gas ECR increased by 5% primarily attributable to the lands acquired through the July 2015 petroleum and natural gas rights exchange with the Province of BC.

The ECR of our NGL's was also evaluated on an unrisked and risked basis in the Resource Evaluation and was subdivided into the Maturity Subclasses of 'development pending' and 'development on hold'. The risked 'development pending' NGL ECR totaled 209 MMbbl and risked 'development on hold' NGL ECR totaled 16 MMbbl. Total NGL ECR increased by 32% due to improved liquids yields resulting from successful development of Crew's West Septimus lands.

On the oil-bearing Montney lands, TPIIP increased 3% to 7,895 MMbbl and DPIIP increased 7% to 1,613 MMbbl.
Oil ECR was evaluated on an unrisked and risked basis in the Resource Evaluation and was subdivided into the Maturity Subclasses of 'development pending' and 'development on hold'. The risked 'development pending' oil ECR totaled 19 MMbbl and risked 'development on hold' oil ECR totaled 4 MMbbl.

Risking of the contingent resources included a quantitative assessment of the contingencies applicable to the project including evaluation drilling, corporate commitment and timing of production and development. Risking of the prospective resources included a quantitative assessment of these same factors, as well as a quantitative assessment of the chance of discovery.

The following tables summarize the results of the Resource Evaluation along with comparatives to the updated December 31, 2014 evaluation (reflecting the impact of the July 2015 petroleum and natural gas rights exchange with the Province of BC), using the resource categories set out in the COGE Handbook on a "best estimate" case.

	Dec. 31, 2015	Dec. 31, 2014	% Change
Conventional Natural Gas Resource Categories (1)(2)(3)(4)	**Tcf**	Tcf	
Total Petroleum Initially In Place (TPIIP)	**64.3**	64.3	**0**
Discovered Petroleum Initially In Place (DPIIP)	**35.2**	30.5	**15**
Undiscovered Petroleum Initially In Place (UPIIP)	**29.1**	33.8	**(14)**

Notes:

(1) TPIIP, DPIIP and UPIIP have been estimated using a one percent porosity cut-off in the 2015 report, which means that essentially all gas bearing rock has been incorporated into the calculations.
(2) All volumes in table are Company gross and raw gas volumes.
(3) Sproule's analysis identified four intervals in the Montney consisting of one interval in the Upper Montney and three intervals in the Lower Montney.
(4) Crew's acreage was divided into five (5) areas in the "gas window".

	Dec. 31, 2015	Dec. 31, 2014	% Change
Light & Medium Crude Oil Resource Categories (1)(2)(3)(4)(5)	**Mmbbls**	Mmbbls	
Total Petroleum Initially In Place (TPIIP)	**7,895**	7,640	**3**
Discovered Petroleum Initially In Place (DPIIP)	**1,613**	1,501	**7**
Undiscovered Petroleum Initially In Place (UPIIP)	**6,282**	6,139	**2**

Notes:

(1) TPIIP, DPIIP and UPIIP have been estimated using a one percent porosity cut-off in the 2015 report, which means that essentially all oil bearing rock has been incorporated into the calculations.
(2) All volumes in table are Company gross.
(3) The oil volumes are quoted as Stock Tank Barrels ("STB").
(4) Sproule's analysis identified four intervals in the Montney consisting of one interval in the Upper Montney and three intervals in the Lower Montney.
(5) Crew's acreage was divided into five (5) areas in the "oil window".

2015 Reserves and Risked and Unrisked ECR(1)(2)(3)(6)(7)(8)	Chance of Development	Best Estimate Unrisked	**Best Estimate Risked**
Conventional Natural gas (Bcf)			
Reserves (3)	100%	1,164	**1,164**
Development Pending ECR	87%	8,160	**7,090**
Development on Hold ECR	85%	515	**437**
NGL (Mmbbls) (4)(5)			
Reserves (3)	100%	43	**43**
Development Pending ECR	88%	238	**209**
Development on Hold ECR	84%	19	**16**
Light & Medium Crude Oil (Mmbbls)			
Reserves (3)	100%	9	**9**
Development Pending ECR	90%	21	**19**
Development on Hold ECR	80%	5	**4**

Notes:

(1) All DPIIP other than cumulative production, reserves, and ECR has been categorized as unrecoverable at this time. A portion of the Unrecoverable DPIIP may in the future be determined to be recoverable and reclassified as contingent resources or reserves as additional technical studies are performed, commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.
(2) All volumes in table are company gross and sales volumes, before economic cutoff.
(3) For reserves, the volumes are proved plus probable reserves as at December 31, 2015
(4) The liquid yields are based on average yield over the producing life of the property.
(5) Liquid yields are unique to each area. They are estimated based on gas composition of gas samples in the area and expected plant recoveries.
(6) There is no certainty that it will be commercially viable to produce any of the resources.
(7) All ECR are risked for the chance of development. For ECR, the chance of development is defined as the probability of a project being commercially viable. In quantifying the chance of development, contingencies that were assessed quantitatively to be less than one in the risking calculation included evaluation drilling, corporate commitment and timing of production and development. The chance of development is multiplied by the unrisked resource volume estimate, which yields the risked volume estimate. As many of these factors have a wide range of uncertainty and are difficult to quantify, the chance of development is an uncertain value that should be used with caution.
(8) The economic status of the 'development not viable' project maturity subclass is deemed to be undetermined and is therefore not included in the ECR reported, representing, on a risked basis, 127 bcf of conventional natural gas, 3 mmbbls of NGLs and 2 mmbbls of light and medium crude oil.

An estimate of risked NPV of future net revenues of the development pending contingent resources subclass only is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of Crew proceeding with the required investment. It includes contingent resources that cannot be classified as reserves until the contingencies are lifted. There is uncertainty that the risked NPV of future net revenue will be realized. The other subclasses of resources are not included in this NPV and therefore this is not reflective of the value of the resource base.

Before-Tax NPV(1) 2015 Risked ECR Development Pending(2)	($ millions)
Undiscounted	29,309
Discounted at 5%	7,403
Discounted at 10%	2,459
Discounted at 15%	964
Discounted at 20%	402

Notes

(1) Based on Sproule's forecast pricing at December 31, 2015 which is set forth in Crew's press release dated February 17, 2016.
(2) Risk in the above table is the chance of development. ECR are discovered resources by definition

The estimated cost to fully develop the 'development pending' sub-classification is approximately $10.9 billion (is approximately $3.0 billion discounted at 10%). The forecasted timeline to bring these resources onto production is between two and 17 years utilizing the same technology in horizontal drilling and multi-stage fracturing that Crew has already proven to be effective in the Montney formation in NE BC.

Prospective Resources (1)(2)(3)(4)(5)(6)(7)	Chance of Commerciality	Best Estimate Unrisked	Best Estimate Risked
Conventional Natural Gas (Tcf)	65%	10,225	6,695
NGL (MMbbl)	65%	354	231
Light & Medium Crude Oil (MMbbl)	66%	145	95

Notes:

(1) All UPIIP other than prospective resources has been categorized as unrecoverable at this time.
(2) All volumes in table are company gross and sales volumes.
(3) The liquid yields are based on average yield over the producing life of the property.
(4) Liquid yields are unique to each area. They are estimated based on gas composition of gas samples in the area and expected plant recoveries.
(5) There is no certainty that it will be commercially viable to produce any of the resources.
(6) Prospective resources are risked for the chance of discovery and the chance of development. For prospective resources, the chance of development multiplied by the chance of discovery is defined as the probability of a project being commercially viable. In quantifying the chance of commerciality, factors that were assessed quantitatively to be less than one in the risking calculation included evaluation drilling, corporate commitment and timing of production and development, along with the overall chance of discovery. The chance of commerciality is multiplied by the unrisked prospective resource volume estimate, which yields the risked volume estimate. As many of these factors have a wide range of uncertainty and are difficult to quantify, the chance of commerciality is an uncertain value that should be used with caution.
(7) All prospective resources are subclassified as either the 'prospect' or 'lead' project maturity subclass.

Resource volumes are estimated using volumetric calculations of the in-place quantities, combined with performance from analog reservoirs. The currently producing assets of Crew and other industry parties in the Montney area of NE B.C. are used as performance analogs for ECR within Crew's areas of operations. The evaluation of ECR is based on an independent third party evaluation that assumes all of Crew's ECR will be recovered using horizontal multi-stage hydraulic fracturing and multi-well pad drilling, which are established technologies.

Crew's ability to recover additional resources is subject to numerous factors, that include minimal well data from the Montney formation in certain intervals; access to capital that would enable us to continue development; low commodity prices which could impact economics; the future performance of wells; regulatory approvals; access to required services; overall industry cost structures; and the continued efficacy of fracture stimulation technologies. In order for ECR to be converted into reserves, Crew's management and technical teams must continue to assess commercial production rates, devise firm development plans that incorporate timing, infrastructure and capital commitments. With continued development and delineation, some resources currently classified as ECR are expected to be reclassified as Reserves.

A key contingency that prevents the classification of ECR as Reserves is the additional drilling, completions and testing required to confirm viable commercial rates. Sproule assigned ECR beyond those areas which were assigned Reserves but which were within three miles of existing wells, or production tests. Further, a lack of infrastructure in the Evaluated Areas which is required to develop the resources, such as gas gathering, processing and natural gas liquids separation facilities, further impedes the reclassification of ECR to Reserves. In addition to these factors, and the general operational risks facing the oil and gas industry, there are several technical and non-technical contingencies that need to be overcome in order to reclassify ECR to Reserves. These include evaluation drilling, corporate commitment and timing of production and development of the ECR.

There is no certainty that any portion of the prospective resources will be discovered. There is uncertainty that it will be commercially viable to produce any portion of the prospective (if discovered) or contingent resources.

Definitions of Oil and Gas Resources and Reserves

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates as follows:

> **Proved Reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
>
> **Probable Reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Cumulative Production is the cumulative quantity of petroleum that has been recovered at a given date.

Resources encompasses all petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including Discovered and Undiscovered (recoverable and unrecoverable) plus quantities already produced. "Total resources" is equivalent to "Total Petroleum Initially-In-Place". Resources are classified in the following categories:

> **Total Petroleum Initially-In-Place ("TPIIP")** is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered.
>
> **Discovered Petroleum Initially-In-Place ("DPIIP")** is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially in place includes production, reserves, and contingent resources; the remainder is unrecoverable.
>
> **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development but which are not currently considered to be commercially recoverable due to one or more contingencies.
>
> **Economic Contingent Resources ("ECR")** are those contingent resources which are currently economically recoverable.
>
> **Project Maturity Subclass Development Pending** is defined as a contingent resource that has been assigned a high chance of development and the resolution of final conditions for development are being actively pursued.

Project Maturity Subclass Development On Hold is defined as a contingent resource that has been assigned a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator.

Project Maturity Subclass Development Unclarified is defined as a contingent resource that requires further appraisal to clarify the potential for development and has been assigned a lower chance of development until contingencies can be clearly defined.

Project Maturity Subclass Development not Viable is defined as a contingent resource where no further data acquisition or evaluation is currently planned and hence there is a low chance of development.

Undiscovered Petroleum Initially-In-Place ("UPIIP") is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of undiscovered petroleum initially in place is referred to as "prospective resources" and the remainder as "unrecoverable."

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development.

Unrecoverable is that portion of DPIIP and UPIIP quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Uncertainty Ranges are described by the Canadian Oil and Gas Evaluation Handbook as low, best, and high estimates for reserves and resources. The **Best Estimate** is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

Information Regarding Disclosure on Oil and Gas Reserves, Resources and Operational Information

All amounts in this news release are stated in Canadian dollars unless otherwise specified. Throughout this report, the terms Boe (barrels of oil equivalent), Mmboe (millions of barrels of oil equivalent), and Tcfe (trillion cubic feet of gas equivalent) are used. Such terms when used in isolation, may be misleading. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE and oil and liquids have been converted to natural gas equivalent on the basis of 1 bbl:6 mcfe. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip, and given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of the 6:1 conversion ratio, utilizing the 6:1 conversion ratio may be misleading as an indication of value. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. In accordance with Canadian practice, production volumes and revenues are reported on a company gross basis, before deduction of Crown and other royalties and without including any royalty interest, unless otherwise stated. Unless otherwise specified, all reserves volumes in this news release (and all information derived therefrom) are based on "company gross reserves" using forecast prices and costs. Our oil and gas reserves statement for the year-ended December 31, 2015 includes complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, and is contained within our Annual Information Form which is available on our SEDAR profile at www.sedar.com.

This report contains metrics commonly used in the oil and natural gas industry, such as "operating netback". Such terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons.

This news release contains references to estimates of oil and gas classified as TPIIP, DPIIP, UPIIP and ECR in the Montney region in NE BC which are not, and should not be confused with, oil and gas reserves. See "Definitions of Oil and Gas Resources and Reserves".

Projects have not been defined to develop the resources in the Evaluated Areas as at the evaluation date. Such projects, in the case of the Montney resource development, have historically been developed sequentially over a number of drilling seasons and are subject to annual budget constraints, Crew's policy of orderly development on a staged basis, the timing of the growth of third party infrastructure, the short and long-term view of Crew on oil and gas prices, the results of exploration and development activities of Crew and others in the area and possible infrastructure capacity constraints. As with any resource estimates, the evaluation will change over time as new information becomes available.

Crew's belief that it will establish significant additional reserves over time with the conversion of DPIIP and prospective resource into contingent resource, contingent resource into probable reserves and probable reserves into proved reserves is a forward looking statement and is based on certain assumptions and is subject to certain risks, as discussed below under the heading "Forward Looking Information and Statements".

Cautionary Statements

Forward-Looking Information and Statements

This news release contains certain forward–looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "project", "should", "believe", "plans", "intends" "forecast" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this news release contains forward-looking information and statements pertaining to the following: the volume and product mix of Crew's oil and gas production; production estimates including 2016 forecast average production; the volumes and estimated value of Crew's resources; the recognition of significant resources under the heading "Northeast British Columbia Montney Resource Evaluation"; future oil and natural gas prices and Crew's commodity risk management programs; future liquidity and financial capacity; future results from operations and operating metrics; anticipated reductions in operating costs, well costs and G&A expenditures and potential to improve ultimate recoveries and initial production rates; future costs, expenses and royalty rates; future interest costs; the exchange rate between the $US and $Cdn; future development, exploration, acquisition and development activities and related capital expenditures and the timing thereof; the number of wells to be drilled, completed and tied-in and the timing thereof; the amount and timing of capital projects; the total future capital associated with development of reserves and resources; and methods of funding our capital program, including possible non-core asset divestitures and asset swaps.

Forward-looking statements or information are based on a number of material factors, expectations or assumptions of Crew which have been used to develop such statements and information but which may prove to be incorrect. Although Crew believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because Crew can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified herein, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; the timely receipt of any required regulatory approvals; the ability of Crew to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects in which Crew has an interest in to operate the field in a safe, efficient and effective manner; the ability of Crew to obtain financing on acceptable terms and the adequacy of cash flow to fund its planned expenditures; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and cost of pipeline, storage and facility construction and expansion and the ability of Crew to secure adequate product transportation; future commodity prices; currency, exchange and interest rates; regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Crew operates; the ability of Crew to successfully market its oil and natural gas products. There are a number of assumptions associated with the potential of resource volumes and development of the Evaluated Areas including the quality of the Montney reservoir, future drilling programs and the funding thereof, continued performance from existing wells and performance of new wells, the growth of infrastructure, well density per section, and recovery factors and development necessarily involves known and unknown risks and uncertainties, including those identified in this report.

The forward-looking information and statements included in this news release are not guarantees of future performance and should not be unduly relied upon. Such information and statements, including the assumptions made in respect thereof, involve known and unknown risks, uncertainties and other factors that may cause actual results or events to defer materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; the potential for variation in the quality of the Montney formation; changes in the demand for or supply of Crew's products; unanticipated operating results or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in development plans of Crew or by third party operators of Crew's properties, increased debt levels or debt service requirements; inaccurate estimation of Crew's oil and gas reserve and resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; and certain other risks detailed from time-to-time in Crew's public disclosure documents (including, without limitation, those risks identified in this news release and Crew's Annual Information Form).

The forward-looking information and statements contained in this news release speak only as of the date of this news release, and Crew does not assume any obligation to publicly update or revise any of the included forward-looking statements or information, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Test Results and Initial Production Rates

A pressure transient analysis or well-test interpretation has not been carried out and thus certain of the test results provided herein should be considered to be preliminary until such analysis or interpretation has been completed. Test results and initial production rates disclosed herein may not necessarily be indicative of long term performance or of ultimate recovery.

BOE equivalent

Barrel of oil equivalents or BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of 6:1, utilizing a 6:1 conversion basis may be misleading as an indication of value.

MANAGEMENT'S DISCUSSION AND ANALYSIS

ADVISORIES

Management's discussion and analysis ("MD&A") is the Company's explanation of its financial performance for the period covered by the financial statements along with an analysis of the Company's financial position. Comments relate to and should be read in conjunction with the unaudited condensed interim consolidated financial statements of the Company for the three month periods ended March 31, 2016 and 2015. The unaudited condensed interim consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). There have been no significant changes to the critical estimates disclosed in the Company's audited financial statements for the year ended December 31, 2015. All figures provided herein and in the March 31, 2016 unaudited condensed interim consolidated financial statements are reported in Canadian dollars. This MD&A is dated May 5, 2016.

Forward Looking Statements

This MD&A contains forward looking statements. Management's assessment of future plans and operations, drilling plans and the timing thereof, plans for the completion and tie-in of wells, facility construction, commissioning and the timing thereof, capital expenditures, timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, production estimates including 2016 average and 2016 exit forecasts, expected commodity mix and prices, future operating costs, future transportation costs, expected royalty rates, expected general and administrative expenses, expected interest rates, debt levels, funds from operations and the timing of and impact of implementing accounting policies, estimates regarding undeveloped land position and estimated future drilling, recompletion or reactivation locations and anticipated impact of potential future transactions may constitute forward looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, the inability to fully realize the benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and inability to access sufficient capital from internal and external sources. As a consequence, the Company's actual results may differ materially from those expressed in, or implied by, the forward looking statements. Forward looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Crew believes that the expectations reflected in such forward looking statements or information are reasonable, undue reliance should not be placed on forward looking statements because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document and other documents filed by the Company, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Company has an interest in to operate the field in a safe, efficient and effective manner; Crew's ability to obtain financing on acceptable terms; changes in the Company's banking facility; field production rates and decline rates; the ability to reduce operating costs; the ability to replace and expand oil and natural gas reserves through acquisition, development or exploration; the timing and costs of pipeline, storage and facility construction and expansion; the ability of the Company to secure adequate product transportation; future petroleum and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company operates; and Crew's ability to successfully market its petroleum and natural gas products. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) or at the Company's website (www.crewenergy.com). Furthermore, the forward looking statements contained in this document are made as at the date of this document and the Company does not undertake any obligation to update publicly or to revise any of the included forward looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Conversions

The oil and gas industry commonly expresses production volumes and reserves on a "barrel of oil equivalent" basis ("boe") whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved analysis of results and comparisons with other industry participants.

Throughout this MD&A, Crew has used the 6:1 boe measure which is the approximate energy equivalency of the two commodities at the burner tip. Boe does not represent a value equivalency at the wellhead nor at the plant gate which is where Crew sells its production volumes and therefore may be a misleading measure, particularly if used in isolation. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a 6:1 conversion may be misleading as an indication of value.

Non-IFRS Measures

Funds from Operations

One of the benchmarks Crew uses to evaluate its performance is funds from operations. Funds from operations is a measure not defined in IFRS but is commonly used in the oil and gas industry. It represents cash provided by operating activities before decommissioning obligations settled, changes in operating non-cash working capital and accretion of deferred financing costs. The Company considers it a key measure as it demonstrates the ability of the Company's continuing operations to generate the cash flow necessary to fund future growth through capital investment and to repay debt. Funds from operations should not be considered as an alternative to or more meaningful than cash provided by operating activities as determined in accordance with IFRS as an indicator of the Company's performance. Crew's determination of funds from operations may not be comparable to that reported by other companies. Crew also presents funds from operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of income per share. The following table reconciles Crew's cash provided by operating activities to funds from operations:

($ thousands)	**Three months ended March 31, 2016**	Three months ended March 31, 2015
Cash provided by operating activities	**19,591**	17,221
Decommissioning obligations settled	**419**	270
Change in operating non-cash working capital	**(8,121)**	3,398
Accretion of deferred financing costs	**(175)**	(169)
Funds from operations	**11,714**	20,720

Debt to EBITDA

The Company uses the terms debt to EBITDA and secured debt to EBITDA which are used in reference to the financial covenants prescribed by the Company's bank facility. Under the bank facility, debt includes drawings on the bank facility and the Company's senior unsecured notes while secured debt refers only to drawings on the bank facility. EBITDA is defined by the credit agreement as earnings before interest, taxes, depreciation and amortization, unrealized gains or losses on financial instruments, share-based compensation, all other non-cash items and EBITDA from disposed properties and acquisitions for the most recent twelve month period. Other non-cash items include impairment, gains or losses on divestitures and unrealized gains or losses on marketable securities for the most recent twelve month period.

Operating Netback

Management uses the industry benchmark operating netback to analyze financial and operating performance. This benchmark as presented does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Operating netback equals total petroleum and natural gas sales including realized gains and losses on commodity related derivative financial instruments less royalties, operating costs and transportation costs calculated on a boe basis. Management considers operating netback an important measure to evaluate its operational performance as it demonstrates its field level profitability relative to current commodity prices. The calculation of Crew's netbacks can be seen below in the operating netbacks section.

Working Capital and Net Debt

The Company closely monitors its capital structure with a goal of maintaining a strong financial position in order to fund the future growth of the Company. Crew monitors working capital and net debt as part of its capital structure. Working capital and net debt do not have a standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. The following tables outline Crew's calculation of working capital and net debt:

($ thousands)	**March 31, 2016**	December 31, 2015
Current assets	**42,842**	34,417
Current liabilities	**(29,401)**	(38,217)
Marketable securities	**(2,038)**	(1,160)
Derivative financial instruments	**(12,261)**	(5,777)
Working capital deficit	**(858)**	(10,737)

($ thousands)	**March 31, 2016**	December 31, 2015
Bank loan	**(98,108)**	(80,980)
Senior unsecured notes	**(146,854)**	(146,679)
Working capital deficit	**(858)**	(10,737)
Net debt	**(245,820)**	(238,396)

RESULTS OF OPERATIONS

Production

	Three months ended March 31, 2016				Three months ended March 31, 2015			
	Oil (bbl/d)	**Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
Northeast British Columbia	**303**	**3,359**	**103,973**	**20,991**	657	2,060	69,258	14,260
Lloydminster	**2,799**	**-**	**251**	**2,841**	4,735	-	240	4,775
Total	**3,102**	**3,359**	**104,224**	**23,832**	5,392	2,060	69,498	19,035

Production for the three months ended March 31, 2016 increased 25% over the same period in 2015 as a result of the successful drilling program in northeastern British Columbia at Septimus and West Septimus where the Company has significantly increased its liquids rich natural gas production. The production increase was partially offset by a decrease in Lloydminster heavy oil production as the Company has significantly curtailed drilling and well reactivation activity in response to the low oil pricing environment combined with the disposition of 225 boe per day of production in the fourth quarter of 2015 and over 700 boe per day of uneconomic heavy oil volumes being shut-in over the past year.

Revenue

	Three months ended March 31, 2016	Three months ended March 31, 2015
Revenue ($ thousands)		
Light crude oil	**1,027**	2,913
Heavy crude oil	**5,208**	15,612
Natural gas liquids	**7,934**	5,038
Natural gas	**22,174**	16,377
Total	**36,343**	39,940
Crew average prices		
Light crude oil ($/bbl)	**37.34**	49.28
Heavy crude oil ($/bbl)	**20.45**	36.63
Natural gas liquids ($/bbl)	**25.95**	27.17
Natural gas ($/mcf)	**2.34**	2.62
Oil equivalent ($/boe)	**16.76**	23.31
Benchmark pricing		
Light crude oil – Cdn$ WTI (Cdn $/bbl)	**45.88**	60.38
Heavy crude oil – WCS (Cdn $/bbl)	**26.61**	42.11
Natural gas liquids – Condensate @ Edmonton (Cdn $/bbl)	**47.27**	54.18
Natural Gas:		
AECO 5A daily index (Cdn $/mcf)	**1.83**	2.75
Chicago City Gate at ATP (Cdn $/mcf)	**2.07**	3.43
NGX AECO + APC – ATP 5A (Cdn $/mcf)(1)	**1.96**	1.96

(1) NGX AECO + APC - ATP 5A benchmark price commenced December 1, 2015, prior thereto, Alliance prices are reflected as AECO + CREC 4A.

Revenue for the first three months of 2016 decreased 9% as compared to the same quarter in 2015 as a result of the 28% decline in realized commodity pricing partially offset by the increased production volumes. The Company's realized light oil price decreased 24% which was consistent with the 24% decline in the Company's Cdn$ West Texas Intermediate ("WTI") benchmark. Crew's first quarter heavy oil price decreased 44% as compared to the 37% decline in the Company's Western Canadian Select ("WCS") benchmark as a result of the Company securing short term sales contracts when WCS differentials were wider than the average market trade for the period. The Company's first quarter realized natural gas liquids ("ngl") price decreased 4% over the same period in 2015 as compared to the 13% decrease in the Condensate at Edmonton benchmark price. Increased condensate production from the West Septimus area, where the production has a higher condensate yield than the Company's Septimus area, enhanced the Company's realized ngl price relative to the change in the Company's benchmark price.

From January through November of 2015, Crew sold the majority of its natural gas into the Spectra Station 2 or Alliance CREC market. On December 1, 2015 Crew began transporting natural gas on the Alliance pipeline under new contracts that are linked to Chicago Citygate, AECO or Alliance Trading Pool ("ATP") referenced pricing. As a result, the Company adopted the new NGX AECO adjusted for the APC – ATP 5A differential and the Chicago City Gate at ATP benchmarks. Crew currently has natural gas sales contracts in place for the majority of its natural gas production. The first quarter sales portfolio was based on the following reference prices:

- 40% - Chicago City Gate at ATP
- 35% - AECO
- 15% - NGX AECO + APC – ATP 5A
- 10% - Station 2

The Company's natural gas price is further enhanced by the high heat content of its Montney natural gas which is approximately 18% hotter than the Alliance standard heat content. The combination of market diversification and high heat content resulted in Crew's average natural gas price per mcf outperforming the AECO 5A benchmark by 28%.

Royalties

($ thousands, except per boe)	Three months ended March 31, 2016	Three months ended March 31, 2015
Royalties	**1,899**	3,434
Per boe	**0.88**	2.00
Percentage of revenue	**5.2%**	8.6%

In the first quarter of 2016, royalties as a percentage of revenue decreased to 5.2% from 8.6% in the same period in 2015 as a result of the significantly lower commodity prices which yield lower price sensitive royalty rates. In addition, royalty rates decreased due to increased production at Septimus and West Septimus which attract lower royalty rates due to additional deep gas royalty holidays from new production additions in British Columbia. As a result of the continued deterioration of commodity pricing, the Company now expects its royalties as a percentage of revenue to average between 5% and 7% in 2016.

Derivative Financial Instruments

Commodities

The Company enters into derivative and physical risk management contracts in order to reduce volatility in financial results, to protect acquisition economics and to ensure a certain level of cash flow to fund planned capital projects. Crew's strategy focuses on the use of puts, costless collars, swaps and fixed price contracts to limit exposure to fluctuations in commodity prices, interest rates and foreign exchange rates while allowing for participation in commodity price increases. The Company's financial derivative trading activities are conducted pursuant to the Company's Risk Management Policy approved by the Board of Directors.

These contracts had the following impact on the condensed interim consolidated statements of loss and comprehensive loss:

($ thousands)	Three months ended March 31, 2016	Three months ended March 31, 2015
Realized gain on derivative financial instruments	**4,798**	11,327
Per boe - Total	**2.21**	6.61
Unrealized gain (loss) on financial instruments	**7,204**	(10,643)

As at March 31, 2016, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Oil	500 bbl/day	April 1, 2016 – June 30, 2016	US$ WCS - WTI diff	$(14.95)	Swap	(108)
Oil	500 bbl/day	April 1, 2016 - December 31, 2016	CDN$ WTI	$116.50	Call	(1)
Gas	25,276 gj/day	April 1, 2016 - December 31, 2016	AECO C Monthly Index	$2.56	Swap	6,528
Gas	2,500 gj/day	April 1, 2016 - October 31, 2016	AECO C Monthly Index	$2.14	Swap	395
Gas	20,000 mmbtu/day	April 1, 2016 - December 31, 2016	CDN$ Chicago Citygate	$3.79	Swap	5,306
Gas	2,500 gj/day	January 1, 2017 - December 31, 2017	AECO C Monthly Index	$2.73	Swap	187
Gas	5,000 gj/day	January 1, 2017 - December 31, 2017	AECO C Monthly Index	$2.90	Call Swaption(1)	(174)
Gas	5,000 mmbtu/day	January 1, 2017 - December 31, 2017	CDN$ Chicago Citygate	$3.89	Swap	548
Total						12,681

(1) The referenced contract is a European call swaption, which the counterparty will accept or decline by December 22, 2016.

Subsequent to March 31, 2016, the Company entered into the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Gas	7,500 mmbtu/day	January 1, 2017 - December 31, 2017	CDN$ Chicago Citygate	$3.71	Swap
Gas	2,500 gj/day	January 1, 2017 - December 31, 2017	AECO C Monthly Index	$2.48	Swap

Operating Costs

($ thousands, except per boe)	**Three months ended March 31, 2016**	Three months ended March 31, 2015
Operating costs	**13,979**	15,897
Per boe	**6.45**	9.28

For the first quarter of 2016, the Company's operating costs per boe decreased 30% compared to the same period in 2015 as a result of increased lower cost Septimus and West Septimus area production combined with the decline in Lloydminster production which attracts higher operating costs per unit as compared to the corporate average. The Company continues to forecast annual operating costs to average between $6.00 and $6.75 per boe for 2016.

Transportation Costs

($ thousands, except per boe)	**Three months ended March 31, 2016**	Three months ended March 31, 2015
Transportation costs	**5,434**	3,358
Per boe	**2.51**	1.96

In the first quarter of 2016, the Company's transportation costs and transportation costs per boe increased as compared to the same period in 2015 as the Company commenced its firm transportation arrangement on the Alliance pipeline in December of 2015 which increased natural gas transportation costs. This arrangement improves the Company's natural gas realized pricing and secures long-term transportation capacity. The increased transportation costs were partially offset by the installation of the lease automatic custody transfer unit ("LACT") in the third quarter of 2015 at the Septimus gas facility that ties the facility into a condensate transportation pipeline reducing the condensate trucking costs in the area. The Company continues to forecast transportation costs per boe to range between $2.50 and $2.80 per boe in 2016.

Operating Netbacks

($/boe)	**Montney Liquids Rich Natural Gas**	**Heavy Oil**	**Other**	**Three months ended March 31, 2016**	Three months ended March 31, 2015
Revenue	16.69	20.31	13.66	**16.76**	23.31
Royalties	(0.79)	(1.31)	(0.98)	**(0.88)**	(2.00)
Realized commodity hedging gain	1.34	7.83	2.19	**2.21**	6.61
Operating costs	(4.43)	(16.06)	(9.71)	**(6.45)**	(9.28)
Transportation costs	(2.21)	(1.01)	(5.89)	**(2.51)**	(1.96)
Operating netbacks	**10.60**	**9.76**	**(0.73)**	**9.13**	16.68
Production (boe/d)	**18,149**	**2,841**	**2,842**	**23,832**	19,035

Operating netbacks for the first quarter of 2016 decreased 45% over the same period in 2015 as a result of the decline in the Company's realized commodity pricing and decreased realized hedging gains combined with an increase in transportation costs. This was partially offset by lower royalty and operating costs in the current period.

General and Administrative Costs

($ thousands, except per boe)	**Three months ended March 31, 2016**	Three months ended March 31, 2015
Gross costs	**5,429**	5,800
Operator's recoveries	**(9)**	(157)
Capitalized costs	**(1,603)**	(1,905)
General and administrative expenses	**3,817**	3,738
Per boe	**1.76**	2.18

Gross general and administrative ("G&A") costs and net G&A costs per boe have decreased in the first quarter of 2016 compared to the same period in 2015 due to reduced staffing levels and a reduction in the Company's compensation program prompted by the substantial decline in commodity prices. Net general and administrative costs have slightly increased as a result of lower recoveries and capitalized costs due to fewer capital projects being undertaken during the quarter. Crew continues to forecast G&A costs per boe will average between $1.40 and $1.60 in 2016 with higher regulatory and office costs being incurred in the first half of 2016.

Share-Based Compensation

($ thousands)	**Three months ended March 31, 2016**	Three months ended March 31, 2015
Gross costs	**5,184**	5,954
Capitalized costs	**(2,333)**	(2,959)
Total share-based compensation	**2,851**	2,995

For the first quarter of 2016, share-based compensation costs decreased compared to the same period in 2015 as a result of lower valued restricted and performance award grants throughout 2015 as compared to the comparative grant values in 2014.

Depletion and Depreciation

($ thousands, except per boe)	**Three months ended March 31, 2016**	Three months ended March 31, 2015
Depletion and depreciation	**24,948**	26,005
Per boe	**11.50**	15.18

Depletion and depreciation costs and costs per boe decreased in the first quarter of 2016, compared to the same period of 2015, as a result of a lower net book value on the Lloydminster CGU from the impairment write-down taken in the third quarter of 2015 combined with increased 2015 year end proved plus probable reserve bookings at Septimus and West Septimus. In addition, increased production at Septimus and West Septimus, where depletion rates are substantially lower than the corporate average, contributed to the 24% reduction in depletion and depreciation costs per boe.

Finance Expenses

($ thousands, except per boe)	**Three months ended March 31, 2016**	Three months ended March 31, 2015
Interest on bank loan	**1,025**	853
Interest on senior notes	**3,098**	3,098
Accretion of deferred financing charges	**175**	169
Accretion of the decommissioning obligation	**433**	471
Total finance expense	**4,731**	4,591
Average debt level	**228,897**	193,220
Average drawings on bank loan	**78,897**	43,220
Effective interest rate on bank loan	**5.2%**	8.0%
Effective interest rate on senior notes	**8.4%**	8.4%
Effective interest rate on long-term debt	**7.2%**	8.3%
Interest on long-term debt per boe	**1.98**	2.40

For the first quarter of 2016, average corporate debt levels were higher than the first quarter of 2015 as capital expenditures over the past year were funded by increased drawings on the bank loan as funds from operations were depressed by low commodity prices. The effective interest rate on the Company's bank loan was lower in the first quarter of 2016, as compared to the same period in 2015, due to reduced standby fees incurred and increased drawings on the Company's lower rate bank facility in 2016. Crew forecasts the effective interest rate on it long-term debt to average between 6.5% and 8.5% for 2016.

Deferred Income Taxes

In the first quarter of 2016, the provision for deferred taxes was a recovery of $1.8 million compared to a recovery of $4.3 million for the same period in 2015. The reduced recovery is a result of a reduced pre-tax loss experienced during the first quarter of 2016.

Cash, Funds from Operations and Net Income

($ thousands, except per share amounts)		**Three months ended March 31, 2016**	Three months ended March 31, 2015
Cash provided by operating activities		**19,591**	17,221
Funds from operations		**11,714**	20,720
Per share	- basic	**0.08**	0.16
	- diluted	**0.08**	0.16
Net loss		**(6,795)**	(15,770)
Per share	- basic	**(0.05)**	(0.12)
	- diluted	**(0.05)**	(0.12)

The decrease in cash provided by operating activities and funds from operations was a result of lower commodity prices and a decline in realized hedging gains partially offset by decreased cash costs and an increase in Septimus and West Septimus production during the first quarter of 2016. The decreased net loss was a result of an unrealized gain on financial instruments compared to a substantial unrealized loss experienced during the first quarter of 2015.

Capital Expenditures, Property Acquisitions and Dispositions

In the first quarter of 2016, the Company drilled four (4.0 net) and completed three (3.0 net) natural gas wells in West Septimus. During the first quarter, upon completion of a major infrastructure project whereby the Septimus and West Septimus facilities were connected with a pipeline spanning the Pine River, the Company earned a $10.8 million government incentive credit which significantly offset its infrastructure costs.

Total net capital expenditures are detailed below:

($ thousands)	**Three months ended March 31, 2016**	Three months ended March 31, 2015
Land	**619**	811
Seismic	**177**	5,518
Drilling and completions	**13,789**	40,992
Facilities, equipment and pipelines	**1,465**	41,767
Other	**1,713**	2,004
Total exploration and development	**17,763**	91,092
Property acquisitions (dispositions)	**956**	258
Total	**18,719**	91,350

LIQUIDITY AND CAPITAL RESOURCES

Capital Funding

The Company has a credit facility with a syndicate of lending banks (the "Syndicate") which includes a revolving line of credit and an operating line of credit (the "Facility"). Subsequent to March 31, 2016, the Facility was approved for extension, subject to customary closing documentation, with the amount available on the revolving line adjusted to $205 million while the operating line of credit remained at $30 million. The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 6, 2017. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 percent and all outstanding balances under the Facility will become repayable in one year from the extension date. The available lending limits of the Facility are reviewed semi-annually and are based on the Syndicate's interpretation of the Company's reserves and future commodity prices. The credit agreement requires the Company to maintain a debt to EBITDA ratio of 4:1 and a secured debt to EBITDA ratio of 3:1 at the end of each fiscal quarter. At March 31, 2016, these ratios were 2.7:1 and 1.1:1, respectively. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled borrowing base review on or before October 31, 2016. At March 31, 2016, the Company had drawings of $98.1 million on the Facility and had issued letters of credit totaling $8.5 million.

The Company has $150 million of 8.375% senior notes outstanding that are due October 21, 2020. These notes are guaranteed, jointly and severally, on an unsecured basis, by each of the Company's current and future restricted subsidiaries. Interest on the notes accrues at the rate of 8.375% per year and is payable semi-annually.

During the first quarter of 2015, the Company issued 16.7 million shares for gross proceeds of approximately $100 million through an equity offering as discussed below in *Share Capital*.

The Company will continue to fund its on-going operations from a combination of cash flow, debt, non-core asset dispositions and additional equity financings as needed. As the majority of our on-going capital expenditure program is directed to the further growth of reserves and production volumes, Crew is readily able to adjust its budgeted capital expenditures should the need arise.

Working Capital

The capital intensive nature of Crew's activities generally results in the Company carrying a working capital deficit. Working capital deficiency includes cash and cash equivalents and accounts receivable less accounts payable and accrued liabilities. The Company maintains sufficient unused bank credit lines to satisfy working capital deficiencies. At March 31, 2016, the Company's working capital deficiency totaled $0.9 million which, when combined with the drawings on its bank loan, represented 42% of its current bank facility.

Included in the working capital deficiency is an accounts receivable of $10.8 million for the government incentive credit earned through the completion of the construction of the Pine River pipeline. The collection of the grant is realized through the reduction of future royalties payable to the British Columbia government.

Share Capital

On March 3, 2015, the Company issued 16,667,000 Common Shares of the Company, on a bought deal basis, at a price of $6.00 per share for aggregate gross proceeds of $100 million.

Crew is authorized to issue an unlimited number of common shares. As at May 5, 2016, there were 142,714,013 common shares and options to acquire 3,607,906 common shares of the Company issued and outstanding. In addition, there were 1,827,777 restricted awards and 2,738,280 performance awards outstanding under the Company's long-term incentive program.

Capital Structure

The Company considers its capital structure to include working capital, the bank loan, the senior unsecured notes and shareholders' equity. Crew's primary capital management objective is to maintain a strong financial position in order to continue to fund the future growth of the Company. Crew monitors its capital structure and makes adjustments on an on-going basis in order to maintain the flexibility needed to achieve the Company's long-term objectives. To manage the capital structure the Company may adjust capital spending, hedge future revenue and costs, issue new equity, issue new debt, amend, revise or extend the terms of the existing bank facility or repay existing debt through non-core asset sales.

The Company monitors debt levels based on the ratio of net debt to annualized funds from operations. The ratio represents the time period it would take to pay off the debt if no further capital expenditures were incurred and if funds from operations remained constant. This ratio is calculated as net debt, defined as the Company's bank loan, senior unsecured notes and net working capital, divided by annualized funds from operations for the most recent quarter.

The Company monitors this ratio and endeavours to maintain it at or below 2.0 to 1. During periods of increased capital expenditures, acquisitions or low commodity prices, this ratio will increase. As shown below, as at March 31, 2016, the Company's ratio of net debt to annualized funds from operations was 5.25 to 1 (December 31, 2015 – 3.04 to 1). As a result of the significant decline in commodity prices over the past 18 months, the Company increased its financial flexibility through the issuance of additional equity in early 2015, as discussed above in *Share Capital,* and the strategic divestiture of non-core assets for $50.1 million in the third quarter of 2015. The Company is closely monitoring its financial position and does not plan to add materially to its current debt position in 2016. Capital expenditures planned in 2016 will be substantially financed by funds from operations. With the Company's Bank Facility approved for extension for another 364 day term while only 42% drawn and the forward market for oil and natural gas signaling an improvement over current pricing, the Company's financial position remains strong. If the Company feels it necessary to improve its financial position it will consider divesting of non-core properties, will adjust its annual capital expenditure program further or may consider other forms of financing.

($ thousands, except ratio)	**March 31, 2016**	December 31, 2015
Working capital deficit	**(858)**	(10,737)
Bank loan	**(98,108)**	(80,980)
Senior unsecured notes	**(146,854)**	(146,679)
Net debt	**(245,820)**	(238,396)
Quarterly funds from operations	**11,714**	19,601
Annualized	**46,856**	78,404
Net debt to annualized funds from operations ratio	**5.25**	3.04

Contractual Obligations

Throughout the course of its ongoing business, the Company enters into various contractual obligations such as credit agreements, purchase of services, royalty agreements, operating agreements, processing agreements, right of way agreements and lease obligations for office space and automotive equipment. All such contractual obligations reflect market conditions prevailing at the time of contract and none are with related parties. The Company believes it has adequate sources of capital to fund all contractual obligations as they come due. The following table lists the Company's obligations with a fixed term.

($ thousands)	Total	2016	2017	2018	2019	2020	Thereafter
Bank Loan (note 1)	98,108	-	98,108	-	-	-	-
Senior unsecured notes (note 2)	150,000	-	-	-	-	150,000	-
Operating leases	4,919	219	783	1,175	1,175	1,175	392
Firm transportation agreements	157,583	22,883	29,347	29,686	29,406	26,224	20,037
Firm processing agreements	61,337	10,039	13,325	13,325	13,325	11,323	-
Total	471,947	33,141	141,563	44,186	43,906	188,722	20,429

Note 1 – Based on the existing terms of the Company's bank facility the first possible repayment date may come in 2017. However, it is expected that the revolving bank facility will be extended and no repayment will be required in the near term.
Note 2 – Matures on October 21, 2020.

The operating leases include the Company's contractual obligation to a third party for the renewed five year lease of office space.

The firm transportation agreements include commitments to third parties to transport natural gas and natural gas liquids from gas processing facilities in northeastern British Columbia.

The firm processing agreements include commitments to process natural gas through the Septimus complex gas processing facilities in northeastern British Columbia.

GUIDANCE

In light of continued commodity price uncertainty and volatility, the Company has taken a conservative approach to capital expenditures in 2016 but as a result of increased activity through 2015, the Company has built an inventory of uncompleted wells that can be completed to maintain production volumes. Further, with continued reductions in drilling and completions costs, there may be opportunities to undertake projects that weren't included in the original 2016 plans without materially increasing the capital budget. The Company's 2016 annual production guidance remains at 23,000 to 25,000 boe per day with a capital budget of $70 million. Capital expenditures will be adjusted with expected funds from operations, with a priority to maintain total net debt between $235 and $250 million at year end 2016.

ADDITIONAL DISCLOSURES

Quarterly Analysis

The following table summarizes Crew's key quarterly financial results for the past eight financial quarters:

($ thousands, except per share amounts)	Mar. 31 2016	Dec. 31 2015	Sept 30 2015	June 30 2015	Mar. 31 2015	Dec. 31 2014	Sept. 30 2014	June 30 2014
Total daily production (boe/d)	23,832	20,706	16,773	17,656	19,035	20,869	20,846	27,200
Exploration and development expenditures	17,763	42,067	58,565	54,694	91,092	81,447	106,405	52,783
Property acquisitions/(dispositions)	956	(36,644)	(50,281)	1,226	258	1,901	(141,796)	(215,115)
Average wellhead price ($/boe)	16.76	18.13	22.54	27.81	23.31	37.65	50.51	50.86
Petroleum and natural gas sales	36,343	34,532	34,784	44,678	39,940	72,295	96,879	125,882
Cash provided by operations	19,591	12,373	22,091	23,013	17,221	37,714	37,566	43,589
Funds from operations	11,714	19,601	17,273	24,769	20,720	33,035	39,023	47,724
Per share – basic	0.08	0.14	0.12	0.18	0.16	0.27	0.32	0.39
– diluted	0.08	0.14	0.12	0.18	0.16	0.27	0.31	0.38
Net income (loss)	(6,795)	(8,167)	(18,179)	(13,239)	(15,770)	(28,424)	(195,389)	3,792
Per share – basic	(0.05)	(0.06)	(0.13)	(0.09)	(0.12)	(0.23)	(1.60)	0.03
– diluted	(0.05)	(0.06)	(0.13)	(0.09)	(0.12)	(0.23)	(1.60)	0.03

Beginning in 2014, Crew embarked on a plan to refocus the Company towards its Montney assets in northeast British Columbia. The new focus began with dispositions of assets in the Deep Basin and Princess areas in 2014 for combined gross proceeds of approximately $384 million which resulted in the sale of a significant portion of the Company's existing production and the realization of losses on the sale of these properties. The majority of the proceeds from these sales have been used over the past two years to partially fund organic Montney production growth through the Company's exploration and development program.

During the past two years, the oil and gas industry has seen a significant decrease in commodity prices that has also negatively impacted revenue. The impact of this has reduced cash provided by operations, funds from operations and net income. The substantial and ongoing decline in commodity prices has also led to the assessment and realization of impairment of the carrying value of certain CGUs. In 2015, the Company incurred $55.4 million in impairment charges and in 2014, the Company also incurred $233.7 million of impairment charges. These losses have been partially offset by gains from the Company's risk management program over the periods.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

The Company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings 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 Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on January 1, 2016 and ended on March 31, 2016 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Dated as of May 5, 2016

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited) (thousands)	**March 31, 2016**	December 31, 2015
Assets		
Current Assets:		
Accounts receivable	**$ 28,390**	$ 26,697
Marketable securities (note 3)	**2,038**	1,160
Derivative financial instruments (note 9)	**12,414**	6,560
	42,842	34,417
Derivative financial instruments (note 9)	**550**	-
Property, plant and equipment (note 4)	**1,204,768**	1,209,866
	$ 1,248,160	$ 1,244,283
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 29,248**	$ 37,434
Derivative financial instruments (note 9)	**153**	783
	29,401	38,217
Derivative financial instruments (note 9)	**130**	300
Bank loan (note 5)	**98,108**	80,980
Senior unsecured notes (note 6)	**146,854**	146,679
Decommissioning obligations (note 7)	**84,764**	85,822
Deferred tax liability	**44,818**	46,589
Shareholders' Equity		
Share capital (note 8)	**1,398,751**	1,398,698
Contributed surplus	**82,758**	77,627
Deficit	**(637,424)**	(630,629)
	844,085	845,696
Subsequent events (notes 5 and 9)		
Commitments (note 10)		
	$ 1,248,160	$ 1,244,283

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF LOSS AND COMPREHENSIVE LOSS

(unaudited) (thousands, except per share amounts)		**Three months ended March 31, 2016**		Three months ended March 31, 2015
Revenue				
Petroleum and natural gas sales	**$**	**36,343**	$	39,940
Royalties		**(1,899)**		(3,434)
Realized gain on derivative financial instruments (note 9)		**4,798**		11,327
Unrealized gain (loss) on derivative financial instruments (note 9)		**7,204**		(10,643)
		46,446		37,190
Expenses				
Operating		**13,979**		15,897
Transportation		**5,434**		3,358
General and administrative		**3,817**		3,738
Share-based compensation		**2,851**		2,995
Depletion and depreciation		**24,948**		26,005
		51,029		51,993
Loss from operations		**(4,583)**		(14,803)
Financing		**4,731**		4,591
Unrealized (gain) loss on marketable securities (note 3)		**(878)**		651
Loss on divestiture of property, plant and equipment		**130**		-
Loss before income taxes		**(8,566)**		(20,045)
Deferred tax recovery		**1,771**		4,275
Net loss and comprehensive loss	**$**	**(6,795)**	$	(15,770)
Net loss per share (note 8)				
Basic	**$**	**(0.05)**	$	(0.12)
Diluted	**$**	**(0.05)**	$	(0.12)

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(unaudited) (thousands)	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 2016	141,067	$ 1,398,698	$ 77,627	$ (630,629)	845,696
Net loss for the period	-	-	-	(6,795)	(6,795)
Share-based compensation expensed	-	-	2,851	-	2,851
Share-based compensation capitalized	-	-	2,333	-	2,333
Issued on vesting of share awards	6	53	(53)	-	-
Balance March 31, 2016	**141,073**	**$ 1,398,751**	**$ 82,758**	**$ (637,424)**	**$ 844,085**

	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 2015	123,429	$ 1,292,693	$ 72,951	$ (575,274)	$ 790,370
Net loss for the period	-	-	-	(15,770)	(15,770)
Share-based compensation expensed	-	-	2,995	-	2,995
Share-based compensation capitalized	-	-	2,959	-	2,959
Issued on vesting of share awards	5	36	(36)	-	-
Issuance of common shares	16,667	100,002	-	-	100,002
Share issue costs, net of tax of $1,341	-	(4,080)	-	-	(4,080)
Balance March 31, 2015	140,101	$ 1,388,651	$ 78,869	$ (591,044)	$ 876,476

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited) (thousands)	**Three months ended March 31, 2016**	Three months ended March 31, 2015
Cash provided by (used in):		
Operating activities:		
Net loss	**$ (6,795)**	$ (15,770)
Adjustments:		
Unrealized (gain) loss on derivative financial instruments	**(7,204)**	10,643
Share-based compensation	**2,851**	2,995
Depletion and depreciation	**24,948**	26,005
Financing expenses	**4,731**	4,591
Interest expense	**(4,123)**	(3,951)
Unrealized (gain) loss on marketable securities	**(878)**	651
Loss on divestiture of property, plant and equipment	**130**	-
Deferred tax recovery	**(1,771)**	(4,275)
Decommissioning obligations settled	**(419)**	(270)
Change in non-cash working capital	**8,121**	(3,398)
	19,591	17,221
Financing activities:		
Increase (decrease) in bank loan	**17,128**	(15,323)
Proceeds from issuance of common shares	**-**	100,002
Share issue costs	**-**	(5,421)
	17,128	79,258
Investing activities:		
Property, plant and equipment expenditures	**(17,763)**	(91,092)
Property acquisitions	**(1,050)**	(258)
Property dispositions	**94**	-
Change in non-cash working capital	**(18,000)**	(5,129)
	(36,719)	(96,479)
Change in cash and cash equivalents	-	-
Cash and cash equivalents, beginning of period	**-**	-
Cash and cash equivalents, end of period	**$ -**	$ -

See accompanying notes to the condensed interim consolidated financial statements.

NOTES TO CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

For the three months ended March 31, 2016 and 2015

(Unaudited) (Tabular amounts in thousands)

1. Reporting entity:

Crew Energy Inc. ("Crew" or the "Company") is an oil and gas exploration, development and production company based in Calgary, Alberta, Canada. Crew conducts its operations in the Western Canadian Sedimentary basin, primarily in the provinces of British Columbia, Saskatchewan and Alberta. The condensed interim consolidated financial statements (the "financial statements") of the Company are comprised of the accounts of Crew and its wholly owned subsidiary, Crew Oil and Gas Inc. which is incorporated in Canada, and two partnerships, Crew Energy Partnership and Crew Heavy Oil Partnership. Crew's principal place of business is located at Suite 800, 250 – 5th Street SW, Calgary, Alberta, Canada, T2P 0R4.

2. Basis of preparation:

These financial statements have been prepared in accordance with IAS 34 – Interim Financial Reporting of the International Financial Reporting Standards ("IFRS"). The financial statements use the accounting policies which the Company applied in its annual consolidated financial statements for the year ended December 31, 2015. The financial statements do not include certain disclosures that are normally required to be included in annual consolidated financial statements which have been condensed or omitted. These financial statements are presented in Canadian dollars, which is the functional currency of the Company, its subsidiary and partnerships.

The condensed interim consolidated financial statements were authorized for issue by the Board of Directors on May 5, 2016.

3. Marketable securities:

The Company holds 1,415,094 common shares of a public company trading on the TSX Venture exchange. The shares were valued at $0.82 per common share for a total value of approximately $1.2 million at December 31, 2015. As at March 31, 2016, the fair market value of the marketable securities was $1.44 per common share and as a result an unrealized gain of $0.9 million (March 31, 2015 – unrealized loss of $0.7 million) was recorded in the Company's financial statements for the three month period then ended.

4. Property, plant and equipment:

Cost or deemed cost	Total
Balance, January 1, 2015	$ 1,851,036
Additions	246,418
Acquisitions	15,147
Divestitures	(65,778)
Change in decommissioning obligations	8,040
Capitalized share-based compensation	6,995
Balance, December 31, 2015	$ 2,061,858
Additions	17,763
Acquisitions	1,070
Divestitures	(244)
Change in decommissioning obligations	(1,072)
Capitalized share-based compensation	2,333
Balance, March 31, 2016	**$ 2,081,708**

Accumulated depletion and depreciation		Total
Balance, January 1, 2015	$	704,440
Depletion and depreciation expense		93,084
Divestitures		(908)
Impairment (net)		55,376
Balance, December 31, 2015	$	851,992
Depletion and depreciation expense		24,948
Balance, March 31, 2016	**$**	**876,940**

Net book value		Total
Balance, March 31, 2016	**$**	**1,204,768**
Balance, December 31, 2015	$	1,209,866

The calculation of depletion for the three months ended March 31, 2016 included estimated future development costs of $1,301.1 million (December 31, 2015 - $1,316.2 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $64.2 million (December 31, 2015 - $64.0 million) and undeveloped land of $214.8 million (December 31, 2015 - $218.9 million) related to future development acreage.

5. Bank loan:

The Company's bank facility consists of a revolving line of credit and an operating line of credit (the "Facility"). Subsequent to March 31, 2016, the Facility was approved for extension, subject to customary closing documentation, with the amount available on the revolving line adjusted to $205 million while the operating line remained at $30 million. The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 6, 2017. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 per cent and all outstanding advances thereunder will become repayable in one year from the extension date. The available lending limits of the Facility (the "Borrowing Base") are reviewed semi-annually and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. The credit agreement requires the Company to maintain a debt to EBITDA ratio of 4:1 and a secured debt to EBITDA ratio of 3:1 at the end of each fiscal quarter. Debt consists of the Company's bank debt and senior unsecured notes while secured debt consists of the Company's bank debt. At March 31, 2016, these ratios were 2.7:1 and 1.1:1, respectively. EBITDA is a non-GAAP measure and is defined in the credit agreement as earnings before interest, taxes, depreciation and amortization, unrealized gains or losses on financial instruments, share-based compensation, all other non-cash items and EBITDA from disposed properties and acquisitions for the most recent twelve month period. Other non-cash items include impairment, gains or losses on divestitures and unrealized gains or losses on marketable securities for the most recent twelve month period. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled borrowing base review on or before October 31, 2016. The Facility is secured by a floating charge debenture and a general securities agreement on the assets of the Company.

Advances under the Facility are available by way of prime rate loans with interest rates between 1.00 percent and 2.50 percent over the bank's prime lending rate and bankers' acceptances and LIBOR loans, which are subject to stamping fees and margins ranging from 2.00 percent to 3.50 percent depending upon the debt to EBITDA ratio of the Company calculated at the Company's previous quarter end. Standby fees are charged on the undrawn facility at rates ranging from 0.50 percent to 0.875 percent depending upon the debt to EBITDA ratio.

As at March 31, 2016, the Company's applicable pricing included a 1.0 percent margin on prime lending and a 2.0 percent stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.50 percent per annum standby fee on the portion of the facility that is not drawn. Borrowing margins and fees are reviewed annually as part of the bank syndicate's annual renewal. At March 31, 2016, the Company had issued letters of credit totaling $8.5 million (December 31, 2015 - $7.8 million). The effective interest rate on the Company's borrowings under its bank facility for the three months ended March 31, 2016 was 5.2% (December 31, 2015 – 6.7%).

6. Senior unsecured notes:

In October 2013, the Company issued $150 million of 8.375% senior notes, due October 21, 2020. These notes are guaranteed, jointly and severally, on an unsecured basis, by each of the Company's current and future restricted subsidiaries. Interest on the notes accrues at the rate of 8.375% per year and is payable semi-annually. At March 31, 2016, the carrying value of the senior unsecured notes was net of deferred financing costs of $3.1 million (December 31, 2015 - $3.3 million).

7. Decommissioning obligations:

	Three months ended March 31, 2016	Year ended December 31, 2015
Decommissioning obligations, beginning of period	**$ 85,822**	$ 82,836
Obligations incurred	**566**	6,696
Obligations settled	**(419)**	(736)
Obligations divested	**-**	(6,159)
Change in estimated future cash outflows	**(1,638)**	1,344
Accretion of decommissioning obligations	**433**	1,841
Decommissioning obligations, end of period	**$ 84,764**	$ 85,822

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning obligations to be $84.8 million as at March 31, 2016 (December 31, 2015 - $85.8 million) based on an inflation adjusted undiscounted total future liability of $112.7 million (December 31, 2015 - $113.9 million). These payments are expected to be made over the next 25 years with the majority of costs to be incurred between 2020 and 2035. The inflation rate applied to the liability is 2% (December 31, 2015 – 2%). The discount factor, being the risk-free rate related to the liability, is 2.03% (December 31, 2015 – 2.03%). The $1.6 million (December 31, 2015 - $1.3 million) change in estimated future cash outflows is a result of a change in future estimated undiscounted abandonment costs.

8. Share capital:

At March 31, 2016, the Company was authorized to issue an unlimited number of common shares with the holders of common shares entitled to one vote per share.

On March 3, 2015, the Company issued 16,667,000 Common Shares of the Company, on a bought deal basis, at a price of $6.00 per share for aggregate gross proceeds of $100 million.

Share based payments:

The Company had a stock option program that entitles officers, directors, employees and certain consultants to purchase shares in the Company. Options were granted at the market price of the shares at the date of grant, have a four year term and vested over three years. The Company elected not to seek shareholder approval for the requisite three-year renewal of its option program at its 2014 annual meeting and, as a result, is no longer eligible to issue new options without shareholder approval. Previously issued options will remain outstanding until exercised or their expiry.

The number and weighted average exercise prices of stock options are as follows:

	Number of options		Weighted average exercise price
Balance January 1, 2016	3,783	$	6.51
Forfeited	(130)	$	12.09
Balance at March 31, 2016	**3,653**	**$**	**6.31**

The following table summarizes information about the stock options outstanding at March 31, 2016:

Range of exercise prices	Outstanding at Mar 31, 2016	Weighted average remaining life (years)		Weighted average exercise price	Exercisable at Mar 31, 2016		Weighted average exercise price
$ 5.16 to $ 5.65	1,972	0.1	$	5.64	1,964	$	5.64
$ 5.66 to $ 7.16	220	1.0	$	6.51	160	$	6.51
$ 7.17 to $ 7.55	1,461	1.0	$	7.18	969	$	7.18
	3,653	0.5	$	6.31	3,093	$	6.17

Restricted and Performance Award Incentive Plan:

The Company has a Restricted and Performance Award Incentive Plan (“RPAP”) which authorizes the Board of Directors to grant restricted awards (“RAs”) and performance awards (“PAs”) to directors, officers, employees, consultants or other service providers of Crew and its affiliates.

Subject to terms and conditions of the RPAP, each RA and PA entitles the holder to an award value to be typically paid as to one-third on each of the first, second and third anniversaries of the date of grant. For the purpose of calculating share-based compensation, the fair value of each award is determined at the grant date using the closing price of the common shares. In the case of PAs, the award value is adjusted for a payout multiplier which can range from 0.0 to 2.0 and is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. On the vesting dates, the Company has the option of settling the award value in cash or common shares of the Company. To date, the Company has not settled any awards with cash. No awards were granted for the three month period ended March 31, 2016.

The number of restricted and performance awards outstanding are as follows:

	Number of RAs	Number of PAs
Balance January 1, 2016	1,087	1,546
Granted	-	-
Vested	(4)	(2)
Forfeited	(30)	(22)
Balance at March 31, 2016	**1,053**	**1,522**

Per share amounts:

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average shares outstanding for the period ended March 31, 2016 was 141,071,000 (March 31, 2015 – 128,617,000).

In computing diluted earnings per share for the period ended March 31, 2016, NIL (March 31, 2015 – NIL) shares were added to the weighted average Common Shares outstanding to account for the dilution of stock options and restricted and performance awards. There were 3,653,000 (March 31, 2015 – 5,204,000) stock options and 2,575,000 (March 31, 2015 – 1,713,000) restricted and performance awards that were not included in the diluted earnings per share calculation because they were anti-dilutive.

9. Financial risk management:

Derivative contracts:

It is the Company's policy to economically hedge a portion of its oil and natural gas revenues through the use of various financial derivative forward sales contracts and physical sales contracts. The Company does not apply hedge accounting for these contracts. The Company's production is usually sold using "spot" or near term contracts, with prices fixed at the time of transfer of custody or on the basis of a monthly average market price. The Company, however, may give consideration in certain circumstances to the appropriateness of entering into long term, fixed price marketing contracts. The Company does not enter into commodity contracts other than to meet the Company's expected sale requirements.

The fair value of options and costless collars is based on option models that use published information with respect to volatility, prices and interest rates. These instruments are considered level two under the fair value hierarchy. The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and published forward price curves as at the date of the statement of financial position, using the remaining contracted oil and natural gas volumes and a risk-free interest rate (based on published government rates).

At March 31, 2016, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Oil	500 bbl/day	April 1, 2016 – June 30, 2016	US$ WCS - WTI diff	$(14.95)	Swap	(108)
Oil	500 bbl/day	April 1, 2016 - December 31, 2016	CDN$ WTI	$116.50	Call	(1)
Gas	25,276 gj/day	April 1, 2016 - December 31, 2016	AECO C Monthly Index	$2.56	Swap	6,528
Gas	2,500 gj/day	April 1, 2016 - October 31, 2016	AECO C Monthly Index	$2.14	Swap	395
Gas	20,000 mmbtu/day	April 1, 2016 - December 31, 2016	CDN$ Chicago Citygate	$3.79	Swap	5,306
Gas	2,500 gj/day	January 1, 2017 - December 31, 2017	AECO C Monthly Index	$2.73	Swap	187
Gas	5,000 gj/day	January 1, 2017 - December 31, 2017	AECO C Monthly Index	$2.90	Call Swaption(1)	(174)
Gas	5,000 mmbtu/day	January 1, 2017 - December 31, 2017	CDN$ Chicago Citygate	$3.89	Swap	548
Total						12,681

(1) The referenced contract is a European call swaption, which the counterparty will accept or decline by December 22, 2016.

Subsequent to March 31, 2016, the Company entered into the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Gas	7,500 mmbtu/day	January 1, 2017 - December 31, 2017	CDN$ Chicago Citygate	$3.71	Swap
Gas	2,500 gj/day	January 1, 2017 - December 31, 2017	AECO C Monthly Index	$2.48	Swap

Capital management:

The Company's objective when managing capital is to maintain a flexible capital structure which will allow it to execute on its capital expenditure program, which includes expenditures on oil and gas activities which may or may not be successful. Therefore, the Company monitors the level of risk incurred in its capital expenditures to balance the proportion of debt and equity in its capital structure.

The Company considers its capital structure to include working capital, long-term debt (including the bank loan and senior unsecured notes) and shareholders' equity. Crew's primary capital management objective is to maintain a strong financial position in order to continue to fund the future growth of the Company. Crew monitors its capital structure and makes adjustments on an ongoing basis in order to maintain the flexibility needed to achieve the Company's long-term objectives. To manage the capital structure the Company may adjust capital spending, hedge future revenue and costs, issue new equity, issue new debt or repay existing debt through non-core asset sales.

The Company monitors debt levels based on the ratio of net debt to annualized funds from operations. The ratio represents the time period it would take to pay off the debt if no further capital expenditures were incurred and if funds from operations remained constant. This ratio is calculated as net debt, defined as outstanding long-term debt and net working capital, divided by annualized funds from operations for the most recent quarter.

The Company monitors this ratio and endeavours to maintain it at or below 2.0 to 1.0. During periods of increased capital expenditures, acquisitions or low commodity prices, this ratio will increase. As shown below, as at March 31, 2016, the Company's ratio of net debt to annualized funds from operations was 5.25 to 1 (December 31, 2015 – 3.04 to 1). As a result of the significant decline in commodity prices over the past 18 months, the Company increased its financial flexibility through the issuance of additional equity in early 2015 (Share Capital – note 8) and the strategic divestiture of non-core assets for $50.1 million in the third quarter of 2015. The Company is closely monitoring its financial position and does not plan to add materially to its current debt position in 2016. Capital expenditures planned in 2016 will be substantially funded by funds from operations. With the Company's Bank Facility approved for extension for another 364 day term while only 42% drawn and the forward market for oil and natural gas signaling an improvement over current pricing, the Company's financial position remains strong. If the Company feels it necessary to improve its financial position it will consider divesting of non-core properties, will adjust its annual capital expenditure program further or may consider other forms of financing.

		March 31, 2016		December 31, 2015
Net debt:				
Accounts receivable	**$**	**28,390**	$	26,697
Accounts payable and accrued liabilities		**(29,248)**		(37,434)
Working capital deficiency	**$**	**(858)**	$	(10,737)
Bank loan		**(98,108)**		(80,980)
Senior unsecured notes		**(146,854)**		(146,679)
Net debt	**$**	**(245,820)**	$	(238,396)
Quarterly Annualized funds from operations:				
Cash provided by operating activities	**$**	**19,591**	$	12,373
Decommissioning obligations settled		**419**		43
Change in non-cash working capital		**(8,121)**		7,300
Accretion of deferred financing charges		**(175)**		(115)
Quarterly Funds from operations	**$**	**11,714**	$	19,601
Annualized	**$**	**46,856**	$	78,404
Net debt to annualized funds from operations		**5.25**		3.04

Neither the Company nor any of its subsidiaries are subject to externally imposed capital requirements. The credit facilities are subject to a semi-annual review of the borrowing base which is directly impacted by the value of the oil and natural gas reserves (Bank loan – note 5).

10. Commitments:

	Total	2016	2017	2018	2019	2020	Thereafter
Operating leases	$ 4,919	$ 219	$ 783	$ 1,175	$ 1,175	$ 1,175	$ 392
Firm transportation agreements	157,583	22,883	29,347	29,686	29,406	26,224	20,037
Firm processing agreement	61,337	10,039	13,325	13,325	13,325	11,323	-
Total	$ 223,839	$ 33,141	$ 43,455	$ 44,186	$ 43,906	$ 38,722	$ 20,429

The operating leases include the Company's contractual obligation to a third party for the renewed five year lease of office space.

The firm transportation agreements include commitments to third parties to transport natural gas and natural gas liquids from gas processing facilities in northeastern British Columbia.

The firm processing agreements include commitments to process natural gas through the Septimus complex gas processing facilities in northeastern British Columbia.

DIRECTORS & OFFICERS

OFFICERS

Dale O. Shwed
President and Chief Executive Officer

John G. Leach, CA
Senior Vice President and Chief Financial Officer

Rob Morgan, P.Eng.
Senior Vice President and Chief Operating Officer

Ken Truscott
Senior Vice President, Business Development and Land

Jamie L. Bowman
Vice President, Marketing

Kurtis Fischer
Vice President, Business Development

Shawn A. Van Spankeren, CMA
Vice President, Finance and Administration

BOARD OF DIRECTORS

John A. Brussa,
Chairman Independent Director

Jeffery E. Errico,
Lead Director Independent Director

Dennis L. Nerland
Independent Director

Dale O. Shwed
President, Crew Energy Inc.

David G. Smith
Independent Director

Corporate Secretary

Michael D. Sandrelli
Partner, Burnet, Duckworth & Palmer LLP

ABBREVIATIONS

bbl barrels
bbl/d barrels per day
bcf billion cubic feet
boe barrels of oil equivalent (6 mcf: 1 bbl)
bopd barrels of oil per day
mboe thousand barrels of oil equivalent (6 mcf: 1 bbl)
mmboe million barrels of oil equivalent (6 mcf: 1 bbl)
mcf thousand cubic feet
mcf/d thousand cubic feet per day
mmcf million cubic feet
mmcf/d million cubic feet per day
ngl natural gas liquids