interim report Q3 2018

third quarter ending September 30, 2018

crew energy inc.

Crew Energy Inc. (TSX: CR) ("Crew" or the "Company") is pleased to announce our operating and financial results for the three and nine month periods ended September 30, 2018.

HIGHLIGHTS

- **Production of 23,680 boe per day:** Volumes exceeded the midpoint of guidance with capital expenditures that were below budget. Greater Septimus production of 19,240 boe per day was 6% higher than the 18,154 boe per day produced in Q3 2017.

- **Montney Condensate Remains in Focus:** With Q3 condensate volumes of 2,077 bbls per day, Crew continued to benefit from strong realized condensate pricing in the quarter, which averaged $81.45 per bbl, a 55% increase over the $52.71 per bbl in Q3 2017.

- **Adjusted Funds Flow ("AFF") Boosted by Strong Liquids Pricing:** Q3 AFF totaled $20.1 million or $0.13 per fully diluted share, compared with Q2 2018 AFF of $21.8 million or $0.14 per fully diluted share, reflecting our focus on higher-value liquids production and improved liquids pricing.

- **Continued Natural Gas Price Outperformance vs. AECO:** Q3 average realized natural gas price of $2.40 per mcf outperformed the AECO 5A benchmark of $1.19 per mcf by 102%, driven by Crew's high heat content natural gas and exposure to diversified, higher-priced sales hubs and gas markets.

- **Exceptional Operational Performance with Lower Capital Spending:** Net exploration and development expenditures in Q3 2018 were $23.7 million, below the lower end of our $25 to $30 million guidance range.

- **Ultra Condensate Rich ("UCR") Drilling in Greater Septimus:** Completed drilling four out of five wells on Crew's first extended length lateral pad with the last well drilled early in Q4. Three of the five wells are currently being completed for production in Q4 2018, with the balance in Q1 2019.

- **Fully Connected to Major Export Pipelines:** Crew's pipeline from West Septimus through Groundbirch connecting to the existing TCPL Saturn meter station was completed during the quarter, further enhancing our marketing and transportation flexibility and access to markets outside of western Canada.

- **Strong Balance Sheet Maintained:** Quarter end net debt of $332.9 million is $12 million lower than year-end 2017, which includes $300 million of term debt due in 2024 with no financial maintenance covenants.

FINANCIAL & OPERATING HIGHLIGHTS

FINANCIAL ($ thousands, except per share amounts)	**Three months ended Sept. 30, 2018**	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Petroleum and natural gas sales	**54,080**	47,824	**167,547**	154,008
Adjusted Funds Flow(1)	**20,107**	24,970	**68,284**	74,042
Per share - basic	**0.13**	0.17	**0.45**	0.50
- diluted	**0.13**	0.17	**0.45**	0.49
Net (loss)/income	**(939)**	2,127	**(5,972)**	32,063
Per share - basic	**(0.01)**	0.01	**(0.04)**	0.22
- diluted	**(0.01)**	0.01	**(0.04)**	0.21
Exploration and Development expenditures	**23,656**	90,069	**70,045**	201,889
Property acquisitions (net of dispositions)	**9**	(144)	**(9,981)**	(46,197)
Net capital expenditures	**23,665**	89,925	**60,064**	155,692

Capital Structure ($ thousands)	**As at Sept. 30, 2018**	As at Dec. 31, 2017
Working capital (surplus) / deficiency(2)	**(11,025)**	29,143
Bank loan	**49,317**	21,977
	38,292	51,120
Senior Unsecured Notes	**294,639**	293,862
Total Net Debt	**332,931**	344,982
Current Debt Capacity(3)	**535,000**	535,000
Common Shares Outstanding (thousands)	**151,730**	149,328

Notes:

(1) Adjusted funds flow 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. Adjusted funds flow 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. See "Non-IFRS Measures" contained within Crew's MD&A.

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

(3) Current Debt Capacity reflects the bank facility of $235 million plus $300 million in senior unsecured notes outstanding.

Operations	**Three months ended Sept. 30, 2018**	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Daily production				
Light crude oil (bbl/d)	**269**	553	**282**	528
Heavy crude oil (bbl/d)	**1,819**	1,902	**1,832**	1,846
Condensate (bbl/d)	**2,077**	2,102	**2,358**	1,856
Other natural gas liquids (bbl/d)	**1,711**	1,686	**1,738**	1,491
Natural gas (mcf/d)	**106,821**	102,046	**109,099**	99,577
Total (boe/d @ 6:1)	**23,680**	23,251	**24,393**	22,317
Average prices (1)				
Light crude oil ($/bbl)	**78.25**	52.47	**73.75**	56.66
Heavy crude oil ($/bbl)	**51.03**	43.91	**47.96**	43.95
Condensate ($/bbl)	**81.45**	52.71	**78.99**	58.41
Other natural gas liquids ($/bbl)	**28.15**	23.71	**26.19**	20.29
Natural gas ($/mcf)	**2.40**	2.51	**2.51**	3.16
Oil equivalent ($/boe)	**24.82**	22.36	**25.16**	25.28

Notes:

(1) Average prices are before deduction of transportation costs and do not include realized gains and losses on commodity hedging.

	Three months ended Sept. 30, 2018	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Netback ($/boe)				
Petroleum and natural gas sales	**24.82**	22.36	**25.16**	25.28
Royalties	**(1.73)**	(1.43)	**(1.76)**	(1.88)
Realized commodity hedging (loss)/gain	**(2.09)**	2.76	**(1.40)**	1.03
Marketing income(1)	**0.25**	-	**0.27**	-
Net operating costs(2)	**(6.21)**	(5.86)	**(6.36)**	(5.78)
Transportation costs	**(1.62)**	(2.18)	**(1.85)**	(2.39)
Operating netback (3)	**13.42**	15.65	**14.07**	16.26
G&A	**(1.39)**	(1.29)	**(1.34)**	(1.43)
Other income	**-**	-	**0.15**	-
Financing costs on long-term debt	**(2.81)**	(2.68)	**(2.64)**	(2.67)
Adjusted funds flow	**9.22**	11.68	**10.24**	12.16
Drilling Activity				
Gross wells	**6**	13	**6**	35
Working interest wells	**6.0**	12.3	**6.0**	34.3
Success rate, net wells (%)	**100%**	100%	**100%**	97%

Notes:

(1) Marketing income was recognized from the monetization of forward physical sales contracts offset by the cost of committed natural gas transportation that was not available during the period.

(2) Net operating costs are calculated as gross operating costs less processing revenue.

(3) 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 adjusted funds flow 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. See "Non-IFRS Measures" contained within Crew's MD&A.

FINANCIAL OVERVIEW

Production Increase at Greater Septimus

- Q3 2018 volumes of 23,680 boe per day were ahead of the midpoint of our quarterly guidance and were 2% higher than the same period in 2017, reflecting volumes from new wells completed late in Q2 2018.
- Greater Septimus production averaged 19,240 boe per day in Q3 2018, a 6% increase over the same period in 2017 and 2% higher than Q2 2018, as the impact of wells completed in the prior quarter contributed to increased production.
- Crew's 2018 drilling program commenced in Q3, as prior 2018 quarters' activities were focused on completion of 2017 drilled and uncompleted wells ("DUCs") within the less condensate-rich area of West Septimus. Active drilling in the UCR area for the remainder of 2018 and 2019 is expected to advance Crew's ongoing goal of increasing the relative weighting of condensate in the production mix and offset condensate declines in the weighting through the first nine months of 2018.

Strength in Liquids Pricing Partially Offsets Natural Gas Weakness

- Liquids revenue in Q3 2018 represented 56% of total revenue, while condensate revenue alone increased 53% over Q3 2017 and represented 29% of Crew's total petroleum and natural gas sales for the period.
- Compared to Q3 2017, Crew's realized liquids prices in Q3 2018 increased meaningfully as light crude oil was 49% higher, heavy crude oil increased 16%, condensate rose 55% and other ngl was 19% higher. Crew's Q3 2018 realized natural gas price was 4% lower than Q3 2017, reflecting continued challenges due to a lack of takeaway and egress options in the western Canadian natural gas market.
- Global crude oil prices continued to rise through Q3 2018 on concerns of shrinking world crude oil inventories, the impact of sanctions on Iran and general global geopolitical unrest. However, Canada's lack of adequate pipeline egress and

crude-by-rail capacity has limited the amount of Canadian crude oil that can be moved to markets where global pricing can be realized. As a result, Canadian benchmark crude oil prices, including light sweet crude and particularly Western Canadian Select ("WCS"), began to realize wider discounts relative to global oil prices late in the quarter extending into Q4 2018.

- During the quarter, Canadian natural gas prices remained challenged relative to prices in the US due to the imbalance between supply and demand, caused by the lack of takeaway and egress options which resulted in bottlenecks at Canadian price hubs. Despite the challenged markets in Canada, North American pricing provided opportunities to increase price realizations through diversification of markets. Crew's realized sales price for natural gas averaged $2.40 per mcf, a $1.21 premium over the average AECO benchmark price of $1.19 per mcf, due to our high heat content natural gas and exposure to diversified and higher-priced gas markets.

Adjusted Funds Flow Supported by Liquids Volumes and Pricing

- AFF of $20.1 million ($0.13 per diluted share) reflected strong realized pricing for crude oil, condensate and other natural gas liquids ("ngl") offsetting lower natural gas prices. AFF was 20% lower than Q3 2017 due to weaker natural gas pricing and the impact of a realized commodity hedge loss in 2018.
- Corporate operating netback of $13.42 per boe in Q3 2018 was 5% lower than Q2 2018 reflecting the impact of a realized hedging loss that was 73% higher than the previous quarter, partially offset by lower overall cash costs. Corporate Q3 operating netback was 14% lower than Q3 2017, reflecting the impact of higher overall cash costs and the impact of a realized $2.09 per boe hedging loss compared to a hedging gain of $2.76 per boe realized in Q3 2017.
- Q3 2018 revenue was consistent with the second quarter of 2018 and grew 13% over the same period in 2017 due to higher volumes from NE BC and the positive impact of stronger pricing for light and heavy crude oil, condensate and other ngl, partially offset by a decline in Lloydminster production and weaker natural gas pricing.
- Corporate cash costs per boe were 2% lower than Q2 2018, as higher general and administrative and financing costs were offset by lower royalties, net operating and transportation costs. Corporate cash costs per boe were 2% higher than in Q3 2017, as higher royalties, net operating costs, general and administrative and financing costs were offset by lower transportation costs.

Capital Expenditures Below Budget

- Q3 2018 exploration and development expenditures totaled $23.7 million and were primarily directed to Montney development including completion of the Groundbirch to Saturn pipeline, which represented 32% of the quarterly spend. Drilling and completions activities were 56% of the total capital program and included the drilling of four (4.0 net) liquids-rich natural gas wells in the UCR area at Greater Septimus. At Lloydminster, Crew drilled two (2.0 net) multi-lateral heavy oil wells, completed one (1.0 net) heavy oil well and recompleted twelve (11.8 net) heavy oil wells.

Stable Net Debt and Continued Balance Sheet Strength

- Net debt at the end of Q3 2018 of $332.9 million was 4% lower than at year end 2017. Crew's debt includes $300 million of term debt that has no financial maintenance covenants or repayment required until 2024 and a $235 million credit facility that was 16% drawn after adjusting for a working capital surplus of approximately $11 million.

TRANSPORTATION, MARKETING & HEDGING

Realized Natural Gas Price Exceeds AECO

- Given Crew's diversified sales portfolio, the Company's realized natural gas sales price was 102% higher than the Canadian AECO 5A benchmark. Natural gas sales reflect the following diversified markets: approximately 36% Chicago City Gate, 23% AECO 5A, 14% AECO 7A, 19% Alliance ATP, 4% Sumas and 4% Station 2.
- During Q1 2018, Crew took steps to monetize the inherent value in our Dawn and Malin market exposure for Q2 and Q3, 2018. As a result, we recognized $1.7 million of marketing revenue in Q3 2018, consistent with the previous quarter. With the differential between Canadian and US natural gas prices remaining wide entering the fourth quarter, the Company

further monetized our Dawn and Malin contracts, as well as a Sumas contract. This will result in additional marketing income, after deduction of transportation costs, of approximately $2.1 million being recognized in the fourth quarter.

- In addition to the realization of the Dawn, Malin and Sumas contract values, Crew's Q4 2018 natural gas sales will be exposed approximately 48% to Chicago City Gate, 19% to AECO 5A, 15% to Alliance ATP, 12% to NYMEX and 6% to Station 2.

Flexibility on Major Export Pipelines

- Completion of the strategic pipeline from our West Septimus facility through Groundbirch connecting to the existing TCPL Saturn meter station fulfills Crew's objective of accessing all three major export pipelines in BC. When this line is commissioned on January 1, 2019, Crew's Greater Septimus gas processing complex will have access to the Alliance Pipeline System, Enbridge T-North System, and the TCPL/Nova system, which allows the Company to manage exposure to different pricing markets and take advantage of relative pricing opportunities on all three pipelines.

Natural Gas & Liquids Hedging

- Approximately 24% of budgeted 2018 natural gas volumes are hedged at an average of $2.54 per GJ or approximately $2.68 per mcf which increases to approximately $3.15 per mcf after adjusting for Crew's heat conversion.
- Through 2018, 2,648 bbls per day of WTI is hedged at a minimum average price of C$72.57 per bbl, 750 bbls per day of WCS for the second half of 2018 at an average price of C$56.62 per bbl and 400 bbls per day of OPIS Conway propane hedged at US$0.7863 per gallon or US$33.03 per bbl.
- Crew's 2019 risk management program currently has 1,874 barrels per day of WTI hedged at an average price of C$75.99 per barrel and 500 barrels per day of WCS for the first half of 2019 at an average price of C$52.93 per bbl. With some positive indications in the forward curve for natural gas, we have layered on incremental natural gas hedges and have 15,000 mmbtu per day of Chicago City Gate gas at C$3.35 per mmbtu, 2,500 mmbtu per day of Dawn gas at C$3.30 per mmbtu and 2,500 mmbtu per day of NYMEX gas at US$2.80 per mmbtu.

OPERATIONS & AREA OVERVIEW

NE BC Montney - Greater Septimus

- In Q3, four wells of a five well extended length horizontal pad were drilled in the UCR area using a revised well design with the fifth well drilled early in Q4. Completion of three of the wells is currently underway using a higher intensity 'plug and perf' completion design to optimize condensate recovery.
- Each horizontal well features lengths 30-50% greater than previous Crew wells. The longest lateral length totaled over 2,700 metres which compares to an average length of 1,840 metres on previous wells. In total, 13,000 metres of reservoir was accessed through these wells.
- Crew executed this program on budget, while reducing drilling days from 21 for the first well to 12 days for the pacesetter well, with an average spud to rig release across the pad of 15.6 days.
- Commencing in Q4,drilling of additional extended length lateral wells in the UCR area is planned, with five to six wells expected to be drilled by the end of 2018 and up to 22 wells available to be drilled on this pad.

Greater Septimus

Production & Drilling	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017
Average daily production (boe/d)	**19,240**	18,953	20,467	20,193	18,154
Wells drilled (gross / net)	**4 / 4.0**	-	-	5 / 3.9	13 / 12.3
Wells completed (gross / net)	**0 / 0**	2 / 1.6	9 / 7.7	3 / 3.0	14 / 14.0

Operating Netback ($ per boe)	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017
Revenue	**22.83**	22.70	25.40	24.43	20.05
Royalties	**(1.15)**	(1.35)	(1.50)	(1.19)	(0.89)
Realized commodity hedge (loss) / gain	**(2.01)**	(1.32)	(1.01)	1.74	2.97
Marketing income (1)	**0.34**	0.34	0.37	-	-
Net operating costs(2)	**(4.61)**	(4.71)	(4.45)	(3.67)	(3.38)
Transportation costs	**(1.22)**	(1.40)	(1.51)	(1.51)	(1.65)
Operating netback(3)	**14.18**	14.26	17.30	19.80	17.10

Notes:

(1) Marketing income was recognized from the monetization of forward physical sales contracts offset by the cost of committed natural gas transportation that was not available during the period.

(2) Net operating costs are calculated as gross operating costs less processing revenue.

(3) Operating netback equals petroleum and natural gas sales including realized hedging gains and losses on commodity contracts less royalties, net operating costs and transportation costs calculated on a boe basis. Operating netback and adjusted funds flow 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. See "Non-IFRS Measures" contained within Crew's MD&A.

Other NE BC Montney

- **Tower:** Production at Tower averaged 843 boe per day in Q3 2018 and was impacted by third-party offset fracturing activity in the early part of the quarter. Crew continues to evaluate the relative economics of Tower development as well as encouraging nearby Lower Montney well results.
- **Attachie:** Crew owns 97 sections of land in this area with approximately 45 sections in the liquids-rich hydrocarbon window. An offsetting operator has been actively testing wells with condensate rates of over 1,000 bbls per day. Crew plans on drilling one well in this area in 2019.
- **Oak / Flatrock:** Crew has over 60 sections of land in this area where drilling activity is gaining momentum for liquids-rich gas. We will continue to monitor well results from this area.
- **Inga:** Crew has eight sections of Montney rights in this area, which is prospective for highly liquids-rich gas.

AB / SK Heavy Oil - Lloydminster

- Drilling and completions activity in Q3 included drilling two, four-leg multilateral wells and one completion. This supplemented our successful 12-well recompletion program at Lloydminster, resulting in average production volumes of 1,819 bbls per day. Volumes were 5% lower than the same quarter in the prior year after minimal capital was invested during the first nine months of 2018.
- Crew's third quarter heavy oil drilling program has out-paced expectations. Production from these new wells is supported by the Company's risk management program, with 750 boe per day of WCS hedged at $56.62 per boe and operating costs on new wells forecasted at $5.00 per boe.
- WCS pricing differentials widened significantly in the latter part of the third quarter with operating netbacks at Lloydminster averaging $18.16 per boe in the period. Wider differentials have persisted into the fourth quarter. With current differentials reaching unprecedented levels, Crew has elected to reduce activity levels and shut-in higher-cost production to preserve economics while differentials remain prohibitively wide.

OUTLOOK

Operations Target Condensate Growth

- With over 280,000 net acres of premium Montney land, connectivity to major export pipelines, increasing condensate production and a positive outlook for LNG development in Canada, Crew remains committed to managing through a challenging market for Canadian oil and gas commodities. Our focus on increasing liquids production from our ultra condensate-rich area at West Septimus and prudently managing our balance sheet will continue to underpin our strategy.
- Crew's successful and focused operating strategy, combined with established infrastructure and market access continues to positively impact our results. We have taken steps that enable the Company to benefit from our diversified marketing strategy, whether it be moving production to new markets that offer higher pricing or having the ability to advantageously monetize physical delivery contracts to crystalize value.

2018 Production Guidance Maintained

- In Q4, Crew has been affected by third party pipeline outages and limited western Canadian egress creating low, volatile and occasionally negative natural gas prices and extremely low WCS prices. In response, Crew has elected to shut-in production volumes to preserve value and forecasts Q4 production to average 22,000 to 23,000 boe per day, with production capability of greater than 24,500 boe per day. Production to the end of September exceeded Crew's original forecast, averaging 24,393 boe per day, positioning the Company to maintain our annual guidance of 23,500 to 24,500 boe per day.

Increased AFF Yields Additional Drilled and Uncompleted Wells ("DUCs")

- Crew's 2018 net capital expenditure budget is expected to approximate the Company's annual estimated AFF, which was forecast at $80 to $85 million based on the Company's original budget. Stronger production and liquids prices earlier in the year, higher condensate production forecasted for Q4 and a significant proportion of our gas sold outside the AECO market in Q4 has resulted in Crew increasing our forecast 2018 AFF to $90 to $95 million.
- The increase in forecast AFF has allowed the Company to continue drilling operations on the 4-21 pad in the UCR area during the fourth quarter, which was previously planned for 2019. As a result, Crew will be positioned to enter 2019 with seven to eight DUCs compared to two that were initially planned. This drilling program will also permit the Company to accelerate condensate production into Q1, 2019 from Q3, 2019, which based on current strip pricing, is expected to generate significant incremental AFF in 2019.
- Q4 2018 capital expenditures are expected to be $30 to $35 million with annual net capital expenditures, after acquisitions and dispositions, forecast at $90 to $95 million.

We would like to thank our employees and Board of Directors for their contribution and commitment to Crew, as well as our shareholders and bondholders for their ongoing support.

<u>Cautionary Statements</u>

Information Regarding Disclosure on Oil and Gas and Operational Information and Non-IFRS Measures

This report contains metrics commonly used in the oil and natural gas industry, such as "adjusted funds flow", "operating netbacks", "working capital" and "net debt". These terms are not defined in IFRS and do not have standardized meanings or standardized methods of calculation and therefore may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included herein to provide readers with additional information to evaluate the Company's performance, however such metrics should not be unduly relied upon. Management uses oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare Crew's operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this report, should not be relied upon for investment or other purposes. See "Non-IFRS Measures" contained within Crew's MD&A for applicable definitions, calculations, rationale for use and reconciliations to the most directly comparable measure under IFRS.

Forward-Looking Information and Statements

This report 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 report contains forward-looking information and statements pertaining to the following: the estimated volumes, including shut-ins, and product mix of Crew's oil and gas production; production estimates including Q4, year to date and 2018 average production forecasts; commodity price expectations including Crew's estimates of natural gas pricing exposure; Crew's commodity risk management programs; marketing, transportation and natural gas egress plans; future liquidity and financial capacity; future results from operations and operating metrics; potential for lower costs and efficiencies going forward; future development, exploration, acquisition and disposition activities (including drilling, completion and infrastructure plans and methodology and associated timing and cost estimates); the amount and timing of capital projects; Q4 and 2018 capital expenditures; possible shut-in activity; operational plans; and Crew's 2018 budget (including forecast net annual capital expenditures and annual funds flow estimates); the potential acceleration of condensate growth into Q1 2019 and expected significant incremental adjusted funds flows in 2019; and methods of funding our capital program.

In addition, 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: that Crew will continue to conduct its operations in a manner consistent with past operations; results from drilling and development activities consistent with past operations; the quality of the reservoirs in which Crew operates and continued performance from existing wells; the continued and timely development of infrastructure in areas of new production; the accuracy of the estimates of Crew's reserve volumes; certain commodity price and other cost assumptions; continued availability of debt and equity financing and cash flow to fund Crew's current and future plans and expenditures; the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; the general continuance of current industry conditions; 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; 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; and the ability of Crew to successfully market its oil and natural gas products.

The forward-looking information and statements included in this report 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; changes in the demand for or supply of Crew's products, the early stage of development of some of the evaluated areas and zones the potential for variation in the quality of the Montney formation; 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 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 report and Crew's Annual Information Form).

The forward-looking information and statements contained in this report speak only as of the date of this report, 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, particularly those short in duration, 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 the 6:1 conversion ratio may be misleading as an indication of value.

MANAGEMENT'S DISCUSSION AND ANALYSIS

ABOUT CREW

Crew Energy Inc. ("Crew" or the "Company") is a growth-oriented oil and natural gas producer, committed to pursuing sustainable per share growth through a balanced mix of financially responsible exploration and development complemented by strategic acquisitions. The Company's operations are primarily focused in the vast Montney resource, situated in northeast British Columbia, and include a large contiguous land base. Crew's liquids-rich Septimus and West Septimus areas ("Greater Septimus") along with Groundbirch and the light oil area at Tower offer significant development potential over the long-term. The Company has access to diversified markets with operated infrastructure and access to multiple pipeline egress options. Crew's common shares are listed for trading on the Toronto Stock Exchange ("TSX") under the symbol "CR".

ADVISORIES

Management's discussion and analysis ("MD&A") is the explanation of the financial performance for the period covered by the financial statements along with an analysis of the financial position of the Company. Comments relate to and should be read in conjunction with the unaudited condensed interim consolidated financial statements of the Company for the three and nine month periods ended September 30, 2018 and 2017. 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, 2017. All figures provided herein and in the September 30, 2018 unaudited condensed interim consolidated financial statements are reported in Canadian dollars ("CDN"). This MD&A is dated November 2, 2018.

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 and pipeline construction, expansion, commissioning and the timing thereof, capital expenditures, including the Company's current 2018 capital budget encompassing anticipated fourth quarter capital expenditures and 2018 net capital expenditures (after dispositions), timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, production estimates including fourth quarter and 2018 average forecasts, expected commodity mix and prices, future net operating costs, future transportation costs, expected royalty rates, expected general and administrative expenses, expected interest rates and other financing charges, debt levels, funds from operations, forecasted 2018 adjusted funds flow 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 net 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 and Adjusted Funds Flow

Funds from operations and adjusted funds flow are measures not defined in IFRS but are commonly used in the oil and gas industry. Funds from operations represents cash provided by operating activities before changes in operating non-cash working capital and accretion of deferred financing costs. Adjusted funds flow represents funds from operations before decommissioning obligations settled. The Company considers these metrics as key measures that demonstrate the ability of the Company's continuing operations to generate the cash flow necessary to fund future growth through capital investment and to service and repay debt. Funds from operations and adjusted funds flow 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 and adjusted funds flow may not be comparable to that reported by other companies. Crew also presents adjusted funds flow 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 and adjusted funds flow:

($ thousands)	**Three months ended Sept. 30, 2018**	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Cash provided by operating activities	**19,095**	15,258	**66,284**	73,806
Change in operating non-cash working capital	**1,127**	9,834	**1,820**	459
Accretion of deferred financing costs	**(259)**	(250)	**(777)**	(707)
Funds from operations	**19,963**	24,842	**67,327**	73,558
Decommissioning obligations settled	**144**	128	**957**	484
Adjusted funds flow	**20,107**	24,970	**68,284**	74,042

Operating Netback

Management uses certain industry benchmarks such as 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 petroleum and natural gas sales including realized gains and losses on commodity related derivative financial instruments, marketing revenue, less royalties, net 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 current operations and 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)	**September 30, 2018**	December 31, 2017
Current assets	**56,458**	42,596
Current liabilities	**(59,633)**	(71,392)
Derivative financial instruments	**14,200**	(347)
Working capital surplus (deficiency)	**11,025**	(29,143)

($ thousands)	**September 30, 2018**	December 31, 2017
Bank loan	**(49,317)**	(21,977)
Senior unsecured notes	**(294,639)**	(293,862)
Working capital surplus (deficiency)	**11,025**	(29,143)
Net debt	**(332,931)**	(344,982)

RESULTS OF OPERATIONS

Production

	Three months ended September 30, 2018					Three months ended September 30, 2017				
	Oil (bbl/d)	**Condensate (bbl/d)**	**Other Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Oil (bbl/d)	Condensate (bbl/d)	Other Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
NE BC	**269**	**2,077**	**1,711**	**106,821**	**21,861**	553	2,102	1,686	102,019	21,344
Lloydminster	**1,819**	**-**	**-**	**-**	**1,819**	1,902	-	-	27	1,907
Total	**2,088**	**2,077**	**1,711**	**106,821**	**23,680**	2,455	2,102	1,686	102,046	23,251

During the third quarter of 2018, production increased 2% over the same period in 2017 as a result of an active and successful drilling and completion program that increased condensate-rich natural gas production by 27% at West Septimus in northeast British Columbia ("NE BC"). This increase was partially offset by a 43% decline in production from the Tower area of NE BC and a 20% decline in production from the Septimus area of NE BC, areas where the Company elected not to direct capital over the past year in favour of directing capital to higher rate of return projects at West Septimus.

	Nine months ended September 30, 2018					Nine months ended September 30, 2017				
	Oil (bbl/d)	**Condensate (bbl/d)**	**Other Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Oil (bbl/d)	Condensate (bbl/d)	Other Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
NE BC	**282**	**2,358**	**1,738**	**109,099**	**22,561**	528	1,856	1,491	99,541	20,465
Lloydminster	**1,832**	**-**	**-**	**-**	**1,832**	1,846	-	-	36	1,852
Total	**2,114**	**2,358**	**1,738**	**109,099**	**24,393**	2,374	1,856	1,491	99,577	22,317

In the first nine months of 2018, production increased 9% as compared to the same period in 2017 as a result of the aforementioned successful drilling and completion program, coupled with the completion of the West Septimus gas processing facility expansion, which increased the facility's processing capacity to 120 mmcf per day in the fourth quarter of 2017. This production increase was partially offset by a decline in light oil production in the Tower area and natural gas in the Septimus area.

Petroleum and Natural Gas Sales

	Three months ended Sept. 30, 2018	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Petroleum and natural gas sales ($ thousands)				
Light crude oil	**1,935**	2,671	**5,670**	8,160
Heavy crude oil	**8,538**	7,683	**23,988**	22,148
Condensate	**15,563**	10,192	**50,839**	29,600
Other natural gas liquids	**4,430**	3,679	**12,422**	8,259
Natural gas	**23,614**	23,599	**74,628**	85,841
Total	**54,080**	47,824	**167,547**	154,008
Crew average prices				
Light crude oil ($/bbl)	**78.25**	52.47	**73.75**	56.66
Heavy crude oil ($/bbl)	**51.03**	43.91	**47.96**	43.95
Condensate ($/bbl)	**81.45**	52.71	**78.99**	58.41
Other natural gas liquids ($/bbl)	**28.15**	23.71	**26.19**	20.29
Natural gas ($/mcf)	**2.40**	2.51	**2.51**	3.16
Oil equivalent ($/boe)	**24.82**	22.36	**25.16**	25.28
Benchmark pricing				
Light crude oil – Cdn$ WTI (Cdn $/bbl)	**90.85**	60.35	**86.01**	64.65
Heavy crude oil – WCS (Cdn $/bbl)	**61.81**	47.90	**57.93**	49.11
Condensate – Condensate @ Edmonton (Cdn $/bbl)	**87.49**	59.72	**85.36**	64.69
Natural Gas:				
AECO 5A daily index (Cdn $/mcf)	**1.19**	1.45	**1.48**	2.31
AECO 7A monthly index (Cdn $/mcf)	**1.35**	2.04	**1.41**	2.58
Chicago City Gate at ATP (Cdn $/mcf)	**2.92**	2.84	**2.88**	3.08
Alliance 5A (Cdn $/mcf)	**1.87**	1.27	**1.99**	2.43

In the third quarter 2018, the Company's revenue increased 13% as compared to the same period in 2017, as a result of the increase in production in NE BC, coupled with an increase in light and heavy crude oil, condensate and other natural gas liquids pricing, partially offset by a decline in Lloydminster production and natural gas pricing. The Company's realized light crude oil price increased 49% which is consistent with the 51% increase in the Company's Cdn$ West Texas Intermediate ("WTI") benchmark for the same period last year. Crew's third quarter heavy crude oil price increased 16%, which is lower than the 29% increase in the Company's Western Canadian Select ("WCS") benchmark, as a result of an increase in the cost of diluent purchased to blend with the heavy crude oil as compared to the same period last year. The Company's third quarter realized condensate price increased 55% over the same period in 2017, which was higher than the 47% increase in the Condensate at Edmonton benchmark price as a result of favourable quality adjustments received for the Company's condensate, partially offset by higher pipeline tariffs. Other natural gas liquids ("ngl") realized price increased 19% in the third quarter, due to an increase in propane and butane pricing as compared to the same period in 2017. Crew's realized natural gas price decreased 4% in the third quarter of 2018 which is directionally consistent with the 1% decrease in the Company's natural gas sales portfolio weighted benchmark price. The Company's natural gas price benefits from the high heat content of its Montney natural gas, reflective of the presence of larger amounts of propane and butane in the gas stream, which yields approximately 20% more value than the standard heat conversion used in the Company's benchmark pricing.

The Company's third quarter 2018 natural gas sales portfolio is based approximately on the following reference prices:

	Q3 2018	Q3 2017
Chicago City Gate at ATP	**36%**	39%
AECO 5A	**23%**	13%
AECO 7A	**14%**	15%
Alliance 5A	**19%**	26%
Station 2	**4%**	7%
Sumas	**4%**	-
Total	**100%**	100%

The Company's revenue for the first nine months of 2018 increased 9% over same period in 2017 as a result of the 9% increase in production. The Company's realized light crude oil price increased 30% which was consistent the 33% increase in the Company's WTI benchmark. Crew's heavy crude oil price for the first nine months of 2018 increased 9% which was lower than the 18% increase in the Company's WCS benchmark, as a result of the Company securing short term sales contracts at weaker spot pricing to manage inventory levels, coupled with an increase in the cost of diluent purchased to blend with the heavy crude oil as compared to the same period last year. In the first nine months of 2018, the Company's realized condensate price increased 35%, which was consistent with the 32% increase in the Condensate at Edmonton benchmark price for the same period last year. Other ngl realized price increased 29% in the first nine months of 2018, due to an increase in propane and butane pricing as compared to the same period in 2017. The Company's natural gas price decreased 21% over the first nine months of 2017, which is consistent with the Company's natural gas sales portfolio weighted benchmark price decrease of 20%.

Royalties

($ thousands, except per boe)	**Three months ended Sept. 30, 2018**	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Royalties	**3,764**	3,067	**11,690**	11,460
Per boe	**1.73**	1.43	**1.76**	1.88
Percentage of petroleum and natural gas sales	**7.0%**	6.4%	**7.0%**	7.4%

For the third quarter of 2018, royalties per boe and as a percentage of petroleum and natural gas sales increased over the same period in 2017, predominantly due to an increase in light and heavy crude oil, condensate and other natural gas liquids pricing. For the first nine months of 2018, royalties per boe and as a percentage of petroleum and natural gas sales decreased over the same period in 2017, predominantly due to a significant decline in natural gas prices. In addition, increased production at West Septimus, which attracts lower royalties due to new deep well gas royalty credit programs, further contributed to the decrease in royalties per boe and as a percentage of petroleum and natural gas sales over the first nine months of 2018. The Company continues to expect its royalties as a percentage of revenue to average between 6% and 8% in 2018.

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) income and comprehensive (loss) income:

($ thousands)	**Three months ended Sept. 30, 2018**	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Realized (loss) gain on derivative financial instruments	**(4,545)**	5,910	**(9,354)**	6,287
Per boe	**(2.09)**	2.76	**(1.40)**	1.03
Unrealized gain (loss) on financial instruments	**1,133**	(1,341)	**(17,421)**	25,475

At September 30, 2018, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value
Gas	2,500 mmbtu/day	October 1, 2018 – October 31, 2018	Chicago Citygate	$3.06/mmbtu	Swap	$ (55)
Gas	5,000 gj/day	October 1, 2018 – December 31, 2018	AECO C Monthly Index	$3.00/gj	Call	(2)
Gas	2,500 gj/day	October 1, 2018 – December 31, 2018	AECO C Daily Index	$2.62/gj	Swap	176
Gas	20,000 mmbtu/day	October 1, 2018 – December 31, 2018	Chicago Citygate	$3.61/mmbtu	Swap	(504)
Gas	5,000 mmbtu/day	October 1, 2018 – December 31, 2018	US$ Nymex Henry Hub	$3.05 US/mmbtu	Swap	3
Gas	7,500 mmbtu/day	January 1, 2019 – December 31, 2019	Chicago Citygate	$3.19/mmbtu	Swap	(509)
Gas	2,500 mmbtu/day	January 1, 2019 – December 31, 2019	Dawn Daily Index	$3.30/mmbtu	Swap	(151)
Propane	400 bbl/day	October 1, 2018 – December 31, 2018	US$ Conway OPIS	$0.79 US/gal	Swap	(142)
Oil	2,250 bbl/day	October 1, 2018 – December 31, 2018	CDN$ WTI	$72.92/bbl	Swap	(4,385)
Oil	250 bbl/day	October 1, 2018 – December 31, 2018	CDN$ WTI	$60.00 - $69.65/bbl	Collar(1)	(583)
Oil	250 bbl/day	October 1, 2018 – December 31, 2018	CDN$ WTI	$69.00 - $74.25/bbl	Collar(2)	(478)
Oil	750 bbl/day	October 1, 2018 – December 31, 2018	CDN$ WCS	$56.62/bbl	Swap	393
Oil	250 bbl/day	January 1, 2019 – June 30, 2019	CDN$ WTI	$83.80/bbl	Swap	(403)
Oil	500 bbl/day	January 1, 2019 – June 30, 2019	CDN$ WCS	$52.93/bbl	Swap	(282)
Oil	1,750 bbl/day	January 1, 2019 – December 31, 2019	CDN$ WTI	$75.44/bbl	Swap	(10,152)
Total						**$ (17,074)**

(1) The referenced contract is a costless collar whereby the Company receives $60.00/bbl when the market price is below $60.00/bbl, and receives $69.65/bbl when the market price is above $69.65/bbl.

(2) The referenced contract is a costless collar whereby the Company receives $69.00/bbl when the market price is below $69.00/bbl, and receives $74.25/bbl when the market price is above $74.25/bbl.

Subsequent to September 30, 2018, 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, 2019 – December 31, 2019	Chicago Citygate	$3.51/mmbtu	Swap
Gas	2,500 mmbtu/day	January 1, 2019 – December 31, 2019	US$ Nymex Henry Hub	$2.80 US/mmbtu	Swap

Marketing Income

($ thousands, except per boe)	**Three months ended Sept. 30, 2018**	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Marketing revenue	**1,689**	-	**3,887**	-
Less: marketing expense	**(1,137)**	-	**(2,062)**	-
Marketing income	**552**	-	**1,825**	
Per boe	**0.25**	-	**0.27**	-

In the third quarter of 2018 and nine months ended September 30, 2018, the Company recognized $1.7 million and $3.9 million, respectively, of marketing revenue related to the monetization of the Company's exposure to the Dawn and Malin natural gas markets. Marketing expense reflects the cost of firm transportation commitments on TransCanada's natural gas pipeline system that is currently not physically accessible. The Company has elected to defer access to the TransCanada natural gas pipeline system until January 1, 2019 and as such, has further liquidated its Dawn and Malin fourth quarter exposure for proceeds of $1.7 million that will be recognized in the fourth quarter of 2018. In the fourth quarter of 2018, the Company monetized its Sumas natural gas sales contract that would have extended through October 2019, and will realize $1.5 million of value.

Net Operating Costs

($ thousands, except per boe)	**Three months ended Sept. 30, 2018**	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Operating costs	**14,770**	13,406	**45,331**	38,397
Less: processing revenue	**(1,241)**	(876)	**(3,029)**	(3,161)
Net operating costs	**13,529**	12,530	**42,302**	35,236
Per boe	**6.21**	5.86	**6.35**	5.78

During the third quarter and first nine months of 2018, net operating costs per boe increased as compared to the same periods in 2017 as a result of increased processing fees from the facility expansion at West Septimus. This was offset in the third quarter of 2018 by higher processing revenue, due to an increase in third party volumes from the previously mentioned West Septimus drilling and completion program. The Company has reduced its forecast for 2018 operating costs to average between $6.35 to $6.60 per boe, due to lower realized operating costs on its Lloydminster heavy oil and Tower oil operations.

Transportation Costs

($ thousands, except per boe)	**Three months ended Sept. 30, 2018**	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Transportation costs	**3,529**	4,672	**12,288**	14,579
Per boe	**1.62**	2.18	**1.85**	2.39

During the third quarter and first nine months of 2018, transportation costs per boe decreased as compared to the same periods in 2017 as a result of increased production in West Septimus, which yields a lower transportation cost per boe when compared to the corporate average. Transportation costs were further reduced in the third quarter of 2018 by a 2017 related adjustment from a third party pipeline operator. Additionally, transportation costs per boe were higher in the third quarter and first nine months of 2017 as a result of third party facility and pipeline outages resulting in unutilized demand charges in 2017. The Company has revised its forecast for 2018 transportation costs down to between $1.75 and $2.00 per boe. The decrease resulted from the deferral of the access to the TransCanada pipeline system to January 1, 2019. As a result, the costs associated with this transportation commitment have been reclassified to marketing expense for 2018.

Operating Netbacks

($/boe)	**Greater Septimus**	**Lloydminster Heavy Oil**	**Other NE BC**	**Three months ended Sept. 30, 2018**	Three months ended Sept. 30, 2017
Petroleum and natural gas sales	**22.83**	**51.03**	**21.29**	**24.82**	22.36
Royalties	**(1.15)**	**(8.32)**	**(1.40)**	**(1.73)**	(1.43)
Realized commodity hedging (loss) gain	**(2.01)**	**(2.17)**	**(2.58)**	**(2.09)**	2.76
Marketing income	**0.34**	**-**	**-**	**0.25**	-
Net operating costs	**(4.61)**	**(21.54)**	**(7.34)**	**(6.21)**	(5.86)
Transportation costs	**(1.22)**	**(0.84)**	**(5.11)**	**(1.62)**	(2.18)
Operating netbacks	**14.18**	**18.16**	**4.86**	**13.42**	15.65
Production (boe/d)	**19,240**	**1,819**	**2,621**	**23,680**	23,251

($/boe)	**Greater Septimus**	**Lloydminster Heavy Oil**	**Other NE BC**	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Petroleum and natural gas sales	**23.68**	**47.95**	**20.93**	**25.16**	25.28
Royalties	**(1.34)**	**(6.81)**	**(1.39)**	**(1.76)**	(1.88)
Realized commodity hedging (loss) gain	**(1.45)**	**(0.72)**	**(1.53)**	**(1.40)**	1.03
Marketing income	**0.34**	**-**	**-**	**0.27**	-
Net operating costs	**(4.58)**	**(22.01)**	**(8.30)**	**(6.35)**	(5.78)
Transportation costs	**(1.38)**	**(0.93)**	**(5.44)**	**(1.85)**	(2.39)
Operating netbacks	**15.27**	**17.48**	**4.27**	**14.07**	16.26
Production (boe/d)	**19,549**	**1,832**	**3,012**	**24,393**	22,317

For the third quarter and first nine months of 2018, the Company's operating netbacks decreased over the same periods in 2017, as a result realized hedging losses and higher net operating costs, partially offset by lower transportation costs and marketing income realized. In the third quarter of 2018, this decrease was further offset by higher overall commodity pricing.

General and Administrative Costs

($ thousands, except per boe)	**Three months ended Sept. 30, 2018**	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Gross costs	**4,648**	4,193	**14,017**	13,639
Operator's recoveries	**(196)**	(105)	**(652)**	(314)
Capitalized costs	**(1,422)**	(1,334)	**(4,462)**	(4,584)
General and administrative expenses	**3,030**	2,754	**8,903**	8,741
Per boe	**1.39**	1.29	**1.34**	1.43

Gross and net general and administrative ("G&A") costs increased in the third quarter and first nine months of 2018 as compared to the same period in 2017, due to an increase in information technology related costs and inflationary pressures on office operating costs. The increase in net G&A costs per boe in the third quarter of 2018 is due to the aforementioned increases in information technology related costs and inflationary pressures on office operating costs, partially offset by an increase in production as compared to the same period in 2017. The decrease in net G&A costs per boe in the nine months ended September

30, 2018 is due to the increased production as compared to the same period in 2017. Crew continues to forecast G&A costs per boe to average between $1.25 and $1.50 in 2018.

Other Income

($ thousands, except per boe)	**Three months ended Sept. 30, 2018**	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Other	**-**	-	**1,000**	-
Per boe	**-**	-	**0.15**	-

In the first nine months of 2018, the Company recognized $1.0 million for the receipt of a non-refundable deposit from a third party for a non-core property disposition that failed to close.

Share-Based Compensation

($ thousands)	**Three months ended Sept. 30, 2018**	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Gross costs	**4,184**	4,108	**10,027**	14,058
Capitalized costs	**(1,975)**	(1,886)	**(4,766)**	(6,675)
Total share-based compensation	**2,209**	2,222	**5,261**	7,383

In the third quarter of 2018, the Company's net share-based compensation expense was consistent with the same period in 2017. For the nine months ended September 30, 2018, the Company's share-based compensation expense decreased as compared to the same period in 2017, as a result of the departure of a Company executive and a lower performance multiplier applied to certain performance awards, as compared to the same period in 2017.

Depletion and Depreciation

($ thousands, except per boe)	**Three months ended Sept. 30, 2018**	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Depletion and depreciation	**18,215**	19,408	**58,914**	55,511
Per boe	**8.36**	9.07	**8.85**	9.11

During the third quarter of 2018, depletion and depreciation costs were lower due to increased reserve bookings resulting from the successful West Septimus drilling program. Depletion and depreciation costs were higher in the first nine months of 2018 when compared to the same period in 2017, due to higher land expiries and increased production, partially offset by a lower corporate depletion rate. In the third quarter and first nine months of 2018, depletion and depreciation costs per boe decreased as a result of increased production in the Greater Septimus area, which has a lower depletion rate when compared to the corporate average, coupled with the impact of the aforementioned increase in reserve bookings.

Gain on Divesture of Property

During the first quarter of 2018, the Company disposed of non-core assets for cash proceeds of $10.0 million. The assets consisted of petroleum and natural gas properties and undeveloped land with a net book value of $0.9 million and associated decommissioning obligations of $0.4 million, resulting in a gain of $9.5 million on closing of the disposition.

Finance Expenses

($ thousands, except per boe)	**Three months ended Sept. 30, 2018**	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Interest on bank loan and other	**954**	576	**2,189**	1,892
Interest on senior notes	**4,915**	4,915	**14,585**	13,638
Accretion of deferred financing charges	**259**	250	**777**	707
Accretion of the decommissioning obligation	**488**	482	**1,467**	1,435
Premium paid on redemption of 2020 Notes	**-**	-	**-**	6,282
Deferred financing costs expensed on 2020 Notes	**-**	-	**-**	2,510
Total finance expense	**6,616**	6,223	**19,018**	26,464
Average long-term debt level	**349,948**	302,702	**343,659**	290,992
Average drawings on bank loan	**49,948**	2,702	**43,659**	25,058
Average senior unsecured notes outstanding	**300,000**	300,000	**300,000**	265,934
Effective interest rate on senior unsecured notes	**6.5%**	6.5%	**6.5%**	6.9%
Effective interest rate on long-term debt	**6.1%**	6.5%	**6.1%**	6.5%
Financing costs on long-term debt per boe	**2.81**	2.68	**2.64**	2.67

The Company's average corporate debt level increased in both the third quarter of 2018 and for the nine months ended September 30, 2018 as compared to the same periods in 2017, as a result of increased capital expenditures in 2017 focused on the West Septimus facility expansion and the drilling and completion of wells associated with the planned start-up of the expanded facility. These expenditures were partially funded with the first quarter 2017 issuance of $300 million of 6.5% senior unsecured notes (the "2024 Notes") as described below in the Capital Funding section. Proceeds from the 2024 Notes were used to redeem the $150 million of 8.375% senior unsecured notes (the "2020 Notes") and repay the drawings on the bank loan. As a result, the effective interest rate on the Company's total long-term debt decreased in the third quarter of 2018 as compared to the same period in 2017, and the effective interest rate on the Company's senior notes and total long-term debt decreased for the nine months ended September 30, 2018 as compared to the same period in 2017. Crew forecasts the effective interest rate on its long-term debt to average between 6.0% and 6.5% in 2018.

Deferred Income Taxes

In the third quarter and first nine months of 2018, the provision for deferred tax expense was $1.3 million and $0.7 million, respectively, as compared to deferred tax expense of $1.5 million and $18.0 million, respectively, for the same periods in 2017. The decreases in the deferred tax expense is predominantly due to higher net income realized in 2017 as a result of significant gains on property dispositions and losses incurred on the Company's risk management program in 2018, partially offset by impairment recorded in the second quarter of 2017 and a change in estimate of the tax deduction associated with share-based compensation.

Cash, Funds from Operations and Net Income (Loss)

($ thousands, except per share amounts)	**Three months ended Sept. 30, 2018**	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Cash provided by operating activities	**19,095**	15,258	**66,284**	73,806
Adjusted funds flow	**20,107**	24,970	**68,284**	74,042
Per share - basic	**0.13**	0.17	**0.45**	0.50
- diluted	**0.13**	0.17	**0.45**	0.49
Net (loss) income	**(939)**	2,127	**(5,972)**	32,063
Per share - basic	**(0.01)**	0.01	**(0.04)**	0.22
- diluted	**(0.01)**	0.01	**(0.04)**	0.21

Cash provided by operating activities increased in the third quarter of 2018 when compared to the same period in 2017 as a result of a change in non-cash working capital in 2017. Cash provided by operating activities for the first nine months of 2018 and adjusted funds flow for the third quarter and first nine months of 2018 decreased when compared to the same periods in 2017, predominantly due to favourable hedging gains on the 2017 risk management program as compared to a loss on the 2018 program. Net income for the third quarter and first nine months of 2018 decreased compared to the same periods in 2017, due to gains on property dispositions in the second and third quarters of 2017, in addition to gains from the 2017 risk management program, offset by impairment recorded in the second quarter of 2017.

Capital Expenditures, Property Acquisitions and Dispositions

($ thousands)	**Three months ended Sept. 30, 2018**	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Land	**857**	796	**2,728**	2,486
Seismic	**93**	232	**751**	714
Drilling and completions	**13,195**	65,349	**38,695**	156,259
Facilities, equipment and pipelines	**8,019**	22,328	**22,910**	37,415
Other	**1,492**	1,364	**4,961**	5,015
Total exploration and development	**23,656**	90,069	**70,045**	201,889
Net property acquisitions/(dispositions)	**9**	(144)	**(9,981)**	(46,197)
Total	**23,665**	89,925	**60,064**	155,692

In the third quarter of 2018, the Company spent a total of $23.7 million on exploration and development expenditures, focused on the continued development of our Montney assets at West Septimus. During the quarter, $13.2 million was spent on drilling and completion activities, including the drilling of four (4.0 net) ultra liquids-rich natural gas wells in NE BC and two (2.0 net) heavy oil wells in Lloydminster, the completion of one (1.0 net) heavy oil wells in Lloydminster and the recompletion of twelve (11.8 net) heavy oil wells in Lloydminster. The Company spent $8.0 million on Montney well site development, facilities and pipelines and $2.5 million on land, seismic and other miscellaneous items.

During the first quarter of 2018, the Company disposed of certain Lloydminster properties for cash proceeds of $10.0 million. The assets included 190 acres of developed non-producing land and 692 acres of undeveloped land.

The Company's Board of Directors have approved a net capital expenditure budget for 2018 of $90 to $95 million.

LIQUIDITY AND CAPITAL RESOURCES

Working Capital

The capital intensive nature of Crew's activities generally results in the Company carrying a working capital deficiency, however at the end of the third quarter of 2018, the Company carried a working capital surplus of $11.0 million. Working capital includes cash and cash equivalents and accounts receivable less accounts payable and accrued liabilities. Included in the working capital surplus is a receivable of $4.4 million for a government grant 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.

The Company ensures that sufficient drawings are available from its Facility to satisfy working capital requirements. At September 30, 2018, the Company's working capital surplus of $11.0 million, when combined with the drawings on its bank loan, represented drawings of 16% on its $235 million Facility described below.

Capital Funding

Bank Loan

As at September 30, 2018, the Company's bank facility consists of a revolving line of credit of $210 million and an operating line of credit of $25 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 5, 2019. 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. 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 November 15, 2018. The Facility is secured by a floating charge debenture and a general securities agreement on the assets of the Company.

Senior Unsecured Notes

On March 14, 2017, the Company issued $300 million of 6.5% senior unsecured notes, due March 14, 2024 (the “2024 Notes”). The 2024 Notes are guaranteed, jointly and severally, on an unsecured basis, by each of the Company’s current and future restricted subsidiaries. Interest on the 2024 Notes accrues at the rate of 6.5% per year and is payable semi-annually.

Prior to March 14, 2020, the Company may redeem, on any one or more occasions, up to 35% of the aggregate principal amount of the 2024 Notes, with the cash proceeds from certain equity issues, at a redemption price of 106.5%, plus accrued and unpaid interest. In addition, at any time prior to March 14, 2020, the Company may redeem, on any one or more occasions, all or part of the 2024 Notes at a price equal to par, plus a “make-whole” premium and any accrued and unpaid interest. At any time on or after March 14, 2020, the Company may redeem, on any one or more occasions, all or part of the 2024 Notes at the redemption prices set forth below, plus any accrued and unpaid interest:

Year(1)	Percentage
2020	103.250%
2021	102.145%
2022	101.040%
2023 and thereafter	100.000%

(1) For the 12 month period beginning on March 14 of each year.

Upon the occurrence of a change of control, the Company will be required to offer to repurchase each holder’s notes at a price equal to not less than 101% of the principal amount, plus any accrued and unpaid interest.

In connection with the issuance of the 2024 Notes, on March 23, 2017 the Company redeemed all of the previously issued and outstanding $150 million of 8.375% senior unsecured notes, due October 21, 2020 (the “2020 Notes”) at a redemption price of $1,041.88 per $1,000 of principal amount, plus accrued and unpaid interest. A redemption premium of $6.3 million and unamortized deferred financing costs of $2.5 million were recorded in financing expense as a result of the 2020 Notes redemption.

The Company will continue to fund its on-going operations from a combination of cash flow, debt, non-core asset dispositions and 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.

Share Capital

On May 25, 2017, the Company commenced a normal course issuer bid (the "NCIB"), under which the Company may purchase for cancellation up to a maximum of 7,491,368 common shares of the Company. The NCIB was terminated on May 24, 2018. Subject to the terms of this NCIB, for the year ended December 31, 2017, 924,100 common shares for a total cost of $3.3 million were purchased, cancelled and removed from share capital. The Company did not purchase any common shares for cancellation under the NCIB for the nine months ended September 30, 2018.

Crew is authorized to issue an unlimited number of common shares. As at November 2, 2018, there were 151,730,009 common shares of the Company issued and outstanding. In addition, there were 3,416,217 restricted awards and 4,475,065 performance awards outstanding.

Related-Party and Off-Balance-Sheet Transactions

Crew was not involved in any off-balance-sheet transactions or related party transactions during the quarter ended September 30, 2018.

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 its capital structure, the Company may adjust capital spending, hedge future revenue through commodity contracts, issue new equity, issue new debt or repay existing debt through asset sales.

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

The Company monitors this ratio and endeavours to maintain it near or below 2.0 to 1.0. During periods of increased capital expenditures, acquisitions or during periods of low commodity prices, this ratio will increase over the Company's target. As shown below, as at September 30, 2018, the Company's ratio of net debt to annualized adjusted funds flow was 4.1 to 1 (December 31, 2017 – 2.5 to 1). As commodity prices remain volatile, including the recent decline in Canadian natural gas pricing, Crew plans to limit capital expenditures to approximate adjusted funds flow. With only 21% drawn on the Company's $235 million Facility and the senior unsecured notes termed out to 2024, the Company's financial position remains strong. The Company will continue to monitor this ratio and if necessary, it will consider divesting of non-core properties, will further adjust its annual capital expenditure program or may consider other forms of financing.

($ thousands, except ratio)	**September 30, 2018**	December 31, 2017
Working capital surplus (deficiency)	**11,025**	(29,143)
Bank loan	**(49,317)**	(21,977)
Senior unsecured notes	**(294,639)**	(293,862)
Net debt	**(332,931)**	(344,982)
Quarterly adjusted funds flow	**20,107**	34,087
Annualized	**80,428**	136,348
Net debt to annualized adjusted funds flow	**4.1**	2.5

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	2018	2019	2020	2021	2022	Thereafter
Bank loan (note 1)	49,317	-	49,317	-	-	-	-
Senior unsecured notes (note 2)	300,000	-	-	-	-	-	300,000
Operating leases	3,036	294	1,175	1,175	392	-	-
Capital commitments	2,072	2,072	-	-	-	-	-
Firm transportation agreements	246,541	9,785	48,994	48,275	26,299	25,705	87,483
Firm processing agreements	116,638	4,445	17,634	16,337	12,354	12,354	53,514
Total	**717,604**	**16,596**	**117,120**	**65,787**	**39,045**	**38,059**	**440,997**

Note 1 – Based on the existing terms of the Company's Facility, the first possible repayment date may come in 2019. However, it is expected that the Facility will be extended and no repayment will be required in the near term.

Note 2 – Matures on March 14, 2024.

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

Capital commitments include the Company's share of the estimated remaining cost for the construction of the pipeline connecting the West Septimus facility to the TransCanada Pipeline Saturn meter station.

Firm transportation agreements include commitments to third parties to transport natural gas and natural gas liquids from gas processing facilities in northeast British Columbia.

Firm processing agreements include commitments to process natural gas through the Septimus complex gas processing facilities in northeast British Columbia.

GUIDANCE

In light of extremely weak, volatile and occasionally negative natural gas prices being experienced in Q4 2018 related to pipeline outages, Crew has elected to shut-in volumes to preserve value. This results in forecasted Q4 production to average between 22,000 to 23,000 boe per day. Production year-to-date has exceeded Crew's original forecast and has averaged 24,291 boe per day, positioning the Company to meet our annual guidance of 23,500 to 24,500 boe per day.

Crew's 2018 capital expenditure budget was planned to approximate the Company's annual estimated adjusted funds flow, which was forecasted at $80 to $85 million based on the Company's original budget. Stronger production and higher liquids pricing has resulted in Crew increasing our forecasted 2018 adjusted funds flow to $90 to $95 million. The increase in forecasted adjusted funds flow has allowed the Company to continue drilling operations, which previously had been planned for 2019. As a result, fourth quarter 2018 capital expenditures are expected to be $30 to $35 million with annual net capital expenditures, after dispositions, forecasted at $90 to $95 million.

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)	**Sep. 30 2018**	June 30 2018	Mar. 31 2018	Dec. 31 2017	Sep. 30 2017	June 30 2017	Mar. 31 2017	Dec. 31 2016
Total daily production (boe/d)	**23,680**	23,583	25,939	25,270	23,251	20,468	23,231	22,380
Exploration and development expenditures	**23,656**	12,468	33,921	36,413	90,069	36,656	75,164	37,612
Net property acquisitions/(dispositions)	**9**	17	(10,007)	(1,709)	(144)	(45,701)	(352)	3,099
Average wellhead price ($/boe)	**24.82**	25.18	25.46	25.87	22.36	26.25	27.40	26.74
Petroleum and natural gas sales	**54,080**	54,040	59,427	60,146	47,824	48,886	57,298	55,051
Cash provided by operations	**19,095**	31,304	15,885	43,484	15,258	31,359	27,189	19,900
Adjusted funds flow	**20,107**	21,804	26,373	34,087	24,970	21,353	27,719	27,879
Per share – basic	**0.13**	0.14	0.18	0.23	0.17	0.14	0.19	0.19
– diluted	**0.13**	0.14	0.17	0.22	0.17	0.14	0.18	0.19
Net (loss) income	**(939)**	(9,181)	4,148	2,342	2,127	21,880	8,056	(40,030)
Per share – basic	**(0.01)**	(0.06)	0.03	0.02	0.01	0.15	0.05	(0.28)
– diluted	**(0.01)**	(0.06)	0.03	0.02	0.01	0.14	0.05	(0.28)

Over the past eight quarters, the Company continued to invest the majority of its capital expenditures in northeastern British Columbia, including the completion of the West Septimus facility expansion in the fourth quarter of 2017, resulting in significant production growth and infrastructure development in the area. Average wellhead pricing began to recover in the latter part of 2016, prompting the Company to increase its capital expenditures at Greater Septimus and Tower. Commodity pricing continued to strengthen in the latter part of 2016 and stabilize in early 2017, where the Company further expanded it capital program and infrastructure spending to allow for the growth realized in the second half of 2017. Late in the third quarter of 2017 through the first three quarters of 2018, natural gas prices decreased significantly below amounts received in the previous few years. This decrease will impact 2018 petroleum and natural gas sales and the associated cash provided by operations and adjusted funds flow. As a result, the Company has reduced its planned capital spending in 2018 as compared to 2017, which will impact production levels as the year proceeds.

For the last two years, significant fluctuations in commodity prices have impacted cash provided by operations, adjusted funds flow and net income (loss). The Company has reduced the financial impact of volatile commodity prices by entering into derivative and physical risk management contracts which can cause significant fluctuations in income due to unrealized gains and losses recognized on a quarterly basis. Crew has also attempted to mitigate the lower price environment by reducing its controllable costs and achieve operational efficiencies. Over the past two years, low commodity prices have also led to the assessment and realization of impairment of the carrying value of the Lloydminster CGU. In the fourth quarter of 2016 and the second quarter of 2017, the Company incurred impairment charges of $44.4 million and $16.7 million, respectively. In the second quarter of 2017, the Company realized a $37.9 million gain on divesture as it continues to monetize non-core properties to fund future growth.

New Accounting Pronouncements

The Company has reviewed the following new and revised accounting pronouncements that have been issued and has determined that the following impact on the Company's financial statements:

a) IFRS 9 Financial Instruments:

   On January 1, 2018, the Company adopted IFRS 9 Financial Instruments. IFRS 9 introduces new requirements for the classification and measurement of financial assets, amends the requirements related to hedge accounting, and introduces a forward-looking expected loss impairment model. As a result of adopting IFRS 9, certain financial assets were reclassified from fair value through profit and loss to assets at amortized cost. The change in classification category did not result in an adjustment to the carrying amount of the related assets and the adoption of this standard has not had a material impact on the Company's financial statements.

b) IFRS 15 Revenue from Contracts with Customers:

   On January 1, 2018, the Company adopted IFRS 15 Revenue from Contracts with Customers. The new standard replaces IAS 18 Revenue, IAS 11 Construction Contracts and related interpretations. IFRS 15 dictates the recognition and measurement requirements for reporting the nature, amount, timing and uncertainty of revenue resulting from an entity's contracts with customers using a single principles based, five step model. The Company used the cumulative effect method to adopt the new standard. There was no adjustment to opening retained earnings as at January 1, 2018 based on the Company's assessment of revenue contracts not yet completed as at January 1, 2018.

c) IFRS 16 Leases:

   As of January 1, 2019, the Company will be required to adopt IFRS 16 Leases, which will replace IAS 17 Leases and IFRIC 4 Determining Whether an Arrangement Contains a Lease. On adoption of IFRS 16, the Company will recognize lease liabilities related to leases previously classified as operating leases. The lease liability will be calculated as the present value of the remaining lease payments, discounted using the Company's borrowing rate on January 1, 2019. The Company plans to use the modified retrospective approach on adoption of IFRS 16 and intends to use the following practical expedients permitted under the standard. Some of these expedients are on a lease-by-lease basis and others are applicable by class of underlying assets:

   - Account for leases with a remaining term of less than 12 months at January 1, 2019 as short-term leases; and
   - Account for lease payments as an expense and not recognize a right-of-use asset if the underlying asset is of a lower dollar value.

   As of September 30, 2018, the Company continues to complete a detailed assessment on the potential impact of the standard on its financial statements. For the remainder of the year, the Company will be focused on completing its assessment, developing and implementing changes to policies, internal controls, information systems and processes. The actual impact of applying the standard will depend on the Company's borrowing rate, lease portfolio, whether the Company will exercise any lease renewal options and the practical expedients applied on January 1, 2019.

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 July 1, 2018 and ended on September 30, 2018 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 November 2, 2018

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited) (thousands)	**September 30, 2018**	December 31, 2017
Assets		
Current Assets:		
Accounts receivable	**$ 56,251**	$ 40,930
Derivative financial instruments (note 4)	**207**	1,666
	56,458	42,596
Other long-term assets	**-**	4,788
Property, plant and equipment (note 5)	**1,354,832**	1,340,736
	$ 1,411,290	$ 1,388,120
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 45,226**	$ 70,073
Derivative financial instruments (note 4)	**14,407**	1,319
	59,633	71,392
Derivative financial instruments (note 4)	**2,874**	-
Bank loan (note 6)	**49,317**	21,977
Senior unsecured notes (note 7)	**294,639**	293,862
Decommissioning obligations (note 8)	**87,512**	88,368
Deferred tax liability	**43,157**	42,427
Shareholders' Equity		
Share capital (note 9)	**1,468,986**	1,458,086
Contributed surplus	**72,294**	73,158
Deficit	**(667,122)**	(661,150)
	874,158	870,094
Subsequent event (note 4)		
Commitments (note 12)		
	$ 1,411,290	$ 1,388,120

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF (LOSS) INCOME AND COMPREHENSIVE (LOSS) INCOME

(unaudited) (thousands, except per share amounts)	**Three months ended Sept. 30, 2018**	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Revenue				
Petroleum and natural gas sales (note 10)	**$ 54,080**	$ 47,824	**$ 167,547**	$ 154,008
Royalties	**(3,764)**	(3,067)	**(11,690)**	(11,460)
Realized (loss) gain on derivative financial instruments	**(4,545)**	5,910	**(9,354)**	6,287
Unrealized gain (loss) on derivative financial instruments	**1,133**	(1,341)	**(17,421)**	25,475
Other revenue (note 10)	**2,930**	876	**7,916**	3,161
	49,834	50,202	**136,998**	177,471
Expenses				
Operating	**14,770**	13,406	**45,331**	38,397
Transportation	**3,529**	4,672	**12,288**	14,579
Marketing	**1,137**	-	**2,062**	-
General and administrative	**3,030**	2,754	**8,903**	8,741
Share-based compensation	**2,209**	2,222	**5,261**	7,383
Depletion and depreciation (note 5)	**18,215**	19,408	**58,914**	55,511
	42,890	42,462	**132,759**	124,611
Income from operations	**6,944**	7,740	**4,239**	52,860
Financing (note 11)	**6,616**	6,223	**19,018**	26,464
Impairment on property, plant and equipment (note 5)	**-**	-	**-**	16,710
Gain on divestiture of property, plant and equipment (note 5)	**-**	(2,123)	**(9,546)**	(40,367)
Income (loss) before income taxes	**328**	3,640	**(5,233)**	50,053
Deferred tax expense	**1,267**	1,513	**739**	17,990
Net (loss) income and comprehensive (loss) income	**$ (939)**	$ 2,127	**$ (5,972)**	$ 32,063
Net (loss) income per share (note 9)				
Basic	**$ (0.01)**	$ 0.01	**$ (0.04)**	$ 0.22
Diluted	**$ (0.01)**	$ 0.01	**$ (0.04)**	$ 0.21

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, 2018	149,328	$ 1,458,086	$ 73,158	$ (661,150)	$ 870,094
Net loss for the period	-	-	-	(5,972)	(5,972)
Share-based compensation expensed	-	-	5,261	-	5,261
Share-based compensation capitalized	-	-	4,766	-	4,766
Issued on vesting of share awards	2,402	10,900	(10,900)	-	-
Tax deduction on excess value of share awards	-	-	9	-	9
Balance, September 30, 2018	**151,730**	**$ 1,468,986**	**$ 72,294**	**$ (667,122)**	**$ 874,158**

(unaudited) (thousands)	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance, January 1, 2017	146,812	$ 1,442,284	$ 74,960	$ (695,555)	$ 821,689
Net income for the period	-	-	-	32,063	32,063
Share-based compensation expensed	-	-	7,383	-	7,383
Share-based compensation capitalized	-	-	6,675	-	6,675
Issued on vesting of share awards	3,068	17,116	(17,116)	-	-
Shares purchased and cancelled (note 9)	(924)	(3,251)	-	-	(3,251)
Balance, September 30, 2017	**148,956**	**$ 1,456,149**	**$ 71,902**	**$ (663,492)**	**$ 864,559**

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited) (thousands)	**Three months ended Sept. 30, 2018**	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Cash provided by (used in):				
Operating activities:				
Net (loss) income	**$ (939)**	$ 2,127	**$ (5,972)**	$ 32,063
Adjustments:				
Unrealized (gain) loss on derivative financial instruments	**(1,133)**	1,341	**17,421**	(25,475)
Share-based compensation	**2,209**	2,222	**5,261**	7,383
Depletion and depreciation (note 5)	**18,215**	19,408	**58,914**	55,511
Financing expenses (note 11)	**6,616**	6,223	**19,018**	26,464
Interest expense (note 11)	**(5,869)**	(5,491)	**(16,774)**	(15,530)
Impairment on property, plant and equipment (note 5)	**-**	-	**-**	16,710
Gain on divestiture of property, plant and equipment (note 5)	**-**	(2,123)	**(9,546)**	(40,367)
Deferred tax expense	**1,267**	1,513	**739**	17,990
Decommissioning obligations settled (note 8)	**(144)**	(128)	**(957)**	(484)
Change in non-cash working capital	**(1,127)**	(9,834)	**(1,820)**	(459)
	19,095	15,258	**66,284**	73,806
Financing activities:				
(Decrease) increase in bank loan	**(5,486)**	31,696	**27,340**	(56,340)
Issuance of senior notes, net of financing costs (note 7)	**-**	-	**-**	293,000
Redemption of senior notes (note 7)	**-**	-	**-**	(156,282)
Shares purchased and cancelled (note 9)	**-**	-	**-**	(3,251)
	(5,486)	31,696	**27,340**	77,127
Investing activities:				
Property, plant and equipment expenditures (note 5)	**(23,656)**	(90,069)	**(68,704)**	(201,889)
Property acquisitions	**(9)**	(6)	**(26)**	(3,826)
Property dispositions	**-**	150	**10,007**	50,023
Change in non-cash working capital	**10,056**	14,891	**(34,901)**	4,759
	(13,609)	(75,034)	**(93,624)**	(150,933)
Change in cash and cash equivalents	**-**	(28,080)	**-**	-
Cash and cash equivalents, beginning of period	**-**	28,080	**-**	-
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 and nine months ended September 30, 2018 and 2017

(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, 2017, with the exception of the changes in accounting policies described below. 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 ("CDN"), which is the functional currency of the Company, its subsidiary and partnerships.

The condensed interim consolidated financial statements were authorized for issuance by Crew's Board of Directors on November 2, 2018.

Certain prior year amounts have been reclassified to conform to current presentation.

3. Change in accounting policies:

(i) Adoption of IFRS 9 – Financial Instruments:

On January 1, 2018, the Company adopted IFRS 9 Financial Instruments. IFRS 9 introduces new requirements for the classification and measurement of financial assets, amends the requirements related to hedge accounting, and introduces a forward-looking expected loss impairment model. As a result of adopting IFRS 9, certain financial assets were reclassified from fair value through profit and loss to assets at amortized cost. The change in classification category did not result in an adjustment to the carrying amount of the related assets and the adoption of this standard has not had a material impact on the Company's financial statements.

(ii) Adoption of IFRS 15 – Revenue from Contracts with Customers:

On January 1, 2018, the Company adopted IFRS 15 Revenue from Contracts with Customers. The new standard replaces IAS 18 Revenue, IAS 11 Construction Contracts and related interpretations. IFRS 15 dictates the recognition and measurement requirements for reporting the nature, amount, timing and uncertainty of revenue resulting from an entity's contracts with customers using a single principles based, five step model. The Company used the cumulative effect method to adopt the new standard. There was no adjustment to opening retained earnings as at January 1, 2018 based on the Company's assessment of revenue contracts not yet completed as at January 1, 2018.

The additional disclosures required by IFRS 15, including those required for the cumulative effect method, are disclosed in note 10.

(iii) Future adoption of IFRS 16 – Leases:

As of January 1, 2019, the Company will be required to adopt IFRS 16 Leases, which will replace IAS 17 Leases and IFRIC 4 Determining Whether an Arrangement Contains a Lease. On adoption of IFRS 16, the Company will recognize lease liabilities related to leases previously classified as operating leases. The lease liability will be calculated as the present value of the remaining lease payments, discounted using the Company's borrowing rate on January 1, 2019. The Company plans to use the modified retrospective approach on adoption of IFRS 16 and intends to use the following practical expedients permitted under the standard. Some of these expedients are on a lease-by-lease basis and others are applicable by class of underlying assets:

- Account for leases with a remaining term of less than 12 months at January 1, 2019 as short-term leases; and
- Account for lease payments as an expense and not recognize a right-of-use asset if the underlying asset is of a lower dollar value.

As of September 30, 2018, the Company continues to complete a detailed assessment on the potential impact of the standard on its financial statements. For the remainder of the year, the Company will be focused on completing its assessment, developing and implementing changes to policies, internal controls, information systems and processes. The actual impact of applying the standard will depend on the Company's borrowing rate, lease portfolio, whether the Company will exercise any lease renewal options and the practical expedients applied on January 1, 2019.

Revenue recognition:

Revenue from the sale of crude oil, natural gas, condensate and natural gas liquids is recorded when control of the product is transferred to the buyer based on the consideration specified in the contracts with customers. This usually occurs when the product is physically transferred at the delivery point agreed upon in the contract and legal title to the product passes to the customer.

The Company evaluates its arrangements with third parties and partners to determine if the Company acts as the principal or as an agent. In making this evaluation, the Company considers if it obtains control of the product delivered or services provided, which is indicated by the Company having the primary responsibility for the delivery of the product or rendering of the service, having the ability to establish prices or having inventory risk. If the Company acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net-basis, only reflecting the fee, if any, realized by the Company from the transaction.

Fees charged to other entities for use of pipelines and facilities owned by the Company are evaluated by management to determine if these originate from contracts with customers or from incidental or collaborative arrangements. Fees charged to other entities that are from contracts with customers are recognized in revenue when the related services are provided.

4. Financial risk management:

Derivative contracts:

It is the Company's policy to 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. 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 September 30, 2018, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value
Gas	2,500 mmbtu/day	October 1, 2018 – October 31, 2018	Chicago Citygate	$3.06/mmbtu	Swap	$ (55)
Gas	5,000 gj/day	October 1, 2018 – December 31, 2018	AECO C Monthly Index	$3.00/gj	Call	(2)
Gas	2,500 gj/day	October 1, 2018 – December 31, 2018	AECO C Daily Index	$2.62/gj	Swap	176
Gas	20,000 mmbtu/day	October 1, 2018 – December 31, 2018	Chicago Citygate	$3.61/mmbtu	Swap	(504)
Gas	5,000 mmbtu/day	October 1, 2018 – December 31, 2018	US$ Nymex Henry Hub	$3.05 US/mmbtu	Swap	3
Gas	7,500 mmbtu/day	January 1, 2019 – December 31, 2019	Chicago Citygate	$3.19/mmbtu	Swap	(509)
Gas	2,500 mmbtu/day	January 1, 2019 – December 31, 2019	Dawn Daily Index	$3.30/mmbtu	Swap	(151)
Propane	400 bbl/day	October 1, 2018 – December 31, 2018	US$ Conway OPIS	$0.79 US/gal	Swap	(142)
Oil	2,250 bbl/day	October 1, 2018 – December 31, 2018	CDN$ WTI	$72.92/bbl	Swap	(4,385)
Oil	250 bbl/day	October 1, 2018 – December 31, 2018	CDN$ WTI	$60.00 - $69.65/bbl	Collar(1)	(583)
Oil	250 bbl/day	October 1, 2018 – December 31, 2018	CDN$ WTI	$69.00 - $74.25/bbl	Collar(2)	(478)
Oil	750 bbl/day	October 1, 2018 – December 31, 2018	CDN$ WCS	$56.62/bbl	Swap	393
Oil	250 bbl/day	January 1, 2019 – June 30, 2019	CDN$ WTI	$83.80/bbl	Swap	(403)
Oil	500 bbl/day	January 1, 2019 – June 30, 2019	CDN$ WCS	$52.93/bbl	Swap	(282)
Oil	1,750 bbl/day	January 1, 2019 – December 31, 2019	CDN$ WTI	$75.44/bbl	Swap	(10,152)
Total						**$ (17,074)**

(1) The referenced contract is a costless collar whereby the Company receives $60.00/bbl when the market price is below $60.00/bbl, and receives $69.65/bbl when the market price is above $69.65/bbl.

(2) The referenced contract is a costless collar whereby the Company receives $69.00/bbl when the market price is below $69.00/bbl, and receives $74.25/bbl when the market price is above $74.25/bbl.

Subsequent to September 30, 2018, 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, 2019 – December 31, 2019	Chicago Citygate	$3.51/mmbtu	Swap
Gas	2,500 mmbtu/day	January 1, 2019 – December 31, 2019	US$ Nymex Henry Hub	$2.80 US/mmbtu	Swap

Capital management:

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 its capital structure, the Company may adjust capital spending, hedge future revenue through commodity contracts, issue new equity, issue new debt or repay existing debt through asset sales.

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

The Company monitors this ratio and endeavours to maintain it near or below 2.0 to 1.0. During periods of increased capital expenditures, acquisitions or during periods of low commodity prices, this ratio will increase over the Company's target. As shown below, as at September 30, 2018, the Company's ratio of net debt to annualized adjusted funds flow was 4.1 to 1 (December 31, 2017 – 2.5 to 1). As commodity prices remain volatile, including the recent decline in Canadian natural gas pricing, Crew plans to limit capital expenditures to approximate adjusted funds flow. With only 21% drawn on the Company's $235 million Facility and the senior unsecured notes termed out to 2024, the Company's financial position remains strong. The Company will continue to monitor this ratio and if necessary, it will consider divesting of non-core properties, will further adjust its annual capital expenditure program or may consider other forms of financing.

		September 30, 2018		December 31, 2017
Net debt:				
Accounts receivable	**$**	**56,251**	$	40,930
Accounts payable and accrued liabilities		**(45,226)**		(70,073)
Working capital surplus (deficiency)	**$**	**11,025**	$	(29,143)
Bank loan		**(49,317)**		(21,977)
Senior unsecured notes		**(294,639)**		(293,862)
Net debt	**$**	**(332,931)**	$	(344,982)
Quarterly annualized adjusted funds flow:				
Cash provided by operating activities	**$**	**19,095**	$	43,484
Decommissioning obligations settled		**144**		29
Change in non-cash working capital		**1,127**		(9,165)
Accretion of deferred financing charges		**(259)**		(261)
Quarterly adjusted funds flow	**$**	**20,107**	$	34,087
Annualized	**$**	**80,428**	$	136,348
Net debt to annualized adjusted funds flow		**4.1**		2.5

Neither the Company nor any of its subsidiaries are subject to externally imposed capital requirements. The Facility is 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 6).

5. Property, plant and equipment:

Cost or deemed cost		Total
Balance, January 1, 2017	$	2,181,279
Additions		238,302
Acquisitions		6,827
Divestitures		(22,626)
Change in decommissioning obligations		2,853
Capitalized share-based compensation		7,690
Balance, December 31, 2017	$	2,414,325
Additions		70,045
Acquisitions		26
Divestitures		(875)
Change in decommissioning obligations		(952)
Capitalized share-based compensation		4,766
Balance, September 30, 2018	**$**	**2,487,335**

Accumulated depletion and depreciation		Total
Balance, January 1, 2017	$	981,827
Depletion and depreciation expense		75,131
Divestitures		(79)
Impairment		16,710
Balance, December 31, 2017	$	1,073,589
Depletion and depreciation expense		58,914
Balance, September 30, 2018	**$**	**1,132,503**

Net book value		Total
Balance, September 30, 2018	**$**	**1,354,832**
Balance, December 31, 2017	$	1,340,736

Included in property, plant and equipment additions for the nine months ended September 30, 2018 is $1.3 million of pipe inventory transferred from other long-term assets upon the construction of the West Septimus pipeline to the TransCanada Pipeline Saturn meter station.

The calculation of depletion for the three months ended September 30, 2018 included estimated future development costs of $1,742.6 million (December 31, 2017 - $1,764.2 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $70.0 million (December 31, 2017 - $70.0 million) and undeveloped land of $158.6 million (December 31, 2017 - $161.6 million) related to future development acreage with no associated reserves.

During the first quarter of 2018, the Company disposed of non-core assets for cash proceeds of $10.0 million. The assets consisted of petroleum and natural gas properties and undeveloped land with a net book value of $0.9 million and associated decommissioning obligations of $0.4 million, resulting in a gain of $9.5 million on closing of the disposition.

There were no indicators of impairment for the Company's cash-generating units ("CGU") as at September 30, 2018, and therefore an impairment test was not performed.

6. Bank loan:

As at September 30, 2018, the Company's bank facility consists of a revolving line of credit of $210 million and an operating line of credit of $25 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 5, 2019. 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. 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 November 15, 2018. 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 0.50 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 1.50 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 0.338 percent to 0.788 percent depending upon the debt to EBITDA ratio. As at September 30, 2018, the Company's applicable pricing included a 0.50 percent margin on prime lending, a 1.50 percent stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.338 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 September 30, 2018, the Company had issued letters of credit totaling $29.4 million (December 31, 2017 – $7.7 million).

7. Senior unsecured notes:

On March 14, 2017, the Company issued $300 million of 6.5% senior unsecured notes, due March 14, 2024 (the "2024 Notes"). The 2024 Notes are guaranteed, jointly and severally, on an unsecured basis, by each of the Company's current and future restricted subsidiaries. Interest on the 2024 Notes accrues at the rate of 6.5% per year and is payable semi-annually. At September 30, 2018, the carrying value of the 2024 Notes was net of deferred financing costs of $5.4 million (December 31, 2017 – $6.1 million).

Prior to March 14, 2020, the Company may redeem, on any one or more occasions, up to 35% of the aggregate principal amount of the 2024 Notes, with the cash proceeds from certain equity issues, at a redemption price of 106.5%, plus accrued and unpaid interest. In addition, at any time prior to March 14, 2020, the Company may redeem, on any one or more occasions, all or part of the 2024 Notes at a price equal to par, plus a "make-whole" premium and any accrued and unpaid interest. At any time on or after March 14, 2020, the Company may redeem, on any one or more occasions, all or part of the 2024 Notes at the redemption prices set forth below, plus any accrued and unpaid interest:

Year[(1)]	Percentage
2020	103.250%
2021	102.145%
2022	101.040%
2023 and thereafter	100.000%

(1) For the 12 month period beginning on March 14 of each year.

Upon the occurrence of a change of control, the Company will be required to offer to repurchase each holder's notes at a price equal to not less than 101% of the principal amount, plus any accrued and unpaid interest.

In connection with the issuance of the 2024 Notes, on March 23, 2017 the Company redeemed all of the previously issued and outstanding $150 million of 8.375% senior unsecured notes, due October 21, 2020 (the "2020 Notes") at a redemption price of $1,041.88 per $1,000 of principal amount, plus accrued and unpaid interest. A redemption premium of $6.3 million and unamortized deferred financing costs of $2.5 million were recorded in financing expense as a result of the 2020 Notes redemption (Financing – note 11).

8. Decommissioning obligations:

	Nine months ended September 30, 2018	Year ended December 31, 2017
Decommissioning obligations, beginning of period	**$ 88,368**	$ 85,859
Obligations incurred	**749**	4,557
Obligations settled	**(957)**	(513)
Obligations divested	**(414)**	(1,765)
Change in estimated future cash outflows	**(1,701)**	(1,704)
Accretion of decommissioning obligations	**1,467**	1,934
Decommissioning obligations, end of period	**$ 87,512**	$ 88,368

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 $87.5 million as at September 30, 2018 (December 31, 2017 – $88.4 million) based on an inflation adjusted undiscounted total future liability of $116.6 million (December 31, 2017 – $118.9 million). These payments are expected to be made over the next 40 years, with the majority of costs to be incurred between 2020 and 2035. The inflation rate applied to the liability is 2% (December 31, 2017 – 2%). The discount factor, being the risk-free rate related to the liability, is 2.22% (December 31, 2017 – 2.22%). The $1.7 million (December 31, 2017 – $1.7 million) change in estimated future cash outflows for the nine months ended September 30, 2018 is a result of a change in future estimated undiscounted abandonment costs.

9. Share capital:

At September 30, 2018, 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 May 25, 2017, the Company commenced a normal course issuer bid (the "NCIB"), under which the Company may purchase for cancellation up to a maximum of 7,491,368 common shares of the Company. The NCIB was terminated on May 24, 2018. Subject to the terms of this NCIB, for the year ended December 31, 2017, 924,100 common shares for a total cost of $3.3 million were purchased, cancelled and removed from share capital. The Company did not purchase any common shares for cancellation under the NCIB in 2018 prior to the expiry of the NCIB on May 24, 2018.

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. Since the inception of the RPAP, the Company has settled all awards through the issuance of common shares from treasury. For RAs and PAs granted subsequent to May 21, 2018, the Company currently intends to settle the award value with common shares purchased on the secondary market as the Company no longer has the ability, in the absence of shareholder approval being obtained, to settle the award values associated with such awards with common shares issued from treasury. Through the vesting of 729,000 RAs and 989,000 PAs, when taking into account the earned multipliers for PAs, 2,402,000 common shares of the Company were issued for the nine months ended September 30, 2018.

The number of RAs and PAs outstanding are as follows:

	Number of RAs	Number of PAs
Balance, January 1, 2018	1,616	2,221
Granted	2,604	3,406
Vested	(729)	(989)
Forfeited	(75)	(163)
Balance, September 30, 2018	**3,416**	**4,475**

Per share amounts:

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average shares outstanding for the three month period ended September 30, 2018 was 151,726,000 (September 30, 2017 – 148,928,000) and for the nine month period ended September 30, 2018, the weighted average number of shares outstanding was 150,881,000 (September 30, 2017 – 148,413,000).

In computing diluted earnings per share for the three month period ended September 30, 2018, nil (September 30, 2017 – 2,117,000) shares were added to the weighted average common shares outstanding to account for the dilution of RAs and PAs, and for the nine month period ended September 30, 2018, nil (September 30, 2017 – 2,551,000) shares were added to the weighted average common shares for the dilution. For the three month period ended September 30, 2018, there were 7,891,000 (September 30, 2017 – 2,474,000) RAs and PAs that were not included in the diluted earnings per share calculation because they were anti-dilutive. For the nine month period ended September 30, 2018, there were 7,891,000 (September 30, 2017 – 2,493,000) RAs and PAs that were not included in the diluted earnings per share calculation because they were anti-dilutive.

10. Revenue:

Petroleum and natural gas sales:

Crew sells its production pursuant to fixed or variable-price contracts. The transaction price for variable priced contracts is based on the commodity price, adjusted for quality, location or other factors, whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under the contracts, the Company is required to deliver a fixed or variable volume of crude oil, condensate, natural gas or natural gas liquids to the customer. Revenue is recognized when a unit of production is delivered to the customer. The amount of revenue recognized is based on the agreed transaction price, whereby any variability in revenue relates specifically to the Company's efforts to transfer production, and therefore the resulting revenue is allocated to the production delivered in the period during which the variability occurs. As a result, none of the variable revenue is considered constrained.

Crude oil, condensate and natural gas liquids are sold under contracts of varying terms of up to one year. The majority of the Company's natural gas is sold on multi-year contracts. Revenues are typically collected on the 25th day of the month following production.

The following table summarizes the Company's petroleum and natural gas sales, all of which are from revenue with contracts with customers:

	Three months ended Sept. 30, 2018	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Light crude oil	**$ 1,935**	$ 2,671	**$ 5,670**	$ 8,160
Heavy crude oil	**8,538**	7,683	**23,988**	22,148
Condensate	**15,563**	10,193	**50,839**	29,600
Other natural gas liquids	**4,430**	3,678	**12,422**	8,259
Natural gas	**23,614**	23,599	**74,628**	85,841
	$ 54,080	$ 47,824	**$ 167,547**	$ 154,008

The adoption of IFRS 15 resulted in the Company evaluating its arrangement with third parties and partners to determine if the Company is the principal or agent. Based on the focus of control of the specified good or service, the Company identified arrangements for processing services where the Company is considered the principal and not a result of collaborative arrangements with partners in jointly owned assets. As a result of this change, the Company has reclassified $3.0 million for the nine months ended September 30, 2018 from operating expenses to processing revenue included in other revenue.

Other revenue:

The following table summarizes the Company's other revenue:

	Three months ended Sept. 30, 2018	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Marketing revenue	**$ 1,689**	$ -	**$ 3,887**	$ -
Processing revenue	**1,241**	876	**3,029**	3,161
Other	**-**	-	**1,000**	-
	$ 2,930	$ 876	**$ 7,916**	$ 3,161

11. Financing:

	Three months ended Sept. 30, 2018	Three months ended Sept. 30, 2017	**Nine months ended Sept. 30, 2018**	Nine months ended Sept. 30, 2017
Interest expense	**$ 5,869**	$ 5,491	**$ 16,774**	$ 15,530
Accretion of deferred financing costs	**259**	250	**777**	707
Accretion of decommissioning obligations	**488**	482	**1,467**	1,435
Premium paid on redemption of 2020 Notes (note 7)	**-**	-	**-**	6,282
Deferred financing costs expensed on 2020 Notes (note 7)	**-**	-	**-**	2,510
	$ 6,616	$ 6,223	**$ 19,018**	$ 26,464

12. Commitments:

	Total	2018	2019	2020	2021	2022	Thereafter
Operating leases	$ 3,036	$ 294	$ 1,175	$ 1,175	$ 392	$ -	$ -
Capital commitments	2,072	2,072	-	-	-	-	-
Firm transportation agreements	246,541	9,785	48,994	48,275	26,299	25,705	87,483
Firm processing agreements	116,638	4,445	17,634	16,337	12,354	12,354	53,514
Total	**$ 368,287**	**$ 16,596**	**$ 67,803**	**$ 65,787**	**$ 39,045**	**$ 38,059**	**$140,997**

Operating leases include the Company's commitment to a third party for the lease of office space.

Capital commitments include the Company's share of the estimated remaining cost for the construction of the pipeline connecting the West Septimus facility to the TransCanada Pipeline Saturn meter station.

Firm transportation agreements include commitments to third parties to transport natural gas and natural gas liquids from gas processing facilities in northeast British Columbia.

Firm processing agreements include commitments to process natural gas through the Septimus complex gas processing facilities in northeast British Columbia.

DIRECTORS & OFFICERS

OFFICERS

Dale O. Shwed
President and Chief Executive Officer

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

James Taylor
Chief Operating Officer

Jamie L. Bowman
Vice President, Marketing & Originations

Kurtis Fischer
Vice President, Planning & Development

Paul Dever
Vice President, Government & Stakeholder Relations

Kevin G. Evers
Vice President, Geosciences

Mark Miller
Vice President, Land & Negotiations

BOARD OF DIRECTORS

John A. Brussa,
Chairman Independent Director

Jeffery E. Errico,
Lead Director Independent Director

Dennis L. Nerland
Independent Director

Karen A. Nielsen
Independent Director

Ryan A. Shay
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