crew
energy inc.

Building Our Future In The Montney

'17 | CREW ENERGY INC. annual report

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. Based in Calgary, Alberta, 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 in British Columbia offer significant development potential over the long-term. We utilize evolving technologies to increase individual well production and maximize overall rates of return, while simultaneously reducing costs and minimizing our environmental footprint. Crew's committed and experienced team has a proven track record of value creation and seeks to manage ongoing financial risk by maintaining a strong balance sheet and an active hedging program. 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".

Corporate Information

AUDITORS
KPMG LLP

LEGAL COUNSEL
Burnet, Duckworth & Palmer LLP

RESERVE ENGINEERS
Sproule Associates Ltd.

TRANSFER AGENT
Computershare Trust Company of Canada

BANKERS
Toronto-Dominion Bank
Alberta Treasury Branches
Bank of Montreal
National Bank of Canada
Bank of Nova Scotia
Business Development Bank of Canada

Investor Contact

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CREW ENERGY INC. 2017 ANNUAL REPORT

Crew Energy Inc. (TSX: CR) ("Crew" or the "Company") is pleased to announce our operating and financial results for the three and twelve month periods ended December 31, 2017. Crew's full audited consolidated Financial Statements and Notes, as well as Management's Discussion and Analysis ("MD&A") for the three and twelve month periods ended December 31, 2017 are available on our website and filed on SEDAR.

Q4 & FULL YEAR 2017 HIGHLIGHTS

- Adjusted Funds Flow ("AFF") in Q4 2017 was $34.1 million ($0.22 per diluted share), higher than both Q4 2016 and Q3 2017 as a result of higher production combined with stronger realized pricing. Annual 2017 AFF increased 37% over 2016 to $108.1 million ($0.72 per diluted share).
- Production in Q4 2017 averaged 25,270 boe per day, 13% higher than Q4 2016 and 9% higher than Q3 2017. Annual 2017 production averaged 23,061 boe per day.
- Corporate operating netbacks averaged $18.04 per boe in Q4 2017, reflecting increased realized product pricing, lower transportation costs per boe and a continued focus on optimizing netbacks by shutting-in low margin production. Annual 2017 operating netbacks of $16.74 per boe were 30% higher than in 2016.
- Realized natural gas prices for Q4 2017 and full year 2017 averaged $2.64 per mcf and $3.01 per mcf, respectively, which were 56% and 39% higher than the AECO 5A daily index for the same periods. Crew's diversified marketing strategy coupled with our higher heat content natural gas contributed to the stronger realized prices.
- Operating netbacks for Q4 2017 at Crew's Greater Septimus Montney area in northeast British Columbia ("NE BC") were $19.80 per boe, 16% higher than the previous quarter.
- Exploration and development spending in Q4 2017 totaled $36.4 million, with approximately $34.7 million invested in our Montney assets, including $15.9 million allocated to infrastructure. Full year 2017 exploration and development spending totaled $238.3 million and predominantly targeted the condensate fairway at West Septimus, coupled with the West Septimus facility expansion to 120 mmcf per day that was completed on time and 8% under budget.
- Balance sheet strength and ongoing financial flexibility were maintained through year end 2017 as net debt totaled $345 million, including $300 million of new term debt with no repayment required until 2024 and only 9% drawn on Crew's $235 million bank facility. Crew exited 2017 with a net debt to annualized fourth quarter 2017 AFF ratio of 2.5 times.

APPOINTMENT OF SENIOR VICE PRESIDENT & CHIEF OPERATING OFFICER

- Crew is pleased to announce the appointment of James Taylor as Senior Vice President and Chief Operating Officer. Mr. Taylor brings 20 years of progressive operational, engineering and management experience with both Imperial Oil and ExxonMobil in conventional and resource plays across North America, most recently in the Duvernay and Montney as Vice President and Engineering Manager of XTO Canada. Mr. Taylor graduated in 1998 from the University of Manitoba with a Bachelor of Science in Geological Engineering.

FINANCIAL & OPERATING HIGHLIGHTS

FINANCIAL ($ thousands, except per share amounts)	**Three months ended Dec. 31, 2017**	Three months ended Dec. 31, 2016	**Year ended Dec. 31, 2017**	Year ended Dec. 31, 2016
Petroleum and natural gas sales	**60,146**	55,051	**214,154**	174,719
Adjusted Funds Flow[1]	**34,087**	27,879	**108,129**	78,674
Per share - basic	**0.23**	0.19	**0.73**	0.55
- diluted	**0.22**	0.19	**0.72**	0.54
Net income (loss)	**2,342**	(40,030)	**34,405**	(64,926)
Per share - basic	**0.02**	(0.28)	**0.23**	(0.45)
- diluted	**0.02**	(0.28)	**0.23**	(0.45)
Exploration and Development expenditures	**36,413**	37,612	**238,302**	108,202
Property acquisitions (net of dispositions)	**(1,709)**	3,099	**(47,906)**	3,973
Net capital expenditures	**34,704**	40,711	**190,396**	112,175

Capital Structure ($ thousands)	**As at Dec. 31, 2017**	As at Dec. 31, 2016
Working capital deficiency[2]	**29,143**	10,006
Bank loan	**21,977**	88,036
	51,120	98,042
Senior Unsecured Notes	**293,862**	147,329
Total Net Debt	**344,982**	245,371
Common Shares Outstanding (thousands)	**149,328**	146,812

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 is used to analyze the Company's operating performance and leverage. 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 deficiency includes cash and cash equivalents plus accounts receivable less accounts payable and accrued liabilities.

Operations	**Three months ended Dec. 31, 2017**	Three months ended Dec. 31, 2016	**Year ended Dec. 31, 2017**	Year ended Dec. 31, 2016
Daily production				
Light crude oil (bbl/d)	**399**	540	**495**	335
Heavy crude oil (bbl/d)	**1,808**	2,188	**1,836**	2,459
Condensate (bbl/d)	**2,617**	1,996	**2,048**	1,940
Other natural gas liquids (bbl/d)	**1,823**	1,406	**1,575**	1,409
Natural gas (mcf/d)	**111,737**	97,501	**102,642**	100,203
Total (boe/d @ 6:1)	**25,270**	22,380	**23,061**	22,844
Average prices [1]				
Light crude oil ($/bbl)	**64.91**	57.49	**58.34**	49.89
Heavy crude oil ($/bbl)	**48.73**	41.44	**45.14**	33.39
Condensate (($/bbl)	**69.60**	59.01	**62.03**	49.53
Natural gas liquids ($/bbl)	**34.58**	10.18	**24.45**	7.47
Natural gas ($/mcf)	**2.64**	3.53	**3.01**	2.71
Oil equivalent ($/boe)	**25.87**	26.74	**25.44**	20.90

Notes:

(1) Average prices do not include gains and losses on financial instruments.

	Three months ended Dec. 31, 2017	Three months ended Dec. 31, 2016	**Year ended Dec. 31, 2017**	Year ended Dec. 31, 2016
Netback ($/boe)				
Revenue	**25.87**	26.74	**25.44**	20.90
Royalties	**(1.59)**	(1.92)	**(1.80)**	(1.27)
Realized commodity hedging gain/(loss)	**1.60**	(0.35)	**1.19**	1.42
Operating costs	**(5.90)**	(5.35)	**(5.82)**	(5.88)
Transportation costs	**(1.94)**	(2.09)	**(2.27)**	(2.25)
Operating netback [(1)]	**18.04**	17.03	**16.74**	12.92
G&A	**(1.36)**	(1.33)	**(1.42)**	(1.41)
Financing costs on long-term debt	**(2.45)**	(2.15)	**(2.61)**	(2.10)
Other income	**0.43**	-	**0.12**	-
Adjusted funds flow	**14.66**	13.55	**12.83**	9.41
Drilling Activity				
Gross wells	**5**	8	**40**	21
Working interest wells	**3.9**	7.7	**38.2**	19.7
Success rate, net wells (%)	**100%**	91%	**97%**	96%

Notes:

(1) Operating netback equals petroleum and natural gas sales including realized hedging gains and losses on commodity contracts less royalties, operating costs and transportation costs calculated on a boe basis. Operating netback and 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.

FINANCIAL OVERVIEW

Increased Adjusted Funds Flow

- Q4 2017 AFF totaled $34.1 million ($0.22 per diluted share), increasing 22% (16% on a diluted per share basis) over Q4 2016, and increasing 37% (29% on a diluted per share basis) over Q3 2017.
- 2017 full year AFF totaled $108.1 million ($0.72 per diluted share), a 37% increase (33% on a diluted per share basis) compared to full year 2016.
- Higher AFF for both Q4 and full year 2017 reflect the impact of higher production volumes and higher operating netbacks relative to the same periods in 2016.

Production Growth with West Septimus Facility Expansion

- Q4 2017 production of 25,270 boe per day reflects increased volumes through the expanded West Septimus facility, coupled with strong results at West Septimus. Approximately 2,800 boe per day was shut-in to accommodate commissioning of the plant expansion and to avoid losses from producing natural gas into a very weak Canadian price environment.
- 2017 full year production averaged 23,061 boe per day, with volumes positively impacted by drilling and completions focused in the West Septimus area, offset by several extended third party pipeline and facility shut-downs in the second and early third quarters, as well as Crew's decision to shut-in low margin natural gas volumes.

Improved Netbacks

- Q4 2017 operating netbacks per boe improved 15% over Q3 2017, while full year 2017 netbacks improved 30% over 2016, a function of improved pricing, higher liquids content, cost control and a continued focus on optimizing netbacks by not producing low margin production.

- Q4 2017 commodity prices averaged $25.87 per boe, a 16% increase over the previous quarter.
  - Total liquids prices increased to $54.04 per bbl, 31% higher than Q4 2016 and 28% higher than Q3 2017. This reflects strengthening oil prices as West Texas Intermediate ("WTI") crude, valued in Canadian dollars, increased over both periods. An increase in higher-valued condensate production as a percentage of total production in Q4 also enhanced Crew's total liquids price.
  - The realized natural gas price of $2.64 per mcf was 56% higher than the AECO 5A daily index average of $1.69 per mcf. Crew's natural gas price benefited from approximately 40% of production being priced at Chicago City Gate, which significantly exceeded prices received for natural gas at Canadian pricing points. Crew's higher heat content Montney natural gas also yields approximately 20% more value than is reflected in benchmark prices due to the presence of larger amounts of butane and propane remaining in the gas.
- 2017 average wellhead prices increased to $25.44 per boe, 22% higher than 2016, having a meaningful impact on netbacks.
  - 2017 average total liquids price was $46.57 per boe, 39% higher than 2016 due to increasing world oil prices.
  - Crew's realized natural gas price increased to $3.01 per mcf in 2017 up from $2.71 per mcf in 2016. The Company's 2017 realized natural gas price benefited from Crew's diversified natural gas marketing arrangements as the realized price was significantly higher than the 2017 Canadian natural gas benchmark AECO 5A price of $2.16 per mcf.

Capital Expenditures Focused at West Septimus

- Q4 2017 exploration and development expenditures of $36.4 million was directed to drilling five (3.9 net) natural gas wells, completion of three (3.0 net) Montney natural gas wells and the recompletion of three (3.0 net) heavy oil wells in Lloydminster. Approximately $15.9 million was invested in infrastructure.
- 2017 full year exploration and development expenditures totaled $238.3 million and included:
  - $175 million for the drilling of 40 (38.2 net) wells, including four (4.0 net) oil wells, 35 (33.2 net) natural gas wells and one (1.0 net) dry and abandoned well. A total of 37 (37.0 net) wells were completed in 2017 and 20 (18.6 net) wells were recompleted.
  - Approximately $53 million of capital was directed to facilities and infrastructure, including the West Septimus facility expansion that was completed with an infrastructure partner participating for a 72% share in the expansion, a pipeline installation to debottleneck the gathering system at Septimus and several infield gathering system upgrades and road improvements.
- Proceeds of $49 million were realized in 2017 from the successful disposition of Crew's non-core Montney assets at Goose (18,400 acres of undeveloped land with no production or reserves). Disposition proceeds were used to help finance the 2017 capital program and support balance sheet flexibility through 2017.

Maintaining Financial Flexibility and Balance Sheet Strength

- Year end 2017 net debt totaled $345.0 million, representing 2.5 times annualized Q4 AFF, and includes:
  - $294 million (net of $6 million of deferred financing costs) of term debt that was re-financed and upsized in early 2017. The new terms include an annual interest charge of 6.5%, no annual financial tests and no repayments required until 2024.
  - Bank facility drawings of $22 million or 9% of Crew's $235 million facility, which was reviewed in the fourth quarter and maintained at $235 million. In conjunction with the Q4 review, the lenders removed the financial covenants that previously governed the facility.
- Crew's $80 to $85 million 2018 capital budget is expected to be funded by funds from operations with minimal draws from the excess capacity on the bank facility.

TRANSPORTATION, MARKETING & HEDGING

Enhanced Market Diversity & Evolving Sales Portfolio

- Through full year 2017, approximately 40% of Crew's production received Chicago City Gate pricing, which was up 20% year-over-year due to strong industrial and retail demand and exceeded the Canadian benchmark AECO 5A by 41%. Canadian natural gas prices were significantly impacted in 2017 by rising industry production, third party pipeline maintenance and a meaningful shortage of takeaway capacity.
- Crew's Montney assets are uniquely positioned for physical connectivity to all three major natural gas export pipeline systems, providing flexibility and access to different markets, including firm service on the TCPL Nova system effective April 1, 2018. Over the past five years Crew has expanded its natural gas marketing portfolio to include multiple North American sales points at favourable terms through 2020 and beyond.
- Natural gas pricing exposure through Q1 2018 will be approximately 44% Chicago City Gate, 40% AECO 5A, 9% Alliance ATP and 7% Station 2. From Q2 2018 through the remainder of the year, Crew has additional market exposure with approximately 40% Chicago City Gate, 19% AECO, 12% Alliance ATP, 13% Dawn, 8% Malin, 4% Nymex Henry Hub and 4% Sumas.

Natural Gas & Liquids Hedging

- Approximately 24% of budgeted 2018 volumes are hedged at $2.50 per GJ or approximately $2.64 per mcf which increases to approximately $3.10 per mcf after adjusting for Crew's heat conversion.
- 2,250 bbls per day of WTI are hedged at an average price of C$71.77 per barrel and 400 bbls per day of OPIS Conway propane hedged at US$0.7863 per gallon or approximately $33.03 US per bbl.

Crew plans to continue layering in hedge contracts for 2018 and 2019 to manage risk and protect AFF. See "Hedge Summary" in Crew's recent corporate presentation for full details of Crew's risk management contract positions as of March 1, 2018, available on Crew's website.

OPERATIONS & AREA OVERVIEW

NE BC Montney - Greater Septimus

- In response to challenging natural gas markets throughout 2017, Crew's development focus shifted to the ultra condensate-rich ("UCR") and transition areas at West Septimus, where higher condensate and liquids rates provide more favourable economics.
- In 2017, Crew drilled 35 (33.2 net) and completed 33 (33.0 net) Montney wells predominantly targeting the liquids-rich fairway at West Septimus. In Q4 2017, the Company drilled five (3.9 net) natural gas wells and completed three (3.0 net) natural gas wells at Greater Septimus.
- Crew is currently completing six (4.7 net) wells at West Septimus and expects to commence flowback and clean-up of the wells prior to spring break up.
- At West Septimus, 2017 PDP, 1P and 2P reserves increased materially by 68%, 16% and 26%, respectively, over year end 2016 reflecting the focused capital investment in the area.

Greater Septimus Operational Statistics

Production & Drilling	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016
Average daily production (boe/d)	20,193	18,154	15,558	17,440	17,307
Wells drilled (gross / net)	5 / 3.9	13 / 12.3	5 / 5.0	10 / 10.0	8 / 7.7
Wells completed (gross / net)	3 / 3.0	14 / 14.0	9 / 9.0	3 / 3.0	5 / 4.0

Operating Netback ($ per boe)	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016
Revenue	24.43	20.05	24.51	26.49	25.10
Royalties	(1.19)	(0.89)	(1.57)	(1.66)	(1.47)
% basis	4.9%	4.4%	6.4%	6.3%	5.9%
Realized commodity hedge gain / (loss)	1.74	2.97	0.77	(0.41)	(0.39)
Operating costs	(3.67)	(3.38)	(4.10)	(3.34)	(3.34)
Transportation costs	(1.51)	(1.65)	(2.03)	(1.67)	(1.68)
Operating netback	19.80	17.10	17.58	19.41	18.22

NE BC Montney - Groundbirch

- Development of the Groundbirch area has slowed due to prevailing market conditions. The area is well positioned for mid-to-longer term production growth based on infrastructure capital being invested.
- Crew is proceeding with the installation of strategic pipeline infrastructure from the West Septimus facility through our Groundbirch acreage and connecting into the existing TCPL Saturn meter station. This will afford flexibility to meet the majority of the transportation arrangements through 2019 without additional processing capacity at Groundbirch. The construction of a Groundbirch processing plant will be further analyzed in the context of longer term structural changes to commodity prices.

NE BC Montney - Tower

- Overall production in the Tower area averaged 1,308 boe per day in the fourth quarter of 2017, which included 372 bbls of oil per day.
- During Q1 2018, a strategic partner is expected to complete construction of a water handling facility at Tower in which Crew will be the anchor tenant. With strengthening oil prices and reduced operating costs associated with improved water handling, Tower's economics represent an attractive option for future development.

AB / SK Heavy Oil - Lloydminster

- Crew's previously announced sales process in respect of its Lloydminster asset is ongoing, while netbacks in the area continue to improve as benchmark crude oil prices increase.
- Production in the area averaged 1,809 boe per day in Q4, with minor amounts of workover capital expended, including the recompletion of three (3.0 net) oil wells. Q4 year-over-year declines were 17% with minimal capital expenditures.

OUTLOOK

Value Optimization Remains the Focus

- Crew's 2018 capital budget of $80 to $85 million is expected to approximate 2018 AFF based on current projections and assumptions. Crew expects to maintain ample liquidity with planned draws on our credit facility anticipated not to exceed 25% at any point during the year.

- Targeting average production of 23,500 to 24,500 boe per day, weighted 24% to liquids and 76% to natural gas. At least 1,500 boe per day of low-margin natural gas production is assumed to remain shut-in throughout the year, with the potential to reduce or increase shut-in volumes in response to sustained price changes.
- Forecast drilling four (4.0 net) and completing 15 (13.2 net) condensate and UCR wells at West Septimus. The restriction of well productivity will be tested to reduce pressure drawdown in the reservoir, which could enhance total condensate recoveries. In 2018, Crew also plans to drill 30% to 50% longer lateral length horizontal wells (2,500 to 2,700 metres), implement tighter spacing between fracs and increase the number of stages per well.

Increasing Liquids Production and Margin Expansion

- Liquids production is expected to represent 50 to 60% of Crew's total revenue in 2018, highlighted by an over 30% increase in forecast condensate production in the first quarter of 2018 compared to the first quarter of 2017.
- Focus remains on optimizing netbacks and returns by drilling in the UCR area targeting wells that are expected to pay out in approximately 12 months at current prices, and shutting-in low margin production.

Maintaining Flexibility to Respond to Market Conditions

- Crew's 2018 capital program will be reviewed on a continuing basis by management and the Board of Directors. The Company is well positioned to efficiently adjust the program in response to changing market conditions.
- With a successful history of executing over $700 million of strategic dispositions, Crew continues to pursue asset sales to improve the Company's financial flexibility and capital allocation optionality.

We thank our employees and directors for their commitment and dedication through these challenging market conditions, and we thank all of our shareholders and bondholders for their continued support of Crew.

Cautionary Statements

Information Regarding Disclosure on Oil and Gas Reserves and Operational Information

Information presented herein in respect of reserves and related information is based on our independent reserves evaluation for the year ended December 31, 2017 prepared by Sproule Associates Limited, details of which were provided in our press release issued on February 8, 2018. Our oil and gas reserves statement for the year ended December 31, 2017, which will include complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, will be contained within our Annual Information Form which will be available on our SEDAR profile at www.sedar.com. The recovery and reserve estimates contained herein are estimates only and there is no guarantee that the estimated reserves will be recovered. In relation to the disclosure of estimates for individual properties, such estimates may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. The Company's belief that it will establish additional reserves over time with conversion of probable undeveloped reserves into proved reserves is a forward-looking statement and is based on certain assumptions and is subject to certain risks, as discussed below under the heading "Forward-Looking Information and Statements".

This report contains metrics commonly used in the oil and natural gas industry, such as "adjusted funds flow" and "operating netbacks". These terms 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.

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 2018 average production target; commodity price expectations including Crew's estimates of natural gas pricing exposure; Crew's commodity risk management programs including plans for additional hedging in 2018 and 2019; marketing and transportation 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 associated timing and cost estimates); the amount and timing of capital projects; the potential sale of our heavy oil assets; 2018 capital expenditure and operational plans and priorities, including drilling, completion and infrastructure plans and associated timing and costs; and Crew's 2018 budget and methods of funding our capital program.*

The reserve estimates provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. 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.

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.

YEAR END 2017

Management's Discussion and Analysis

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Consolidated Financial Statements

MANAGEMENT'S DISCUSSION AND ANALYSIS

FINANCIAL & OPERATING HIGHLIGHTS

Financial ($ thousands, except per share amounts)	**Year ended** **December 31, 2017**	Year ended December 31, 2016
Petroleum and natural gas sales	**214,154**	174,719
Cash provided by operations	**117,290**	77,478
Adjusted funds flow (1)	**108,129**	78,674
Per share -basic	**0.73**	0.55
-diluted	**0.72**	0.54
Net income (loss)	**34,405**	(64,926)
Per share -basic	**0.23**	(0.45)
-diluted	**0.23**	(0.45)
Exploration and development expenditures	**238,302**	108,202
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Capital structure ($ thousands)	**As at** **December 31, 2017**	As at December 31, 2016
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	51,120	98,042
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Total net debt	**344,982**	245,371
Common shares outstanding (thousands)	**149,328**	146,812

Operations	**Year ended** **December 31, 2017**	Year ended December 31, 2016
Daily production		
Light crude oil (bbl/d)	**495**	335
Heavy crude oil (bbl/d)	**1,836**	2,459
Condensate (bbl/d)	**2,048**	1,940
Other natural gas liquids (bbl/d)	**1,575**	1,409
Natural gas (mcf/d)	**102,642**	100,203
Oil equivalent (boe/d @ 6:1)	**23,061**	22,844
Average prices (3)		
Light crude oil ($/bbl)	**58.34**	49.89
Heavy crude oil ($/bbl)	**45.14**	33.39
Condensate ($/bbl)	**62.03**	49.53
Other natural gas liquids ($/bbl)	**24.45**	7.47
Natural gas ($/mcf)	**3.01**	2.71
Oil equivalent ($/boe)	**25.44**	20.90
Netback ($/boe)		
Operating netback (4)	**16.74**	12.92
G&A	**(1.42)**	(1.41)
Financing costs on long-term debt	**(2.61)**	(2.10)
Other income	**0.12**	-
Funds from operations (4)	**12.83**	9.41
Drilling activity		
Gross wells	**40**	21
Working interest wells	**38.2**	19.7
Success rate, net wells	**97%**	96%

Notes:

(1) Adjusted funds flow is calculated as cash provided by operating activities, adding the change in operating non-cash working capital, decommissioning obligations settled and accretion of deferred financing costs on the senior unsecured notes. Adjusted funds flow is used to analyze the Company's operating performance and leverage. 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.

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

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

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

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 in British Columbia 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 audited consolidated financial statements of the Company for the year ended December 31, 2017 and 2016. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). All figures provided herein and in the December 31, 2017 audited consolidated financial statements are reported in Canadian dollars ("CDN"). This MD&A is dated March 1, 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, commissioning and the timing thereof, capital expenditures, timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, production estimates including 2018 averages, expected commodity mix and prices, future operating costs, future transportation costs, expected royalty rates, expected general and administrative expenses, expected interest rates, debt levels, funds from operations, adjusted funds flow and the timing of and impact of implementing accounting policies, 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 or dispositions, 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 maintain operating and transportation 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

One of the benchmarks Crew uses to evaluate its performance is 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 December 31, 2017**	Three months ended December 31, 2016	**Year ended December 31, 2017**	Year ended December 31, 2016
Cash provided by operating activities	**43,484**	19,900	**117,290**	77,478
Change in operating non-cash working capital	**(9,165)**	7,394	**(8,706)**	435
Accretion of deferred financing costs	**(261)**	(178)	**(968)**	(650)
Funds from operations	**34,058**	27,116	**107,616**	77,263
Decommissioning obligations settled	**29**	763	**513**	1,411
Adjusted funds flow	**34,087**	27,879	**108,129**	78,674

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 total petroleum and natural gas sales including realized gains and losses on commodity related derivative financial instruments less royalties, operating costs and transportation costs calculated on a boe basis. Management considers operating netback an important measure to evaluate its operational performance as it demonstrates its field level profitability relative to current commodity prices. The calculation of Crew's netbacks can be seen below in the Operating Netbacks section.

Working Capital and Net Debt

The Company closely monitors its capital structure with a goal of maintaining a strong financial position in order to fund 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)	**December 31, 2017**	December 31, 2016
Current assets	**42,596**	39,588
Current liabilities	**(71,392)**	(68,494)
Derivative financial instruments	**(347)**	18,900
Working capital deficit	**(29,143)**	(10,006)

($ thousands)	**December 31, 2017**	December 31, 2016
Bank loan	**(21,977)**	(88,036)
Senior unsecured notes	**(293,862)**	(147,329)
Working capital deficit	**(29,143)**	(10,006)
Net debt	**(344,982)**	(245,371)

RESULTS OF OPERATIONS

Overview

Crew's focus in 2017 was on the expanded development of our Greater Septimus Montney assets with an emphasis on the higher-value, liquids-rich West Septimus area. Entering the year with limited excess processing, the Company worked towards completing an expansion of the West Septimus facility from 60 mmcf per day to 120 mmcf per day. This project was commissioned on time and 8% under budget in early November. In combination with the expansion, the Company's drilling and completion activities were focused on having production tested and ready to bring on-stream when the expanded facility was commissioned.

Production during the year averaged 23,061 boe per day, a slight increase over 2016, despite several challenges encountered through the year. While the Company efficiently executed a capital program that provided significant fourth quarter production growth, annual production was impacted negatively by several extended third party pipeline and facility shut-downs in the second and early third quarters. Further, a very weak Canadian natural gas environment emerged during the third quarter with the daily AECO Canadian benchmark price dipping below $1 per gigajoule for extended periods during the second half of the year. This resulted in Crew electing to shut-in uneconomic production for most of the second half of the year and to defer the start-up of new production until the expanded West Septimus facility was commissioned in November, which coincided with expectations for improvements in Canadian natural gas pricing. Average production levels increased from 20,200 boe per day in October to over 27,850 boe per day in November and December, with uneconomic production remaining shut-in throughout the quarter as Canadian natural gas prices did not recover as anticipated.

Cash provided by operations and adjusted funds flow increased 51% and 37% respectively in 2017 as compared to 2016. These increases were primarily the result of increased commodity prices, as average wellhead prices received for the Company's production increased 22% from $20.90 per boe in 2016 to $25.44 per boe in 2017. Higher adjusted funds flow reflects the positive impact of higher realized commodity prices while Crew's costs remained in line with those incurred in 2016.

The average price received for the Company's total liquids production increased 39% to $46.57 per boe in 2017 as compared to 2016. This price escalation was the result of increasing world oil prices that were buoyed by the Organization of Petroleum Exporting Countries ("OPEC") implementing production quotas in early 2017. The Company's benchmark West Texas Intermediate ("WTI") oil price increased to average CDN $66.11 in 2017, representing a 15% increase over 2016. The Company's liquids revenues were also enhanced by a 12% increase in light oil and condensate production which attracts a premium price compared to the declining volume of heavy oil that it replaced within the Company's production mix.

Crew's natural gas production also attracted higher prices in 2017, averaging $3.01 per mcf, an 11% increase over 2016. The Company's diversified natural gas sales portfolio helped to provide support to Crew's natural gas pricing with approximately 40% of the Company's production sold at Chicago City Gate prices, which have historically traded at a premium to AECO benchmark prices. Chicago City Gate prices were up 20% year-over-year supported by strong industrial and retail demand. This helped offset weaker realized prices in Canada, caused by increasing production through the first half of the year, third party pipeline maintenance and a meaningful shortage of Canadian natural gas takeaway capacity. As a result of these factors, AECO C daily prices averaged only $1.57 per mcf in the second half of the year. This second half weakness offset relatively strong first half prices, leading to an AECO C daily annual average of $2.16 per mcf, consistent with 2016.

Capital expenditures during the year focused on the drilling and completion of wells in the Greater Septimus area with a focus on the condensate-rich West Septimus area. Expenditures totaled $238 million, including $175 million directed to the drilling of 40 (38.2 net) wells and the completion of 37 (37.0 net) wells. Spending in 2017 also included $53 million for facilities and infrastructure, including the West Septimus facility expansion which was completed jointly with an infrastructure partner who participated for a 72% share in the expansion, and several infield gathering system upgrades and road improvements.

The Company continued to extract value from its vast acreage position that is well positioned within the resource-rich Montney fairway. During the second quarter of 2017, the Company disposed of 18,400 acres of undeveloped land in the non-core Goose area of northeast British Columbia ("NE BC") for proceeds of $49 million, resulting in a gain of $38 million over the carrying value of this asset. These proceeds were used to help finance the Company's 2017 capital program, resulting in reduced total year-end debt levels.

Crew exited 2017 with net debt of $345 million, including $22 million, or 9%, drawn on the Company's $235 million bank facility. In the first quarter of 2017, the Company completed a refinancing of its high yield notes whereby the existing $150 million, 8.375% notes maturing in 2020 were repaid and replaced with $300 million of notes bearing interest at 6.5% and maturing in 2024 as discussed in the Capital Funding section below. With no near-term maturities, an increasing reserve base and substantial liquidity, Crew is strongly positioned to manage its current debt position. The Company's plan for 2018 will be to fund capital expenditures with funds from operations in order to maintain debt at or near its current level. The Company also continues to pursue the sale of non-core assets and other opportunities which would enable Crew to pay down debt and fund future growth.

Production

	Three months ended December 31, 2017					Three months ended December 31, 2016				
	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	**399**	**2,617**	**1,823**	**111,733**	**23,461**	540	1,996	1,406	97,481	20,189
Lloydminster	**1,808**	**-**	**-**	**4**	**1,809**	2,188	-	-	20	2,191
Total	**2,207**	**2,617**	**1,823**	**111,737**	**25,270**	2,728	1,996	1,406	97,501	22,380

In the fourth quarter of 2017, production increased 13% over the same period in 2016 as the Company successfully completed the West Septimus facility expansion, increasing Company operated Montney processing capacity to 180 mmcf per day, coupled with strong drilling and completion results from its Montney liquids-rich natural gas assets at West Septimus. Light oil and associated natural gas production also increased at Tower in the fourth quarter of 2017 as a result of the implementation of gas lift in the area. This was partially offset by a decline in heavy oil production as the Company continues to curtail investment in the Lloydminster area. In addition, the Company shut-in approximately 2,800 boe per day to accommodate the commissioning of the plant expansion and as a result of the low Canadian natural gas pricing during the fourth quarter of 2017.

	Year ended December 31, 2017					Year ended December 31, 2016				
	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	**495**	**2,048**	**1,575**	**102,614**	**21,220**	335	1,940	1,409	100,041	20,358
Lloydminster	**1,836**	**-**	**-**	**28**	**1,841**	2,459	-	-	162	2,486
Total	**2,331**	**2,048**	**1,575**	**102,642**	**23,061**	2,794	1,940	1,409	100,203	22,844

Production in 2017 slightly increased as compared to the same period in 2016 as the Company executed an active drilling and completion program in northeast British Columbia, focusing on the condensate-rich wells at West Septimus in advance of the start-up of the West Septimus facility expansion in the fourth quarter. In addition, Tower light oil and natural gas production increased by approximately 75% in 2017 as a result of the aforementioned gas lift installation. This production increase was partially offset by several extended planned and unplanned third party facility and pipeline outages, coupled with the aforementioned shut-in natural gas volumes which negatively affected production in the Company's NE BC properties. In addition, Lloydminster heavy oil production declined as the Company continues to shift its capital spending to Greater Septimus.

Revenue

	Three months ended December 31, 2017	Three months ended December 31, 2016	**Year ended December 31, 2017**	Year ended December 31, 2016
Revenue ($ thousands)				
Light crude oil	**2,381**	2,856	**10,541**	6,108
Heavy crude oil	**8,106**	8,343	**30,254**	30,052
Condensate	**16,760**	10,834	**46,360**	35,155
Other natural gas liquids	**5,800**	1,317	**14,059**	3,853
Natural gas	**27,099**	31,701	**112,940**	99,551
Total	**60,146**	55,051	**214,154**	174,719
Crew average prices				
Light crude oil ($/bbl)	**64.91**	57.49	**58.34**	49.89
Heavy crude oil ($/bbl)	**48.73**	41.44	**45.14**	33.39
Condensate ($/bbl)	**69.60**	59.01	**62.03**	49.53
Other natural gas liquids ($/bbl)	**34.58**	10.18	**24.45**	7.47
Natural gas ($/mcf)	**2.64**	3.53	**3.01**	2.71
Oil equivalent ($/boe)	**25.87**	26.74	**25.44**	20.90
Benchmark pricing				
Light crude oil – WTI (Cdn $/bbl)	**70.47**	65.73	**66.11**	57.26
Heavy crude oil – WCS (Cdn $/bbl)	**54.85**	46.61	**50.55**	38.96
Natural gas liquids – Condensate @ Edmonton (Cdn $/bbl)	**73.71**	64.49	**66.94**	56.22
Natural Gas:				
AECO 5A daily index (Cdn $/mcf)	**1.69**	3.09	**2.16**	2.16
Chicago City Gate at ATP (Cdn $/mcf)	**2.93**	3.22	**3.04**	2.54
Alliance 5A (Cdn $/mcf)	**1.25**	3.12	**2.14**	2.35

In the fourth quarter of 2017, Crew's revenue increased 9% over the same period in 2016 as a result of the increased production at Greater Septimus and Tower, partially offset by a decline in the realized wellhead pricing for the same period. Crew's realized light oil price increased 13% in the fourth quarter as compared to the 7% increase in the Company's Cdn$ WTI benchmark as a result of the Company's ability to secure sales contracts when differentials between the WTI price and Canadian light crude price were narrower than the same period in 2016. The Company's heavy oil price increased 18% in the quarter which was consistent with the 18% increase in the Company's Western Canadian Select ("WCS") benchmark. The Company's fourth quarter realized condensate price increased 18% over the same period in 2016 as compared to the 14% increase in the Condensate at Edmonton benchmark price as a result of lower pipeline tariffs and quality differentials applied against the Company's condensate sales in the fourth quarter of 2017, as compared to the same period in 2016. Other natural gas liquids ("other ngl") realized price increased significantly in the fourth quarter as a result of increased propane and butane market pricing as compared to the fourth quarter of 2016. The Company's natural gas price decreased 25% which is directionally consistent with the 32% decrease in the Company's natural gas sales portfolio weighted benchmark price over the same period in 2016. 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 fourth quarter 2017 natural gas sales portfolio was based approximately on the following reference prices:

	Q4 2017	Q4 2016
Chicago City Gate at ATP	**40%**	40%
AECO	**35%**	30%
Alliance 5A	**18%**	19%
Station 2[1]	**7%**	9%
Sumas	**-**	2%
Total	**100%**	100%

(1) The Company secured fixed short term sales contracts that were greater than the average price realized during the quarter.

For 2017, the Company's revenue increased 23% over the same period in 2016 as a result of the 22% increase in the realized wellhead pricing for the same period combined with a small increase in production. Crew's realized light oil price increased 17% which was consistent with the 15% increase in the Company's WTI benchmark price for 2017. The Company's heavy oil price increased 35% as compared to the 30% increase in the WCS benchmark as a result of securing short term contracts when WCS differentials were narrower than the average market trade for the period. The Company's realized condensate price increased 25% over the same period in 2016 as compared to the 19% increase in the Condensate at Edmonton benchmark price, as a result of the lower pipeline tariffs and quality differentials incurred in 2017 as compared to 2016. In 2017 other ngl realized price increased significantly, due to the significant increase in market price received for propane and butane as compared to the same period last year. For 2017, the Company's natural gas price increased 11% which is directionally consistent with the 7% increase in the Company's natural gas sales portfolio weighted benchmark price as compared to the same period in 2016.

Royalties

($ thousands, except per boe)	**Three months ended December 31, 2017**	Three months ended December 31, 2016	**Year ended December 31, 2017**	Year ended December 31, 2016
Royalties	**3,692**	3,952	**15,152**	10,614
Per boe	**1.59**	1.92	**1.80**	1.27
Percentage of petroleum and natural gas sales	**6.1%**	7.2%	**7.1%**	6.1%

In the fourth quarter of 2017, royalties and royalties as a percentage of petroleum and natural gas sales decreased as compared to same period in 2016 as a result of the increased production at Greater Septimus, where the Company's royalty rate is lower than the corporate average, combined with lower realized natural gas prices that attract a lower royalty rate. In addition, heavy oil production at Lloydminster, which attracts higher royalties than the Company's average, declined as compared to the same period in 2016. This was partially offset by an increase in oil production at Tower, which yields higher royalty rates than the corporate average, coupled with an increase in the realized light oil price that attracts a higher royalty rate. For 2017, royalties and royalties as a percentage of petroleum and natural gas sales increased as compared to 2016, as a result of higher realized wellhead prices and increased Tower production which yield higher royalty rates as compared to the corporate average, partially offset by the new production at Greater Septimus that yields lower royalty rates. Crew expects royalties as a percentage of petroleum and natural gas sales to average between 5% and 7% 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 consolidated statements of income (loss) and comprehensive income (loss):

($ thousands)	**Three months ended December 31, 2017**	Three months ended December 31, 2016	**Year ended December 31, 2017**	Year ended December 31, 2016
Realized gain (loss) on derivative financial instruments	**3,731**	(720)	**10,018**	11,851
Per boe	**1.60**	(0.35)	**1.19**	1.42
Unrealized (loss) gain on financial instruments	**(5,738)**	(15,807)	**19,737**	(24,867)

As at December 31, 2017, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value
Gas	5,000 gj/day	January 1, 2018 - December 31, 2018	AECO C Monthly Index	$3.00/gj	Call	$ (20)
Gas	2,500 gj/day	January 1, 2018 - December 31, 2018	AECO C Daily Index	$2.62/gj	Swap	956
Gas	17,500 mmbtu/day	January 1, 2018 - December 31, 2018	Chicago Citygate	$3.64/mmbtu	Swap	1,632
Gas	5,000 mmbtu/day	January 1, 2018 - December 31, 2018	US$ Nymex Henry Hub	$3.05 US/mmbtu	Swap	474
Propane	400 bbl/day	January 1, 2018 - December 31, 2018	US$ Conway OPIS	$0.79 US/gal	Swap	(181)
Oil	1,500 bbl/day	January 1, 2018 - December 31, 2018	CDN$ WTI	$70.94/bbl	Swap	(1,856)
Oil	250 bbl/day	January 1, 2018 - December 31, 2018	CDN$ WTI	$60.00 - $69.65/bbl	Collar(1)	(520)
Oil	250 bbl/day	January 1, 2018 - December 31, 2018	CDN$ WTI	$69.00 - $74.25/bbl	Collar(2)	(138)
Total						**$ 347**

1) The referenced contract is a costless collar whereby the Company receives $60/bbl when the market price is below $60/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/bbl when the market price is below $69/bbl, and receives $74.25/bbl when the market price is above $74.25/bbl.

Subsequent to December 31, 2017, the Company entered into the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Oil	250 bbl/day	January 1, 2018 - December 31, 2018	CDN$ WTI	$76.38/bbl	Swap
Gas	2,500 mmbtu/day	February 1, 2018 - December 31, 2018	Chicago Citygate	$3.41/mmbtu	Swap
Gas	2,500 mmbtu/day	April 1, 2018 - October 31, 2018	Chicago Citygate	$3.06/mmbtu	Swap
Oil	500 bbl/day	January 1, 2019 - December 31, 2019	CDN$ WTI	$70.90/bbl	Swap

Operating Costs

($ thousands, except per boe)	**Three months ended December 31, 2017**	Three months ended December 31, 2016	**Year ended December 31, 2017**	Year ended December 31, 2016
Operating costs	**13,716**	11,021	**48,952**	49,148
Per boe	**5.90**	5.35	**5.82**	5.88

For the fourth quarter of 2017, the Company's operating costs per boe increased 10% over the same period in 2016. This increase is a result of higher water handling costs from increased production at Tower, increased processing fees from the facility expansion at West Septimus and higher seasonal costs in Lloydminster as compared to the same period in 2016. In 2017, the Company's operating costs per boe were slightly lower as compared to the same period in 2016, as the Company continues to add lower cost production at Greater Septimus replacing declining higher cost heavy oil production. This was partially offset by increased higher cost Tower light oil production as compared to the corporate average. The Company forecasts operating costs to average $6.50 to $6.75 per boe in 2018.

Transportation Costs

($ thousands, except per boe)	**Three months ended December 31, 2017**	Three months ended December 31, 2016	**Year ended December 31, 2017**	Year ended December 31, 2016
Transportation costs	**4,517**	4,308	**19,096**	18,812
Per boe	**1.94**	2.09	**2.27**	2.25

For the fourth quarter of 2017, the Company's transportation costs per boe decreased as a result of increased Greater Septimus production which yield lower transportation costs as compared to the corporate average. This was partially offset with lower production from Lloydminster heavy oil where transportation cost per boe are lower as compared to the corporate average and increased production in Other NE BC which yields higher transportation costs. In 2017, transportation costs per boe slightly increased as compared to 2016 as a result of the Company incurring unutilized fixed facility and pipeline demand charges from extended third party outages during the second and third quarters of 2017. This was coupled with an increase in higher transportation cost production from Other NE BC and a decline in Lloydminster production where transportation costs are lower than the corporate average. The Company expects transportation costs per boe to range between $2.50 and $2.75 per boe in 2018. The increase is expected as a result of the addition of new natural gas pipeline egress contracted to begin in the second quarter of 2018.

Operating Netbacks

($/boe)	Greater Septimus	Lloydminster Heavy Oil	Other NE BC	Three months ended December 31, 2017	Three months ended December 31, 2016
Revenue	**24.43**	**48.71**	**22.12**	**25.87**	26.74
Royalties	**(1.19)**	**(5.63)**	**(1.79)**	**(1.59)**	(1.92)
Realized commodity hedging gain/(loss)	**1.74**	**-**	**1.66**	**1.60**	(0.35)
Operating costs	**(3.67)**	**(22.15)**	**(10.66)**	**(5.90)**	(5.35)
Transportation costs	**(1.51)**	**(1.01)**	**(5.12)**	**(1.94)**	(2.09)
Operating netbacks	**19.80**	**19.92**	**6.21**	**18.04**	17.03
Production (boe/d)	**20,193**	**1,809**	**3,268**	**25,270**	22,380

Operating netbacks for the fourth quarter of 2017 increased over the same period in 2016 as a result of realized commodity hedging gains and lower royalty and transportation costs, which were partially offset by lower realized commodity pricing and higher operating costs in the period.

($/boe)	Greater Septimus	Lloydminster Heavy Oil	Other NE BC	Year ended December 31, 2017	Year ended December 31, 2016
Revenue	**23.82**	**45.06**	**23.32**	**25.44**	20.90
Royalties	**(1.31)**	**(5.54)**	**(2.35)**	**(1.80)**	(1.27)
Realized commodity hedging gain/(loss)	**1.31**	**(0.33)**	**1.38**	**1.19**	1.42
Operating costs	**(3.61)**	**(21.85)**	**(8.74)**	**(5.82)**	(5.88)
Transportation costs	**(1.70)**	**(0.96)**	**(6.00)**	**(2.27)**	(2.25)
Operating netbacks	**18.51**	**16.38**	**7.61**	**16.74**	12.92
Production (boe/d)	**17,845**	**1,841**	**3,375**	**23,061**	22,844

For the year ended December 31, 2017, operating netbacks increased over the same period in 2016 predominantly due to an increase in commodity prices, partially offset by an increase in royalties and reduced realized hedging gains.

General and Administrative Costs

($ thousands, except per boe)	Three months ended December 31, 2017	Three months ended December 31, 2016	Year ended December 31, 2017	Year ended December 31, 2016
Gross costs	**4,759**	4,552	**18,398**	18,438
Operator's recoveries	**(231)**	(198)	**(545)**	(385)
Capitalized costs	**(1,355)**	(1,620)	**(5,939)**	(6,285)
General and administrative expenses	**3,173**	2,734	**11,914**	11,768
Per boe	**1.36**	1.33	**1.42**	1.41

Gross general and administrative ("G&A") costs have increased in the fourth quarter of 2017 as compared to the same period in 2016, due to the adjusted office rent costs from the renewed five year lease term. Gross annual 2017 G&A costs decreased as a result of lower compensation costs due to reduced staffing levels, partially offset by the aforementioned increase in rent costs. The decrease in compensation costs resulted in a decrease in capitalized costs, which contributed to the increase in net G&A costs and net G&A per boe in both the fourth quarter of 2017 and the year ended December 31, 2017, as compared to the same periods in 2016. Crew forecasts G&A costs per boe to average between $1.25 and $1.50 in 2018.

Share-Based Compensation

($ thousands)	**Three months ended December 31, 2017**	Three months ended December 31, 2016	**Year ended December 31, 2017**	Year ended December 31, 2016
Gross costs	**2,282**	3,739	**16,340**	16,495
Capitalized costs	**(1,015)**	(1,802)	**(7,690)**	(7,696)
Total share-based compensation	**1,267**	1,937	**8,650**	8,799

In the fourth quarter of 2017 and for the year ended December 31, 2017, the Company's share-based compensation expense decreased as compared to the same periods in 2016, due to a reduction in share-based compensation expense recorded as a result of the departure of a Company executive. This was partially offset by additional share-based compensation expense recorded as a result of a higher fair value of awards granted in the current year as compared to the same period in 2016.

Depletion and Depreciation

($ thousands, except per boe)	**Three months ended December 31, 2017**	Three months ended December 31, 2016	**Year ended December 31, 2017**	Year ended December 31, 2016
Depletion and depreciation	**19,620**	18,923	**75,131**	85,403
Per boe	**8.44**	9.19	**8.93**	10.21

In the fourth quarter of 2017 and for the year ended December 31, 2017, depletion and depreciation costs per boe decreased by 8% and 13%, respectively, when compared to the same periods in 2016. These decreases were due to increased proved plus probable reserve bookings at Greater Septimus where improved drilling and completion efficiencies have reduced costs, combined with increased production in these areas where depletion rates are lower than the corporate average. The Company increased proved plus probable reserves by 14% to 370 mmboe during 2017, highlighted by a 15% increase in Greater Septimus proved plus probable reserves. Additionally, lower depletion was recognized on the Lloydminster property due to impairment write downs in 2016 and the second quarter of 2017, which reduced the carrying value of the cash generating unit ("CGU"). In the fourth quarter of 2017, depletion and depreciation expense increased 4% due to an increase in production when compared to the same period in 2016. Depletion and depreciation expense for the year ended December 31, 2017 decreased 12% as a result of lower depletion rates applied to the Company's Montney production, due to lower cost per boe of added reserves, and increased production from those Montney areas relative to other producing areas.

Impairment

At December 31, 2017, due to weakness in the Canadian natural gas price environment, the Company tested its northeast British Columbia CGU for impairment. It was determined that the recoverable amount of the northeast British Columbia CGU exceeded its carrying value and an impairment charge was not recorded. For the Lloydminster CGU, the Company did not identify indicators of impairment at December 31, 2017.

In the second quarter of 2017, due to the continuing decline in the Canadian heavy oil price environment, reduced future heavy oil development plans and the prevailing heavy oil transaction market, the Company tested its Lloydminster CGU for impairment using the fair value less cost to sell measure. It was determined that the carrying value of the Lloydminster heavy oil CGU exceeded its fair value and a $16.7 million impairment charge was recorded.

During 2016, due to the ongoing reduced heavy oil price environment combined with the Company's future heavy oil development plans in the area and the existing heavy oil transaction market, the Company tested its Lloydminster CGU for impairment. It was determined that the carrying value of the Lloydminster heavy oil CGU exceeded its recoverable amount and a $44.4 million impairment charge was recorded.

Gain (Loss) on Divestitures of Property

During the fourth quarter of 2017, the Company disposed of non-core assets for cash proceeds of $1.7 million. The assets consisted of petroleum and natural gas properties and undeveloped land with a net book value of $9.3 million and associated decommissioning obligations of $1.2 million, resulting in a loss of $6.4 million on closing of the disposition.

During the third quarter of 2017, the Company entered into a swap of petroleum and natural gas properties and undeveloped land with a total net book value of $1.1 million and associated decommissioning obligations of $0.1 million for land with a fair value of $3.0 million and $0.1 million cash, resulting in a gain of $2.1 million.

During the second quarter of 2017, the Company disposed of non-core assets in northeast British Columbia for cash proceeds of $49.1 million. The assets consisted of undeveloped land and had a net book value of $11.4 million and associated decommissioning obligations of $0.2 million, resulting in a gain of $37.9 million on closing of the disposition.

Finance Expenses

($ thousands, except per boe)	**Three months ended December 31, 2017**	Three months ended December 31, 2016	**Year ended December 31, 2017**	Year ended December 31, 2016
Interest on bank loan and other	**516**	1,093	**2,408**	4,342
Interest on senior notes	**4,915**	3,166	**18,553**	12,562
Accretion of deferred financing charges	**261**	178	**968**	650
Accretion of the decommissioning obligation	**499**	461	**1,934**	1,768
Premium paid on redemption of 2020 Notes	**-**	-	**6,282**	-
Deferred financing costs expensed on 2020 Notes	**-**	-	**2,510**	-
Total finance expense	**6,191**	4,898	**32,655**	19,322
Average debt level	**332,100**	242,396	**301,353**	239,908
Average drawings on bank loan	**32,100**	92,396	**26,833**	89,908
Average senior unsecured notes outstanding	**300,000**	150,000	**274,520**	150,000
Effective interest rate on senior notes	**6.5%**	8.4%	**6.8%**	8.4%
Effective interest rate on long-term debt	**6.2%**	6.4%	**6.5%**	5.9%
Financing costs on long-term debt per boe	**2.45**	2.15	**2.61**	2.10

The Company's average corporate debt level increased in both the fourth quarter of 2017 and for the year ended December 31, 2017 as compared to the same periods in 2016, due to increased capital expenditures which was predominately spent in the first and third quarters of 2017. In addition, during the first quarter of 2017, the Company issued $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 senior notes decreased for both the fourth quarter of 2017 and year ended December 31, 2017 as compared to the same periods in 2016. The effective interest rate on the Company's long-term debt decreased in the fourth quarter of 2017 as a result of the lower interest rate on the 2024 Notes. For the year ended December 31, 2017, the Company's effective interest rate on long-term debt increased as the issuance of the 2024 Notes resulted in the senior unsecured notes accounting for a larger percentage of the average debt level, than the lower interest rate bank loan. 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 fourth quarter of 2017, the provision for deferred taxes was a recovery of $1.8 million compared to a recovery of $13.7 million for the same period in 2016. The decreased recovery is the result of an increase in pre-tax income in the period due to an impairment charge that lowered 2016 fourth quarter pre-tax income, partially offset by the fourth quarter 2017 recognition of a previously unrealized tax deduction associated with share-based compensation. For 2017, the provision for deferred taxes was an expense of $16.2 million compared to a recovery of $20.8 million. The change from a recovery to an expense was a result of pre-tax income in 2017, an income tax rate change in British Columbia effective in 2018 and a flow-through share renunciation in the first quarter of 2017, partially offset by the aforementioned unrecognized tax benefit being recognized in the fourth quarter of 2017.

A summary of the Company's estimated income tax pools is outlined below:

($ thousands)	**December 31, 2017**	December 31, 2016
Cumulative Canadian Exploration Expense	**290,400**	280,500
Cumulative Canadian Development Expense	**276,000**	276,700
Undepreciated Capital Cost	**234,800**	178,300
Non-capital losses	**257,100**	218,600
Share issue costs	**7,800**	4,300
Other	**13,900**	-
	1,080,000	958,400

The estimated income tax pools for 2017 have been increased as a result of capital spending in the period. The Company did not pay cash taxes in 2017 and estimates sufficient tax pools available to shelter estimated income until 2020 or beyond.

Cash, Adjusted Funds Flow and Net Income (Loss)

($ thousands, except per share amounts)	**Three months ended December 31, 2017**	Three months ended December 31, 2016	**Year ended December 31, 2017**	Year ended December 31, 2016
Cash provided by operating activities	**43,484**	19,900	**117,290**	77,478
Adjusted funds flow	**34,087**	27,879	**108,129**	78,674
Per share -basic	**0.23**	0.19	**0.73**	0.55
-diluted	**0.22**	0.19	**0.72**	0.54
Net income (loss)	**2,342**	(40,030)	**34,405**	(64,926)
Per share -basic	**0.02**	(0.28)	**0.23**	(0.45)
-diluted	**0.02**	(0.28)	**0.23**	(0.45)

For the fourth quarter of 2017 and year ended December 31, 2017, the increase in cash provided by operating activities and adjusted funds flow was a result of increased production and higher operating netbacks as compared to the same periods in 2016. The decrease to net loss in the fourth quarter of 2017 was a result of an impairment charge for the Lloydminster CGU booked to the net loss in the fourth quarter of 2016. For year ended December 31, 2017, the change from a net loss to net income in 2017 was a result of significantly higher gains on divestitures and gains on derivative financial instruments, in addition to lower impairment charges and depletion and depreciation expense.

Other Long-Term Assets

Other long-term assets includes pipe inventory for the construction of a pipeline from the West Septimus facility through the Company's Groundbirch acreage, connecting into the TransCanada Pipeline Saturn meter station. Construction of this pipeline is planned to commence and be completed during 2018.

Capital Expenditures, Property Acquisitions and Dispositions

($ thousands)	**Three months ended December 31, 2017**	Three months ended December 31, 2016	**Year ended December 31, 2017**	Year ended December 31, 2016
Land	**1,022**	1,294	**3,508**	3,689
Seismic	**(357)**	254	**357**	832
Drilling and completions	**18,427**	25,925	**174,686**	80,585
Facilities, equipment and pipelines	**15,880**	8,437	**53,295**	16,500
Other	**1,441**	1,702	**6,456**	6,596
Total exploration and development	**36,413**	37,612	**238,302**	108,202
Property (dispositions) acquisitions	**(1,709)**	3,099	**(47,906)**	3,973
Total	**34,704**	40,711	**190,396**	112,175

In the fourth quarter of 2017, the Company spent a total of $36.4 million on exploration and development expenditures. The majority of this amount was spent on the continued development of our Montney assets at West Septimus including the commissioning of the West Septimus facility expansion to 120 mmcf per day on time and under budget in early November. During the quarter, $18.4 million was spent on drilling and completion activities, $15.9 million on well site development, facilities and pipelines and $2.1 million on land, seismic, recompletions and other miscellaneous amounts. During the fourth quarter of 2017, the Company drilled five (3.9 net) natural gas wells and completed three (3.0 net) natural gas wells in the northeast British Columbia area. The Company also recompleted three (3.0 net) heavy oil wells in the Lloydminster area.

In 2017, the Company drilled a total of 40 (38.2 net) wells resulting in four (4.0 net) oil wells, 35 (33.2 net) natural gas wells and one (1.0 net) dry and abandoned well. During the year, the Company completed 37 (37.0 net) wells and recompleted 20 (18.6 net) wells. The Company's focus in 2017 was the expansion of our Montney asset in the West Septimus area with the drilling and completion of wells and new infrastructure to support the aforementioned West Septimus facility expansion. The 2017 program saw the drilling and completion of wells in the Company's proven condensate-rich area at West Septimus along with new drilling and completions that provided proof of concept for our ultra condensate-rich area at West Septimus, allowing for additional drilling in this area late in the year. The expanded facility has been configured to handle the higher amounts of condensate that have been experienced with the completion of wells in the ultra condensate-rich area.

During the second quarter of 2017, the Company disposed of 18,400 acres of undeveloped land in the non-core Goose area of NE BC for proceeds of $49 million.

LIQUIDITY AND CAPITAL RESOURCES

Working Capital

The capital intensive nature of Crew's activities generally results in the Company carrying a working capital deficit. Working capital deficiency includes cash and cash equivalents and accounts receivable less accounts payable and accrued liabilities. Included in the working capital deficit is a receivable of $7.1 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 maintains sufficient unused bank credit lines to satisfy working capital deficiencies. At December 31, 2017, the Company's working capital deficit totaled $29.1 million which, when combined with the drawings on its bank loan, represented 22% of its bank facility at December 31, 2017.

Capital Funding

Bank Loan

As at December 31, 2017, 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 6, 2018. 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 June 6, 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 will terminate on May 24, 2018 or such earlier time as the maximum number of common shares are purchased pursuant to the NCIB or the NCIB is terminated at the option of the Company. 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.

In 2016, the Company closed a non-brokered private placement offering of 1,845,100 common shares at a price of $8.13 per share for gross proceeds of $15.0 million. The shares were issued on a flow-through basis, with an issuance premium to the common share trading value at the time of issuance of $1.4 million. Pursuant to the provisions of the Income Tax Act (Canada) and the terms of the offering, the Company committed to renounce to the subscribers Canadian Development Expenses incurred by the Company of $7.5 million by each of January 31, 2017 and March 31, 2017. The Company renounced the Canadian Development Expenses such that the full proceeds were deductible against the subscribers' income in 2017. The Company incurred the entire $15.0 million in qualifying expenditures under this flow-through share offering during 2017.

Crew is authorized to issue an unlimited number of common shares. As at March 1, 2018, there were 149,340,851 common shares of the Company issued and outstanding. In addition, there were 1,554,788 restricted awards and 2,061,095 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 year ended December 31, 2017.

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 and costs, 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 at 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 December 31, 2017, the Company's ratio of net debt to annualized adjusted funds flow was 2.5 to 1 (December 31, 2016 – 2.2 to 1). As commodity prices remain volatile, including recent weakness in Canadian natural gas pricing, the Company will be cautious in 2018 with plans to limit capital expenditures to approximate adjusted funds flow. With only 9% 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 closely 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)	**December 31, 2017**	December 31, 2016
Working capital deficit	**(29,143)**	(10,006)
Bank loan	**(21,977)**	(88,036)
Senior unsecured notes	**(293,862)**	(147,329)
Net debt	**(344,982)**	(245,371)
Fourth quarter adjusted funds flow	**34,087**	27,879
Annualized	**136,348**	111,516
Net debt to annualized adjusted funds flow	**2.5**	2.2

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, transportation 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)	21,977	-	21,977	-	-	-	-
Senior unsecured notes (note 2)	300,000	-	-	-	-	-	300,000
Operating leases	3,917	1,175	1,175	1,175	392	-	-
Firm transportation agreements	271,873	44,004	47,908	47,023	24,057	23,881	85,000
Firm processing agreement	129,827	17,634	17,634	16,337	12,354	12,354	53,514
Total	**727,594**	**62,813**	**88,694**	**64,535**	**36,803**	**36,235**	**438,514**

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.

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

The Company's Board of Directors has approved an $80-$85 million exploration and development budget for 2018. This budget will focus predominantly on Crew's long-term plan to diversify market access and increase condensate volumes while positioning Crew to achieve forecasted and average production of 23,500 to 24,500 boe per day. The Company plans to execute a four (4.0 net) well Montney drill program and complete 15 (13.2 net) condensate and ultra condensate-rich wells at West Septimus.

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)	**Dec. 31 2017**	Sep. 30 2017	June 30 2017	Mar. 31 2017	Dec. 31 2016	Sep. 30 2016	June 30 2016	Mar. 31 2016
Total daily production (boe/d)	**25,270**	23,251	20,468	23,231	22,380	23,211	21,950	23,832
Exploration and development expenditures	**36,413**	90,069	36,656	75,164	37,612	37,731	15,096	17,763
Property (dispositions)/acquisitions	**(1,709)**	(144)	(45,701)	(352)	3,099	(98)	16	956
Average wellhead price ($/boe)	**25.87**	22.36	26.25	27.40	26.74	22.05	18.14	16.76
Petroleum and natural gas sales	**60,146**	47,824	48,886	57,298	55,051	47,093	36,232	36,343
Cash provided by operations	**43,484**	15,258	31,359	27,189	19,900	25,940	12,047	19,591
Adjusted funds flow	**34,087**	24,970	21,353	27,719	27,879	23,033	16,048	11,714
Per share – basic	**0.23**	0.17	0.14	0.19	0.19	0.16	0.11	0.08
– diluted	**0.22**	0.17	0.14	0.18	0.19	0.16	0.11	0.08
Net income (loss)	**2,342**	2,127	21,880	8,056	(40,030)	(1,286)	(16,815)	(6,795)
Per share – basic	**0.02**	0.01	0.15	0.05	(0.28)	(0.01)	(0.12)	(0.05)
– diluted	**0.02**	0.01	0.14	0.05	(0.28)	(0.01)	(0.12)	(0.05)

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 2017, where the Company further expanded it capital program and infrastructure spending to allow for the growth realized in the second half of 2017.

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.

The following table summarizes Crew's key financial results over the past three years:

($ thousands, except per share amounts)	**Year ended Dec. 31, 2017**	Year ended Dec. 31, 2016	Year ended Dec. 31, 2015
Petroleum and natural gas sales	**214,154**	174,719	153,934
Cash provided by operations	**117,290**	77,478	74,698
Adjusted funds flow	**108,129**	78,674	82,363
Per share -basic	**0.73**	0.55	0.60
-diluted	**0.72**	0.54	0.60
Net income (loss)	**34,405**	(64,926)	(55,355)
Per share -basic	**0.23**	(0.45)	(0.40)
-diluted	**0.23**	(0.45)	(0.40)
Daily production (boe/d)	**23,061**	22,844	18,542
Crew average sales price ($/boe)	**25.44**	20.90	22.74
Total assets	**1,388,120**	1,239,040	1,244,283
Working capital deficiency (1)	**29,143**	10,006	10,737
Bank loan	**21,977**	88,036	80,980
Senior unsecured notes	**293,862**	147,329	146,679
Total other long-term liabilities	**134,947**	113,492	132,711

Notes:
(1) Working capital includes accounts receivable, accounts payable and accrued liabilities.

Over the last three years, a volatile commodity price environment has impacted revenue, cash provided by operations, adjusted funds flow and net income (loss). The overall decline in forecasted future commodity prices has also led to the assessment and realization of impairment charges on certain CGUs in each of the past three years.

New Accounting Pronouncements

The Company has reviewed the following new and revised accounting pronouncements that have been issued but are not yet effective and determined that the following may have an impact on the Company's financial statements:

(a) IFRS 15 Revenue from Contracts with Customers:

As of January 1, 2018, the Company will be required to adopt IFRS 15 Revenue from Contracts with Customers. The new standard replaces IAS 18 Revenue, IAS 11 Construction Contracts and related interpretations. The standard 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 standard is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with earlier adoption permitted.

Crew will adopt IFRS 15 using the modified retrospective approach on January 1, 2018. Based on the Company's review of contracts with customers and its assessment of various revenue streams, the Company has concluded that the adoption of IFRS 15 will not have a material impact on Crew's net income (loss) and financial position. However, Crew will expand the disclosures in the notes to its consolidated financial statements as prescribed by IFRS 15, including disclosing the Company's disaggregated revenue streams by product type.

(b) IFRS 9 Financial Instruments:

As of January 1, 2018, the Company will be required to adopt IFRS 9 Financial Instruments, which replaces IAS 39 Financial Instruments: Recognition and Measurement. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has two classification categories: amortized cost and fair value. In addition, updates have also been applied surrounding hedge accounting requirements which are now more aligned with an entity's risk management activities. The impact of this standard has been evaluated and is expected to have no material impact on the Company's consolidated financial statements.

(c) IFRS 16 Leases:

As of January 1, 2019, the Company will be required to adopt IFRS 16 Leases, which will replace IFRS 17 Leases and IFRIC 4 Determining Whether an Arrangement Contains a Lease. For lessees applying the new standard, a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for all leases. As of December 31, 2017, Crew is in the process of identifying and gathering contracts impacted by the new standard. Although the impact is still being determined, it is expected that adoption of IFRS 16 will have a material impact on the Company's consolidated financial statements.

Application of Critical Accounting Estimates

Crew's significant accounting policies are disclosed in note 3 to the December 31, 2017 consolidated financial statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Crew continuously refines its management and reporting systems to ensure that accurate, timely and useful information is gathered and disseminated. Crew's financial and operating results incorporate certain estimates including the following:

- Estimated accruals for revenues, royalties, operating expenses and general administrative expenses where actual revenues and costs have not been received;
- Estimated capital expenditures where actual costs have not been received or for projects that are in progress;
- Estimated depletion, depreciation and amortization charges are based on estimates of oil and gas reserves that Crew expects to recover in the future. As a key component in the depletion, depreciation and amortization calculation, the reserve estimates have a significant impact on net earnings and the Company's financial results could differ if there is a revision in our estimate of reserve quantities;

- Estimated future recoverable value of property, plant and equipment and any related impairment charges or recoveries are assessed for impairment when circumstances suggest the carrying amount may exceed its recoverable amount. The recoverable amount calculation requires the use of estimates which are subject to change as new information becomes available. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets;
- Estimated fair values of derivative contracts, which are used to manage commodity price, foreign currency and interest rate swaps, are determined using valuation models which require assumptions regarding the amount and timing of future cash flows and discount rates. As the Company's assumptions rely on external market data, the resulting fair value estimates may not be indicative of the amounts realized or settled and are therefore subject to market uncertainty;
- Decommissioning obligations are based on assumptions which take into consideration current economic factors and experience to date which we believe are reasonable. The actual cost of the Company's decommissioning obligations may change in response to numerous factors;
- Estimated deferred income tax assets and liabilities are based on current tax interpretations, regulations and legislation which are subject to change. As a result, there are usually a number of tax matters under review and therefore income taxes are subject to measurement uncertainty.

Crew hires employees and engages consultants who have the expertise to ensure these estimates are accurate and ensures departments with the most knowledge of the activity are responsible for the estimates. Past estimates are reviewed and analyzed regularly to ensure future estimates continue to track actuals. The emergence of new information and changed circumstances may result in actual results or changes to estimate amounts that differ materially from current estimates.

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. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's disclosure controls and procedures at the financial year end of the Company and have concluded that the Company's disclosure controls and procedures are effective at the financial year end of the Company for the foregoing purposes.

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. Utilizing the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") Internal Control – Integrated Framework (2013), such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal controls over financial reporting at the financial year end of the Company and concluded that the Company's internal controls over financial reporting are effective, at the financial year end of the Company, for the foregoing purpose. 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 October 1, 2017 and ended on December 31, 2017 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 March 1, 2018

MANAGEMENT'S REPORT

Management, in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board, has prepared the accompanying consolidated financial statements of Crew Energy Inc. ("Crew" or the "Company"). Financial and operating information presented throughout this report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

KPMG LLP were appointed by the Company's Board of Directors to conduct an audit of the consolidated financial statements. Their examination included a review and evaluation, including tests and procedures, of Crew's internal control systems as they considered necessary, to provide reasonable assurance that the consolidated financial statements are presented fairly in accordance with IFRS.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual evaluation of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the independent auditors to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of the external auditors and reviews their fees. The external auditors have access to the Audit Committee without the presence of management.

(signed)

Dale O. Shwed

President and Chief Executive Officer

(signed)

John G. Leach

Senior Vice-President and Chief Financial Officer

March 1, 2018

AUDITORS' REPORT

To the Shareholders of Crew Energy Inc.

We have audited the accompanying consolidated financial statements of Crew Energy Inc., which comprise the consolidated statements of financial position as at December 31, 2017 and December 31, 2016, the consolidated statements of income (loss) and comprehensive income (loss), changes in shareholders' equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Crew Energy Inc. as at December 31, 2017 and December 31, 2016, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

(Signed)

"KPMG LLP"
Chartered Professional Accountants
March 1, 2018
Calgary, Canada

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(thousands)	**December 31, 2017**	December 31, 2016
Assets		
Current Assets:		
Accounts receivable	**$ 40,930**	$ 39,588
Derivative financial instruments (note 6)	**1,666**	-
	42,596	39,588
Other long-term assets (note 7)	**4,788**	-
Property, plant and equipment (note 8)	**1,340,736**	1,199,452
	$ 1,388,120	$ 1,239,040
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 70,073**	$ 49,594
Derivative financial instruments (note 6)	**1,319**	18,900
	71,392	68,494
Derivative financial instruments (note 6)	**-**	490
Bank loan (note 10)	**21,977**	88,036
Senior unsecured notes (note 11)	**293,862**	147,329
Decommissioning obligations (note 12)	**88,368**	85,859
Deferred premium on flow-through shares (note 13)	**-**	1,419
Deferred tax liability (note 14)	**42,427**	25,724
Shareholders' Equity		
Share capital (note 13)	**1,458,086**	1,442,284
Contributed surplus	**73,158**	74,960
Deficit	**(661,150)**	(695,555)
	870,094	821,689
Commitments (note 19)		
Subsequent event (note 6)		
	$ 1,388,120	$ 1,239,040

See accompanying notes to the consolidated financial statements.

On behalf of the Board of Directors:

(signed)

David G. Smith

Director

(signed)

Dennis L. Nerland

Director

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

(thousands, except per share amounts)	**Year ended December 31, 2017**	Year ended December 31, 2016
Revenue		
Petroleum and natural gas sales	**$ 214,154**	$ 174,719
Royalties	**(15,152)**	(10,614)
Realized gain on derivative financial instruments (note 6)	**10,018**	11,851
Unrealized gain (loss) on derivative financial instruments (note 6)	**19,737**	(24,867)
Other income (note 15)	**1,000**	-
	229,757	151,089
Expenses		
Operating	**48,952**	49,148
Transportation	**19,096**	18,812
General and administrative	**11,914**	11,768
Share-based compensation	**8,650**	8,799
Depletion and depreciation	**75,131**	85,403
	163,743	173,930
Income (loss) from operations	**66,014**	(22,841)
Financing (note 16)	**32,655**	19,322
Gain on marketable securities	**-**	(955)
Impairment of property, plant and equipment (note 9)	**16,710**	44,432
(Gain) loss on divestiture of property, plant and equipment (note 8)	**(33,951)**	130
Income (loss) before income taxes	**50,600**	(85,770)
Deferred tax expense (recovery) (note 14)	**16,195**	(20,844)
Net income (loss) and comprehensive income (loss)	**$ 34,405**	$ (64,926)
Net income (loss) per share (note 13)		
Basic	**$ 0.23**	$ (0.45)
Diluted	**$ 0.23**	$ (0.45)

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(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	-	-	-	34,405	34,405
Share-based compensation expensed	-	-	8,650	-	8,650
Share-based compensation capitalized	-	-	7,690	-	7,690
Issued on vesting of share awards	3,440	19,053	(19,053)	-	-
Tax deduction on excess value of share awards	-	-	911	-	911
Shares purchased and cancelled (note 13)	(924)	(3,251)	-	-	(3,251)
Balance, December 31, 2017	**149,328**	**$1,458,086**	**$ 73,158**	**$ (661,150)**	**$ 870,094**

(thousands)	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 2016	141,067	$1,398,698	$ 77,627	$ (630,629)	$ 845,696
Net loss for the period	-	-	-	(64,926)	(64,926)
Share-based compensation expensed	-	-	8,799	-	8,799
Share-based compensation capitalized	-	-	7,696	-	7,696
Transfer to share capital for exercised options	-	5,087	(5,087)	-	-
Issued on exercise of options	1,903	10,899	-	-	10,899
Issued on vesting of share awards	1,997	14,075	(14,075)	-	-
Issued on offering of flow-through shares (note 13)	1,845	15,001	-	-	15,001
Deferred premium on flow-through shares (note 13)	-	(1,419)	-	-	(1,419)
Share issue costs, net of tax of $21	-	(57)	-	-	(57)
Balance, December 31, 2016	**146,812**	**$1,442,284**	**$ 74,960**	**$ (695,555)**	**$ 821,689**

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands)	**Year ended December 31, 2017**	Year ended December 31, 2016
Cash provided by (used in):		
Operating activities:		
Net income (loss)	**$ 34,405**	$ (64,926)
Adjustments:		
Unrealized (gain) loss on derivative financial instruments (note 6)	**(19,737)**	24,867
Share-based compensation	**8,650**	8,799
Depletion and depreciation	**75,131**	85,403
Financing expenses (note 16)	**32,655**	19,322
Interest expense (note 16)	**(20,961)**	(16,904)
Gain on sale of marketable securities	**-**	(955)
Impairment of property, plant and equipment (note 9)	**16,710**	44,432
(Gain) loss on divestiture of property, plant and equipment (note 8)	**(33,951)**	130
Deferred tax expense (recovery) (note 14)	**16,195**	(20,844)
Decommissioning obligations settled (note 12)	**(513)**	(1,411)
Change in non-cash working capital (note 18)	**8,706**	(435)
	117,290	77,478
Financing activities:		
(Decrease) increase in bank loan	**(66,059)**	7,056
Issuance of senior notes, net of financing costs (note 11)	**293,055**	-
Redemption of senior notes (note 11)	**(156,282)**	-
Shares purchased and cancelled (note 13)	**(3,251)**	-
Proceeds from exercise of options	**-**	10,899
Proceeds from issuance of flow-through shares (note 13)	**-**	15,001
Share issue costs	**-**	(78)
	67,463	32,878
Investing activities:		
Property, plant and equipment expenditures (note 8)	**(238,302)**	(108,202)
Property acquisitions	**(3,827)**	(4,077)
Property dispositions	**51,733**	104
Purchase of other long-term assets (note 7)	**(4,788)**	-
Proceeds on marketable securities disposed	**-**	2,115
Change in non-cash working capital (note 18)	**10,431**	(296)
	(184,753)	(110,356)
Change in cash and cash equivalents	**-**	-
Cash and cash equivalents, beginning of year	**-**	-
Cash and cash equivalents, end of year	**$ -**	$ -

See accompanying notes to the consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2017 and 2016

(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 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 International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. A summary of the significant accounting policies and method of computation is presented in note 3.

The financial statements have been prepared on the historical cost basis except for derivative financial instruments which are measured at fair value. The methods used to measure fair values are discussed in note 4.

These financial statements are presented in Canadian dollars ("CDN"), which is the functional currency of the Company, its subsidiary and partnerships.

Expenses in the statement of income (loss) are presented as a combination of function and nature in conformity with industry practice. Share-based compensation and depletion and depreciation are presented on separate lines by their nature, while operating expenses, transportation costs and general and administrative expenses are presented on a functional basis.

The financial statements were authorized for issuance by Crew's Board of Directors on March 1, 2018.

3. Significant accounting policies:

The accounting policies set out below have been applied consistently to all years presented in these financial statements.

Certain comparative amounts have been reclassified to conform with the current year's presentation.

(a) Basis of consolidation:

(i) Subsidiaries:

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, substantive potential voting rights are taken into account. The financial statements of subsidiaries are included in the financial statements from the date that control commences until the date that control ceases. The acquisition method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in the statement of income (loss).

(ii) Jointly owned assets:

Some of the Company's oil and natural gas activities involve jointly owned assets. The financial statements include the Company's share of these jointly owned assets and its proportionate share of the relevant revenue and related costs.

(iii) Transactions eliminated on consolidation:

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the financial statements.

(b) Foreign currency:

Transactions in foreign currencies are translated to Canadian dollars at exchange rates at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at the period end exchange rate. Non-monetary assets and liabilities denominated in foreign currencies that are measured at fair value are translated to the functional currency at the exchange rate at the date that the fair value was determined. Foreign currency differences arising on translation are recognized in profit or loss.

(c) Financial instruments:

(i) Non-derivative financial instruments:

Non-derivative financial instruments are comprised of cash and cash equivalents, accounts receivable, accounts payable, the bank loan and the senior unsecured notes. Non-derivative financial instruments are recognized initially at fair value plus, for instruments not at fair value through profit or loss, any directly attributable transaction costs. Subsequent to initial recognition, non-derivative financial instruments are measured as described below.

Cash and cash equivalents is comprised of cash on hand, term deposits held with banks and other short-term highly liquid investments with original maturities of three months or less. Bank overdrafts that are repayable on demand and form an integral part of the Company's cash management, whereby management has the ability and intent to net bank overdrafts against cash, are included as a component of cash and cash equivalents for the purpose of the statement of cash flows.

Other non-derivative financial instruments, such as accounts receivable, the bank loan, the senior unsecured notes and accounts payable, are measured at amortized cost using the effective interest method, less any impairment losses.

(ii) Derivative financial instruments:

The Company enters into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices, interest rates and the exchange rate between Canadian and United States dollars. These instruments are not used for trading or speculative purposes. The Company has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though the Company considers all financial derivative contracts to be economic hedges. As a result, all financial derivative contracts are classified at fair value through profit or loss and are recorded on the statement of financial position at fair value. Transaction costs are recognized in profit or loss when incurred.

(iii) Share capital:

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

(d) Property, plant and equipment and intangible exploration assets:

(i) Recognition and measurement:

Exploration and evaluation ("E&E") expenditures:

Pre-license costs are recognized in the statement of income (loss) as incurred.

E&E costs, including the costs of acquiring leases and licenses initially are capitalized as E&E assets. The costs are accumulated in cost centres by well, field or exploration area pending determination of technical feasibility and commercial viability.

E&E assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, E&E assets are allocated to the related cash-generating unit ("CGU").

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proven and/or probable reserves are determined to exist. A review of each exploration license or field is carried out, at least annually, to ascertain whether proven and/or probable reserves have been discovered. Upon determination of proven and/or probable reserves, intangible E&E assets attributable to those reserves are first tested for impairment and then reclassified from E&E assets to a separate category within tangible assets referred to as oil and natural gas interests.

Development and production costs:

Items of property, plant and equipment, which include oil and gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development and production assets are grouped into CGUs for impairment testing. When significant parts of an item of property, plant and equipment, including oil and natural gas interests, have different useful lives they are accounted for as separate items (major components).

Gains and losses on disposal of property, plant and equipment, property swaps and farm-outs, are determined by comparing the proceeds or fair value of the asset received or given up with the carrying amount of property, plant and equipment and are recognized in profit or loss.

(ii) Subsequent costs:

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing on or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as operating costs as incurred.

(iii) Depletion and depreciation:

The net carrying value of development or production assets is depleted using the unit of production method by reference to the ratio of production in the year to the related proven and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Relative volumes of reserves and production are converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually.

The estimated useful lives for certain production assets for the current and comparative years are as follows:

Gas processing plants	Unit of production
Pipeline facilities	Unit of production
Turnaround and workover costs	2 years straight line

For other assets, depreciation is recognized in profit or loss on a straight-line basis over the estimated useful lives of each part of an item of property, plant and equipment. Assets that are subject to finance leases are depreciated over the shorter of the lease term and their useful lives, unless it is reasonably certain that the Company will obtain ownership by the end of the lease term. Land is not depreciated.

The estimated useful lives for other assets for the current and comparative years are as follows:

Office equipment	5 years

Depreciation methods, useful lives and residual values are reviewed at each reporting date.

(iv) Assets held for sale:

Non-current assets, or disposal groups consisting of assets and liabilities, are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is met when the sale is highly probable and the asset is available for immediate sale in its present condition.

Non-current assets classified as held for sale are measured at the lower of the carrying amount and fair value less costs to sell, with impairments recognized in profit or loss in the period measured. Non-current assets and disposal groups held for sale are presented in current assets and liabilities on the statement of financial position.

(e) Leased assets:

Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases. Upon initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

Minimum lease payments made under finance leases are apportioned between finance expenses and the reduction of the outstanding liability. The finance expenses are allocated to each year during the lease term to produce a constant periodic rate of interest on the remaining balance of the liability. The Company does not currently hold any finance leases.

Other leases are operating leases, which are not recognized on the Company’s statement of financial position.

Payments made under operating leases are recognized in profit or loss on a straight-line basis over the term of the lease. Lease incentives received are recognized as an integral part of the total lease expense, over the term of the lease.

(f) Impairment:

(i) Financial assets:

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in profit or loss.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost, the reversal is recognized in profit or loss.

(ii) Non-financial assets:

The carrying amounts of the Company's non-financial assets, other than E&E assets and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. For goodwill, an impairment test is completed each year. E&E assets are assessed for impairment when they are reclassified to property, plant and equipment, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets or CGUs. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proven and probable reserves.

The goodwill acquired in an acquisition, for the purpose of impairment testing, is allocated to the CGUs that are expected to benefit from the synergies of the combination. E&E assets are allocated to related CGUs when they are assessed for impairment, both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to property, plant and equipment.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the unit (group of units) on a pro rata basis.

An impairment loss in respect of property, plant and equipment and E&E assets, recognized in prior years, is assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized. An impairment loss in respect of goodwill is not reversed.

(g) Share based payments:

The grant date fair value of restricted and performance units granted to employees is recognized as compensation expense, with a corresponding increase in contributed surplus over the vesting period. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of restricted and performance units that are expected to vest. A performance multiplier is estimated on the grant date for performance units and adjusted to reflect the number of performance units that are expected to vest.

(h) Provisions:

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

(i) Decommissioning obligations:

The Company's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of expenditure required to settle the present obligation at the statement of financial position date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as a finance cost whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

(i) Revenue:

Revenue from the sale of petroleum and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer which is usually when legal title passes to the external party.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

(j) Finance income and expenses:

Finance expense comprises interest expense on borrowings, accretion of the discount on provisions, accretion of deferred financing costs, impairment losses recognized on financial assets and corporate acquisition costs.

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. All other borrowing costs are recognized in profit or loss using the effective interest method. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Company's outstanding borrowings during the period.

Interest income is recognized as it accrues in profit or loss, using the effective interest method.

(k) Income tax:

Income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(l) Earnings per share:

Basic earnings per share is calculated by dividing the profit or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted earnings per share is determined by adjusting the profit or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as restricted and performance awards granted to employees.

(m) Flow-through shares:

The resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. On issuance, the premium received on the flow-through shares, being the difference in price over a common share with no tax attributes, is recognized on the statement of financial position. As expenditures are incurred the deferred tax liability associated with the renounced tax deductions are recognized through profit or loss along with a pro-rata portion of the deferred premium.

(n) Inventory:

The Company evaluates the carrying value of its inventory at the lower of cost and net realizable value. The net realizable value is estimated based on anticipated current market prices that the Company would expect to receive from the sale of its inventory.

(o) Critical accounting judgments and key sources of estimation uncertainty:

The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of these financial statements are outlined below.

Critical judgments in applying accounting policies:

The following are the critical judgments that management has made in the process of applying the Company's accounting policies and that have the most significant effect on the amounts recognized in these consolidated financial statements:

(i) Identification of CGUs

Crew's assets are aggregated into CGUs, for the purpose of calculating impairment, based on their ability to generate largely independent cash flows. By their nature, these estimates and assumptions are subject to measurement uncertainty and may impact the carrying value of the Company's assets in future periods.

(ii) Impairment of petroleum and natural gas assets

Judgments are required to assess when impairment indicators, or reversal indicators, exist and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future oil and natural gas prices, future costs, discount rates, market value of land and other relevant assumptions.

(iii) Exploration and evaluation assets

The application of the Company's accounting policy for exploration and evaluation assets requires management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found in assessing economic and technical feasibility.

(iv) Deferred income taxes

Judgments are made by management to determine the likelihood of whether deferred income tax assets at the end of the reporting period will be realized from future taxable earnings. To the extent that assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in profit or loss in the period in which the change occurs.

Key sources of estimation uncertainty:

The following are the key assumptions concerning the sources of estimation uncertainty at the end of the reporting period, that have a significant risk of causing adjustments to the carrying amounts of assets and liabilities.

(i) Reserves

The assessment of reported recoverable quantities of proved and probable reserves include estimates regarding production profile, commodity prices, exchange rates, remediation costs, timing and amount of future development costs, and production, transportation and marketing costs for future cash flows. It also requires interpretation of geological and geophysical models in anticipated recoveries. The economical, geological and technical factors used to estimate reserves may change from period to period. Changes in reported reserves can impact the carrying values of the Company's petroleum and natural gas properties and equipment, the calculation of depletion and depreciation, the provision for decommissioning obligations, and the recognition of deferred tax assets due to changes in expected future cash flows. The recoverable quantities of reserves and estimated cash flows from Crew's petroleum and natural gas interests are independently evaluated by reserve engineers at least annually.

The Company's petroleum and natural gas reserves represent the estimated quantities of petroleum, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be economically recoverable in future years from known reservoirs and which are considered commercially producible. Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon (i) a reasonable assessment of the future economics of such production; (ii) a reasonable expectation that there is a market for all or substantially all the expected petroleum and natural gas production; and (iii) evidence that the necessary production, transmission and transportation facilities are available or can be made available. Reserves may only be considered proven and probable if producibility is supported by either production or conclusive formation tests. Crew's petroleum and gas reserves are determined pursuant to Alberta Securities Commission National Instrument 51-101, Standard of Disclosures for Oil and Gas Activities.

(ii) Decommissioning obligations

The Company estimates future remediation costs of production facilities, wells and pipelines at different stages of development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires assumptions regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

(iii) Business combinations

In a business combination, management makes estimates of the fair value of assets acquired and liabilities assumed which includes assessing the value of oil and gas properties based upon the estimation of recoverable quantities of proven and probable reserves being acquired.

(iv) Share-based payments

All equity-settled, share-based awards issued by the Company are recorded at fair value. The fair value of restricted and performance awards are valued based on the closing stock price at grant date. In assessing the fair value of equity-based compensation, estimates have to be made regarding the performance multiplier for performance awards.

(v) Income taxes

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in profit or loss both in the period of change, which would include any impact on cumulative provisions, and in future periods. Deferred tax assets, if any, are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse.

(vi) Derivatives

The Company's estimate of the fair value of derivative financial instruments is dependent on estimate forward prices and volatility in those prices.

4. Determination of fair values:

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

(i) Property, plant and equipment and intangible exploration assets:

The fair value of property, plant and equipment recognized in an acquisition is based on market values. The market value of property, plant and equipment is the estimated amount for which property, plant and equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of oil and natural gas interests (included in property, plant and equipment) and intangible exploration assets is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions.

The market value of other items of property, plant and equipment is based on the quoted market prices for similar items.

(ii) Cash and cash equivalents, accounts receivable, accounts payable, bank loans and the senior unsecured notes:

The fair value of cash and cash equivalents, accounts receivable, accounts payable, bank loans and the senior unsecured notes are estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2017 and December 31, 2016, the fair value of accounts receivable and accounts payable approximated their carrying value due to their short term to maturity. Bank loans bear a floating rate of interest and the margins charged by the lenders are indicative of current credit spreads and therefore carrying value approximates fair value. The fair value of the senior unsecured notes fluctuates in response to changes in the market rates of interest payable on similar instruments. At December 31, 2017 and December 31, 2016, the carrying value of the unsecured notes approximated fair value.

(iii) Derivatives:

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 statement of financial position date, using the remaining contracted volumes and a credit adjusted interest rate. 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.

(iv) Restricted and performance awards:

The fair value of restricted and performance awards is measured at the grant date using the closing price of the common shares.

5. Future accounting policies:

The Company has reviewed the following new and revised accounting pronouncements that have been issued but are not yet effective and determined that the following may have an impact on the Company's financial statements:

(d) IFRS 15 Revenue from Contracts with Customers:

As of January 1, 2018, the Company will be required to adopt IFRS 15 Revenue from Contracts with Customers. The new standard replaces IAS 18 Revenue, IAS 11 Construction Contracts and related interpretations. The standard 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 standard is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with earlier adoption permitted.

Crew will adopt IFRS 15 using the modified retrospective approach on January 1, 2018. Based on the Company's review of contracts with customers and its assessment of various revenue streams, the Company has concluded that the adoption of IFRS 15 will not have a material impact on Crew's net income (loss) and financial position. However, Crew will expand the disclosures in the notes to its consolidated financial statements as prescribed by IFRS 15, including disclosing the Company's disaggregated revenue streams by product type.

(e) IFRS 9 Financial Instruments:

As of January 1, 2018, the Company will be required to adopt IFRS 9 Financial Instruments, which replaces IAS 39 Financial Instruments: Recognition and Measurement. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has two classification categories: amortized cost and fair value. In addition, updates have also been applied surrounding hedge accounting requirements which are now more aligned with an entity's risk management activities. The impact of this standard has been evaluated and is expected to have no material impact on the Company's consolidated financial statements.

(f) IFRS 16 Leases:

As of January 1, 2019, the Company will be required to adopt IFRS 16 Leases, which will replace IFRS 17 Leases and IFRIC 4 Determining Whether an Arrangement Contains a Lease. For lessees applying the new standard, a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for all leases. As of December 31, 2017, Crew is in the process of identifying and gathering contracts impacted by the new standard. Although the impact is still being determined, it is expected that adoption of IFRS 16 will have a material impact on the Company's consolidated financial statements.

6. Financial risk management:

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities such as:

- credit risk;
- market risk; and
- liquidity risk.

This note presents information about the Company's exposure to each of the above risks, the Company's objectives, policies and processes for measuring and managing risk and the Company's management of capital. Further quantitative disclosures are included throughout these financial statements.

The Board of Directors oversees management's establishment and execution of the Company's risk management framework. Management has implemented and monitors compliance with risk management policies. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

(a) Credit risk:

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations and arises principally from the Company's receivables from partners within jointly owned assets and operations, oil and natural gas marketers and counterparties to derivative financial assets. The maximum exposure to credit risk at year-end is as follows:

	December 31, 2017	December 31, 2016
Trade and other receivables	**$ 40,930**	$ 39,588
Derivative financial assets	**1,666**	-
	$ 42,596	$ 39,588

Trade and other receivables:

Substantially all of the Company's petroleum and natural gas production is marketed under standard industry terms. Receivables from petroleum and natural gas marketers are normally collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large credit worthy purchasers and to sell through multiple purchasers. During 2017, the Company had four customers that individually accounted for 10% or more of the Company's total revenues. The Company historically has not experienced any collection issues with its petroleum and natural gas marketers. Receivables from partners within jointly owned assets and operations are typically collected within one to three months of the bill being issued to the partner. The Company attempts to mitigate the risk from these receivables by obtaining partner approval of significant capital expenditures prior to the expenditure. However, the receivables are from participants in the petroleum and natural gas sector and collection of the outstanding balances can be impacted by industry factors such as commodity price fluctuations, limited capital availability and unsuccessful drilling programs. The Company does not typically obtain collateral from petroleum and natural gas marketers or joint asset partners; however the Company can cash call for major projects and does have the ability, in some cases, to withhold production from joint asset partners in the event of non-payment.

Derivative financial assets:

Derivative financial assets can consist of commodity, interest rate and foreign exchange contracts used to manage the Company's exposure to fluctuations in commodity prices, interest rates and the exchange rate between United States and Canadian dollars. The Company manages the credit risk exposure related to derivative financial assets by selecting investment grade counterparties and by not entering into contracts for trading or speculative purposes.

The carrying amount of accounts receivable and derivative financial assets, when outstanding, represents the maximum credit exposure. As at December 31, 2017, the Company's receivables consisted of $27.2 million (December 31, 2016 - $24.6 million) of receivables from petroleum and natural gas marketers, of which all have been subsequently collected, $3.8 million (December 31, 2016 - $2.0 million) from partners within jointly owned assets and operations of which $1.7 million has been subsequently collected, and $9.9 million (December 31, 2016 - $13.0 million) of deposits, prepaids and other accounts receivable, of which $1.5 million has subsequently been collected. The Company does not consider any receivables to be past due.

(b) Market risk:

Market risk is the risk that changes in market conditions, such as commodity prices, foreign exchange rates and interest rates, will affect the Company's cash flow, income or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while maximizing the Company's return.

The Company utilizes both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted in accordance with the Company's risk management policy that has been approved by the Board of Directors.

Foreign currency exchange rate risk:

Foreign currency exchange rate risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. The majority of the Company's petroleum and natural gas sales are conducted in Canada and are denominated in Canadian dollars however, Canadian commodity prices are influenced by fluctuations in the Canadian to U.S. dollar exchange rate.

Interest rate risk:

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its bank loan which bears a floating rate of interest. Average bank debt outstanding during the year ending December 31, 2017 was $26.8 million (December 31, 2016 - $89.9 million). For the year ended December 31, 2017, a 1.0 percent change to the effective interest rate would have a $0.3 million impact on net income (December 31, 2016 - $0.8 million). The interest rate on the senior unsecured notes is fixed and is not subject to interest rate risk.

Commodity price risk:

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by not only the relationship between the Canadian and United States dollar, but also North American and global economic events that dictate the levels of supply and demand. The Company has attempted to mitigate a portion of the commodity price risk through the use of various financial derivative and physical delivery sales contracts as outlined below. The Company's policy is to enter into commodity price contracts when considered appropriate to a maximum of 50% of forecasted gross production volumes for a period of not more than two years. Any contracts for volumes greater than 50% of forecasted gross production or extending beyond two years require approval from the Board of Directors.

Derivative assets:

Derivatives are recorded on the statement of financial position at fair value at each reporting period with the change in fair value being recognized as an unrealized gain or loss on the statement of income (loss).

The Company's derivatives are measured in accordance with a three level hierarchy. The hierarchy groups financial assets and liabilities into three levels based on the significance of inputs used in measuring the fair value of the financial assets and liabilities. The fair value hierarchy has the following levels:

a) Level 1: fair value is based on quoted prices (unadjusted) in active markets for identical assets or liabilities;

b) Level 2: fair value is based on inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (ie. as prices) or indirectly (ie. derived from prices); and

c) Level 3: fair value is based on inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The Company's derivative contracts are valued using Level 2 of the hierarchy.

At December 31, 2017, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value
Gas	5,000 gj/day	January 1, 2018 - December 31, 2018	AECO C Monthly Index	$3.00/gj	Call	$ (20)
Gas	2,500 gj/day	January 1, 2018 - December 31, 2018	AECO C Daily Index	$2.62/gj	Swap	956
Gas	17,500 mmbtu/day	January 1, 2018 - December 31, 2018	Chicago Citygate	$3.64/mmbtu	Swap	1,632
Gas	5,000 mmbtu/day	January 1, 2018 - December 31, 2018	US$ Nymex Henry Hub	$3.05 US/mmbtu	Swap	474
Propane	400 bbl/day	January 1, 2018 - December 31, 2018	US$ Conway OPIS	$0.79 US/gal	Swap	(181)
Oil	1,500 bbl/day	January 1, 2018 - December 31, 2018	CDN$ WTI	$70.94/bbl	Swap	(1,856)
Oil	250 bbl/day	January 1, 2018 - December 31, 2018	CDN$ WTI	$60.00 - $69.65/bbl	Collar(1)	(520)
Oil	250 bbl/day	January 1, 2018 - December 31, 2018	CDN$ WTI	$69.00 - $74.25/bbl	Collar(2)	(138)
Total						**$ 347**

(1) The referenced contract is a costless collar whereby the Company receives $60/bbl when the market price is below $60/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/bbl when the market price is below $69/bbl, and receives $74.25/bbl when the market price is above $74.25/bbl.

As at December 31, 2017, a 10% change in future commodity prices applied against these contracts would have a $4.8 million impact on net income.

Subsequent to December 31, 2017, the Company entered into the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Oil	250 bbl/day	January 1, 2018 - December 31, 2018	CDN$ WTI	$76.38/bbl	Swap
Gas	2,500 mmbtu/day	February 1, 2018 - December 31, 2018	Chicago Citygate	$3.41/mmbtu	Swap
Gas	2,500 mmbtu/day	April 1, 2018 - October 31, 2018	Chicago Citygate	$3.06/mmbtu	Swap
Oil	500 bbl/day	January 1, 2019 - December 31, 2019	CDN$ WTI	$70.90/bbl	Swap

(c) Liquidity risk:

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with the financial liabilities. The Company's financial liabilities consist of accounts payable, financial instruments, the bank loan and the senior unsecured notes. Accounts payable consists of invoices payable to trade suppliers for office, field operating activities and capital expenditures. The Company processes invoices within a normal payment period. Accounts payable and financial instruments have contractual maturities of less than one year. The Company maintains a revolving credit facility, as outlined in note 10, which is subject to annual renewal by the lenders and has a contractual maturity in 2018. In addition, the Company issued $300 million in senior unsecured notes in 2017 that are scheduled to mature in 2024, as discussed in note 11.

The Company maintains and monitors cash flow which is used to partially finance operating and capital expenditures. The Company does not pay dividends.

Capital management:

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

The Company considers its capital structure to include working capital, long-term debt (including the bank loan and senior unsecured notes) and shareholders' equity. Crew's primary capital management objective is to maintain a strong financial position in order to continue to fund the future growth of the Company. Crew monitors its capital structure and makes adjustments on an ongoing basis in order to maintain the flexibility needed to achieve the Company's long-term objectives. To manage its capital structure, the Company may adjust capital spending, hedge future revenue and costs, 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 at 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 December 31, 2017, the Company's ratio of net debt to annualized adjusted funds flow was 2.5 to 1 (December 31, 2016 – 2.2 to 1). As commodity prices remain volatile, including recent weakness in Canadian natural gas pricing, the Company will be cautious in 2018 with plans to limit capital expenditures to approximate adjusted funds flow. With only 9% 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 closely 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.

	December 31, 2017	December 31, 2016
Net debt:		
Accounts receivable	**$ 40,930**	$ 39,588
Accounts payable and accrued liabilities	**(70,073)**	(49,594)
Working capital deficiency	**$ (29,143)**	$ (10,006)
Bank loan	**(21,977)**	(88,036)
Senior unsecured notes	**(293,862)**	(147,329)
Net debt	**$ (344,982)**	$ (245,371)
Fourth quarter annualized adjusted funds flow:		
Cash provided by operating activities	**$ 43,484**	$ 19,900
Decommissioning obligations settled	**29**	763
Change in non-cash working capital	**(9,165)**	7,394
Accretion of deferred financing charges	**(261)**	(178)
Fourth quarter adjusted funds flow	**$ 34,087**	$ 27,879
Annualized	**$ 136,348**	$ 111,516
Net debt to annualized adjusted funds flow	**2.5**	2.2

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 10).

7. Other long-term assets:

Other long-term assets includes pipe inventory for the construction of a pipeline from the West Septimus facility through the Company's Groundbirch acreage, connecting into the TransCanada Pipeline Saturn meter station. Construction of this pipeline is planned to commence and be completed during 2018.

8. Property, plant and equipment:

Cost or deemed cost	Total
Balance, January 1, 2016	$ 2,061,858
Additions	108,202
Acquisitions	4,097
Divestitures	(254)
Change in decommissioning obligations	(320)
Capitalized share-based compensation	7,696
Balance, December 31, 2016	$ 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**

Accumulated depletion and depreciation	Total
Balance, January 1, 2016	$ 851,992
Depletion and depreciation expense	85,403
Impairment (net)	44,432
Balance, December 31, 2016	$ 981,827
Depletion and depreciation expense	75,131
Divestitures	(79)
Impairment (net)	16,710
Balance, December 31, 2017	**$ 1,073,589**

Net book value	Total
Balance, December 31, 2017	**$ 1,340,736**
Balance, December 31, 2016	$ 1,199,452

The calculation of depletion for the three months ended December 31, 2017 included estimated future development costs of $1,764.2 million (December 31, 2016 - $1,603.2 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $70.0 million (December 31, 2016 - $67.3 million) and undeveloped land of $161.6 million (December 31, 2016 - $182.3 million) related to future development acreage, with no associated reserves.

During the fourth quarter of 2017, the Company disposed of non-core assets for cash proceeds of $1.7 million. The assets consisted of petroleum and natural gas properties and undeveloped land with a net book value of $9.3 million and associated decommissioning obligations of $1.2 million, resulting in a loss of $6.4 million on closing of the disposition.

During the third quarter of 2017, the Company entered into a swap of petroleum and natural gas properties and undeveloped land with a total net book value of $1.1 million and associated decommissioning obligations of $0.1 million for land with a fair value of $3.0 million and $0.1 million cash, resulting in a gain of $2.1 million.

During the second quarter of 2017, the Company disposed of non-core assets in northeast British Columbia for cash proceeds of $49.1 million. The assets consisted of undeveloped land and had a net book value of $11.4 million and associated decommissioning obligations of $0.2 million, resulting in a gain of $37.9 million on closing of the disposition.

9. Impairment:

	Year Ended December 31, 2017	Year Ended December 31, 2016
Impairment losses:		
PP&E	**$ 16,710**	$ 44,432
	$ 16,710	$ 44,432

Assessment:

At December 31, 2017 and 2016, the Company completed an assessment of the indicators of impairment. As a result of indicators being present, the Company tested the northeast British Columbia CGU for impairment at December 31, 2017, and tested the Lloydminster CGU for impairment at December 31, 2016. For the Lloydminster CGU, the Company also identified indicators of impairment at Q2 2017.

For the purpose of impairment testing, the recoverable amount of the Company's CGUs is the greater of its value in use and its fair value less costs to sell. Value in use is generally the future cash flows expected to be derived from production of proven and probable reserves estimated by the Company's third party reserve evaluators and the internally estimated future cash flows of undeveloped lands. At December 31, 2017, the Company used value in use, discounted at pre-tax rates between 10% and 20% dependent on the risk profile of the reserve category. At December 31, 2016 and Q2 2017, the fair value less cost to sell was determined to be the appropriate measure.

Impairment reversals are recognized to the extent that impairment had been previously recorded, but are limited to the net book value that would exist had the original impairment never been recorded, including estimates for depletion.

(a) Results of 2017 assessment:

The following estimates were used in determining whether an impairment or reversal to the carrying value of the CGU existed at December 31, 2017:

	WTI Oil (US$/bbl)	WCS ($CDN/bbl)	AECO Gas ($CDN/mmbtu)	$US/$CDN
2018	55.00	51.05	2.85	0.79
2019	65.00	59.61	3.11	0.82
2020	70.00	64.94	3.65	0.85
2021	73.00	68.43	3.80	0.85
2022	74.46	69.80	3.95	0.85
2023	75.95	71.20	4.05	0.85
2024	77.47	72.62	4.15	0.85
2025	79.02	74.07	4.25	0.85
2026	80.60	75.55	4.36	0.85
2027	82.21	77.06	4.46	0.85
2028	83.85	78.61	4.57	0.85
Remainder	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.85 thereafter

At December 31, 2017, due to weakness in the Canadian natural gas price environment, the Company tested its northeast British Columbia CGU for impairment. It was determined that the recoverable amount of the northeast British Columbia CGU exceeded its carrying value and an impairment charge was not recorded.

In the second quarter of 2017, due to the continuing decline in the Canadian heavy oil price environment, reduced future heavy oil development plans and the prevailing heavy oil transaction market, the Company tested its Lloydminster CGU for impairment using the fair value less cost to sell measure. It was determined that the carrying value of the Lloydminster heavy oil CGU exceeded its fair value and a $16.7 million impairment charge was recorded.

(b) Results of 2016 assessment:

The following estimates were used in determining whether an impairment or reversal to the carrying value of the CGUs existed at December 31, 2016:

	WTI Oil (US$/bbl)	WCS ($CDN/bbl)	AECO Gas ($CDN/mmbtu)	$US/$CDN
2017	55.00	53.12	3.44	0.78
2018	65.00	61.85	3.27	0.82
2019	70.00	64.94	3.22	0.85
2020	71.40	66.93	3.91	0.85
2021	72.83	68.27	4.00	0.85
2022	74.28	69.64	4.10	0.85
2023	75.77	71.03	4.19	0.85
2024	77.29	72.45	4.29	0.85
2025	78.83	73.90	4.40	0.85
2026	80.41	75.38	4.50	0.85
2027	82.02	76.88	4.61	0.85
Remainder	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.85 thereafter

During 2016, due to the ongoing reduced heavy oil price environment combined with the Company's future heavy oil development plans in the area and the existing heavy oil transaction market, the Company tested its Lloydminster CGU for impairment. It was determined that the carrying value of the Lloydminster heavy oil CGU exceeded its recoverable amount and a $44.4 million impairment charge was recorded.

10. Bank loan:

As at December 31, 2017, 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 6, 2018. 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 June 6, 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 0.375 percent to 0.875 percent depending upon the debt to EBITDA ratio. As at December 31, 2017, 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 0.375 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 December 31, 2017, the Company had issued letters of credit totaling $7.7 million (December 31, 2016 - $13.6 million). The effective interest rate on the Company's borrowings under its Facility for the year ended December 31, 2017 was 4.5% (December 31, 2016 – 4.8%), which includes standby fees on the undrawn amounts of the Facility.

11. 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%

(2) 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 16).

At December 31, 2017, the carrying value of the 2024 Notes was net of deferred financing costs of $6.1 million.

12. Decommissioning obligations:

	As at December 31, 2017	As at December 31, 2016
Decommissioning obligations, beginning of year	**$ 85,859**	$ 85,822
Obligations incurred	**4,557**	1,344
Obligations acquired	**-**	4,061
Obligations settled	**(513)**	(1,411)
Obligations divested	**(1,765)**	-
Change in estimated future cash outflows	**(1,704)**	(5,725)
Accretion of decommissioning obligations	**1,934**	1,768
Decommissioning obligations, end of year	**$ 88,368**	$ 85,859

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 $88.4 million as at December 31, 2017 (December 31, 2016 - $85.9 million) based on an inflation adjusted undiscounted total future liability of $118.9 million (December 31, 2016 - $113.4 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, 2016 – 2%). The discount factor, being the risk-free rate related to the liability, is 2.22% (December 31, 2016 – 2.21%). The $1.7 million (December 31, 2016 - $5.7 million) change in estimated future cash outflows is a result of a change in the discount factor and estimated future obligations.

13. Share capital:

At December 31, 2017, 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 will terminate on May 24, 2018 or such earlier time as the maximum number of common shares are purchased pursuant to the NCIB or the NCIB is terminated at the option of the Company. 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.

In 2016, the Company closed a non-brokered private placement offering of 1,845,100 common shares at a price of $8.13 per share for gross proceeds of $15.0 million. The shares were issued on a flow-through basis, with an issuance premium to the common share trading value at the time of issuance of $1.4 million. Pursuant to the provisions of the Income Tax Act (Canada) and the terms of the offering, the Company committed to renounce to the subscribers Canadian Development Expenses incurred by the Company of $7.5 million by each of January 31, 2017 and March 31, 2017. The Company renounced the Canadian Development Expenses such that the full proceeds were deductible against the subscribers' income in 2017. The Company incurred the entire $15.0 million in qualifying expenditures under this flow-through share offering during 2017.

Stock Option Plan:

The Company had a stock option program that entitles officers, directors, employees and certain consultants to purchase shares in the Company. Options were granted at the market price of the shares at the date of grant, have a four year term and vested over three years. The Company elected not to seek shareholder approval for the requisite three-year renewal of its option program at its 2014 annual meeting and, as a result, is no longer eligible to issue new options without shareholder approval. Previously issued options will remain outstanding until exercised or their expiry. All outstanding options at December 31, 2017 are exercisable and will expire in the first quarter of 2018, if not exercised.

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

	Number of options	Weighted average exercise price
Balance January 1, 2016	3,783	$ 6.51
Exercised	(1,903)	5.73
Forfeited	(113)	6.99
Expired	(337)	8.32
Balance December 31, 2016	1,430	$ 7.08
Forfeited	(3)	7.17
Expired	(1,425)	7.08
Balance December 31, 2017	**2**	**$ 7.25**

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. For the year ended December 31, 2017, the fair value of awards granted was calculated using an estimated forfeiture rate of 8% (December 31, 2016 – 12%). The weighted average fair value of awards granted for the year ended December 31, 2017 was $5.11 (December 31, 2016 - $3.88). 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. Through the vesting of 808,000 restricted awards and 1,316,000 performance awards, when taking into account the earned multipliers for performance awards, 3,440,000 common shares of the Company were issued for the year ended December 31, 2017. On the vesting dates, the Company has the option of settling the award value in cash or common shares of the Company. To date, the Company has not settled any awards with cash.

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

	Number of restricted awards	Number of performance awards
Balance January 1, 2016	1,087	1,546
Granted	1,209	1,862
Vested	(492)	(759)
Forfeited	(105)	(112)
Balance December 31, 2016	1,699	2,537
Granted	902	1,309
Vested	(808)	(1,316)
Forfeited	(177)	(309)
Balance December 31, 2017	**1,616**	**2,221**

Per share amounts:

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average shares outstanding for the year ended December 31, 2017 was 148,603,000 (December 31, 2016 – 143,087,000).

In computing diluted earnings per share for the year ended December 31, 2017, 2,467,000 (December 31, 2016 – nil) shares were added to the basic weighted average common shares outstanding to account for the dilution of stock options and restricted and performance awards. There were 2,000 (December 31, 2016 – 1,430,000) stock options and 2,316,000 (December 31, 2016 – 4,236,000) restricted and performance awards that were not included in the diluted earnings per share calculation because they were anti-dilutive.

The volume weighted average trading price of the Company's common shares was $4.63 during the year ended December 31, 2017 (December 31, 2016 - $5.48).

14. Income taxes:

(a) Deferred income tax recovery:

The deferred income tax recovery in the financial statements differs from the result which would have been obtained by applying the combined federal and provincial income tax rate to the Company's income (loss) before income taxes. This difference results from the following items:

		Year ended December 31, 2017		Year ended December 31, 2016
Income (loss) before income taxes	**$**	**50,600**	$	(85,770)
Combined federal and provincial income tax rate		**26.6%**		26.6%
Computed "expected" income tax expense (recovery)	**$**	**13,460**	$	(22,806)
Increase (decrease) in income taxes resulting from:				
Change in income tax rates		**832**		-
Flow-through share renunciation		**3,989**		-
Non-deductible expenses and other		**(667)**		1,962
	$	**17,614**	$	(20,844)
Premium on flow-through shares		**(1,419)**		-
Deferred income tax expense (recovery)	**$**	**16,195**	$	(20,844)

(b) Deferred income tax liability:

The components of the Company's deferred income tax liability are as follows:

		December 31, 2017		December 31, 2016
Deferred tax liabilities:				
Property, plant and equipment	**$**	**132,749**	$	112,573
Derivative financial instruments		**94**		-
Other		**2,852**		(445)
Deferred tax assets:				
Decommissioning obligations	**$**	**(23,859)**	$	(22,907)
Non-capital losses		**(69,409)**		(58,324)
Derivative financial instruments		**-**		(5,173)
Deferred income tax liability	**$**	**42,427**	$	25,724

The following tables provide a continuity of the deferred income tax liability:

	January 1, 2017	Recognized in equity	Recognized in other	Recognized in profit or loss	December 31, 2017
Property, plant and equipment	$ 112,573	$ -	$ 1,419	$ 18,757	$ 132,749
Decommissioning obligations	(22,907)	-	-	(952)	(23,859)
Derivative financial instruments	(5,173)	-	-	5,267	94
Non-capital losses	(58,324)	-	-	(11,085)	(69,409)
Other	(445)	(911)	-	4,208	2,852
	$ 25,724	**$ (911)**	**$ 1,419**	**$ 16,195**	**$ 42,427**

	January 1, 2016	Recognized in equity	Recognized in other	Recognized in profit or loss	December 31, 2016
Property, plant and equipment	$ 74,036	$ -	$ -	$ 38,537	$ 112,573
Decommissioning obligations	(22,595)	-	-	(312)	(22,907)
Derivative financial instruments	1,461	-	-	(6,634)	(5,173)
Non-capital losses	(5,512)	-	-	(52,812)	(58,324)
Other	(801)	(21)	-	377	(445)
	$ 46,589	**$ (21)**	**$ -**	**$ (20,844)**	**$ 25,724**

The Company's assets have an approximate tax basis of $1,080 million at December 31, 2017 (December 31, 2016 - $958 million) available for deduction against future taxable income. The following table summarizes the tax pools:

	December 31, 2017	December 31, 2016
Cumulative Canadian Exploration Expense	**$ 290,400**	$ 280,500
Cumulative Canadian Development Expense	**276,000**	276,700
Undepreciated Capital Costs	**234,800**	178,300
Non-capital losses	**257,100**	218,600
Share issue costs	**7,800**	4,300
Other	**13,900**	-
Estimated tax basis	**$ 1,080,000**	$ 958,400

Non-capital losses will begin expiring in 2028. The estimated income tax pools for 2017 have been reduced by the estimated deferred partnership income for 2017.

15. Other income:

In 2017, the Company recognized $1.0 million as income, representing the receipt of a non-refundable deposit from a third party for a non-core property disposition that failed to close.

16. Financing:

	Year ended December 31, 2017	Year ended December 31, 2016
Interest expense	**$ 20,961**	$ 16,904
Accretion of deferred financing costs	**968**	650
Accretion of decommissioning obligations	**1,934**	1,768
Premium paid on redemption of 2020 Notes (note 11)	**6,282**	-
Deferred financing costs expensed on 2020 Notes (note 11)	**2,510**	-
	$ 32,655	$ 19,322

17. Personnel expenses:

The aggregate payroll expense of key personnel was as follows:

	Year ended December 31, 2017	Year ended December 31, 2016
Short-term benefits	**$ 3,136**	$ 3,872
Long-term benefits	**8,837**	8,518
	$ 11,973	$ 12,390

Crew has determined that its key personnel include both officers and directors. Short-term benefits are comprised of salaries and directors fees, annual bonuses and other benefits. Long-term benefits include share-based compensation expense from share awards under Crew's long-term incentive plans. Short-term employee benefits and share-based compensation include the capitalized and non-capitalized portion of these expenditures recorded in the financial statements during the respective periods.

18. Supplemental cash flow information:

Changes in non-cash working capital is comprised of:

	Year ended December 31, 2017	Year ended December 31, 2016
Changes in non-cash working capital:		
Accounts receivable	**$ (1,342)**	$ (12,891)
Accounts payable and accrued liabilities	**20,479**	12,160
	$ 19,137	$ (731)
Operating activities	**$ 8,706**	$ (435)
Investing activities	**10,431**	(296)
	$ 19,137	$ (731)
Interest paid	**$ (16,701)**	$ (15,366)

19. Commitments:

	Total	2018	2019	2020	2021	2022	Thereafter
Operating leases	$ 3,917	$ 1,175	$ 1,175	$ 1,175	$ 392	$ -	$ -
Firm transportation agreements	271,873	44,004	47,908	47,023	24,057	23,881	85,000
Firm processing agreement	129,827	17,634	17,634	16,337	12,354	12,354	53,514
Total	**$ 405,617**	**$62,813**	**$66,717**	**$64,535**	**$36,803**	**$36,235**	**$ 138,514**

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

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
Senior Vice President and Chief Operating Officer

Ken Truscott
Senior Vice President, Business Development & Land

Jamie L. Bowman
Vice President, Marketing & Originations

Kurtis Fischer
Vice President, Business Development

Paul Dever
Vice President, Government & Stakeholder Relations

Kevin G. Evers, P. Geol.
Vice President, Geosciences

Mark Miller
Vice President, Land and Negotiations

BOARD OF DIRECTORS

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Chairman Independent Director

Jeffery E. Errico,
Lead Director Independent Director

Dennis L. Nerland
Independent Director

Dale O. Shwed
President and Chief Executive Officer, 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