MANAGEMENT'S DISCUSSION AND ANALYSIS

FINANCIAL & OPERATING HIGHLIGHTS

Financial ($ thousands, except per share amounts)	**Year ended** **December 31, 2019**	Year ended December 31, 2018
Petroleum and natural gas sales	**193,532**	218,385
Adjusted funds flow (1)	**81,034**	91,996
Per share -basic	**0.53**	0.61
-diluted	**0.53**	0.61
Net income	**12,071**	12,799
Per share -basic	**0.08**	0.08
-diluted	**0.08**	0.08
Exploration and development expenditures	**114,094**	103,219
Property acquisitions (net of dispositions)	**(19,084)**	(9,806)
Net capital expenditures	**95,010**	93,413
Capital structure ($ thousands)	**As at** **December 31, 2019**	As at December 31, 2018
Working capital surplus (2)	**(149)**	(11,984)
Bank loan	**52,136**	59,904
	51,987	47,920
Senior unsecured notes	**295,868**	294,885
Net debt	**347,855**	342,805
Common shares outstanding (thousands)	**151,534**	151,730

Operations	**Year ended** **December 31, 2019**	Year ended December 31, 2018
Daily production		
Light crude oil (bbl/d)	**216**	276
Heavy crude oil (bbl/d)	**1,639**	1,782
Natural gas liquids (bbl/d)	**2,056**	1,761
Condensate (bbl/d)	**2,693**	2,380
Natural gas (mcf/d)	**97,398**	106,116
Oil equivalent (boe/d @ 6:1)	**22,837**	23,885
Average prices (3)		
Light crude oil ($/bbl)	**63.24**	65.32
Heavy crude oil ($/bbl)	**50.65**	39.27
Natural gas liquids ($/bbl)	**6.78**	23.18
Condensate ($/bbl)	**64.40**	72.22
Natural gas ($/mcf)	**2.53**	2.80
Oil equivalent ($/boe)	**23.22**	25.05
Netback ($/boe)		
Operating netback (4)	**14.05**	14.49
G&A	**(1.40)**	(1.39)
Financing costs on long-term debt	**(2.94)**	(2.67)
Other income	**-**	0.11
Funds from operations netback (4)	**9.71**	10.54
Drilling activity		
Gross wells	**8**	14
Working interest wells	**8**	14
Success rate, net wells	**100%**	100%

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 surplus includes accounts receivable and net assets held for sale, less accounts payable and accrued liabilities. Refer to the section entitled "Non-IFRS Measures" contained within this MD&A.

(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, marketing income, less royalties, net 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. Refer to the section entitled "Non-IFRS Measures" contained within this MD&A.

(5) Throughout this MD&A, other natural gas liquids or ngls comprise all natural gas liquids as defined by NI 51-101, other than condensate which is disclosed desperately.

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 (“NE BC”), 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 consolidated 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, 2019 and 2018. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”). All figures provided herein and in the December 31, 2019 audited consolidated financial statements are reported in Canadian dollars (“CDN”). This MD&A is dated March 10, 2020.

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, including the Company’s 2020 exploration and development program (including guidance), timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, production estimates including 2020 average production forecast, 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 potential impact of possible 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). The internal projections, expectations or beliefs contained in this MD&A are based on the 2020 capital budget which is subject to change in light of ongoing results, prevailing economic circumstances, commodity prices, and industry conditions and regulations. Accordingly, readers are cautioned that events or circumstances could cause results to defer materially from those predicted. 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 crude oil, condensate, other natural gas liquids ("ngl") 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

Throughout this MD&A, the Company uses certain measures to analyze operational and financial performance. These non-IFRS measures do not have any standardized meaning prescribed under IFRS and therefore, may not be calculated in a similar fashion nor comparable to similar measures presented by other entities. Management believes that the presentation of these non-IFRS measures provides useful information to shareholders and investors as the measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis.

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 maintain production at current levels and fund future growth through capital investment and to service and repay debt. Management believes that such measures provide an insightful assessment of the Company's operations on a continuing basis by eliminating certain non-cash charges and actual settlements of decommissioning obligations, the timing of which is discretionary. 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, 2019**	Three months ended December 31, 2018	**Year ended December 31, 2019**	Year ended December 31, 2018
Cash provided by operating activities	**21,106**	22,878	**81,395**	89,162
Change in operating non-cash working capital	**(5,315)**	843	**(3,297)**	2,663
Accretion of deferred financing costs	**(246)**	(246)	**(983)**	(1,023)
Funds from operations	**15,545**	23,475	**77,115**	90,802
Decommissioning obligations settled	**541**	237	**3,919**	1,194
Adjusted funds flow	**16,086**	23,712	**81,034**	91,996

Operating Netback

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

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, 2019**	December 31, 2018
Current assets	**50,019**	78,904
Current liabilities	**(46,690)**	(58,538)
Derivative financial instruments	**(3,180)**	(8,382)
Working capital surplus	**149**	11,984

($ thousands)	**December 31, 2019**	December 31, 2018
Bank loan	**(52,136)**	(59,904)
Senior unsecured notes	**(295,868)**	(294,885)
Working capital surplus	**149**	11,984
Net debt	**(347,855)**	(342,805)

RESULTS OF OPERATIONS

Overview

In 2019, Crew continued to emphasize the drilling and completion of its higher-value, ultra condensate-rich ("UCR") West Septimus area, with a focus on increasing the Company's higher valued liquids production. Production during the year averaged 22,837 boe per day, a 4% decrease over 2018, with the Company successfully increasing condensate production by 13% year-over-year. Production was impacted by third party facility and pipeline outages, and voluntary shut-ins of sub-economic natural gas production. Crew's 2019 adjusted funds flow decreased 12% over 2018, primarily driven by weaker commodity prices and higher transportation costs. The weakness in North American commodity markets, in particular natural gas and ngl, has focused the Company on a disciplined capital expenditure program, emphasizing UCR condensate production, reducing operating costs and improving the efficiencies of our capital program.

During 2019, world crude oil prices underperformed 2018, with the average Canadian dollar denominated West Texas Intermediate ("WTI") price declining 10% year-over-year, as production growth from U.S. shale oil basins and slowing global oil demand growth was not fully offset by OPEC production curtailments. Benchmark prices for Canadian light crude oil and condensate also declined marginally, 10% and 11% respectively, as the Alberta Government's production curtailment initiatives stabilized prices late in 2018. Crew's 2019 light crude oil and condensate prices followed the benchmark trends with year-over-year prices decreasing 3% and 11%, respectively.

The Canadian heavy crude oil benchmark was also fairly stable throughout 2019, but the average annual price increased 18% over 2018 as the Alberta Government's curtailment initiatives and demand for Canadian heavy crude oil bolstered the 2019 average price. The Company's heavy crude oil price followed the benchmark trend, increasing 29% and exceeding the benchmark increase as the Company benefited from lower relative blending costs required to facilitate pipeline transportation.

U.S. shale basin production of natural gas and ngl had a more dramatic impact on North American prices for these products in 2019. The supply of ngl in North America increased through the latter part of 2018 and throughout 2019. This coupled with moderate weather through most of 2019, impacted domestic and international demand, which placed downward pressure on prices throughout the year. The benchmark prices for the two main components of Crew's ngl production, propane and butane, declined in Crew's primary market by 34% and 31% year-over-year, respectively. The impact of the downturn on the Company's ngl price in 2019 was a 71% drop as compared to 2018, reflective of the depressed North American market and enhanced by the fixed cost of ngl fractionation embedded in the net price Crew receives for the majority of its ngl production.

During 2019, Crew's natural gas sales were exposed to a diversified portfolio of North American pricing points, including approximately 70% to U.S. based Chicago City and NYMEX pricing and approximately 30% to Canadian based Alliance, AECO and Station 2 pricing. This U.S. focused weighting benefited Crew with strong U.S. pricing early in 2019, as low U.S. inventories and early cold weather supported prices through late 2018 and the early part of 2019. As the year progressed and large volumes of associated natural gas supply were brought on-stream, primarily from the Permian basin, U.S. natural gas prices at Crew's primary pricing points fell as the increasing supply overwhelmed North American demand. The price for Chicago City Gate natural gas, delivered to Crew's ATP delivery point, declined by 36% from the first quarter to the fourth quarter of 2019. Canadian natural gas markets also benefited from supportive winter weather and low inventory early in the year, but substantially lagged behind U.S. pricing as continued lack of egress and maintenance issues on major Canadian egress pipelines drove a wide differential between the two markets. In September, TC Energy announced a Temporary Service Protocol ("TSP") that stabilized spot and term AECO pricing by reconnecting the AECO storage and transportation markets during periods of planned TC mainline maintenance. The result was an immediate boost to Canadian prices and a corresponding reduction in the differential between Canadian and US prices. The average price for Canadian Benchmark AECO 5A natural gas was enhanced by 173% in the fourth quarter as compared to the third quarter, mainly the result of the TSP, which also helped to deliver a 17% increase in the average annual price for AECO 5A over 2018. With a large portion of Crew's 2019 natural gas portfolio linked to U.S. price points, Crew's average annual gas price followed the U.S. year-over-year declining price trend with a realized natural gas price decline of 10% as compared to 2018.

Crew's risk management program and market diversification strategy helped to mitigate a portion of the effects of the 2019 commodity price decline. The Company's hedging program realized a gain of $2.4 million in 2019 as compared to a $10.6 million loss in 2018. In addition, the Company's exposure to U.S. natural gas markets at Dawn and Malin were monetized throughout the year for a realized gain of $8.7 million as compared to $6.9 million in 2018.

Crew continues to work on lowering its controllable costs with net operating costs decreasing by 9% and gross general and administrative costs declining by 5%. Transportation costs increased 42% over 2018 as contracts that were entered into 2015 and 2016, to increase the Company's natural gas egress options, came into effect in March and November of 2019. This added capacity will provide the Company with flexibility to alter its natural gas exposure to the most profitable natural gas markets over the next two years and will replace more expensive natural gas egress options that expire in 2020 and 2021.

Capital expenditures during the year focused on the drilling and completion of wells primarily in the UCR area at West Septimus. Exploration and Development expenditures totaled $114 million and included $89 million directed to the drilling of 8 (8.0 net) wells, the completion of 13 (13.0 net) wells and the re-completion of 26 (25.0 net) heavy oil wells. Spending also included $14 million for facilities, equipment on well sites, gathering pipelines and infrastructure. During 2019 the Company also disposed of minor non-producing properties in north eastern British Columbia for proceeds of approximately $21 million. The 2019 program was highlighted by the drilling and completion of extended reach horizontal ("ERH") wells of approximately 3,000 meters in length in Crew's UCR area. These wells recognized significant efficiencies and improvements in recoveries relative to previous shorter-reach horizontal wells, with a 35% improvement in drilling costs per lateral length realized from 2016 to 2019. The ERH program can generate improved recoveries and superior economic returns with a smaller environmental footprint, lower operating costs and significantly lower development costs.

Throughout 2019, the Company worked towards the completion of a strategic debt and cost reduction initiative that resulted in the early 2020 announcement of the sale of a 22% net working interest in each of its two Greater Septimus gas processing facilities for $70 million. The transaction consists of two phases, the first of which closed in February, with the second expected to close in November 2020, with each phase to include the sale of an 11% working interest in the facilities for $35 million. In a separate transaction Crew has elected to exercise its option to acquire an approximate 16% interest in the same two facilities for approximately $12 million. Upon the closing of the transactions, the net proceeds will be used to reduce the Company's outstanding indebtedness under Crew's credit facility by a net $58 million.

Crew exited 2019 with net debt of $348 million, which is slightly higher than the $343 million outstanding at the end of 2018. Year-end net debt was comprised of approximately $52 million, or 22%, drawn on the Company's $235 million bank facility, positive working capital and the balance represented by the Company's outstanding senior unsecured notes. Crew's senior unsecured notes carry a favorable interest rate of 6.5%, do not mature until March 2024 and have no financial maintenance covenants. With no near-term maturities, a substantial reserve base and substantial liquidity, Crew is strongly positioned to manage its current debt position.

Production

	Three months ended December 31, 2019					Three months ended December 31, 2018				
	Oil (bbl/d)	**Condensate (bbl/d)**	**Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Oil (bbl/d)	Condensate (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
NE BC	**251**	**2,455**	**2,011**	**96,743**	**20,840**	260	2,446	1,832	97,239	20,745
Lloydminster	**1,600**	**-**	**-**	**33**	**1,606**	1,634	-	-	26	1,638
Total	**1,851**	**2,455**	**2,011**	**96,776**	**22,446**	1,894	2,446	1,832	97,265	22,383

Production during the fourth quarter of 2019 was consistent with the same period in 2018, as declines were replaced by a successful 2019 drilling program.

	Year ended December 31, 2019					Year ended December 31, 2018				
	Oil (bbl/d)	**Condensate (bbl/d)**	**Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Oil (bbl/d)	Condensate (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
NE BC	**216**	**2,693**	**2,056**	**97,351**	**21,190**	276	2,380	1,761	106,108	22,102
Lloydminster	**1,639**	**-**	**-**	**47**	**1,647**	1,782	-	-	8	1,783
Total	**1,855**	**2,693**	**2,056**	**97,398**	**22,837**	2,058	2,380	1,761	106,116	23,885

Production in 2019 decreased 4% when compared to the same period in 2018, as a result of natural production declines, voluntary shut-ins of sub-economic natural gas production, pipeline outages in the second quarter of 2019 and a third party facility outage in NE BC. These declines were partially offset by new production added from the completion of 12 wells in the UCR area at Greater Septimus during the year.

Petroleum and Natural Gas Sales

	Three months ended December 31, 2019	Three months ended December 31, 2018	**Year ended December 31, 2019**	Year ended December 31, 2018
Petroleum and natural gas sales ($ thousands)				
Light crude oil	**1,449**	912	**4,993**	6,582
Heavy crude oil	**6,591**	1,560	**30,310**	25,548
Natural gas liquids	**1,602**	2,478	**5,086**	14,900
Condensate	**14,291**	11,892	**63,290**	62,731
Natural gas	**21,008**	33,996	**89,853**	108,624
Total	**44,941**	50,838	**193,532**	218,385
Crew average prices				
Light crude oil ($/bbl)	**62.85**	38.18	**63.24**	65.32
Heavy crude oil ($/bbl)	**44.76**	10.38	**50.65**	39.27
Natural gas liquids ($/bbl)	**8.66**	14.71	**6.78**	23.18
Condensate ($/bbl)	**63.29**	52.85	**64.40**	72.22
Natural gas ($/mcf)	**2.36**	3.80	**2.53**	2.80
Oil equivalent ($/boe)	**21.76**	24.69	**23.22**	25.05
Benchmark pricing				
Light crude oil – WTI (Cdn $/bbl)	**75.19**	77.56	**75.69**	83.89
Heavy crude oil – WCS (Cdn $/bbl)	**54.18**	25.14	**58.79**	49.73
Condensate – Condensate @ Edmonton (Cdn $/bbl)	**70.40**	59.89	**70.37**	79.00
Natural Gas:				
AECO 5A daily index (Cdn $/mcf)	**2.48**	1.56	**1.76**	1.50
AECO 7A monthly index (Cdn $/mcf)	**2.34**	1.90	**1.62**	1.53
Alliance 5A (Cdn $/mcf)	**2.05**	2.71	**1.76**	2.17
Chicago City Gate at ATP (Cdn $/mcf)	**2.15**	4.13	**2.47**	3.20
Henry Hub Close (Cdn $/mcf)	**3.30**	4.81	**3.49**	4.00

In the fourth quarter of 2019, the Company's petroleum and natural gas sales decreased 12% as compared to the same period in 2018, as a result of a 12% decrease in realized wellhead pricing during the quarter.

The Company's fourth quarter realized light crude oil price increased 65% over the fourth quarter of 2018, while the Company's Cdn$ WTI benchmark decreased by 3% over the same period. This divergence was the result of depressed year end 2018 Canadian crude oil prices caused by high Canadian inventory levels brought on by a lack of Canadian egress and reduced demand due to extended fall 2018 refinery outages. Crew's fourth quarter heavy crude oil price increased 331% as compared to the same period last year, which is greater than the 116% increase in the Company's Western Canadian Select ("WCS") benchmark, as a result of a decrease in the relative cost of diluent utilized to blend with the heavy crude oil for transportation purposes. In addition, the Company had entered into short term sales contracts at weaker spot pricing to manage inventory levels during the fourth quarter of 2018. Crew's ngl realized price decreased 41% in the fourth quarter as compared to the same period in 2018, due to a decrease in the value of component pricing, in particular a large decline in realized propane and butane pricing. Crew's ngl pricing includes embedded cost to process the ngl product out of the Company's gas stream, which occurs after the custody transfer point. The Company's fourth quarter realized condensate price increased 20% over the same period in 2018, which approximated the 18% increase in the Condensate at Edmonton benchmark price.

Crew's realized natural gas price decreased by 38% in the fourth quarter of 2019, which is higher than the 29% decrease in the Company's natural gas sales portfolio weighted benchmark price. The variance was the result of Crew's gas sold at Chicago City Gate and Henry Hub prices being physically sold at the Alliance Trading Pool in Canada, where it is bought by third parties at a Chicago City Gate or Henry Hub market price less a fixed cost to transport the product to the end market. As the fixed cost is embedded in the price, the impact of a fluctuating price, as compared to benchmark pricing, is enhanced.

The Company's fourth quarter 2019 natural gas sales portfolio was based approximately on the following reference prices:

	Q4 2019	Q4 2018
AECO 5A	**7%**	13%
AECO 7A	**0%**	5%
Alliance 5A	**16%**	23%
Chicago City Gate at ATP	**58%**	45%
Henry Hub	**16%**	10%
Station 2	**3%**	3%
Sumas	**0%**	1%
Total	**100%**	100%

For 2019, the Company's petroleum and natural gas sales decreased 11% as compared to the prior year as a result of the 4% decrease in production combined with a 7% decrease in realized commodity pricing.

The Company's realized light crude oil price decreased 3% which was less than the WTI benchmark decrease of 10% in 2018, as a result of Crew's 2018 realized pricing being discounted by the previously mentioned 2018 wide differential between WTI and Canadian light sweet crude oil. Crew's heavy crude oil price for 2019 increased 29% as compared to the same period last year, which was greater than the 18% increase in the Company's WCS benchmark, as a result of a decrease in the cost of diluent utilized to blend with the heavy crude oil. For 2019, the Company's realized ngl price decreased 71% over to the same period in 2018, due to substantial decreases in component pricing at the Company's primary pricing point. The Company's realized condensate price decreased 11%, which was consistent with the 11% decrease in the Condensate at Edmonton benchmark price as compared to the prior year.

The Company's natural gas price decreased 10% over 2018, which is lower than the Company's natural gas sales portfolio weighted benchmark price decrease of 1%, due to the aforementioned fixed transportation costs embedded in the price received for a portion of the Company's natural gas sales.

Royalties

($ thousands, except per boe)	**Three months ended December 31, 2019**	Three months ended December 31, 2018	**Year ended December 31, 2019**	Year ended December 31, 2018
Royalties	**4,076**	3,433	**14,758**	15,123
Per boe	**1.97**	1.67	**1.77**	1.73
Percentage of petroleum and natural gas sales	**9.1%**	6.8%	**7.6%**	6.9%

For the fourth quarter of 2019 and year ended December 31, 2019, royalties per boe and as a percentage of petroleum and natural gas sales increased over the same periods in 2018, predominantly due to a one-time prior period gas cost allowance adjustment related to the Company's NE BC royalty assessments, partially offset by a decrease in realized wellhead pricing. The Company expects its royalties as a percentage of revenue to average between 5% and 7% in 2020.

Derivative Financial Instruments

Commodities

The Company enters into derivative and physical risk management contracts in order to reduce volatility in financial results 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 and comprehensive income;

($ thousands)	**Three months ended December 31, 2019**	Three months ended December 31, 2018	**Year ended December 31, 2019**	Year ended December 31, 2018
Realized gain (loss) on derivative financial instruments	**1,621**	(1,291)	**2,352**	(10,645)
Per boe	**0.78**	(0.63)	**0.28**	(1.22)
Unrealized (loss) gain on financial instruments	**(4,079)**	25,456	**(5,202)**	8,035

As at December 31, 2019, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value
Gas	12,500 mmbtu/day	January 1, 2020 - December 31, 2020	Chicago Citygate	$3.32/mmbtu	Swap	$ 2,300
Gas	2,500 mmbtu/day	January 1, 2020 - December 31, 2020	US$ Nymex Henry Hub	$2.48/mmbtu	Swap	199
Oil	250 bbl/day	January 1, 2020 - June 30, 2020	CDN$ WTI	$75.50/bbl	Swap	(102)
Oil	250 bbl/day	January 1, 2020 - June 30, 2020	USD$ WCS - WTI Differential	($17.25)/bbl	Swap	131
Oil	500 bbl/day	January 1, 2020 - June 30, 2020	CDN$ WCS	$52.25/bbl	Swap	(9)
Oil	1,000 bbl/day	January 1, 2020 - December 31, 2020	CDN$ WTI	$77.65/bbl	Swap	639
Oil	250 bbl/day	July 1, 2020 - December 31, 2020	CDN$ WCS	$51.50/bbl	Swap	5
Condensate	250 bbl/day	January 1, 2020 - March 31, 2020	USD$ C5+ Differential	$2.00/bbl	Swap	17
Total						**$ 3,180**

Subsequent to December 31, 2019, the Company entered into the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Oil	250 bbl/day	July 1, 2020 - September 30, 2020	USD$ WCS - WTI Differential	($16.00/bbl)	Swap
Oil	250 bbl/day	July 1, 2020 - December 31, 2020	CDN$ WTI	$76.00/bbl	Swap
Oil	250 bbl/day	July 1, 2020 - December 31, 2020	USD$ WCS - WTI Differential	($15.60/bbl)	Swap

Marketing Income

($ thousands, except per boe)	**Three months ended December 31, 2019**	Three months ended December 31, 2018	**Year ended December 31, 2019**	Year ended December 31, 2018
Marketing revenue	**(32)**	2,968	**8,658**	6,855
Marketing expense	**-**	(852)	**(414)**	(2,914)
Marketing income	**(32)**	2,116	**8,244**	3,941
Per boe	**(0.02)**	1.03	**0.99**	0.45

Through 2018 and the first three quarters of 2019, the Company recognized marketing revenue from the monetization of the Company's exposure to the Dawn, Malin and Sumas natural gas markets. During the third quarter of 2019, the value inherent in the Dawn, Malin and Sumas markets faded as the differential between Canadian natural gas prices and US natural gas prices narrowed. In the fourth quarter of 2019, the Company recognized a small loss on the monetization of its Malin exposure, while the Dawn and Sumas contracts had been monetized in previous quarters.

Net Operating Costs

($ thousands, except per boe)	**Three months ended December 31, 2019**	Three months ended December 31, 2018	**Year ended December 31, 2019**	Year ended December 31, 2018
Operating costs	**12,015**	13,010	**52,487**	58,341
Processing revenue	**(640)**	(1,105)	**(3,090)**	(4,134)
Net operating costs	**11,375**	11,905	**49,397**	54,207
Per boe	**5.51**	5.78	**5.93**	6.22

During the fourth quarter of 2019 and year ended December 31, 2019, net operating costs and net operating costs per boe decreased as compared to the same periods in 2018, as a result of efforts by the Company to optimize field operations and reduce costs across all operating areas, coupled with volume declines in Tower and Lloydminster production, which yield higher operating costs per boe. The Company forecasts 2020 net operating costs to average between $6.25 and $6.75 per boe.

Transportation Costs

($ thousands, except per boe)	**Three months ended December 31, 2019**	Three months ended December 31, 2018	**Year ended December 31, 2019**	Year ended December 31, 2018
Transportation costs	**5,943**	3,719	**22,804**	16,007
Per boe	**2.88**	1.81	**2.74**	1.84

For the fourth quarter of 2019 and year ended December 31, 2019, the Company's transportation costs increased 60% and 42%, respectively, as compared to the same periods in 2018, as a result of the Company's new West Septimus to TC Energy's Saturn meter station natural gas sales pipeline system, which came on-line late in the first quarter of 2019. The Company also added firm TC Energy mainline receipt service in conjunction with the new sales pipeline commissioning that has increased the Company's exposure to diversified natural gas markets. The Company forecasts 2020 transportation costs to average between $3.25 and $3.75 per boe.

Operating Netbacks[1]

($/boe)	Greater Septimus	Lloydminster Heavy Oil	Other NE BC	Three months ended December 31, 2019	Three months ended December 31, 2018
Petroleum and natural gas sales	**20.13**	**44.67**	**18.81**	**21.76**	24.69
Royalties	**(1.76)**	**(6.03)**	**(0.76)**	**(1.97)**	(1.67)
Realized commodity hedging gain (loss)	**0.90**	**(0.81)**	**0.96**	**0.78**	(0.63)
Marketing income	**(0.02)**	**-**	**-**	**(0.02)**	1.03
Net operating costs	**(3.99)**	**(21.94)**	**(6.41)**	**(5.51)**	(5.78)
Transportation costs	**(2.61)**	**(0.41)**	**(7.12)**	**(2.88)**	(1.81)
Operating netbacks	**12.65**	**15.48**	**5.48**	**12.16**	15.83
Production (boe/d)	**18,720**	**1,606**	**2,120**	**22,446**	22,383

Operating netbacks for the fourth quarter of 2019 decreased 23% over the same period in 2019 as a result of lower realized natural gas pricing, higher royalties and transportation costs, and lower marketing income. This was partially offset by increased realized commodity hedging gains and decreases in net operating expenses at Greater Septimus and Other NE BC properties.

($/boe)	Greater Septimus	Lloydminster Heavy Oil	Other NE BC	Year ended December 31, 2019	Year ended December 31, 2018
Petroleum and natural gas sales	**21.31**	**50.46**	**18.84**	**23.22**	25.05
Royalties	**(1.40)**	**(6.93)**	**(1.01)**	**(1.77)**	(1.73)
Realized commodity hedging gain (loss)	**0.56**	**(3.30)**	**0.60**	**0.28**	(1.22)
Marketing income	**1.17**	**-**	**-**	**0.99**	0.45
Net operating costs	**(4.39)**	**(21.68)**	**(8.09)**	**(5.93)**	(6.22)
Transportation costs	**(2.44)**	**(0.55)**	**(7.83)**	**(2.74)**	(1.84)
Operating netbacks	**14.81**	**18.00**	**2.51**	**14.05**	14.49
Production (boe/d)	**19,373**	**1,647**	**1,817**	**22,837**	23,885

Note:
(1) Non-IFRS measure. See "Non-IFRS Measures" contained within this MD&A.

For the year ended December 31, 2019, operating netbacks decreased 3% as compared to the prior year due to a decrease in realized commodity prices, higher royalties and transportation costs, partially offset by increased realized hedging gains, marketing income and reduced net operating costs.

General and Administrative Costs

($ thousands, except per boe)	Three months ended December 31, 2019	Three months ended December 31, 2018	Year ended December 31, 2019	Year ended December 31, 2018
Gross costs	**4,081**	4,548	**17,607**	18,565
Operator's recoveries	**(38)**	(97)	**(91)**	(749)
Capitalized costs	**(1,305)**	(1,264)	**(5,880)**	(5,726)
General and administrative expenses	**2,738**	3,187	**11,636**	12,090
Per boe	**1.33**	1.55	**1.40**	1.39

Gross and net general and administrative ("G&A") costs decreased in both the fourth quarter of 2019 and year ended December 31, 2019 as compared to the same periods in 2018, mainly due to the impact from the adoption of IFRS 16, where a portion of the Company's head office lease is no longer charged to G&A, partially offset by a decrease in operator's recoveries as a result of reduced capital spending on partnered wells. The decrease in G&A costs per boe in the fourth quarter of 2019 is mainly due to the aforementioned impact from the adoption of IFRS 16. The increase in G&A costs per boe in the year ended December 31, 2019 is mainly due to a decrease in production and operator's recoveries as compared to the same period in 2018, partially offset by the aforementioned impact from the adoption of IFRS 16. Crew forecasts G&A costs per boe to average between $1.25 and $1.50 in 2020.

Share-Based Compensation

($ thousands)	**Three months ended December 31, 2019**	Three months ended December 31, 2018	**Year ended December 31, 2019**	Year ended December 31, 2018
Gross costs	**2,187**	3,430	**10,237**	13,457
Capitalized costs	**(1,058)**	(1,615)	**(4,897)**	(6,381)
Total share-based compensation	**1,129**	1,815	**5,340**	7,076

In the fourth quarter of 2019 and year ended December 31, 2019, the Company's total share-based compensation expense decreased as compared to the same periods in 2018, mainly due to the lower value of awards granted in 2019 as compared to 2018.

Depletion and Depreciation

($ thousands, except per boe)	**Three months ended December 31, 2019**	Three months ended December 31, 2018	**Year ended December 31, 2019**	Year ended December 31, 2018
Depletion and depreciation	**18,356**	18,459	**75,776**	77,373
Per boe	**8.89**	8.96	**9.09**	8.88

In the fourth quarter of 2019, depletion and depreciation costs per boe decreased when compared to the same period in 2018, due to a decrease in future development costs per boe associated with reserves bookings at the end of 2019 as compared to 2018, partially offset by the addition of depreciation on right-of-use assets, which was the result of the adoption of IFRS 16 in the first quarter of 2019. In 2019, depletion and depreciation costs per boe increased when compared to 2018 as a result of an increase to the per boe depletion rate of Tower production, due to lower reserve bookings at Tower as some probable locations were removed as their planned development extended beyond the required time guidelines. In addition, the aforementioned depreciation on right-of-use assets contributed to the increase in depletion and depreciation costs per boe, partially offset by lower land expiries as compared to the same period in 2018. Proved plus probable reserves remained relatively unchanged with reserves of 410.6 MMboe at December 31, 2019, as compared to 411.0 MMboe at December 31, 2018.

Impairment

At December 31, 2019, due to weakness in the Canadian commodity price environment and the depressed share price of the Company, the Company tested its northeast British Columbia cash-generating unit ("CGU") and Lloydminster CGU for impairment. It was determined that the recoverable amount of the northeast British Columbia CGU and Lloydminster CGU exceeded their carrying value and an impairment charge was not recorded.

At December 31, 2018, 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 and Lloydminster CGU for impairment at December 31, 2018. It was determined that the recoverable amount of both the northeast British Columbia CGU and Lloydminster CGU exceeded their carrying value and therefore an impairment charge was not recorded.

Finance Expenses

($ thousands, except per boe)	**Three months ended December 31, 2019**	Three months ended December 31, 2018	**Year ended December 31, 2019**	Year ended December 31, 2018
Interest on bank loan and other	**1,151**	546	**4,009**	2,735
Interest on senior notes	**4,915**	4,915	**19,500**	19,500
Accretion of deferred financing charges	**246**	246	**983**	1,023
Accretion of the decommissioning obligation	**462**	491	**1,901**	1,958
Total finance expense	**6,774**	6,198	**26,393**	25,216
Average long-term debt level	**352,128**	353,425	**352,191**	346,121
Average drawings on bank loan	**52,128**	53,425	**52,191**	46,121
Average senior unsecured notes outstanding	**300,000**	300,000	**300,000**	300,000
Effective interest rate on senior unsecured notes	**6.5%**	6.5%	**6.5%**	6.5%
Effective interest rate on long-term debt	**6.1%**	6.1%	**6.1%**	6.1%
Financing costs on long-term debt per boe	**3.06**	2.77	**2.94**	2.67

Average corporate debt levels and the associated interest charges have remained relatively consistent year-over-year, as the Company has limited net capital expenditures to approximate adjusted funds flow over the past several quarters. Crew forecasts the effective interest rate on its long-term debt to average between 6.0% and 6.5% in 2020.

Gain on Divestitures of Property

During 2019, the Company disposed of non-core lands with no associated production or assigned reserves, for gross proceeds of $20.8 million. The lands consisted of petroleum and natural gas properties and undeveloped land with a net book value of $1.1 million and associated decommissioning obligations of $0.3 million, resulting in a gain of $20.0 million.

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

Deferred Income Taxes

In the fourth quarter of 2019, the provision for deferred taxes was a recovery of $1.5 million as compared to an expense of $9.6 million for the same period in 2018. The deferred income tax recovery in the fourth quarter of 2019 is due to a pre-tax loss realized in the fourth quarter of 2019, primarily a result of lower petroleum and natural gas sales as compared to the fourth quarter of 2018 and a large unrealized gain on financial instruments contributing to pre-tax income in the fourth quarter of 2018. For 2019, the provision for deferred taxes was an expense of $0.8 million as compared to an expense of $10.4 million in 2018. The decrease in expense is the result of lower pre-tax income in 2019, resulting from the aforementioned decrease in petroleum and natural gas sales, partially offset by a realized gain as compared to a 2018 loss on financial instruments and higher gains on dispositions.

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

($ thousands)	**December 31, 2019**	December 31, 2018
Cumulative Canadian Exploration Expense	**293,400**	291,400
Cumulative Canadian Development Expense	**282,900**	238,800
Undepreciated Capital Cost	**202,400**	202,800
Non-capital losses	**311,600**	335,600
Share issue costs	**2,800**	5,300
Other	**7,900**	8,000
	1,101,000	1,081,900

Cash, Adjusted Funds Flow and Net (Loss) Income

($ thousands, except per share amounts)	**Three months ended December 31, 2019**	Three months ended December 31, 2018	**Year ended December 31, 2019**	Year ended December 31, 2018
Cash provided by operating activities	**21,106**	22,878	**81,395**	89,162
Adjusted funds flow (1)	**16,086**	23,712	**81,034**	91,996
Per share -basic	**0.11**	0.16	**0.53**	0.61
-diluted	**0.11**	0.16	**0.53**	0.61
Net (loss) income	**(6,235)**	18,771	**12,071**	12,799
Per share -basic	**(0.04)**	0.12	**0.08**	0.09
-diluted	**(0.04)**	0.12	**0.08**	0.09

Note:
(1) Non-IFRS measure. 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. See "Non-IFRS Measures" contained within this MD&A.

Cash provided by operating activities and adjusted funds flow decreased in both the fourth quarter of 2019 and year ended December 31, 2019, predominantly due to lower petroleum and natural gas sales, and increased transportation costs as compared to the same periods in 2018. The Company had a net loss for the fourth quarter of 2019 as compared to net income in the same period in 2018, predominantly due to lower petroleum and natural gas sales and a favourable unrealized hedging gain in the fourth quarter of 2018 as compared to an unrealized hedging loss in the fourth quarter of 2019. Net income for the year ended December 31, 2019 decreased as compared to the same period in 2018, due to lower petroleum and natural gas sales, partially offset by higher gains on dispositions and lower operating costs.

Capital Expenditures, Property Acquisitions and Dispositions

($ thousands)	**Three months ended December 31, 2019**	Three months ended December 31, 2018	**Year ended December 31, 2019**	Year ended December 31, 2018
Land	**890**	1,393	**3,311**	4,121
Seismic	**234**	1,188	**1,163**	1,939
Drilling and completions	**19,954**	32,829	**89,156**	71,524
Facilities, equipment and pipelines	**3,976**	(3,592)	**14,069**	19,318
Other	**1,336**	1,356	**6,395**	6,317
Total exploration and development	**26,390**	33,174	**114,094**	103,219
Net property acquisitions (dispositions)	**82**	175	**(19,084)**	(9,806)
Total	**26,472**	33,349	**95,010**	93,413

In the fourth quarter of 2019, the Company spent a total of $26.4 million on exploration and development expenditures. The majority of this amount was spent on the continued development of the Montney assets. During the quarter, $20.0 million was spent on drilling and completion activities, $4.0 million on facilities, equipment and pipelines spending and $2.4 million was spent on land, seismic, recompletions and other miscellaneous amounts. The Company completed four (4.0 net) natural gas wells in NE BC and recompleted six (5.0 net) heavy crude oil wells in Lloydminster.

In 2019, the Company drilled a total of 8 (8.0 net) natural gas wells. During the year, the Company completed 13 (13.0 net) wells and recompleted 26 (25.0 net) wells. The Company's spending focus in 2019 was on UCR drilling and completions in the West Septimus area.

LIQUIDITY AND CAPITAL RESOURCES

Working Capital

The capital intensive nature of Crew's activities generally results in the Company carrying a working capital deficiency; however, at the end of the fourth quarter of 2019, the Company carried a working capital surplus of $0.1 million. Working capital includes accounts receivable and net assets held for sale less accounts payable and accrued liabilities. Included in the working capital surplus is a receivable of $5.0 million for a Government of British Columbia infrastructure credit earned through the completion of a pipeline connecting the West Septimus processing facility to the TC Energy Saturn meter station. The collection of the credit is realized through the reduction of future royalties payable to the British Columbia government.

Subsequent to December 31, 2019, the Company entered into a final purchase and sale agreement with a third party midstream company for the disposition of a 22% net working interest in each of its Septimus gas processing facility and West Septimus gas processing facility located in Northeast British Columbia for aggregate consideration of $70.0 million. The purchase and sale agreement is structured with two closings, whereby an 11% working interest was disposed of for $35 million on February 27, 2020, with proceeds applied to reduce borrowings on the Facility, and the sale of an additional 11% working interest for $35 million is expected to close in the fourth quarter of 2020, subject to certain closing conditions. This transaction will enable the Company to capture efficiencies and strengthen the balance sheet, ultimately reducing net debt by $58.3 million with $2.1 million of annual cost savings. As at December 31, 2019, the first closing was considered highly probable of occurring and the facilities were available for immediate sale in their present condition and as such, were classified as held for sale and included in working capital.

The Company ensures that sufficient drawings are available from its Facility to satisfy working capital requirements. At December 31, 2019, the Company's working capital surplus of $0.1 million, when combined with the drawings on its bank loan, represented drawings of 22% on its $235 million Facility described below.

Capital Funding

Bank Loan

As at December 31, 2019, 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 4, 2020. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 per cent and all outstanding advances thereunder will become repayable in one year from the extension date. The available lending limits of the Facility (the "Borrowing Base") are reviewed semi-annually and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. The Facility requires the Company to maintain a Liability Management Rating ("LMR") of greater than 1.2:1 in the provinces of Alberta and Saskatchewan, and greater than 2.0:1 in the province of British Columbia, if the uninflated, undiscounted abandonment and reclamation liabilities ("Decommissioning Obligations"), as determined by the individual province, is greater than $20 million. If the LMR falls below the required level in any province, the lenders have the option to re-determine the Borrowing Base. As at December 31, 2019, the Company's Decommissioning Obligations exceeded $20 million in the provinces of Alberta and British Columbia, which carried an LMR of 1.8:1 and 7.0:1, respectively. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled Borrowing Base review on or before June 4, 2020. The Facility is secured by a floating charge debenture and a general securities agreement on all 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.

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 maintenance and growth of reserves and production volumes, the Company is readily able to adjust its budgeted capital expenditures should the need arise.

Share Capital

Crew is authorized to issue an unlimited number of common shares. As at March 10, 2020, there were 156,300,746 common shares of the Company issued and outstanding, which includes 4,738,496 of shares held in trust for the potential future settlement of awards issued under the Company's Restricted and Performance Award Incentive Plan. In addition, there were 3,573,109 restricted awards and 4,135,674 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, 2019.

Capital Structure

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

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. 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	2020	2021	2022	2023	2024	Thereafter
Bank Loan (note 1)	52,136	-	52,136	-	-	-	-
Senior unsecured notes (note 2)	300,000	-	-	-	-	300,000	-
Lease obligations	3,381	290	-	244	731	731	1,385
Firm transportation agreements	240,332	48,467	42,804	30,753	25,994	25,524	66,790
Firm processing agreement	94,558	16,337	12,354	12,354	12,354	12,388	28,771
Total	**690,407**	**65,094**	**107,294**	**43,351**	**39,079**	**338,643**	**96,946**

Note 1 – Based on the existing terms of the Company's Facility the first possible repayment date may come in 2021. 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.

Lease obligations relate primarily to the Company's commitment to a third party for the lease of office space.

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

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

GUIDANCE

Crew's Board of Directors has approved full year 2020 capital expenditures of $35 million to $45 million, before acquisitions and dispositions, of which approximately 60% is planned to be invested in the first half of 2020, and the remaining 40% in the second half of 2020. This level of capital investment is a reflection of the current extreme volatility in commodity prices and the heightened level of uncertainty associated with the global economy. The Company has taken a proactive approach to managing through this environment and expects that capital expenditures will be limited, while higher-cost or lower-netback production may be shut-in from time-to-time to preserve economics. With this in mind, Crew expects to generate average annual production of between 20,000 and 22,000 boe per day. Our focus in 2020 will be to preserve our reserves and resources, reduce water handling costs, optimize production and improve financial strength through debt reduction.

The Company continues to prioritize financial flexibility and will take steps to refine our annual capital spending plans to maintain a strong balance sheet and focus on developing and producing the assets which provide the highest returns in the current environment.

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 2019**	Sep. 30 2019	June 30 2019	Mar. 31 2019	Dec. 31 2018	Sep. 30 2018	June 30 2018	Mar. 31 2018
Total daily production (boe/d)	**22,446**	22,824	22,865	23,222	22,383	23,680	23,583	25,939
Exploration and development expenditures	**26,390**	18,466	13,997	55,241	33,174	23,656	12,468	33,921
Property acquisitions/(dispositions)	**82**	7	(3,249)	(15,924)	175	9	17	(10,007)
Average wellhead price ($/boe)	**21.76**	19.81	24.77	26.53	24.69	24.82	25.18	25.46
Petroleum and natural gas sales	**44,941**	41,597	51,543	55,451	50,838	54,080	54,040	59,427
Cash provided by operating activities	**21,106**	8,877	40,879	10,533	22,878	19,095	31,304	15,885
Adjusted funds flow[1]	**16,086**	16,664	22,513	25,771	23,712	20,107	21,804	26,373
Per share – basic	**0.11**	0.11	0.15	0.17	0.16	0.13	0.14	0.18
– diluted	**0.11**	0.11	0.15	0.17	0.16	0.13	0.14	0.17
Net (loss) income	**(6,235)**	(3,255)	15,375	6,186	18,771	(939)	(9,181)	4,148
Per share – basic	**(0.04)**	(0.02)	0.10	0.04	0.12	(0.01)	(0.06)	0.03
– diluted	**(0.04)**	(0.02)	0.10	0.04	0.12	(0.01)	(0.06)	0.03

Note:
(1) Non-IFRS measure. See "Non-IFRS Measures" contained within this MD&A.

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 production growth and infrastructure development in the area. The Company reduced capital spending in 2018 and 2019 as compared to 2017, due to weakening Canadian natural gas prices over the past three years. As a result, the Company's net capital expenditures, after proceeds from acquisitions and dispositions, have approximated adjusted funds flow over this period, effectively maintaining production at a consistent level.

The significant fluctuations in commodity prices have impacted cash provided by operating activities, 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. Despite these efforts, cash flow from operations used to fund the Company's capital program has been impacted.

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

($ thousands, except per share amounts)	**Year ended Dec. 31, 2019**	Year ended Dec. 31, 2018	Year ended Dec. 31, 2017
Petroleum and natural gas sales	**193,532**	218,385	214,154
Cash provided by operating activities	**81,395**	89,162	117,290
Adjusted funds flow[(1)]	**81,034**	91,996	108,129
Per share -basic	**0.53**	0.61	0.73
-diluted	**0.53**	0.61	0.72
Net income	**12,071**	12,799	34,405
Per share -basic	**0.08**	0.08	0.23
-diluted	**0.08**	0.08	0.23
Daily production (boe/d)	**22,837**	23,885	23,061
Crew average sales price ($/boe)	**23.22**	25.05	25.44
Total assets	**1,451,647**	1,451,923	1,388,120
Working capital surplus (deficiency)[(2)]	**149**	11,984	(29,143)
Bank loan	**52,136**	59,904	21,977
Senior unsecured notes	**295,868**	294,885	293,862
Total other long-term liabilities	**143,295**	142,246	130,795

Note:

(1) Non-IFRS measure. 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. See "Non-IFRS Measures" contained within this MD&A.

(2) Non-IFRS measure. Working capital includes accounts receivable, net assets held for sale and accounts payable and accrued liabilities. See "Non-IFRS Measures" contained within this MD&A.

Over the last three years, a volatile commodity price environment has impacted revenue, cash provided by operating activities, adjusted funds flow and net income. The overall decline in forecasted future commodity prices has also led to the assessment and realization of impairment charges on certain CGUs in 2017.

New Accounting Pronouncements

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

a) Adoption of IFRS 16 – Leases:

On January 1, 2019, the Company adopted IFRS 16 Leases, which replaces IAS 17 Leases and IFRIC 4 Determining Whether an Arrangement Contains a Lease. IFRS 16 uses a single lease accounting model for lessees, which requires the Company to recognize a right-of-use asset and lease liability on the statement of financial position, for all contracts that contain a lease.

The Company adopted IFRS 16 using the modified retrospective approach, and therefore comparative information has not been restated and continues to be reported under IAS 17 and IFRIC 4. The cumulative effect of initially applying the standard was recognized through $2.6 million in right-of-use assets (included in "Property, plant and equipment") and $2.6 million in lease obligations, split between the current portion of $1.1 million included in "Accounts payable and accrued liabilities", and the long term portion of $1.5 million included in "Lease obligations". The weighted average incremental borrowing rate used to calculate the lease obligation at adoption was 4.5%. The right-of-use assets and lease obligations relate primarily to the Company's head office lease in Calgary.

The Company applied the following practical expedients as permitted under the standard. Some of these expedients are on a lease-by-lease basis and others are applicable by class of underlying assets:

- Maintain classification of contracts previously identified as leases under IAS 17 and IFRIC 4;
- Account for leases with a remaining term of less than 12 months at January 1, 2019 as short-term leases;
- Account for lease payments as an expense and not recognize a right-of-use asset if the underlying asset is of a lower dollar value;
- Apply a single discount rate to a portfolio of leases with similar characteristics; and
- Recognize lease liabilities at the present value of the remaining lease payments, discounted using the interest rate implicit in the lease or the Company's incremental borrowing rate as at January 1, 2019. The associated right-of-use assets will be measured at the amount equal to the lease liability on the date of transition, with no impact to opening retained earnings (deficit).

As at December 31, 2018, the Company had operating lease commitments of $2.7 million, which would have resulted in a discounted lease obligation of $2.6 million. At January 1, 2019, the Company recognized a current and non-current lease obligation of $2.6 million.

Application of Critical Accounting Estimates

Crew's significant accounting policies are disclosed in note 3 to the December 31, 2019 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, as defined in national Instrument 52-109 Certification of Disclosures in Issuers' Annual and Interim Filings ("NI 52-109"), 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.

The Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting, as defined in NI 52-109, 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. 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, 2019 and ended on December 31, 2019 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 10, 2020

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)	*(signed)*
Dale O. Shwed	John G. Leach
President and Chief Executive Officer	Executive Vice-President and Chief Financial Officer

March 10, 2020

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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Crew Energy Inc.

Opinion

We have audited the consolidated financial statements of Crew Energy Inc. (the "Company"), which comprise:

- the consolidated statements of financial position as at December 31, 2019 and December 31, 2018
- the consolidated statements of income and comprehensive income for the years then ended
- the consolidated statements of changes in shareholders' equity for the years then ended
- the consolidated statements of cash flows for the years then ended
- and notes to the consolidated financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements".)

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2019 and December 31, 2018, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards ("IFRS").

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "*Auditors' Responsibilities for the Audit of the Financial Statements*" section of our auditors' report.

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

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

Other Information

Management is responsible for the other information. Other information comprises:

– the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions.

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions as at the date of this auditors' report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditors' report.

We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

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

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit 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 Company's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

- Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

The engagement partner on the audit resulting in this auditors' report is Timothy Arthur Richards.

KPMG LLP

Chartered Professional Accountants

Calgary, Canada
March 10, 2020

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(thousands)	**December 31, 2019**	December 31, 2018
Assets		
Current Assets:		
Accounts receivable	**$ 26,994**	$ 70,522
Derivative financial instruments (note 6)	**3,180**	8,382
Assets held for sale (note 7)	**19,845**	-
	50,019	78,904
Property, plant and equipment (note 8)	**1,401,628**	1,373,019
	$ 1,451,647	$ 1,451,923
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 45,949**	$ 58,538
Liabilities associated with assets held for sale (note 7)	**741**	-
	46,690	58,538
Bank loan (note 10)	**52,136**	59,904
Senior unsecured notes (note 11)	**295,868**	294,885
Lease obligations (note 12)	**2,708**	-
Decommissioning obligations (note 13)	**87,024**	89,448
Deferred tax liability (note 15)	**53,563**	52,798
Shareholders' Equity		
Share capital (note 14)	**1,478,294**	1,468,986
Contributed surplus	**71,644**	75,715
Deficit	**(636,280)**	(648,351)
	913,658	896,350
Commitments (note 20)		
Subsequent event (note 6, 7)		
	$ 1,451,647	$ 1,451,923

See accompanying notes to the consolidated financial statements.

On behalf of the Board of Directors:

(signed)

David G. Smith

Director

(signed)

Ryan A. Shay

Director

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

(thousands, except per share amounts)	**Year ended December 31, 2019**	Year ended December 31, 2018
Revenue		
Petroleum and natural gas sales (note 16)	**$ 193,532**	$ 218,385
Royalties	**(14,758)**	(15,123)
Realized gain (loss) on derivative financial instruments	**2,352**	(10,645)
Unrealized (loss) gain on derivative financial instruments	**(5,202)**	8,035
Other revenue (note 16)	**11,748**	11,989
	187,672	212,641
Expenses		
Operating	**52,487**	58,341
Transportation	**22,804**	16,007
Marketing	**414**	2,914
General and administrative	**11,636**	12,090
Share-based compensation	**5,340**	7,076
Depletion and depreciation (note 8)	**75,776**	77,373
	168,457	173,801
Income from operations	**19,215**	38,840
Financing (note 17)	**26,393**	25,216
Gain on divestiture of property, plant and equipment (note 8)	**(20,014)**	(9,546)
Income before income taxes	**12,836**	23,170
Deferred tax expense (note 15)	**765**	10,371
Net income and comprehensive income	**$ 12,071**	$ 12,799
Net income per share (note 14)		
Basic	**$ 0.08**	$ 0.08
Diluted	**$ 0.08**	$ 0.08

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(thousands)	Number of shares, net of shares in trust	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 2019	151,730	$1,468,986	$ 75,715	$ (648,351)	$ 896,350
Net income for the year	-	-	-	12,071	12,071
Share-based compensation expensed	-	-	5,340	-	5,340
Share-based compensation capitalized	-	-	4,897	-	4,897
Issued from treasury on vesting of share awards	4,542	14,212	(14,212)	-	-
Released from trust on vesting of share awards	45	96	(96)	-	-
Purchase of shares held in trust (note 14)	(4,783)	(5,000)	-	-	(5,000)
Balance, December 31, 2019	**151,534**	**$1,478,294**	**$ 71,644**	**$ (636,280)**	**$ 913,658**

(thousands)	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 2018	149,328	$1,458,086	$ 73,158	$ (661,150)	$ 870,094
Net income for the year	-	-	-	12,799	12,799
Share-based compensation expensed	-	-	7,076	-	7,076
Share-based compensation capitalized	-	-	6,381	-	6,381
Issued on vesting of share awards	2,402	10,900	(10,900)	-	-
Balance, December 31, 2018	**151,730**	**$1,468,986**	**$ 75,715**	**$ (648,351)**	**$ 896,350**

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands)	**Year ended December 31, 2019**	Year ended December 31, 2018
Cash provided by (used in):		
Operating activities:		
Net income	**$ 12,071**	$ 12,799
Adjustments:		
Unrealized loss (gain) on derivative financial instruments	**5,202**	(8,035)
Share-based compensation	**5,340**	7,076
Depletion and depreciation (note 8)	**75,776**	77,373
Financing expenses (note 17)	**26,393**	25,216
Interest expense (note 17)	**(23,516)**	(22,235)
Gain on divestiture of property, plant and equipment (note 8)	**(20,014)**	(9,546)
Deferred tax expense (note 15)	**765**	10,371
Decommissioning obligations settled (note 13)	**(3,919)**	(1,194)
Change in non-cash working capital (note 19)	**3,297**	(2,663)
	81,395	89,162
Financing activities:		
(Decrease) increase in bank loan	**(7,768)**	37,927
Payments on lease obligations (note 12)	**(1,071)**	-
Shares purchased and held in trust (note 14)	**(5,000)**	-
	(13,839)	37,927
Investing activities:		
Property, plant and equipment expenditures (note 8)	**(114,094)**	(101,878)
Property acquisitions (note 8)	**(1,570)**	(201)
Property dispositions (note 8)	**20,654**	10,007
Change in non-cash working capital (note 19)	**27,454**	(35,017)
	(67,556)	(127,089)
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, 2019 and 2018

(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 Canada 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 consolidated statements of income ("statements of income") are presented as a combination of function and nature in conformity with industry practice. Share-based compensation and depletion and depreciation expenses are presented on separate lines by their nature, while operating, transportation, marketing 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 10, 2020.

3. Significant accounting policies:

The accounting policies set out below have been applied consistently to all years presented in these consolidated financial statements, with the exception of the adoption of IFRS 16 Leases, as described in note 5.

(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 statements of income.

(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 the statements of income.

(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 the statements of income, 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 the statements of income and are recorded on the statement of financial position at fair value. Transaction costs are recognized in the statements of income when incurred.

(iii) Share capital:

Common shares are classified as equity. Incremental costs directly attributable to the issuance of common shares and 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 statements of income 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 the statements of income.

(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 the statements of income 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 the statements of income 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 the statements of income on a straight-line basis over the estimated useful lives of each part of an item of property, plant and equipment.

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 the statements of income 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:

When Crew is party to a lease arrangement as the lessee, it recognizes a right-of-use asset ("ROU asset") and a corresponding lease obligation on the balance sheets on the date that a leased asset becomes available for use. Interest associated with the lease obligation is recognized over the lease period with a corresponding increase to the underlying lease obligation. ROU assets are depreciated on a straight-line basis over the shorter of the asset’s useful life and the lease term. Depreciation on ROU assets is recognized in depletion and depreciation. ROU assets and lease obligations are initially measured on a present value basis. Lease obligations are measured as the net present value of the lease payments which may include: fixed lease payments, variable lease payments based on an index or a rate, and amounts expected to be payable under residual value guarantees and payments to exercise an extension or termination option, if Crew is reasonably certain to exercise either of those options. ROU assets are measured at cost, which is composed of the amount of the initial measurement of the lease obligation, less any incentives received, plus any lease payments made at, or before, the commencement date and initial direct costs and asset restoration costs, if any. The rate implicit in the lease is used to determine the present value of the liability and ROU asset arising from a lease, unless this rate is not readily determinable, in which case the Company's incremental borrowing rate is used.

In cases where the leased asset is used in the Company’s jointly controlled operations, Crew, as the operator, is the obligor to the lessor and presents the full amount of the lease obligation and ROU asset at the commencement date of the lease. Certain payments relating to the Company’s lease obligation may be recovered over time in accordance with billings for each partner’s proportionate interest in the joint operation and are recognized in other revenue.

Short-term leases and leases of low-value assets are not recognized on the statement of financial position and lease payments are instead recognized in the financial statements as incurred. For certain classes of leases, Crew does not separate lease and non-lease components, accounting for these leases as a single lease component.

(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 by measuring the asset's expected credit loss ("ECL"). Accounts receivable are due within one year or less; therefore, these financial assets are not considered to have a significant financing component and a lifetime ECL is measured at the date of initial recognition of the accounts receivable.

The ECL pertaining to accounts receivable is assessed at initial recognition and this provision is re-assessed at each reporting date. ECLs are a probability-weighted estimate of all possible default events related to the financial asset (over the lifetime or within 12 months after the reporting period, as applicable) and are measured as the difference between the present value of the cash flows due to Crew and the cash flows the Company expects to receive. In making an assessment as to whether financial assets are credit-impaired, the Company considers historically realized bad debts, evidence of a debtor's present financial condition and whether a debtor has breached certain contracts, the probability that a debtor will enter bankruptcy or other financial reorganization, changes in economic conditions that correlate to increased levels of default, the number of days a debtor is past due in making a contractual payment, and the term to maturity of the specified receivable. The carrying amounts of financial assets are reduced by the amount of the ECL through an allowance account and losses are recognized in the statements of income.

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 the statements of income. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

(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 the statements of income. 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 awards 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 awards that are expected to vest. A performance multiplier is estimated on the grant date for performance awards and adjusted to reflect the number of performance awards 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 crude oil, natural gas, condensate and natural gas liquids is recorded when control of the product is transferred to the buyer based on the consideration specified in the contracts with customers. This usually occurs when the product is physically transferred at the delivery point agreed upon in the contract and legal title to the product passes to the customer.

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

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

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 the statements of income 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 the statements of income, using the effective interest method.

(k) Income tax:

Income tax expense comprises current and deferred tax. Income tax expense is recognized in the statements of income 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 the statements of income 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 the statements of income in the period in which the change occurs.

(v) Leased assets

The Company is required to make judgements and assumptions on incremental borrowing rates and lease terms. The carrying amount of the ROU assets, lease obligations, interest and depreciation expense may differ due to changes in market conditions and expected lease terms. Incremental borrowing rates are based on the Company's borrowing rate at the commencement date of the lease, the security of the asset and market conditions. Lease terms are based on management's assumptions of future market conditions and operational decisions.

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 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 the statements of income 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 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, 2019 and December 31, 2018, 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, 2019, the carrying value of the unsecured notes made up 120% of the 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. Change in accounting policies:

(i) Adoption of IFRS 16 – Leases:

On January 1, 2019, the Company adopted IFRS 16 Leases, which replaces IAS 17 Leases and IFRIC 4 Determining Whether an Arrangement Contains a Lease. IFRS 16 uses a single lease accounting model for lessees, which requires the Company to recognize a ROU asset and lease liability on the statement of financial position, for all contracts that contain a lease.

The Company adopted IFRS 16 using the modified retrospective approach, and therefore comparative information has not been restated and continues to be reported under IAS 17 and IFRIC 4. The cumulative effect of initially applying the standard was recognized through $2.6 million in ROU assets (included in "Property, plant and equipment") and $2.6 million in lease obligations, split between the current portion of $1.1 million included in "Accounts payable and accrued liabilities", and the long term portion of $1.5 million included in "Lease obligations". The weighted average incremental borrowing rate used to calculate the lease obligation at adoption was 4.5%. The ROU assets and lease obligations relate primarily to the Company's head office lease in Calgary.

The Company applied the following practical expedients as permitted under the standard. Some of these expedients are on a lease-by-lease basis and others are applicable by class of underlying assets:

- Maintain classification of contracts previously identified as leases under IAS 17 and IFRIC 4;
- Account for leases with a remaining term of less than 12 months at January 1, 2019 as short-term leases;
- Account for lease payments as an expense and not recognize a ROU asset if the underlying asset is of a lower dollar value;
- Apply a single discount rate to a portfolio of leases with similar characteristics; and
- Recognize lease liabilities at the present value of the remaining lease payments, discounted using the interest rate implicit in the lease or the Company's incremental borrowing rate as at January 1, 2019. The associated ROU assets will be measured at the amount equal to the lease liability on the date of transition, with no impact to opening retained earnings (deficit).

As at December 31, 2018, the Company had operating lease commitments of $2.7 million, which would have resulted in a discounted lease obligation of $2.6 million. At January 1, 2019, the Company recognized a current and non-current lease obligation of $2.6 million.

The additional disclosures required by IFRS 16 are disclosed in note 12.

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, 2019	December 31, 2018
Trade and other receivables	**$ 26,994**	$ 70,522
Derivative financial assets	**3,180**	8,382
	$ 30,174	$ 78,904

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 2019, 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, 2019, the Company's receivables consisted of $19.7 million (December 31, 2018 - $23.9 million) of receivables from petroleum and natural gas marketers, of which all have been subsequently collected, $0.6 million (December 31, 2018 - $34.6 million) from partners with jointly owned assets and operations, none of which has been subsequently collected, and $6.7 million (December 31, 2018 - $12.0 million) of deposits, prepaids and other accounts receivable, which includes a $5.0 million (December 31, 2018 - $9.5 million) receivable for a Government of British Columbia infrastructure credit earned through the completion of a pipeline connecting the West Septimus processing facility to the TC Energy Saturn meter station. The Company does not consider any of its 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, 2019 was $52.2 million (December 31, 2018 - $46.1 million). For the year ended December 31, 2019, a 1.0 percent change to the effective interest rate would have had a $0.5 million impact on net income (December 31, 2018 - $0.5 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 regional, North American and global economic events that dictate the levels of crude oil, natural gas and natural gas liquids supply and demand. The Company has attempted to mitigate a portion of the commodity price risk through the use of a diversified portfolio of market pricing points and the use of various financial derivative and physical delivery sales contracts as outlined below. The Company's policy is to only 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 statements of income.

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, 2019, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value
Gas	12,500 mmbtu/day	January 1, 2020 - December 31, 2020	Chicago Citygate	$3.32/mmbtu	Swap	$ 2,300
Gas	2,500 mmbtu/day	January 1, 2020 - December 31, 2020	US$ Nymex Henry Hub	$2.48/mmbtu	Swap	199
Oil	250 bbl/day	January 1, 2020 - June 30, 2020	CDN$ WTI	$75.50/bbl	Swap	(102)
Oil	250 bbl/day	January 1, 2020 - June 30, 2020	USD$ WCS - WTI Differential	($17.25)/bbl	Swap	131
Oil	500 bbl/day	January 1, 2020 - June 30, 2020	CDN$ WCS	$52.25/bbl	Swap	(9)
Oil	1,000 bbl/day	January 1, 2020 - December 31, 2020	CDN$ WTI	$77.65/bbl	Swap	639
Oil	250 bbl/day	July 1, 2020 - December 31, 2020	CDN$ WCS	$51.50/bbl	Swap	5
Condensate	250 bbl/day	January 1, 2020 - March 31, 2020	USD$ C5+ Differential	$2.00/bbl	Swap	17
Total						**$ 3,180**

As at December 31, 2019, a 10% change in future commodity prices applied against these contracts would have a $3.9 million impact on net income.

Subsequent to December 31, 2019, the Company entered into the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Oil	250 bbl/day	July 1, 2020 - September 30, 2020	USD$ WCS - WTI Differential	($16.00/bbl)	Swap
Oil	250 bbl/day	July 1, 2020 - December 31, 2020	CDN$ WTI	$76.00/bbl	Swap
Oil	250 bbl/day	July 1, 2020 - December 31, 2020	USD$ WCS - WTI Differential	($15.60/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 2021 if not extended. 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 considers its capital structure to include working capital, long-term debt (including the bank loan and senior unsecured notes) and shareholders' equity. Crew's primary capital management objective is to maintain a strong financial position in order to continue to fund the future growth of the Company. Crew monitors its capital structure and makes adjustments on an ongoing basis in order to maintain the flexibility needed to achieve the Company's long-term objectives. To manage its capital structure, the Company may adjust capital spending, hedge future revenue through commodity contracts, issue new equity, issue new debt or repay existing debt through asset sales.

In the current depressed and volatile commodity price environment, Crew plans to monitor capital expenditures. With only 22% drawn on the Company's $235 million Facility and the senior unsecured notes termed out to 2024, the Company's financial position remains strong. The Company will continue to monitor debt levels 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 to further strengthen its financial position.

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 net debt as part of its capital structure.

The following tables outline Crew's calculation of net debt:

	December 31, 2019	December 31, 2018
Current assets	**$ 50,019**	$ 78,904
Current liabilities	**(46,690)**	(58,538)
Derivative financial instruments	**(3,180)**	(8,382)
Working capital surplus	**149**	11,984
Bank loan	**(52,136)**	(59,904)
Senior unsecured notes	**(295,868)**	(294,885)
Net debt	**$ (347,855)**	$ (342,805)

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).

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 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 maintain production at current levels and fund future growth through capital investment and to service and repay debt. Management believes that such measures provide an insightful assessment of the Company's operations on a continuing basis by eliminating certain non-cash charges and actual settlements of decommissioning obligations, the timing of which is discretionary.

	Year ended December 31, 2019	Year ended December 31, 2018
Cash provided by operating activities	**$ 81,395**	$ 89,162
Change in operating on-cash working capital	**(3,297)**	2,663
Accretion of deferred financing costs	**(983)**	(1,023)
Funds from operations	**77,115**	90,802
Decommissioning obligations settled	**3,919**	1,194
Adjusted funds flow	**$ 81,034**	$ 91,996

7. Assets held for sale:

Assets held for sale	Total
Transfer from property, plant and equipment – cost	$ 21,824
Transfer from property, plant and equipment – accumulated depletion and depreciation	(1,979)
Balance, December 31, 2019	**$ 19,845**

Liabilities associated with assets held for sale	Total
Transfer from decommissioning obligations	$ 741
Balance, December 31, 2019	**$ 741**

Subsequent to December 31, 2019, the Company entered into and closed on February 27, 2020, a final purchase and sale agreement with a third party midstream company for the disposition of an 11% net working interest in each of its Septimus gas processing facility and West Septimus gas processing facility located in Northeast British Columbia for aggregate consideration of $35.0 million.

As at December 31, 2019, the closing was considered highly probable of occurring and the facilities were available for immediate sale in their present condition and, as such, were classified as held for sale. Immediately prior to classifying the assets as held for sale, the Company conducted a review of the assets' recoverable amounts based on expected consideration to be received and transferred these assets at their carrying amount, with no impairment or reversal of impairment recognized.

8. Property, plant and equipment:

Cost	Total
Balance, January 1, 2018	$ 2,414,325
Additions	103,219
Acquisitions	201
Divestitures	(875)
Change in decommissioning obligations	730
Capitalized share-based compensation	6,381
Balance, December 31, 2018	$ 2,523,981
Additions	114,094
Acquisitions	1,570
Increase in right-of-use assets	3,974
Transfer to assets held for sale (note 7)	(21,824)
Divestitures	(1,300)
Change in decommissioning obligations	686
Capitalized share-based compensation	4,897
Balance, December 31, 2019	**$ 2,626,078**

Accumulated depletion and depreciation	Total
Balance, January 1, 2018	$ 1,073,589
Depletion and depreciation expense	77,373
Balance, December 31, 2018	$ 1,150,962
Depletion and depreciation expense	75,776
Divestitures	(309)
Transfer to assets held for sale (note 7)	(1,979)
Balance, December 31, 2019	**$ 1,224,450**

Net book value	Total
Balance, December 31, 2019	**$ 1,401,628**
Balance, December 31, 2018	$ 1,373,019

The calculation of depletion for the three months ended December 31, 2019 included estimated future development costs of $1,787.2 million (December 31, 2018 - $1,894.4 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $70.6 million (December 31, 2018 - $70.5 million) and undeveloped land of $155.7 million (December 31, 2018 - $159.3 million) related to future development acreage, with no associated reserves.

During 2019, the Company disposed of non-core lands with no associated production or assigned reserves, for gross proceeds of $20.8 million. The lands consisted of petroleum and natural gas properties and undeveloped land with a net book value of $1.1 million and associated decommissioning obligations of $0.3 million, resulting in a gain of $20.0 million.

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

9. Impairment:

	Year Ended December 31, 2019	Year Ended December 31, 2018
Impairment losses:		
property, plant and equipment	**$ -**	$ -
	$ -	$ -

Assessment:

At December 31, 2019 and 2018, 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 and Lloydminster CGU for impairment.

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, 2019, the Company used value in use, discounted at pre-tax rates between 10% and 30% (December 31, 2018 – 10% and 30%) dependent on the risk profile of the reserve category and CGU.

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 2019 assessment:

The following estimates were used in determining whether an impairment or reversal to the carrying value of the CGU existed at December 31, 2019:

	WTI Oil (US$/bbl)	WCS ($CDN/bbl)	AECO Gas ($CDN/mmbtu)	$US/$CDN
2020	61.00	59.81	2.04	0.76
2021	65.00	63.98	2.27	0.77
2022	67.00	63.77	2.81	0.80
2023	68.34	65.04	2.89	0.80
2024	69.71	66.34	2.98	0.80
2025	71.10	67.67	3.06	0.80
2026	72.52	69.02	3.15	0.80
2027	73.97	70.40	3.24	0.80
2028	75.45	71.81	3.33	0.80
2029	76.96	73.25	3.42	0.80
2030	78.50	74.71	3.51	0.80
Remainder	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.80 thereafter

At December 31, 2019, due to weakness in the Canadian commodity price environment and the depressed share price of the Company, the Company tested its northeast British Columbia CGU and Lloydminster CGU for impairment. It was determined that the recoverable amount of the northeast British Columbia CGU and Lloydminster CGU exceeded their carrying value and an impairment charge was not recorded.

(b) Results of 2018 assessment:

The following estimates were used in determining whether an impairment or reversal to the carrying value of the CGUs existed at December 31, 2018:

	WTI Oil (US$/bbl)	WCS ($CDN/bbl)	AECO Gas ($CDN/mmbtu)	$US/$CDN
2019	63.00	59.47	1.95	0.77
2020	67.00	62.31	2.44	0.80
2021	70.00	67.45	3.00	0.80
2022	71.40	69.53	3.21	0.80
2023	72.83	71.66	3.30	0.80
2024	74.28	73.10	3.39	0.80
2025	75.77	74.56	3.49	0.80
2026	77.29	76.05	3.58	0.80
2027	78.83	77.57	3.68	0.80
2028	80.41	79.12	3.78	0.80
2029	82.02	80.70	3.88	0.80
Remainder	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.80 thereafter

At December 31, 2018, due to weakness in the Canadian commodity price environment, the Company tested its northeast British Columbia CGU and Lloydminster CGU for impairment. It was determined that the recoverable amount of the northeast British Columbia CGU and Lloydminster CGU exceeded their carrying value and an impairment charge was not recorded.

10. Bank loan:

As at December 31, 2019, 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 4, 2020. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 per cent and all outstanding advances thereunder will become repayable in one year from the extension date. The available lending limits of the Facility (the "Borrowing Base") are reviewed semi-annually and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. The Facility requires the Company to maintain a Liability Management Rating ("LMR") of greater than 1.2:1 in the provinces of Alberta and Saskatchewan, and greater than 2.0:1 in the province of British Columbia, if the uninflated, undiscounted abandonment and reclamation liabilities ("Decommissioning Obligations"), as determined by the individual province, is greater than $20 million. If the LMR falls below the required level in any province, the lenders have the option to re-determine the Borrowing Base. As at December 31, 2019, the Company's Decommissioning Obligations exceeded $20 million in the provinces of Alberta and British Columbia, which carried an LMR of 1.8:1 and 7.0:1, respectively. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled Borrowing Base review on or before June 4, 2020. The Facility is secured by a floating charge debenture and a general securities agreement on all the assets of the Company.

Advances under the Facility are available by way of prime rate loans with interest rates between 0.50 percent and 2.50 percent over the bank's prime lending rate and bankers' acceptances and LIBOR loans, which are subject to stamping fees and margins ranging from 1.50 percent to 3.50 percent depending upon the debt to EBITDA ratio of the Company calculated at the Company's previous quarter end. Standby fees are charged on the undrawn Facility at rates ranging from 0.338 percent to 0.788 percent depending upon the debt to EBITDA ratio. As at December 31, 2019, the Company's applicable pricing included a 0.50 percent margin on prime lending, a 1.50 percent stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.338 percent per annum standby fee on the portion of the Facility that is not drawn. Borrowing margins and fees are reviewed annually as part of the bank syndicate's annual renewal.

At December 31, 2019, the Company had issued letters of credit totaling $11.4 million (December 31, 2018 - $20.9 million).

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%

(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.

At December 31, 2019, the carrying value of the 2024 Notes was net of deferred financing costs of $4.1 million (December 31, 2018 – $5.1 million).

12. Lease obligations:

		As at December 31, 2019
Less than 1 year	$	**290**
1 – 3 years		**244**
After 3 years		**2,847**
Total undiscounted future lease payments	$	**3,381**
Total undiscounted future interest payments		**(485)**
Present value of lease obligations	$	**2,896**
Current portion of lease obligations, included in accounts payable and accrued liabilities		**(188)**
Long-term portion of lease obligations	$	**2,708**

		Year ended December 31, 2019
Principal payments	$	**1,071**
Interest payments		**100**
Total cash outflow	$	**1,171**

The Company's total undiscounted future lease payments of $3.4 million equate to future operating lease obligations. This amount excludes commitments for firm transportation and processing agreements, as disclosed in note 20, as they do not meet the definition of a lease as the Company does not control the asset or receive substantially all of the asset's economic benefits.

13. Decommissioning obligations:

		As at December 31, 2019		As at December 31, 2018
Decommissioning obligations, beginning of year	$	**89,448**	$	88,368
Obligations incurred		**3,481**		1,523
Obligations settled		**(3,919)**		(1,194)
Obligations divested		**(351)**		(414)
Change in estimated future cash outflows		**(2,795)**		(793)
Accretion of decommissioning obligations		**1,901**		1,958
Transferred to liabilities associated with assets held for sale		**(741)**		-
Decommissioning obligations, end of year	$	**87,024**	$	89,448

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning obligations to be $87.0 million as at December 31, 2019 (December 31, 2018 - $89.4 million) based on an inflation adjusted undiscounted total future liability of $110.1 million (December 31, 2018 - $117.8 million). These payments are expected to be made over the next 40 years with the majority of costs to be incurred between 2022 and 2036. The inflation rate applied to the liability is 1.35% (December 31, 2018 – 2%). The discount factor, being the risk-free rate related to the liability, is 1.76% (December 31, 2018 – 2.13%). The $2.8 million (December 31, 2018 - $0.8 million) change in estimated future cash outflows is a result of a change in the inflation rate, discount factor and estimated future obligations.

14. Share capital:

At December 31, 2019, the Company was authorized to issue an unlimited number of common shares with the holders of common shares entitled to one vote per share.

Restricted and Performance Award Incentive Plan:

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

Subject to terms and conditions of the RPAP, each RA and PA entitles the holder to an award value to be typically paid as to one-third on each of the first, second and third anniversaries of the date of grant. For the purpose of calculating share-based compensation, the fair value of each award is determined at the grant date using the closing price of the common shares. In the case of PAs, the award value is adjusted for a payout multiplier which can range from 0.0 to 2.0 and is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. On the vesting dates, the Company has the option of settling the award value in cash or common shares of the Company.

Subsequent to May 21, 2018, being the third anniversary from the date the Company last obtained approval from shareholders for the continued issuance of common shares from treasury under the RPAP, the Company is no longer eligible to issue common shares from treasury to settle the award value of any newly granted RAs and PAs. The Company remains eligible to settle the award value for any such grants either in cash or in common shares acquired by an independent trustee in the open market for such purposes. Common shares acquired in the open market are held in trust for the potential future settlement of award values and are netted out of share capital, including the cumulative purchase cost, until they are distributed for future settlements. For the year ended December 31, 2019, the trustee purchased 4,783,000 common shares for a total cost of $5.0 million and as at December 31, 2019, holds 4,738,000 common shares in trust.

Upon the vesting of 1,459,000 RAs and 2,036,000 PAs, when taking into account the earned multipliers for PAs, 4,542,000 common shares of the Company were issued from treasury and 45,000 common shares were released from trust in settlement of such awards for the year ended December 31, 2019.

The number of RAs and PAs outstanding are as follows:

	Number of RAs	Number of PAs
Balance January 1, 2018	1,616	2,221
Granted	2,628	3,427
Vested	(729)	(989)
Forfeited	(78)	(164)
Balance December 31, 2018	3,437	4,495
Granted	1,825	2,050
Vested	(1,459)	(2,036)
Forfeited	(190)	(337)
Balance December 31, 2019	**3,613**	**4,172**

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, 2019 was 151,893,000 (December 31, 2018 – 151,095,000).

In computing diluted earnings per share for the year ended December 31, 2019, 38,000 (December 31, 2018 – 725,000) shares were added to the basic weighted average common shares outstanding to account for the dilution of RAs and PAs that will be settled with common shares issued from treasury. There were 4,662,000 (December 31, 2018 – 8,773,000) RAs and PAs 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 $0.86 during the year ended December 31, 2019 (December 31, 2018 - $1.95).

15. Income taxes:

(a) Deferred income tax expense:

The deferred income tax expense 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 before income taxes. This difference results from the following items:

	Year ended December 31, 2019	Year ended December 31, 2018
Income before income taxes	**$ 12,836**	$ 23,170
Combined federal and provincial income tax rate	**26.7%**	27.0%
Computed "expected" income tax expense	**$ 3,431**	$ 6,256
Increase (decrease) in income taxes resulting from:		
Change in income tax rates	**(4,633)**	-
Non-deductible expenses and other	**36**	63
Change in share-based compensation estimate	**1,931**	4,052
Deferred income tax expense	**$ 765**	$ 10,371

In 2019, the blended statutory tax rate was 26.7% (December 31, 2018 – 27.00%). In the second quarter of 2019, the Alberta government enacted a decrease in the Alberta corporate income tax rate from 12% to 11% effective July 1, 2019, with a further reduction of 1% on January 1st for each of the years 2020, 2021 and 2022 bringing the provincial rate to 8%.

(b) Deferred income tax liability:

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

	December 31, 2019	December 31, 2018
Deferred tax liabilities:		
Property, plant and equipment	**$ 144,436**	$ 158,926
Derivative financial instruments	**789**	2,263
Other	**7,369**	6,362
Deferred tax assets:		
Decommissioning obligations	**$ (21,766)**	$ (24,151)
Non-capital losses	**(77,265)**	(90,602)
Deferred income tax liability	**$ 53,563**	$ 52,798

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

	January 1, 2019	Recognized in equity	Recognized in other	Recognized in statements of income	December 31, 2019
Property, plant and equipment	$ 158,926	$ -	$ -	$ (14,490)	$ 144,436
Decommissioning obligations	(24,151)	-	-	2,385	(21,766)
Derivative financial instruments	2,263	-	-	(1,475)	788
Non-capital losses	(90,602)	-	-	13,337	(77,265)
Other	6,362	-	-	1,008	7,370
	$ 52,798	**$ -**	**$ -**	**$ 765**	**$ 53,563**

	January 1, 2018	Recognized in equity	Recognized in other	Recognized in statements of income	December 31, 2018
Property, plant and equipment	$ 132,749	$ -	$ -	$ 26,177	$ 158,926
Decommissioning obligations	(23,859)	-	-	(292)	(24,151)
Derivative financial instruments	94	-	-	2,169	2,263
Non-capital losses	(69,409)	-	-	(21,193)	(90,602)
Other	2,852	-	-	3,510	6,362
	$ 42,427	**$ -**	**$ -**	**$ 10,371**	**$ 52,798**

The Company's assets have an approximate tax basis of $1,101.0 million at December 31, 2019 (December 31, 2018 - $1,081.9 million) available for deduction against future taxable income. The following table summarizes the tax pools:

	December 31, 2019	December 31, 2018
Cumulative Canadian Exploration Expense	**$ 293,400**	$ 291,400
Cumulative Canadian Development Expense	**282,900**	238,800
Undepreciated Capital Costs	**202,400**	202,800
Non-capital losses	**311,600**	335,600
Share issue costs	**2,800**	5,300
Other	**7,900**	8,000
Estimated tax basis	**$ 1,101,000**	$ 1,081,900

Non-capital losses will begin expiring in 2028. The estimated income tax pools for 2019 have been reduced by the estimated deferred partnership income for 2019.

16. Revenue:

Petroleum and natural gas sales:

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

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

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

	Year ended December 31, 2019	Year ended December 31, 2018
Light crude oil	**$ 4,993**	$ 6,582
Heavy crude oil	**30,310**	25,548
Natural gas liquids	**5,086**	14,900
Condensate	**63,290**	62,731
Natural gas	**89,853**	108,624
	$ 193,532	$ 218,385

Other revenue:

The following table summarizes the Company's other revenue:

	Year ended December 31, 2019	Year ended December 31, 2018
Marketing revenue	**$ 8,658**	$ 6,855
Processing revenue	**3,090**	4,134
Other	**-**	1,000
	$ 11,748	$ 11,989

17. Financing:

	Year ended December 31, 2019	Year ended December 31, 2018
Interest expense	**$ 23,516**	$ 22,235
Gain on lease modification	**(7)**	-
Accretion of deferred financing costs	**983**	1,023
Accretion of decommissioning obligations	**1,901**	1,958
	$ 26,393	$ 25,216

18. Key personnel expenses:

The aggregate payroll expense of key personnel was as follows:

	Year ended December 31, 2019	Year ended December 31, 2018
Short-term benefits	**$ 3,579**	$ 3,545
Long-term benefits	**4,905**	6,836
	$ 8,484	$ 10,381

Crew has determined that its key personnel include both officers and the Company's Board of 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.

19. Supplemental cash flow information:

Changes in non-cash working capital is comprised of:

	Year ended December 31, 2019	Year ended December 31, 2018
Changes in non-cash working capital:		
Accounts receivable	$ 43,528	$ (29,592)
Accounts payable and accrued liabilities	(12,589)	(11,535)
Other long-term assets	-	3,447
	$ 30,939	$ (37,680)
Operating activities	$ 3,297	$ (2,663)
Investing activities	27,454	(35,017)
Current portion of lease obligations, included in accounts payable and accrued liabilities	188	-
	$ 30,939	$ (37,680)
Interest paid	$ (22,871)	$ (22,167)

20. Commitments:

	Total	2020	2021	2022	2023	2024	Thereafter
Firm transportation agreements	$ 240,332	$ 48,467	$42,804	$30,753	$25,994	$25,524	$ 66,790
Firm processing agreement	94,558	16,337	12,354	12,354	12,354	12,388	28,771
Total	**$ 334,890**	**$64,804**	**$55,158**	**$43,107**	**$38,348**	**$37,912**	**$ 95,561**

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 Greater Septimus complex gas processing facilities in northeast British Columbia.