Focus on Value Creation

Crew Energy Inc. Annual Report

2018

ABOUT CREW

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

Corporate Information

AUDITORS
KPMG LLP

LEGAL COUNSEL
Burnet, Duckworth & Palmer LLP

RESERVE ENGINEERS
Sproule Associates Ltd.

TRANSFER AGENT
Odyssey Trust

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

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CREW ENERGY INC. 2018 ANNUAL REPORT

Crew Energy Inc. (TSX: CR) ("Crew" or the "Company") is pleased to announce our operating and financial results for the three and twelve month periods ended December 31, 2018. Crew's full audited consolidated Financial Statements and Notes, as well as Management's Discussion and Analysis ("MD&A") for the three and twelve month periods ended December 31, 2018 are available on Crew's website and filed on SEDAR at www.sedar.com.

Q4 & FULL YEAR 2018 HIGHLIGHTS

- **Improving Capital Efficiencies and Robust Recycle Ratios[1]**: Crew's 2P finding and development ("F&D") and finding, development and acquisition ("FD&A") costs (both including changes in future development capital) were $4.72 per boe and $4.52 per boe, respectively, while F&D recycle ratios for proved developed producing, total proved and proved plus probable reserves were 1.4x, 2.3x and 3.4x respectively, demonstrating improvement over prior years and reflecting the success of the Company's 2018 drilling program. Proved developed producing reserves were 60.2 million boe and had a net present value discounted at 10% of $508 million, including $2.3 million of future development capital, which equates to $1.10 per share after the deduction of net debt.

- **2018 Production of 23,885 boe per day:** 2018 volumes increased 4% over 2017 and were within guidance of 23,500 and 24,500 boe per day including 2,380 bbls per day of condensate, an increase of 16% over 2017. Q4 2018 production averaged 22,383 boe per day within guidance of 22,000 and 23,000 boe per day, reflecting an average of 1,790 boe per day that was curtailed in the quarter due to low prices, and condensate volumes that were 18% higher than in Q3 2018.

- **Quarterly Adjusted Funds Flow ("AFF")[2] 18% Higher**: Q4 AFF totaled $23.7 million or $0.16 per fully diluted share, 18% higher than the $20.1 million or $0.13 per fully diluted share in Q3 2018, reflecting improved realized natural gas prices, reduced hedging losses and a 7% decline in net operating costs. AFF was supported by a strong operating netback[1] at Greater Septimus of $18.53 per boe in Q4, which reflects an 8% increase in production, improved gas prices, lower net operating and transportation costs.

- **Rising Montney Condensate Weighting:** Q4 2018 condensate volumes totaled 2,446 bbls per day, representing 11% of quarterly production and 23% of quarterly revenue. Full year 2018 condensate volumes of 2,380 bbls per day contributed 29% to annual revenue as Crew's focus on development opportunities in the higher-value Ultra-Condensate Rich ("UCR") area at West Septimus continued.

- **Outperformed AECO Natural Gas Prices:** Average realized natural gas prices for the quarter outperformed the AECO 5A benchmark by 144%, driven by the Company's exposure to diversified natural gas markets outside of Western Canada which will continue in 2019. Crew's Q4 2018 realized natural gas price of $3.80 per mcf represents a 44% increase over $2.64 per mcf in Q4 2017 and a 58% increase over Q3 2018.

- **Balancing Capital Expenditures with AFF to Maintain Financial Flexibility:** Net capital expenditures in 2018 totaled $93.4 million and approximated AFF of $92.0 million. Year-end net debt totaled $342.8 million, which is $2.2 million lower than at year-end 2017, and includes $300 million of term debt due in 2024 with no financial maintenance covenants.

- **Non-Core Asset Disposition:** Consistent with our strategy to continue high-grading our portfolio of assets, in Q1 2019, Crew has closed the sale of non-core land with no associated production or assigned reserves, for gross proceeds of $17.5 million which will be directed to debt repayment, strengthening the balance sheet.

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[1] "Finding, Development and Acquisitions costs" or "FD&A costs", "Finding and Development costs" or "F&D costs", "recycle ratio" and "operating netback" as previously disclosed in Crew's February 7, 2019 reserves press release, do not have standardized meanings. See "Information Regarding Disclosure on Oil and Gas Reserves, Operational Information" and Non-IFRS Measures contained in this annual report.

[2] Non-IFRS measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-IFRS Measures" contained within the Company's MD&A filed on SEDAR.

FINANCIAL & OPERATING HIGHLIGHTS

FINANCIAL ($ thousands, except per share amounts)	**Three months ended Dec. 31, 2018**	Three months ended Dec. 31, 2017	**Year ended Dec. 31, 2018**	Year ended Dec. 31, 2017
Petroleum and natural gas sales	**50,838**	60,146	**218,385**	214,154
Adjusted Funds Flow(1)	**23,712**	34,087	**91,996**	108,129
Per share - basic	**0.16**	0.23	**0.61**	0.73
- diluted	**0.16**	0.22	**0.61**	0.72
Net income	**18,771**	2,342	**12,799**	34,405
Per share - basic	**0.12**	0.02	**0.08**	0.23
- diluted	**0.12**	0.02	**0.08**	0.23
Exploration and Development expenditures	**33,174**	36,413	**103,219**	238,302
Property acquisitions (net of dispositions)	**175**	(1,709)	**(9,806)**	(47,906)
Net capital expenditures	**33,349**	34,704	**93,413**	190,396

Capital Structure ($ thousands)	**As at Dec. 31, 2018**	As at Dec. 31, 2017
Working capital (surplus) / deficiency(2)	**(11,984)**	29,143
Bank loan	**59,904**	21,977
	47,920	51,120
Senior Unsecured Notes	**294,885**	293,862
Total Net Debt	**342,805**	344,982
Current Debt Capacity(3)	**535,000**	535,000
Common Shares Outstanding (thousands)	**151,730**	149,328

Notes:

(1) AFF is calculated as cash provided by operating activities, adding the change in non-cash working capital, decommissioning obligation expenditures and accretion of deferred financing costs on the senior unsecured notes. AFF does not have a standardized measure prescribed by International Financial Reporting Standards, ("IFRS") and therefore may not be comparable with the calculations of similar measures for other companies. See "Non-IFRS Measures" contained within Crew's MD&A for details including a reconciliation of AFF to its most closely related IFRS measure.

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

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

Operations	**Three months ended Dec. 31, 2018**	Three months ended Dec. 31, 2017	**Year ended Dec. 31, 2018**	Year ended Dec. 31, 2017
Daily production				
Light crude oil (bbl/d)	**260**	399	**276**	495
Heavy crude oil (bbl/d)	**1,634**	1,808	**1,782**	1,836
Condensate (bbl/d)	**2,446**	2,617	**2,380**	2,048
Other natural gas liquids (bbl/d)	**1,832**	1,823	**1,761**	1,575
Natural gas (mcf/d)	**97,265**	111,737	**106,116**	102,642
Total (boe/d @ 6:1)	**22,383**	25,270	**23,885**	23,061
Average prices (1)				
Light crude oil ($/bbl)	**38.18**	64.91	**65.32**	58.34
Heavy crude oil ($/bbl)	**10.38**	48.73	**39.27**	45.14
Condensate ($/bbl)	**52.85**	69.60	**72.22**	62.03
Other natural gas liquids ($/bbl)	**14.71**	34.58	**23.18**	24.45
Natural gas ($/mcf)	**3.80**	2.64	**2.80**	3.01
Oil equivalent ($/boe)	**24.69**	25.87	**25.05**	25.44

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

	Three months ended Dec. 31, 2018	Three months ended Dec. 31, 2017	**Year ended Dec. 31, 2018**	Year ended Dec. 31, 2017
Netback ($/boe)				
Petroleum and natural gas sales	**24.69**	25.87	**25.05**	25.44
Royalties	**(1.67)**	(1.59)	**(1.73)**	(1.80)
Realized commodity hedging (loss)/gain	**(0.63)**	1.60	**(1.22)**	1.19
Marketing income(1)	**1.03**	-	**0.45**	-
Net operating costs(2)	**(5.78)**	(5.90)	**(6.22)**	(5.82)
Transportation costs	**(1.81)**	(1.94)	**(1.84)**	(2.27)
Operating netback (3)	**15.83**	18.04	**14.49**	16.74
G&A	**(1.55)**	(1.36)	**(1.39)**	(1.42)
Other income	**-**	0.43	**0.11**	0.12
Financing costs on long-term debt	**(2.77)**	(2.45)	**(2.67)**	(2.61)
Adjusted funds flow	**11.51**	14.66	**10.54**	12.83
Drilling Activity				
Gross wells	**8.0**	5	**14**	40
Working interest wells	**8.0**	3.9	**14**	38.2
Success rate, net wells (%)	**100%**	100%	**100%**	97%

Notes:
(1) Marketing income was recognized from the monetization of forward physical sales contracts offset by the cost of committed natural gas transportation that was not available during the period.
(2) Net operating costs are calculated as gross operating costs less processing revenue.
(3) Operating netback equals petroleum and natural gas sales including realized hedging gains and losses on commodity contracts, marketing income, less royalties, net operating costs and transportation costs calculated on a boe basis. Operating netback and adjusted funds flow netback do not have a standardized measure prescribed by IFRS and therefore may not be comparable with the calculations of similar measures for other companies. See "Non-IFRS Measures" contained within Crew's MD&A.

FINANCIAL OVERVIEW

Production In Line with Guidance

- Volumes for the quarter and full year averaged 22,383 boe per day and 23,885 boe per day, respectively, in line with our guidance for both periods of 22,000 to 23,000 boe per day and of 23,500 to 24,500 boe per day, respectively, despite curtailing an average of 1,790 boe per day of production in the fourth quarter. Annual volumes increased 4% over 2017, due to our successful West Septimus drilling and completions program.
- In the interests of preserving value, during Q4, 2018 an average of 1,340 boe per day of non-Montney natural gas production and 450 bbls per day of Lloydminster heavy crude oil volumes were shut-in due to low pricing. Improvements in the oil differential have supported bringing these volumes back on line earlier than anticipated in 2019.
- Greater Septimus production averaged 18,447 boe per day in Q4 2018 compared to 19,240 boe per day in Q3 2018 and 20,193 boe per day in Q4 2017 as wells were shut-in for offsetting completion operations during the quarter.

Revenue Contributions Reflect Pricing Environment

- Through most of 2018, world crude oil prices outperformed 2017 as production curtailments implemented by the Organization of the Petroleum Exporting Countries ("OPEC") in early 2018 helped reduce global supply and bolster benchmark oil prices. The overall price Crew received for our liquids production over the first three quarters of 2018 outperformed the same period of 2017 by 26%.
- During Q4, Canada's lack of adequate pipeline egress and crude-by-rail capacity caused a severe and sudden widening of the Canadian crude oil price differential relative to US prices. In addition, the continued strengthening of US shale oil production and a slowing global economy led to a return to an oversupplied world oil market, resulting in benchmark world prices declining significantly at the end of the year. As a result, Canadian benchmark crude oil prices, including light sweet crude and particularly Western Canadian Select ("WCS"), were subject to significantly wider discounts relative to declining global oil prices in the fourth quarter.
- Due to the severely depressed crude oil and liquids benchmark pricing during Q4, 2018, liquids contributed 33% to Crew's total revenue compared to 56% in Q3 2018, and 55% in Q4 2017.
- As condensate prices are linked to the price of Canadian light crude prices, and also impacted by the demand for Canadian heavy oil, realized condensate prices in Q4 declined 35% compared to the previous quarter, and 24% compared to Q4 2017. Overall, 2018 condensate prices benefited from stronger world oil prices and hence were 16% higher than in 2017, averaging $72.22 per bbl.
- In 2018, Canadian natural gas prices continued to be impacted by oversupply and the lack of egress outside of the major natural gas producing areas of western Canada. As a result, the Canadian benchmark AECO price declined 31% over 2017 to average $1.50 per mcf compared to $2.16 per mcf in 2017. With approximately 40% of 2018 natural gas sold at Chicago pricing and another 21% sold into the strong Alliance spot market, Crew's 2018 natural gas sales price averaged $2.80 per mcf, representing a decline of 7% compared to 2017.
- In the fourth quarter, the Company continued to diversify our gas marketing portfolio with the addition of a contract at NYMEX-linked pricing. With 56% of our fourth quarter natural gas sales tied to US pricing hubs, the Company benefited from a spike in US prices due to early winter cold weather experienced in the gas-consuming regions of the midwest and eastern US. The early cold pushed Chicago prices to average C$4.13 per mcf in Q4 compared to C$2.92 per mcf in the third quarter.
- Crew's Q4 2018 realized natural gas price of $3.80 per mcf was 58% higher than in Q3 2018 and 44% higher than Q4 2017 and represents a $2.24 premium over the average AECO benchmark price of $1.56 per mcf.

Improving Gas Prices and Lower Operating Costs Improves AFF

- Significantly higher natural gas prices supported Crew's AFF in Q4 2018 which totaled $23.7 million ($0.16 per diluted share), an increase of 18% over the previous quarter, while the severely depressed liquids and condensate prices combined with lower production caused Q4 2018 AFF to be 30% lower than the same period in 2017. For the full year 2018, our AFF totaled $92.0 million ($0.61 per diluted share), which was lower than the prior year largely due to a realized hedging gain recorded in 2017.
- Corporate operating netbacks in Q4 2018 improved by 18% over Q3 to average $15.83 per boe benefitting from improved gas pricing, lower realized hedging losses and lower operating costs per boe. Crew's Q4 and full year 2018 operating netbacks were 12% and 13% lower than the same periods in 2017.
- Crew's continued focus on controlling costs contributed to lower net operating costs in Q4 2018 compared to Q3 and to Q4 2017, while Q4 and full year 2018 transportation expenses per boe improved 7% and 19%, respectively, over the same periods in 2017.

Capital Expenditures Targeting Higher Margin Liquids

- Q4 2018 net capital expenditures totaled $33.3 million and 2018 expenditures totaled $93.4 million. Of the Q4 capital, approximately $32.8 million was directed to drilling and completion activities, with $3.9 million spent on land, seismic, recompletions and other miscellaneous items.
- During Q4 2018, the Company drilled six (6.0 net) and completed three (3.0 net) natural gas wells in the UCR area at West Septimus and drilled two (2.0 net) heavy oil wells, completed three (3.0 net) and recompleted two (2.0 net) heavy oil wells in Lloydminster.

Stable Net Debt Supports Ongoing Financial Flexibility

- Ending 2018 net debt of $342.8 million was 1% lower than year end 2017 and includes $300 million of term debt with no financial maintenance covenants or repayment required until 2024, as well as a $235 million credit facility that was only 20% drawn after adjusting for a working capital surplus of approximately $12 million at year end.

TRANSPORTATION, MARKETING & HEDGING

Diversified Market Access Underpins Strategy

- Crew strategically chose to monetize the inherent value in our Dawn, Sumas and Malin market exposure during 2018, which resulted in marketing revenue being realized in Q4 and for the year ended December 31, 2018, of $3.0 million and $6.9 million, respectively.
- For 2019, our natural gas sales exposure is currently expected to be approximately 43% to Chicago, 16% to NYMEX, 15% to Dawn, 10% to Alliance ATP, 8% to Malin, 4% to Station 2 and 4% to AECO 5A.
- The strategic pipeline from our West Septimus facility through Groundbirch connecting to the existing TCPL Saturn #2 meter station was completed late in 2018, affording our Greater Septimus gas processing complex access to the Alliance Pipeline System, Enbridge T-North System, and the TCPL/Nova System. This strategic access allows for increased exposure to further capitalize on relative pricing opportunities available on all three pipelines.

Natural Gas & Liquids Hedging

- Approximately 36% of Crew's budgeted 2019 natural gas volumes are hedged at $2.57 per GJ or approximately $2.71 per mcf, which increases to approximately $3.19 per mcf after adjusting for Crew's higher heat content natural gas.
- Natural gas hedges currently include 25,000 mmbtu per day of Chicago gas at C$3.53 per mmbtu, 7,500 mmbtu per day of Dawn gas at C$3.55 per mmbtu and 10,000 mmbtu per day of NYMEX gas at US$2.95 per mmbtu.

- For liquids, 1,874 bbls per day of WTI are hedged at an average price of C$75.99 per bbl for 2019 and 500 bbls per day of WCS hedged for the first half of 2019 at an average price of C$52.93 per bbl. In addition, Crew has 250 bbls per day of WCS differential hedged at C$25.75 per bbl for the first half of 2019 and 500 bbls per day of WCS differential hedged at C$25.23 per bbl for the second half of 2019.

OPERATIONS & AREA OVERVIEW

NE BC Montney - Greater Septimus

- In Q4, the final well on a five-well pad was drilled in the UCR area using a revised well design. The Company has continued to refine a number of variables in our drilling operations to improve efficiencies and as a result, have seen a 34% reduction in costs per metre of lateral length drilled. Crew continues to trial different lateral lengths, fluid systems, drill bits, downhole assemblies and fracture intensities in order to optimize cost and production efficiencies.
- Three wells on Crew's 15-20 five well pad were completed in the fourth quarter of 2018 and produced for 25 days in December before being shut-in to accommodate offsetting fracture operations of adjacent wells occurring in January and February. The three wells were producing at a combined sales rate of 4,584 boe per day (61% liquids), for an average per well rate of 1,528 boe per day comprised of 3.6 mmcf per day (599 boe per day) of sales gas, 776 bbls per day of condensate and 153 bbls per day of natural gas liquids ("NGL"). The condensate-gas ratio averaged 216 bbls per mmcf. In 2019, Crew plans on drilling six (6.0 net) UCR wells and completing ten (10.0 net) in the Greater Septimus area.

Greater Septimus Operational Statistics

Production & Drilling	**Q4 2018**	Q3 2018	Q2 2018	Q1 2018	Q4 2017
Average daily production (boe/d)	**18,447**	19,240	18,953	20,467	20,193
Wells drilled (gross / net)	**6 (6.0)**	4 / 4.0	-	-	5 / 3.9
Wells completed (gross / net)	**3 (3.0)**	0 / 0	2 / 1.6	9 / 7.7	3 / 3.0

Operating Netback ($ per boe)	**Q4 2018**	Q3 2018	Q2 2018	Q1 2018	Q4 2017
Revenue	**26.53**	22.83	22.70	25.40	24.43
Royalties	**(1.58)**	(1.15)	(1.35)	(1.50)	(1.19)
Realized commodity hedge (loss) / gain	**(1.79)**	(2.01)	(1.32)	(1.01)	1.74
Marketing income (1)	**1.23**	0.34	0.34	0.37	-
Net operating costs(2)	**(4.51)**	(4.61)	(4.71)	(4.45)	(3.67)
Transportation costs	**(1.35)**	(1.22)	(1.40)	(1.51)	(1.51)
Operating netback(3)	**18.53**	14.18	14.26	17.30	19.80

Notes:
(1) Marketing income was recognized from the monetization of forward physical sales contracts offset by the cost of committed natural gas transportation that was not available during the period.
(2) Net operating costs are calculated as gross operating costs less processing revenue.
(3) Operating netback equals petroleum and natural gas sales including realized hedging gains and losses on commodity contracts, marking income, less royalties, net operating costs and transportation costs calculated on a boe basis. Operating netback does not have a standardized measure prescribed by IFRS and therefore may not be comparable with the calculations of similar measures for other companies. See "Non-IFRS Measures" contained within Crew's MD&A.

Other NE BC Montney

- **Tower**: Production at Tower averaged 858 boe per day in Q4 2018 and 910 boe per day during 2018. Crew continues to evaluate the relative economics of Tower development as well as encouraging nearby Lower Montney well results.
- **Attachie**: Of Crew's 97 sections of land in this area, approximately 45 sections are situated within the liquids-rich hydrocarbon window. Given the positive results generated by offsetting operators, a lease retention well was drilled in January and finished on schedule and under budget.
- **Oak / Flatrock**: Drilling activity is gaining momentum for liquids-rich gas in this area where Crew has over 60 sections of land. We will continue to monitor industry activity and offsetting well results from this area.

AB / SK Heavy Oil - Lloydminster

- Q4 heavy oil activity at Lloydminster included drilling two (2.0 net) wells, completing three (3.0 net) wells and recompleting two (2.0 net) heavy oil wells, which resulted in average production volumes of 1,638 boe per day for the quarter. Production volumes were 9% lower than Q4 2017 due to shutting in lower margin production caused by extremely wide differentials along with minimal capital investment in 2018, given Crew's investment focused in the higher-return UCR area at West Septimus.
- WCS pricing differentials widened significantly in the fourth quarter with operating netbacks at Lloydminster averaging $2.27 per boe in the period. With differentials reaching unprecedented levels, Crew elected to reduce activity levels and preserve value by shutting-in up to 700 bbls per day, for an average of 450 bbls per day of shut-in heavy oil production in Q4.
- Crew plans on drilling three (3.0 net) multi-lateral horizontal wells in this area in 2019 should prices be supportive.

OUTLOOK

Increasing Liquids Production and Margin Expansion

- With an active drilling and completion program planned in the UCR area at West Septimus in 2019, Crew's production will continue to reflect our ongoing goal of increasing the weighting of condensate in our production mix, contributing to continued improvements in realized pricing and operating netbacks. Under current strip pricing, the UCR wells being drilled by Crew are expected to generate robust internal rates of return ("IRR") of over 70% with over $6.0 million per well of before tax net present value discounted at 10% (NPV10) [3].
- The Company's focus remains on optimizing netbacks and returns by drilling UCR wells that target condensate - gas ratios of 150 to 250 bbls per mmcf and are expected to pay out in approximately 12 to18 months at current prices.

Balancing Capital Expenditures with AFF

- Crew's 2019 capital expenditure budget, forecast to range between $95 and $105 million, is expected to approximate annual AFF and will be heavily weighted to the first quarter. This budget is designed to enable the Company to effectively manage our balance sheet and retain flexibility while averaging production of 22,000 to 23,000 boe per day. Proceeds from the sale of non-core assets in Q1 2019 of $17.5 million will be used to pay down bank debt to strengthen our financial position.
- Q1 2019 capital expenditures are expected to be between $60 and $70 million, invested in continued Montney development including the planned drilling of five to six net UCR wells, the completion, equip and tie-in of eight net UCR wells, and the drilling of two net exploratory wells. Crew planned to complete four wells on the 4-21 pad in Q1, and the remaining two wells in Q3. The Company now plans to complete all six wells concurrently which will reduce mobilization costs and avoid production downtime in Q3 that would have resulted from shutting-in wells in order to complete the remaining two wells. Eight UCR wells are expected to be tied-in and on production by the end of May. This will position Crew with approximately

[3] See "Information Regarding Disclosure on Oil and Gas Reserves, Operational Information and Non-IFRS Measures".

$35 to $45 million to complete our 2019 capital program consisting of two net Montney completions, three multi-lateral heavy oil wells and other minor expenditures with excess funds planned to be directed to strengthening the balance sheet.

2018 RESERVES HIGHLIGHTS

With net capital expenditures of $93 million ($103.2 million gross), Crew successfully expanded reserves through the drilling of ten (10.0 net) and completion of 14 (12.2 net) wells in the Montney at West Septimus, of which three (3.0 net) extended reach horizontal ("ERH") wells were drilled in the Ultra-Condensate Rich ("UCR") area. In addition, four (4.0 net) multi-lateral horizontal wells were drilled at Lloydminster.

Highlights of the proved developed producing ("PDP"), total proved ("1P") and total proved plus probable ("2P") reserves from the Sproule Report are provided below. Finding, development and acquisition ("FD&A")[4] costs and finding and development ("F&D")[4] costs include changes in future development capital ("FDC")[4].

- **Improving Capital Efficiencies and Robust Recycle Ratios[4]:** Crew's 2P F&D and FD&A cost per boe has improved over prior years and reflects the success of the Company's UCR drilling program which features enhanced completions design, longer lateral lengths and reduced drill times compared to previous wells. Recycle ratios are based on the estimated corporate operating netback[1] divided by the F&D costs or the FD&A costs.

	F&D per boe	F&D recycle	FD&A per boe	FD&A recycle
PDP	$11.62	1.4x	$10.52	1.5x
1P	$6.82	2.3x	$6.03	2.6x
2P	$4.72	3.4x	$4.52	3.5x

- **Continued Development Success at West Septimus:** PDP reserves at West Septimus increased 10% over 2017, with 1P and 2P reserves up 3% and 2%, respectively, primarily due to the focus on drilling in the UCR area which generates higher returns and stronger economics in the current commodity price environment.
- **Condensate Growth a Focus at West Septimus**: Within the UCR area at West Septimus, shifting to ERH wells led to a 28% increase in 1P reserves to 30,170 mboe, while 2P reserves increased 17% to 71,681 mboe. Condensate increased by 30% on 1P reserves and represents 30% of UCR 2P reserves[5]. Corporate 2P condensate reserves totaled 50,053 mbbl.
- **Meaningful Reserves Value in UCR Area**: Within Crew's UCR area, the net present value of future net revenue discounted at 10% (before tax) ("NPV10 BT") for 2P was $774.1 million[6] assigned to 14 of 32 net prospective sections at West Septimus. Corporately, the Company's NPV10 BT totaled $507.9 million on PDP reserves, $1.2 billion on 1P reserves and $2.5 billion on 2P reserves.
- **ERH Wells Improve Capital Efficiencies:** Crew brought three new ERH wells onto production in late 2018 within our UCR area and has an additional six (6.0 net) wells to bring on in the first quarter of 2019. The Company now has 38 ERH undeveloped 2P locations assigned by Sproule in the UCR area. The ERH program will require fewer wells to develop the resource, resulting in a smaller overall surface footprint providing superior economic returns relative to the previously drilled shorter-reach horizontal wells.

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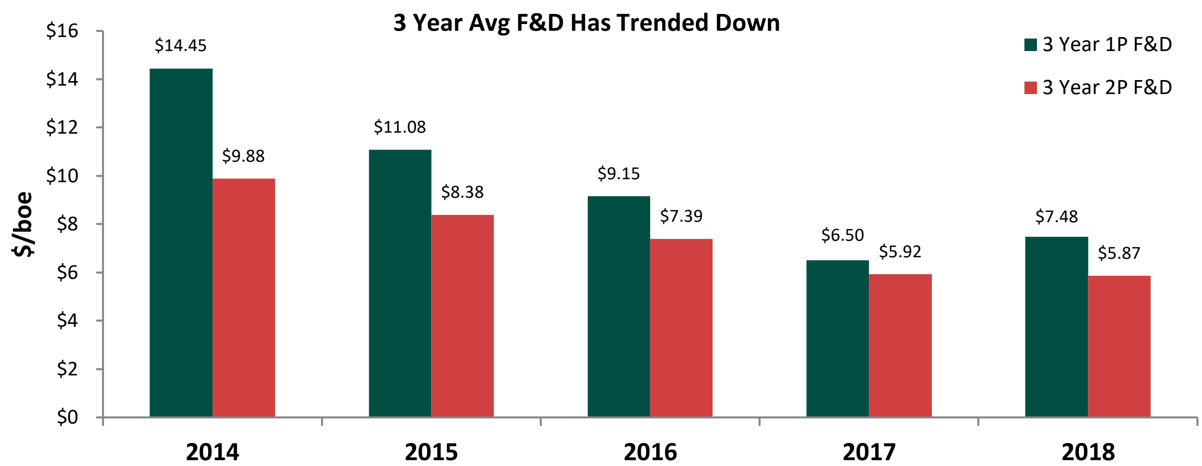
[4] *"Finding, Development and Acquisitions costs" or "FD&A costs", "Finding and Development costs" or "F&D costs", "recycle ratio" and "operating netback" do not have standardized meanings. See the table "Capital Program Efficiency" and "Information Regarding Disclosure on Oil and Gas Reserves, Operational Information and Non-IFRS Measures" contained in this annual report.*

[5] *Condensate reserves referenced herein include wellhead plus plant recovery.*

[6] *Excludes field-level facility and maintenance operating expenses.*

- **Average 3-Year F&D Trending in the Right Direction:** With an ongoing focus on lowering capital costs while improving drilling and completions efficiencies, Crew achieved another consecutive year of declining average three year 2P F&D costs in 2018.



- **Continued Corporate Reserves Growth with Conservative Capital Program**: Approximately $67 million of our $103.2 million exploration and development capital program was directed to drilling and completions activities in 2018. This generated increases across all reserves categories, including approximately 0.3% growth in PDP reserves, 2% in 1P reserves and 11% in 2P reserves compared to 2017, with Crew's reserves replacement ratios[7] on PDP, 1P and 2P totaling 102%, 140% and 568%, respectively.
- **Multilateral Development Increased Heavy Oil Inventory:** Recent success drilling multilateral horizontal wells resulted in additions to overall heavy oil reserves in 2018. Heavy oil multilaterals now represent 32% and 31% of Crew's total 1P and 2P heavy oil reserves, respectively.

2018 RESERVES DETAIL

The detailed reserves data set forth below is based upon an independent reserves assessment and evaluation prepared by Sproule with an effective date of December 31, 2018. The following presentation summarizes the Company's crude oil, natural gas liquids and natural gas reserves and the net present values before income tax of future net revenue for the Company's reserves using forecast prices and costs based on the Sproule Report. The Sproule Report has been prepared in accordance with definitions, standards, and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("NI-51-101"). The reserves evaluation was based on Sproule forecast escalated pricing and foreign exchange rates at December 31, 2018 as outlined in the table herein entitled "Price Forecast".

All evaluations and summaries of future net revenue are stated prior to provision for interest, debt service charges and general administrative expenses and after deduction of royalties, operating costs, estimated well abandonment and reclamation costs for entities with reserves assigned and estimated future capital expenditures associated with reserves. It should not be assumed that the estimates of net present value of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of our crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein. Reserves included herein are stated on a company gross basis (working interest before deduction of royalties without including any royalty interests) unless noted otherwise. In addition

[7] *"Reserves replacement" and "reserves replacement ratio" do not have standardized meanings. See the table "Capital Program Efficiency" and "Information Regarding Disclosure on Oil and Gas Reserves, Operational Information and Non-IFRS Measures" contained in this annual report.*

to the detailed information disclosed in this annual report, more detailed information will be included in the Company's Annual Information Form (the "AIF") for the year ended December 31, 2018, which will be filed on the Company's profile at www.sedar.com on or before March 29, 2019.

See "Information Regarding Disclosure on Oil and Gas Reserves, Operational Information and Non-IFRS Measures" for additional cautionary language, explanations and discussions and "Forward Looking Information and Statements" for a statement of principal assumptions and risks that may apply.

Corporate Reserves[1,2,5]

	Light Crude Oil and Medium Crude Oil	Heavy Crude Oil	Natural Gas Liquids	Conventional Natural Gas[3]	Barrels of oil equivalent[4]
	(mbbl)	(mbbl)	(mbbl)	(mmcf)	(mboe)
Proved					
Developed Producing	411	1,414	11,456	281,509	60,199
Developed Non-producing	22	1,198	118	5,079	2,184
Undeveloped	1,379	2,119	24,122	497,023	110,457
Total Proved	**1,811**	**4,731**	**35,696**	**783,611**	**172,840**
Total Probable	9,089	3,941	45,342	1,078,529	238,127
Total Proved plus Probable	**10,900**	**8,672**	**81,038**	**1,862,140**	**410,967**

Notes:
(1) Reserves have been presented on a "gross" basis which is defined as Crew's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Company.
(2) Based on Sproule's December 31, 2018 escalated price forecast.
(3) Reflects 100% Conventional Natural Gas by product type.
(4) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.
(5) Columns may not add due to rounding.

Reserves Values[1][2][3][4]

The estimated before tax net present value ("NPV") of future net revenues associated with Crew's reserves effective December 31, 2018 and based on the Sproule Report and the published Sproule (December 31, 2018) future price forecast are summarized in the following table:

(m$)	0%	5%	10%	15%	20%
Proved					
Developed Producing	836,054	636,129	507,945	423,426	364,631
Developed Non-producing	35,548	29,715	25,415	22,137	19,559
Undeveloped	1,905,289	1,052,586	646,886	428,435	298,470
Total Proved	**2,776,892**	**1,718,430**	**1,180,246**	**873,998**	**682,660**
Total Probable	4,951,916	2,276,352	1,277,008	812,555	562,075
Total Proved plus Probable	**7,728,808**	**3,994,783**	**2,457,254**	**1,686,553**	**1,244,736**

Notes:
(1) Based on Sproule's December 31, 2018 escalated price forecast.
(2) The estimated future net revenues are stated prior to provision for interest, debt service charges, general administrative expenses, the impact of hedging activities, and after deduction of royalties, operating costs, certain estimated well abandonment and reclamation costs and estimated future capital expenditures.
(3) The after-tax present values of future net revenue attributed to Crew's reserves will be included in the Company's 2018 AIF to be filed on or before March 29, 2019.
(4) Columns may not add due to rounding.

Price Forecast

The Sproule December 31, 2018 price forecast is summarized as follows:

Year	Exchange Rate	WTI @ Cushing	Canadian Light Sweet	Western Canada Select	Natural gas AECO-C spot	Westcoast Station 2
	($US/$Cdn)	(US$/bbl)	(C$/bbl)	(C$/bbl)	(C$/mmbtu)	(C$/mmbtu)
2019	0.770	63.00	75.27	59.47	1.95	1.35
2020	0.800	67.00	77.89	62.31	2.44	1.94
2021	0.800	70.00	82.25	67.45	3.00	2.60
2022	0.800	71.40	84.79	69.53	3.21	2.81
2023	0.800	72.83	87.39	71.66	3.30	2.90
2024	0.800	74.28	89.14	73.10	3.39	2.99
2025	0.800	75.77	90.92	74.56	3.49	3.09
2026	0.800	77.29	92.74	76.05	3.58	3.18
2027	0.800	78.83	94.60	77.57	3.68	3.28
2028	0.800	80.41	96.49	79.12	3.78	3.38
2029	0.800	82.02	98.42	80.70	3.88	3.48
2030 +(1)		2.0%/yr	2.0%/yr	2.0%/yr	2.0%/yr	2.0%/yr

Note:

(1) Escalated at 2.0% per year starting in 2030 with the exception of foreign exchange which remains flat.

Reserves Reconciliation

The following reconciliation of Crew's gross reserves compares changes in the Company's reserves as at December 31, 2018 based on the Sproule (December 31, 2018) future price forecast relative to the reserves as at December 31, 2017.

TOTAL PROVED	Light & Medium Crude Oil (mbbl)	Heavy Crude Oil (mbbl)	Natural Gas Liquids (mbbl)	Conventional Natural Gas (mmcf)	Oil Equivalent (mboe)
Opening Balance	**1,809**	**4,382**	**31,403**	**790,685**	**169,376**
Extensions & Improved Recovery(1)	0	866	1,959	19,606	6,093
Infill Drilling	0	16	0	0	16
Technical Revisions	110	119	4,251	22,677	8,259
Discoveries	0	0	0	0	0
Acquisitions	0	0	0	0	0
Dispositions	0	(18)	0	0	(18)
Economic Factors	(7)	17	(406)	(10,624)	(2,167)
Production	(101)	(651)	(1,512)	(38,732)	(8,718)
Closing Balance	**1,811**	**4,731**	**35,696**	**783,612**	**172,840**

Notes:

(1) Increases to Extensions and Improved Recovery are the result of step-out locations drilled by Crew. Reserves additions for improved recovery and extensions are combined and reported as "Extensions and Improved Recovery".

(2) Columns may not add due to rounding.

TOTAL PROVED PLUS PROBABLE	Light & Medium Crude Oil (mbbl)	Heavy Crude Oil (mbbl)	Natural Gas Liquids (mbbl)	Conventional Natural Gas (mmcf)	Oil Equivalent (mboe)
Opening Balance	**12,527**	**8,339**	**68,879**	**1,682,775**	**370,208**
Extensions & Improved Recovery(1)	0	1,776	6,137	105,585	25,511
Infill Drilling	0	15	682	17,944	3,688
Technical Revisions	(1,510)	(800)	6,986	100,560	21,436
Discoveries	0	0	0	0	0
Acquisitions	0	0	0	0	0
Dispositions	0	(28)	0	0	(28)
Economic Factors	(16)	20	(134)	(5,991)	(1,129)
Production	(101)	(651)	(1,512)	(38,732)	(8,718)
Closing Balance	**10,900**	**8,672**	**81,038**	**1,862,141**	**410,967**

Notes:

(1) Increases to Extensions and Improved Recovery are the result of step-out locations drilled by Crew. Reserves additions for improved recovery and extensions are combined and reported as "Extensions and Improved Recovery".

(2) Columns may not add due to rounding.

Capital Program Efficiency

	2018		2017		3 Year Average 2018-2016	
	1P	**2P**	1P	2P	1P	2P
Exploration and Development Expenditures(1) ($ thousands)	**103,219**	**103,219**	238,302	238,302	449,723	449,723
Acquisitions/(Dispositions)(1) ($ thousands)	**(9,805)**	**(9,805)**	(47,906)	(47,906)	(53,737)	(53,737)
Change in Future Development Capital(1) ($ thousands)						
- Exploration and Development	**(19,952)**	**130,237**	9,514	182,870	126,749	600,090
- Acquisitions/Dispositions	**(40)**	**(40)**	(7,875)	(21,800)	(7,915)	(21,840)
Reserves Additions with Revisions and Economic Factors (mboe)						
- Exploration and Development	**12,201**	**49,505**	25,870	59,370	77,023	178,865
- Acquisitions/Dispositions	**(18)**	**(28)**	(1,284)	(4,688)	42	(3,031)
	12,183	**49,478**	24,585	54,681	77,065	175,834

Notes:

(1) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development capital generally will not reflect total finding and development costs related to reserve additions for that year.

Finding & Development Costs[2][5]						
($ per boe)						
- with revisions and economic factors	**6.82**	**4.72**	9.58	7.09	7.48	5.87
Finding, Development & Acquisition Costs[2][5]						
($ per boe)						
- with revisions and economic factors	**6.03**	**4.52**	7.81	6.43	6.68	5.54
Recycle Ratio[3][5] **(F&D)**	**2.3**	**3.4**	1.9	2.5		
Reserves Replacement[4][5]	**140%**	**568%**	292%	650%		

Notes:

(2) The calculation of F&D and FD&A costs incorporates the change in FDC required to bring proved undeveloped and developed reserves into production. In all cases, the F&D or FD&A number is calculated by dividing the identified capital expenditures by the applicable reserves additions after changes in FDC costs.

(3) Recycle ratio is defined as operating netback per boe divided by F&D costs on a per boe basis. Operating netback is calculated as revenue (including realized hedging gains and losses) minus royalties, operating expenses, and transportation expenses. Crew's operating netback in fourth quarter 2018, used in the above calculations, averaged $15.83 per boe (unaudited).

(4) Reserves replacement ratio is calculated as total reserve additions (including acquisitions net of dispositions) divided by annual production. Crew's 2018 annual production averaged 23,885 boe per day.

(5) "Reserves Replacement", "FD&A Cost", "F&D Cost", and "Recycle Ratio" do not have standardized meanings. See "Information Regarding Disclosure on Oil and Gas Reserves and Operational Information" in this annual report.

Future Development Capital

The following table provides a summary of the estimated FDC required to bring Crew's reserves on production.

Future Development Capital ($millions)[1]	**Total Proved**	**Total Proved plus Probable**
2019	34	102
2020	120	207
2021	137	257
2022	206	282
2023	95	184
Remainder	117	863
Total FDC undiscounted	710	1,894
Total FDC discounted at 10%	520	1,190

Notes:

(1) Reflects development costs deducted by Sproule in the Sproule Report in the estimation of future net revenue attributed to the noted reserve categories using Sproule's forecast pricing and foreign exchange rates at December 31, 2018.

(2) Columns may not add due to rounding

Cautionary Statements

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

Information presented herein in respect of reserves, NPV10 and related information is based on our independent reserves evaluation for the year ended December 31, 2018 prepared by Sproule Associates Limited (the "Sproule Report"). Estimates provided in respect of NPV10 before tax for Crew's UCR wells at West Septimus is derived from the Sproule Report and based on Sproule's year end 2018 2P type wells for West Septimus. Our oil and gas reserves statement for the year ended December 31, 2018, which include complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, are contained within our Annual Information Form which will be available on our SEDAR profile at www.sedar.com on or before March 29, 2019. The recovery and reserve estimates contained herein are estimates only and there is no guarantee that the estimated reserves will be recovered. In relation to the disclosure of estimates for individual properties, such estimates may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. The Company's belief that it will establish additional reserves over time with conversion of probable undeveloped reserves into proved reserves is a forward-looking statement and is based on certain assumptions and is subject to certain risks, as discussed below under the heading "Forward-Looking Information and Statements".

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

Both F&D and FD&A costs take into account reserves revisions during the year on a per boe basis. The aggregate of the costs incurred in the financial year and changes during that year in estimated FDC may not reflect total F&D costs related to reserves additions for that year. Finding and development costs both including and excluding acquisitions and dispositions have been presented in this press release because acquisitions and dispositions can have a significant impact on our ongoing reserves replacement costs and excluding these amounts could result in an inaccurate portrayal of our cost structure.

Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare Crew's performance over time, however, such measures are not reliable indicators of Crew's future performance and future performance may not compare to the performance in previous periods. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this press release, should not be relied upon for investment or other purposes.

Forward-Looking Information and Statements

This report contains certain forward–looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "project", "should", "believe", "plans", "intends" "forecast" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this report contains forward-looking information and statements pertaining to the following: as to the execution of Crew's business plan including guidance as to its capital expenditure plans in the first quarter and balance of 2019; as to plans to internally fund its capital program with funds flow generated from Crew's existing business; as to plans to internally fund capital in 2019 with adjusted funds flow; as to the Company's ongoing goal of increasing the overall weighting of condensate in its production mix and associated improvements in realized pricing and operating netbacks for 2019 and beyond; as to estimates of net present value and expectations that the Company's UCR wells will generate internal rates of return of over 70%; as to the Company's estimates that its UCR wells will pay out in approximately 12 – 18 months at current prices; the estimated volumes, including shut-ins, and product mix of Crew's oil and gas production; production estimates including 2019 average production target; commodity price expectations including Crew's estimates of natural gas pricing exposure; Crew's commodity risk management programs including plans for additional hedging in 2019; marketing and transportation plans; future liquidity and financial capacity; future results from operations and operating metrics; potential for lower costs and efficiencies going forward; future development, exploration, acquisition and disposition activities (including drilling, completion and infrastructure plans and associated timing and cost estimates); and the amount and timing of capital projects.

In addition, forward-looking statements or information are based on a number of material factors, expectations or assumptions of Crew which have been used to develop such statements and information but which may prove to be incorrect. Although Crew believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because Crew can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified herein, assumptions have been made regarding, among other things: that Crew will continue to conduct its operations in a manner consistent with past operations; results from drilling and development activities consistent with past operations; the quality of the reservoirs in which Crew operates and continued performance from existing wells; the continued and timely development of infrastructure in areas of new production; the accuracy of the estimates of Crew's reserve volumes; certain commodity price and other cost assumptions; continued availability of debt and equity financing and cash flow to fund Crew's current and future plans and expenditures; the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; the general continuance of current industry conditions; the timely receipt of any required regulatory approvals; the ability of Crew to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects in which Crew has an interest in to operate the field in a safe, efficient and effective manner; the ability of Crew to obtain financing on acceptable terms; field production rates and decline rates;

the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and cost of pipeline, storage and facility construction and expansion and the ability of Crew to secure adequate product transportation; future commodity prices; currency, exchange and interest rates; regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Crew operates; and the ability of Crew to successfully market its oil and natural gas products.

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

The internal projections, expectations or beliefs underlying the Company's 2019 capital budget and corporate outlook for 2019 and beyond are subject to change in light of ongoing results, prevailing economic circumstances, commodity prices and industry conditions. Crew's outlook for 2019 and beyond provides shareholders with relevant information on management's expectations for results of operations, excluding any potential acquisitions, dispositions or strategic transactions that may be completed in 2019 and beyond. Accordingly, readers are cautioned that events or circumstances could cause results to differ materially from those predicted and Crew's 2019 guidance and outlook may not be appropriate for other purposes. The forward-looking information and statements contained in this report speak only as of the date of this report, and Crew does not assume any obligation to publicly update or revise any of the included forward-looking statements or information, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Test Results and Initial Production Rates

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

BOE equivalent

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

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

YEAR END 2018

Management's Discussion and Analysis

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Consolidated Financial Statements

MANAGEMENT'S DISCUSSION AND ANALYSIS

FINANCIAL & OPERATING HIGHLIGHTS

Financial ($ thousands, except per share amounts)	**Year ended** **December 31, 2018**	Year ended December 31, 2017
Petroleum and natural gas sales	**218,385**	214,154
Cash provided by operating activities	**89,162**	117,290
Adjusted funds flow (1)	**91,996**	108,129
Per share -basic	**0.61**	0.73
-diluted	**0.61**	0.72
Net income	**12,799**	34,405
Per share -basic	**0.08**	0.23
-diluted	**0.08**	0.23
Exploration and development expenditures	**103,219**	238,302
Property acquisitions (net of dispositions)	**(9,806)**	(47,906)
Net capital expenditures	**93,413**	190,396

Capital structure ($ thousands)	**As at** **December 31, 2018**	As at December 31, 2017
Working capital (surplus) deficiency (2)	**(11,984)**	29,143
Bank loan	**59,904**	21,977
	47,920	51,120
Senior unsecured notes	**294,885**	293,862
Net debt	**342,805**	344,982
Common shares outstanding (thousands)	**151,730**	149,328

Operations	**Year ended** **December 31, 2018**	Year ended December 31, 2017
Daily production		
Light crude oil (bbl/d)	**276**	495
Heavy crude oil (bbl/d)	**1,782**	1,836
Condensate (bbl/d)	**2,380**	2,048
Other natural gas liquids (bbl/d)	**1,761**	1,575
Natural gas (mcf/d)	**106,116**	102,642
Oil equivalent (boe/d @ 6:1)	**23,885**	23,061
Average prices (3)		
Light crude oil ($/bbl)	**65.32**	58.34
Heavy crude oil ($/bbl)	**39.27**	45.14
Condensate ($/bbl)	**72.22**	62.03
Other natural gas liquids ($/bbl)	**23.18**	24.45
Natural gas ($/mcf)	**2.80**	3.01
Oil equivalent ($/boe)	**25.05**	25.44
Netback ($/boe)		
Operating netback (4)	**14.49**	16.74
G&A	**(1.39)**	(1.42)
Financing costs on long-term debt	**(2.67)**	(2.61)
Other income	**0.11**	0.12
Funds from operations netback (4)	**10.54**	12.83
Drilling activity		
Gross wells	**14**	40
Working interest wells	**14**	38.2
Success rate, net wells	**100%**	97%

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) deficiency includes accounts receivable 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.

ABOUT CREW

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

ADVISORIES

Management's discussion and analysis ("MD&A") is the explanation of the financial performance for the period covered by the 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, 2018 and 2017. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). All figures provided herein and in the December 31, 2018 audited consolidated financial statements are reported in Canadian dollars ("CDN"). This MD&A is dated March 4, 2019.

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 2019 exploration and development budget, timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, production estimates including 2019 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). Furthermore, the forward looking statements contained in this document are made as at the date of this document and the Company does not undertake any obligation to update publicly or to revise any of the included forward looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Conversions

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

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

Non-IFRS Measures

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, 2018**	Three months ended December 31, 2017	**Year ended December 31, 2018**	Year ended December 31, 2017
Cash provided by operating activities	**22,878**	43,484	**89,162**	117,290
Change in operating non-cash working capital	**843**	(9,165)	**2,663**	(8,706)
Accretion of deferred financing costs	**(246)**	(261)	**(1,023)**	(968)
Funds from operations	**23,475**	34,058	**90,802**	107,616
Decommissioning obligations settled	**237**	29	**1,194**	513
Adjusted funds flow	**23,712**	34,087	**91,996**	108,129

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, 2018**	December 31, 2017
Current assets	**78,904**	42,596
Current liabilities	**(58,538)**	(71,392)
Derivative financial instruments	**(8,382)**	(347)
Working capital surplus (deficit)	**11,984**	(29,143)

($ thousands)	**December 31, 2018**	December 31, 2017
Bank loan	**(59,904)**	(21,977)
Senior unsecured notes	**(294,885)**	(293,862)
Working capital surplus (deficit)	**11,984**	(29,143)
Net debt	**(342,805)**	(344,982)

RESULTS OF OPERATIONS

Overview

In 2018, Crew continued its successful strategy of developing our Greater Septimus assets, with particular emphasis on the higher-value, ultra condensate-rich ("UCR") West Septimus area. The Company also significantly enhanced its marketing and transportation flexibility by connecting new pipelines at West Septimus through the Company's Groundbirch area to the TransCanada Saturn #2 meter station. The completion of this project improves the Company's access to diversified markets with a growing infrastructure footprint in 2019. The completion of this project uniquely positions the Company's significant Montney land base with direct access to three existing export pipelines, potential liquefied natural gas exports and rail transportation. Production during the year averaged 23,885 boe per day, a 4% increase over 2017, despite shut-in production resulting from depressed Canadian commodity prices and a disciplined 2018 capital budget, which resulted in a decline in drilling and completion expenditures as compared to 2017.

For the majority of 2018, world crude oil prices outperformed 2017 as production curtailments implemented by the Organization of the Petroleum Exporting Countries ("OPEC") in early 2018 helped to reduce overall world supply and bolster benchmark crude oil prices worldwide. The overall price Crew received for its liquids production for the first three quarters of 2018 outperformed the same period of 2017 by 26%. In the fourth quarter, Canada's lack of adequate pipeline egress and crude-by-rail capacity caused a severe and sudden widening of the Canadian crude oil price differential relative to US prices. In addition, the continued strengthening of US shale oil production and a slowing global economy led to a return of an oversupplied world oil market, resulting in benchmark world prices declining significantly at the end of the year. As a result, Canadian benchmark crude oil prices including light sweet crude and, in particular, Western Canadian Select ("WCS"), were subject to significantly wider discounts relative to declining global crude oil prices in the fourth quarter. The decline in prices resulted in the Company shutting-in uneconomic heavy crude oil production during the fourth quarter and early part of 2019. The average price received for the Company's total liquids production in 2018 slightly increased to $48.51 per boe as compared to $46.57 in 2017. Increases in realized light crude oil and condensate pricing, which receive premium pricing as compared to other liquids, were partially offset by declines in heavy crude oil and other natural gas liquids prices in 2018.

During the year, Crew's realized sales price on its natural gas production averaged $2.80 per mcf, a small decline over 2017. The Company continues to successfully diversify its natural gas sales portfolio, by increasing its exposure to pricing hubs outside of western Canada, which have historically traded at a premium to AECO benchmark prices. In addition, in the fourth quarter of 2018, the Company reduced the proportion of its 2018 natural gas sales that are priced at AECO benchmark prices to 18% of corporate natural gas volumes. Chicago City Gate sales, at which approximately 45% of Crew's natural gas sales volumes were priced, were up 5% year-over-year, supported by strong industrial and retail demand. Furthermore, the Company added new North American downstream sales points in 2018, consisting of Henry Hub, Dawn and Malin. A portion of the Company's natural gas is processed through third party processing facilities into the British Columbia Station 2 sales market. As a result of the higher costs associated with the third party processing and lower realized pricing at British Columbia Station 2, the Company elected to shut-in approximately 1,000 to 1,500 boe per day of this natural gas production at various times during the year.

Cash provided by operating activities and adjusted funds flow decreased 24% and 15%, respectively, in 2018 as compared to 2017. These decreases were primarily the result of significant realized hedging gains on the 2017 risk management program as compared to realized losses and depressed natural gas and heavy crude oil pricing in 2018.

Capital expenditures during the year focused on the drilling and completion of wells in the Greater Septimus area with a focus on the UCR area at West Septimus. Expenditures totaled $103 million compared to $238 million in 2017 and included $72 million directed to the drilling of 14 (14.0 net) wells and the completion of 18 (16.2 net) wells compared to the drilling of 40 (38.2 net) wells and the completion of 37 (37.0 net) wells in 2017. Spending also included $19 million for facilities and infrastructure, including connecting new pipelines at West Septimus through the Company's Groundbirch area to the existing TransCanada Saturn #2 meter station. Early in 2018 the Company also disposed of a non-producing property in the Lloydminster area for proceeds of $10 million.

Crew exited 2018 with net debt of $343 million, including $60 million, or 25%, drawn on the Company's $235 million bank facility. With no near-term maturities, an increasing reserve base and substantial liquidity, Crew is strongly positioned to manage its current debt position. The Company's plan for 2019 is to fund capital expenditures with adjusted funds flow. Early in 2019, the Company disposed of non-core land, with no associated production or assigned reserves, for gross proceeds of $17.5 million. The proceeds of the disposition have been applied to reduce outstanding bank debt.

Production

	Three months ended December 31, 2018					Three months ended December 31, 2017				
	Oil (bbl/d)	**Condensate (bbl/d)**	**Other Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Oil (bbl/d)	Condensate (bbl/d)	Other Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
NE BC	**260**	**2,446**	**1,832**	**97,239**	**20,745**	399	2,617	1,823	111,733	23,461
Lloydminster	**1,634**	**-**	**-**	**26**	**1,638**	1,808	-	-	4	1,809
Total	**1,894**	**2,446**	**1,832**	**97,265**	**22,383**	2,207	2,617	1,823	111,737	25,270

In the fourth quarter of 2018, production decreased 11% over the same period in 2017 as a result of the 59% decline in drilling and completion capital expenditures in 2018 as compared to 2017. This decline was further increased by shut-in volumes averaging 1,790 boe per day for the quarter in the Other NE BC and Lloydminster areas due to a low pricing environment.

	Year ended December 31, 2018					Year ended December 31, 2017				
	Oil (bbl/d)	**Condensate (bbl/d)**	**Other Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Oil (bbl/d)	Condensate (bbl/d)	Other Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
NE BC	**276**	**2,380**	**1,761**	**106,108**	**22,102**	495	2,048	1,575	102,614	21,220
Lloydminster	**1,782**	**-**	**-**	**8**	**1,783**	1,836	-	-	28	1,841
Total	**2,058**	**2,380**	**1,761**	**106,116**	**23,885**	2,331	2,048	1,575	102,642	23,061

Production in 2018 increased 4% when compared to the same period in 2017 as a result of a successful drilling and completion program completed in the West Septimus area of NE BC in 2017 and 2018, resulting in area production increasing 28% year-over-year. This increase was offset by the aforementioned decline in capital expenditures in 2018 and the shut-in production in the fourth quarter due to volatile Canadian natural gas and heavy oil pricing.

Petroleum and Natural Gas Sales

	Three months ended December 31, 2018	Three months ended December 31, 2017	**Year ended December 31, 2018**	Year ended December 31, 2017
Petroleum and natural gas sales ($ thousands)				
Light crude oil	**912**	2,381	**6,582**	10,541
Heavy crude oil	**1,560**	8,106	**25,548**	30,254
Other natural gas liquids	**2,478**	5,800	**14,900**	14,059
Condensate	**11,892**	16,760	**62,731**	46,360
Natural gas	**33,996**	27,099	**108,624**	112,940
Total	**50,838**	60,146	**218,385**	214,154
Crew average prices				
Light crude oil ($/bbl)	**38.18**	64.91	**65.32**	58.34
Heavy crude oil ($/bbl)	**10.38**	48.73	**39.27**	45.14
Other natural gas liquids ($/bbl)	**14.71**	34.58	**23.18**	24.45
Condensate ($/bbl)	**52.85**	69.60	**72.22**	62.03
Natural gas ($/mcf)	**3.80**	2.64	**2.80**	3.01
Oil equivalent ($/boe)	**24.69**	25.87	**25.05**	25.44
Benchmark pricing				
Light crude oil – WTI (Cdn $/bbl)	**77.56**	70.47	**83.89**	66.11
Heavy crude oil – WCS (Cdn $/bbl)	**25.14**	54.85	**49.73**	50.55
Condensate – Condensate @ Edmonton (Cdn $/bbl)	**59.89**	73.71	**79.00**	66.94
Natural Gas:				
AECO 5A daily index (Cdn $/mcf)	**1.56**	1.69	**1.50**	2.16
AECO 7A monthly index (Cdn $/mcf)	**1.90**	1.96	**1.53**	2.43
Alliance 5A (Cdn $/mcf)	**2.71**	1.25	**2.17**	2.14
Chicago City Gate at ATP (Cdn $/mcf)	**4.13**	2.93	**3.20**	3.04
Henry Hub Close (Cdn $/mcf)	**4.81**	3.73	**4.00**	4.04

In the fourth quarter of 2018, the Company's petroleum and natural gas sales decreased 15% as compared to the same period in 2017, as a result of the 11% decrease in production, coupled with a decrease in light and heavy crude oil, condensate and other natural gas liquids pricing, partially offset by an increase in natural gas pricing. The Company's realized light crude oil price decreased 41% whereas the Company's Cdn$ West Texas Intermediate ("WTI") benchmark increased 10% for the same period last year, as a result of the differential between WTI and Canadian light sweet crude oil being materially discounted due to a lack of Canadian pipeline egress, reduced demand resulting from extended refinery outages and elevated storage levels. Crew's fourth quarter heavy crude oil price decreased 79%, which is greater than the 54% decrease in the Company's WCS benchmark, as a result of the Company entering into short term sales contracts at weaker spot pricing to manage inventory levels, coupled with an increase in the diluent blending rate of heavy crude oil as compared to the same period last year. The Company's fourth quarter realized condensate price decreased 24% over the same period in 2017, which approximated the 19% decrease in the Condensate at Edmonton benchmark price. Other natural gas liquids ("ngl") realized price decreased 57% in the fourth quarter, due to a decrease in propane and butane pricing as compared to the same period in 2017. Crew's realized natural gas price increased by 44% in the fourth quarter of 2018 which is directionally consistent with the 59% increase in the Company's natural gas sales portfolio weighted benchmark price. The Company's natural gas price benefits from the high heat content of its Montney natural gas, reflective of the presence of larger amounts of propane and butane in the gas stream, which yields approximately 20% more value than the standard heat conversion used in the Company's benchmark pricing.

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

	Q4 2018	Q4 2017
AECO 5A	**13%**	21%
AECO 7A	**5%**	14%
Alliance 5A	**23%**	18%
Chicago City Gate at ATP	**45%**	40%
Henry Hub	**10%**	-
Station 2	**3%**	7%
Sumas	**1%**	-
Total	**100%**	100%

For 2018, the Company's petroleum and natural gas sales increased 2% as compared to the prior year as a result of the 4% increase in production, partially offset by a decrease in realized commodity pricing. The Company's realized light crude oil price increased 12% whereas the Company's WTI benchmark increased 27%, as a result of the differential between WTI and Canadian light sweet crude oil being materially discounted later in 2018 due to a lack of pipeline egress, reduced demand resulting from extended refinery outages and elevated storage levels. Crew's heavy crude oil price for 2018 decreased 13% which was greater than the 2% decrease in the Company's WCS benchmark, as a result of the Company entering into short term sales contracts at weaker spot pricing to manage inventory levels, coupled with an increase in the cost of diluent purchased to blend with the heavy crude oil as compared to the same period last year. In 2018, the Company's realized condensate price increased 16%, which was consistent with the 18% increase in the Condensate at Edmonton benchmark price as compared to the prior year. Other ngl realized price decreased 5% in 2018, due to an overall decrease in the mix of other ngl pricing. The Company's natural gas price decreased 7% over 2017, which is consistent with the Company's natural gas sales portfolio weighted benchmark price decrease of 4%.

Royalties

($ thousands, except per boe)	**Three months ended December 31, 2018**	Three months ended December 31, 2017	**Year ended December 31, 2018**	Year ended December 31, 2017
Royalties	**3,433**	3,692	**15,123**	15,152
Per boe	**1.67**	1.59	**1.73**	1.80
Percentage of petroleum and natural gas sales	**6.8%**	6.1%	**6.9%**	7.1%

For the fourth quarter of 2018, royalties per boe and as a percentage of petroleum and natural gas sales increased over the same period in 2017, predominantly due to an increase in natural gas pricing that attracted a higher royalty rate. For the year ended December 31, 2018, royalties per boe and as a percentage of petroleum and natural gas sales decreased over the same period in 2017, predominantly due to increased production at West Septimus, which attracts lower royalties due to new deep well gas royalty credit programs, coupled with the decrease in annual natural gas pricing. The Company expects its royalties as a percentage of revenue to average between 5% and 7% in 2019.

Derivative Financial Instruments

Commodities

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

These contracts had the following impact on the consolidated statements of income and comprehensive income;

($ thousands)	**Three months ended December 31, 2018**	Three months ended December 31, 2017	**Year ended December 31, 2018**	Year ended December 31, 2017
Realized (loss) gain on derivative financial instruments	**(1,291)**	3,731	**(10,645)**	10,018
Per boe	**(0.63)**	1.60	**(1.22)**	1.19
Unrealized gain (loss) on financial instruments	**25,456**	(5,738)	**8,035**	19,737

As at December 31, 2018, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value
Gas	22,500 mmbtu/day	January 1, 2019 - December 31, 2019	Chicago Citygate	$3.54/mmbtu	Swap	$ (1,054)
Gas	5,000 mmbtu/day	January 1, 2019 - December 31, 2019	Dawn Daily index	$3.56 US/mmbtu	Swap	(113)
Gas	7,500 mmbtu/day	January 1, 2019 - December 31, 2019	US$ Nymex Henry Hub	$2.98 US/mmbtu	Swap	653
Oil	250 bbl/day	January 1, 2019 - June 30, 2019	CDN$ WTI	$83.80/bbl	Swap	926
Oil	500 bbl/day	January 1, 2019 - June 30, 2019	CDN$ WCS	$52.93/bbl	Swap	1,272
Oil	250 bbl/day	January 1, 2019 - June 30, 2019	CDN$ WCS - WTI Differential	($25.75)/bbl	Swap	(56)
Oil	1,750 bbl/day	January 1, 2019 - December 31, 2019	CDN$ WTI	$75.44/bbl	Swap	6,754
Total						**$ 8,382**

Subsequent to December 31, 2018, the Company entered into the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Gas	2,500 mmbtu/day	April 1, 2019 - October 31, 2019	Chicago Citygate	$3.44/mmbtu	Swap
Gas	2,500 mmbtu/day	April 1, 2019 - October 31, 2019	Dawn Daily index	$3.52 US/mmbtu	Swap
Gas	2,500 mmbtu/day	April 1, 2019 - October 31, 2019	US$ Nymex Henry Hub	$2.85 US/mmbtu	Swap
Oil	500 bbl/day	July 1, 2019 - December 31, 2019	CDN$ WCS - WTI Differential	($25.23)/bbl	Swap

Marketing Income

($ thousands, except per boe)	**Three months ended December 31, 2018**	Three months ended December 31, 2017	**Year ended December 31, 2018**	Year ended December 31, 2017
Marketing revenue	**2,968**	-	**6,855**	-
Less: marketing expense	**(852)**	-	**(2,914)**	-
Marketing income	**2,116**	-	**3,941**	-
Per boe	**1.03**	-	**0.45**	-

In the fourth quarter of 2018 and year ended December 31, 2018, the Company recognized $3.0 million and $6.9 million, respectively, of marketing revenue related to the monetization of the Company's exposure to the Dawn, Malin and Sumas natural gas markets. Marketing expense reflects the cost of firm transportation commitments on TransCanada's natural gas pipeline system that was not accessible during the year.

Net Operating Costs

($ thousands, except per boe)	**Three months ended December 31, 2018**	Three months ended December 31, 2017	**Year ended December 31, 2018**	Year ended December 31, 2017
Operating costs	**13,010**	14,668	**58,341**	52,933
Less: processing revenue	**(1,105)**	(952)	**(4,134)**	(3,981)
Net operating costs	**11,905**	13,716	**54,207**	48,952
Per boe	**5.78**	5.90	**6.22**	5.82

For the fourth quarter of 2018, the Company's net operating costs per boe decreased 2% over the same period in 2017, as a result of Lloydminster heavy crude oil shut-in production that carried a higher average operating cost per boe than the corporate average In 2018, net operating costs per boe increased 7% due to an increase in payment of third party processing fees resulting from the late 2017 expansion of the West Septimus gas processing facility expansion, owned 72% owned by third parties. The Company forecasts operating costs to average between $5.90 and $6.15 per boe in 2019.

Transportation Costs

($ thousands, except per boe)	**Three months ended December 31, 2018**	Three months ended December 31, 2017	**Year ended December 31, 2018**	Year ended December 31, 2017
Transportation costs	**3,719**	4,517	**16,007**	19,096
Per boe	**1.81**	1.94	**1.84**	2.27

For the fourth quarter of 2018, the Company's transportation costs per boe decreased 7% as a result of a decrease in Other NE BC production which yields a higher transportation cost per boe when compared to the corporate average. In 2018, transportation costs per boe decreased 19% as a result of increased production in West Septimus which yields a lower transportation cost per boe when compared to the corporate average. In addition, 2017 transportation costs were inflated due to third party facility and pipeline outages resulting in higher unutilized demand charges. The Company expects transportation costs to range between $3.60 and $3.85 per boe in 2019, as a result of the addition of new natural gas pipeline egress contracted to begin in stages during the first half of 2019.

Operating Netbacks

($/boe)	Greater Septimus	Lloydminster Heavy Oil	Other NE BC	Three months ended December 31, 2018	Three months ended December 31, 2017
Petroleum and natural gas sales	**26.53**	**10.37**	**20.13**	**24.69**	25.87
Royalties	**(1.58)**	**(2.97)**	**(1.47)**	**(1.67)**	(1.59)
Realized commodity hedging (loss) gain	**(1.79)**	**14.26**	**(1.90)**	**(0.63)**	1.60
Marketing income	**1.23**	**-**	**-**	**1.03**	-
Net operating costs	**(4.51)**	**(18.38)**	**(6.96)**	**(5.78)**	(5.90)
Transportation costs	**(1.35)**	**(1.01)**	**(6.07)**	**(1.81)**	(1.94)
Operating netbacks	**18.53**	**2.27**	**3.73**	**15.83**	18.04
Production (boe/d)	**18,447**	**1,638**	**2,298**	**22,383**	25,270

Operating netbacks for the fourth quarter of 2018 decreased over the same period in 2017 as a result of lower realized pricing in Other NE BC and Lloydminster, and realized commodity hedging losses, which were partially offset by marketing income, and decreases in net operating and transportation expenses.

($/boe)	Greater Septimus	Lloydminster Heavy Oil	Other NE BC	Year ended December 31, 2018	Year ended December 31, 2017
Petroleum and natural gas sales	**24.36**	**39.25**	**20.77**	**25.05**	25.44
Royalties	**(1.39)**	**(5.92)**	**(1.41)**	**(1.73)**	(1.80)
Realized commodity hedging (loss) gain	**(1.53)**	**2.75**	**(1.62)**	**(1.22)**	1.19
Marketing income	**0.56**	**-**	**-**	**0.45**	-
Net operating costs	**(4.57)**	**(21.17)**	**(8.03)**	**(6.22)**	(5.82)
Transportation costs	**(1.37)**	**(0.95)**	**(5.57)**	**(1.84)**	(2.27)
Operating netbacks	**16.06**	**13.96**	**4.14**	**14.49**	16.74
Production (boe/d)	**19,271**	**1,783**	**2,831**	**23,885**	23,061

For the year ended December 31, 2018, operating netbacks decreased as compared to the prior year due to a decrease in realized commodity prices, realized hedging losses and higher net operating costs, partially offset by marketing income and lower transportation costs.

General and Administrative Costs

($ thousands, except per boe)	Three months ended December 31, 2018	Three months ended December 31, 2017	Year ended December 31, 2018	Year ended December 31, 2017
Gross costs	**4,548**	4,759	**18,565**	18,398
Operator's recoveries	**(97)**	(231)	**(749)**	(545)
Capitalized costs	**(1,264)**	(1,355)	**(5,726)**	(5,939)
General and administrative expenses	**3,187**	3,173	**12,090**	11,914
Per boe	**1.55**	1.36	**1.39**	1.42

Gross general and administrative ("G&A") costs have decreased in the fourth quarter of 2018 as compared to the same period in 2017, due to lower compensation costs per employee. Gross annual 2018 G&A costs increased as a result of an increase in information technology related costs and inflationary pressures on office operating costs, partially offset by the aforementioned decrease in compensation costs. The decrease in compensation costs resulted in a decrease in capitalized costs, which contributed to the increase in net G&A costs in both the fourth quarter of 2018 and year ended December 31, 2018, as compared to the same periods in 2017. The increase in G&A costs per boe in the fourth quarter of 2018 was due to the decrease in production as compared to the same period in 2017, while the decrease in net G&A costs per boe for the year ended December 31, 2018 was due to the increase in production as compared to the prior year. Crew forecasts G&A costs per boe to average between $1.40 and $1.65 in 2019.

Other Income

($ thousands, except per boe)	**Three months ended December 31, 2018**	Three months ended December 31, 2017	**Year ended December 31, 2018**	Year ended December 31, 2017
Other	**-**	1,000	**1,000**	1,000
Per boe	**-**	0.43	**0.11**	0.12

In the years ended December 31, 2018 and 2017, the Company recognized $1.0 million for the receipt of non-refundable deposits from third parties for a non-core property disposition that failed to close.

Share-Based Compensation

($ thousands)	**Three months ended December 31, 2018**	Three months ended December 31, 2017	**Year ended December 31, 2018**	Year ended December 31, 2017
Gross costs	**3,430**	2,282	**13,457**	16,340
Capitalized costs	**(1,615)**	(1,015)	**(6,381)**	(7,690)
Total share-based compensation	**1,815**	1,267	**7,076**	8,650

In the fourth quarter of 2018, the Company's total share-based compensation expense increased as compared to the same period in 2017, due to lower than normal share-based compensation expense in the fourth quarter of 2017 as a result of the departure of a Company executive. For the year ended December 31, 2018, the Company's share-based compensation expense decreased as compared to the prior year, as a result of the departure of a Company executive and a lower performance multiplier applied to certain performance awards.

Depletion and Depreciation

($ thousands, except per boe)	**Three months ended December 31, 2018**	Three months ended December 31, 2017	**Year ended December 31, 2018**	Year ended December 31, 2017
Depletion and depreciation	**18,459**	19,620	**77,373**	75,131
Per boe	**8.96**	8.44	**8.88**	8.93

In the fourth quarter of 2018, depletion and depreciation costs per boe increased 6% when compared to the same period in 2017, due to an increase in future development costs associated with additional liquids reserves bookings, resulting in a higher depletion rate when compared to the same period in 2017. In 2018, depletion and depreciation costs per boe decreased when compared to 2017 as a result of increased production at West Septimus, which yields a depletion rate lower than the corporate average, partially offset by higher land expiries in 2018. The Company increased proved plus probable reserves by 11% to 411 mmboe during 2018.

Impairment

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. At December 31, 2017, the Company identified indicators of impairment and completed impairment testing for the northeast British Columbia CGU, but did not identify indicators of impairment for the Lloydminster CGU. It was determined that the recoverable amount of the northeast British Columbia CGU exceeded its carrying value and therefore an impairment charge was not recorded.

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

Gain (Loss) on Divestitures of Property

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

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

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

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

Finance Expenses

($ thousands, except per boe)	**Three months ended December 31, 2018**	Three months ended December 31, 2017	**Year ended December 31, 2018**	Year ended December 31, 2017
Interest on bank loan and other	**546**	516	**2,735**	2,408
Interest on senior notes	**4,915**	4,915	**19,500**	18,553
Accretion of deferred financing charges	**246**	261	**1,023**	968
Accretion of the decommissioning obligation	**491**	499	**1,958**	1,934
Premium paid on redemption of 2020 Notes	**-**	-	**-**	6,282
Deferred financing costs expensed on 2020 Notes	**-**	-	**-**	2,510
Total finance expense	**6,198**	6,191	**25,216**	32,655
Average debt level	**353,400**	332,100	**346,121**	301,353
Average drawings on bank loan	**53,400**	32,100	**46,121**	26,833
Average senior unsecured notes outstanding	**300,000**	300,000	**300,000**	274,520
Effective interest rate on senior notes	**6.5%**	6.5%	**6.5%**	6.8%
Effective interest rate on long-term debt	**6.1%**	6.2%	**6.1%**	6.5%
Financing costs on long-term debt per boe	**2.77**	2.45	**2.67**	2.61

The Company's average corporate debt level increased in both the fourth quarter of 2018 and year ended December 31, 2018 as compared to the same periods in 2017, as a result of increased joint venture accounts receivables related to capital projects not yet completed and the majority of which is expected to be collected early in 2019. These expenditures were partially funded with the first quarter 2017 issuance of $300 million of 6.5% senior unsecured notes (the "2024 Notes") as described below in the Capital Funding section. Proceeds from the 2024 Notes were used to redeem the $150 million of 8.375% senior unsecured notes (the "2020 Notes") and repay the drawings on the bank loan. As a result, the effective interest rate on the Company's senior notes and total long-term debt decreased for the year ended December 31, 2018 as compared to the same period in 2017. Crew forecasts the effective interest rate on its long-term debt to average between 6.0% and 6.5% in 2019.

Deferred Income Taxes

In the fourth quarter of 2018, the provision for deferred taxes was an expense of $9.6 million compared to a recovery of $1.8 million for the same period in 2017. The change from a recovery to an expense was the result of a previously unrealized tax deduction associated with share-based compensation recorded in the fourth quarter of 2017. For 2018, the provision for deferred taxes was an expense of $10.4 million compared to an expense of $16.2 million. The decrease in expense is the result of higher pre-tax income in 2017, resulting from higher gains on the Company's risk management program and a material gain on dispositions.

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

($ thousands)	**December 31, 2018**	December 31, 2017
Cumulative Canadian Exploration Expense	**291,400**	290,400
Cumulative Canadian Development Expense	**238,800**	276,000
Undepreciated Capital Cost	**202,800**	234,800
Non-capital losses	**335,600**	257,100
Share issue costs	**5,300**	7,800
Other	**8,000**	13,900
	1,081,900	1,080,000

The Company did not pay cash taxes in 2018 and estimates sufficient tax pools available to shelter estimated income until 2021 or beyond.

Cash, Adjusted Funds Flow and Net Income

($ thousands, except per share amounts)		**Three months ended December 31, 2018**	Three months ended December 31, 2017	**Year ended December 31, 2018**	Year ended December 31, 2017
Cash provided by operating activities		**22,878**	43,484	**89,162**	117,290
Adjusted funds flow (1)		**23,712**	34,087	**91,996**	108,129
Per share	-basic	**0.16**	0.23	**0.61**	0.73
	-diluted	**0.16**	0.22	**0.61**	0.72
Net income		**18,771**	2,342	**12,799**	34,405
Per share	-basic	**0.12**	0.02	**0.09**	0.23
	-diluted	**0.12**	0.02	**0.09**	0.23

Note:

(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.

Cash provided by operating activities and adjusted funds flow decreased in the fourth quarter of 2018 and year ended December 31, 2018, predominantly due to favourable realized hedging gains on the 2017 risk management program as compared to a small realized loss on the 2018 program. Cash provided by operating activities was further impacted by the change in non-cash working capital in 2017. Net income for the fourth quarter of 2018 increased as compared to the same period in 2017, predominantly due to favourable unrealized hedging gains in the fourth quarter of 2018 as compared to an unrealized hedging loss in the fourth quarter of 2017. Net income for the year ended December 31, 2018 decreased as compared to the same period in 2017, due to gains on property dispositions in the second and third quarters of 2017, in addition to gains from the 2017 risk management program, offset by an impairment charge recorded in the second quarter of 2017.

Capital Expenditures, Property Acquisitions and Dispositions

($ thousands)	**Three months ended December 31, 2018**	Three months ended December 31, 2017	**Year ended December 31, 2018**	Year ended December 31, 2017
Land	**1,393**	1,022	**4,121**	3,508
Seismic	**1,188**	(357)	**1,939**	357
Drilling and completions	**32,829**	18,427	**71,524**	174,686
Facilities, equipment and pipelines	**(3,592)**	15,880	**19,318**	53,295
Other	**1,356**	1,441	**6,317**	6,456
Total exploration and development	**33,174**	36,413	**103,219**	238,302
Property acquisitions (dispositions)	**175**	(1,709)	**(9,806)**	(47,906)
Total	**33,349**	34,704	**93,413**	190,396

In the fourth quarter of 2018, the Company spent a total of $33.2 million on exploration and development expenditures. The majority of this amount was spent on the continued development of our Montney assets. During the quarter, $32.8 million was spent on drilling and completion activities, facilities, equipment and pipelines spending was a net recovery of $3.6 million due to a $9.5 million British Columbia infrastructure credit realized in the quarter and $3.9 million was spent on land, seismic, recompletions and other miscellaneous amounts. During the fourth quarter of 2018, the Company drilled six (6.0 net) and completed three (3.0 net) natural gas wells in northeast British Columbia. The Company also drilled two (2.0 net), completed three (3.0 net) and recompleted two (2.0 net) heavy oil wells in Lloydminster.

In 2018, the Company drilled a total of 14 (14.0 net) wells resulting in four (4.0 net) oil wells, and ten (10.0 net) natural gas wells. During the year, the Company completed 18 (16.2 net) wells and recompleted 35 (33.8 net) wells. The Company's spending focus in 2018 was on UCR drilling and completions in the West Septimus area and completion of a pipeline from West Septimus through Groundbirch connecting to the TransCanada Saturn #2 meter station. Crew retained a 28% working interest in this pipeline, which further enhances Crew's marketing and transportation flexibility and provides access to markets outside of western Canada.

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

Subsequent to December 31, 2018, the Company disposed of non-core land with no associated production or assigned reserves, for gross proceeds of $17.5 million.

LIQUIDITY AND CAPITAL RESOURCES

Working Capital

The capital intensive nature of Crew's activities generally results in the Company carrying a working capital deficiency; however, at the end of the fourth quarter of 2018, the Company carried a working capital surplus of $12.0 million. Working capital includes cash and cash equivalents and accounts receivable less accounts payable and accrued liabilities. Included in the working capital surplus is a receivable of $9.6 million for a government grant credit earned through the completion of the construction of the Pine River pipeline and a new infrastructure credit received in late 2018. The collection of the grants is realized through the reduction of future royalties payable to the British Columbia government.

The Company ensures that sufficient drawings are available from its Facility to satisfy working capital requirements. At December 31, 2018, the Company's working capital surplus of $12.0 million, when combined with the drawings on its bank loan, represented drawings of 20% on its $235 million Facility described below.

Capital Funding

Bank Loan

As at December 31, 2018, the Company's bank facility consists of a revolving line of credit of $210 million and an operating line of credit of $25 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 5, 2019. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 per cent and all outstanding advances thereunder will become repayable in one year from the extension date. The available lending limits of the Facility (the "Borrowing Base") are reviewed semi-annually and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled Borrowing Base review on or before June 5, 2019. The Facility is secured by a floating charge debenture and a general securities agreement on the assets of the Company.

Senior Unsecured Notes

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

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

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

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

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

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

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

Share Capital

From May 25, 2017 to May 24, 2018, the Company executed under a normal course issuer bid (the "NCIB") the purchase of 924,100 common shares for cancellation for a total cost of $3.3 million that were removed from share capital in the year ended December 31, 2017. The Company did not purchase any common shares for cancellation under the NCIB in 2018 prior to the expiry of the NCIB.

Crew is authorized to issue an unlimited number of common shares. As at March 4, 2019, there were 151,730,009 common shares of the Company issued and outstanding. In addition, there were 3,405,096 restricted awards and 4,480,797 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, 2018.

Capital Structure

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

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

The Company monitors this ratio and endeavours to maintain it near or below 2.0 to 1.0. During periods of increased capital expenditures, acquisitions or low commodity prices, this ratio will increase over the Company's target. As shown below, as at December 31, 2018, the Company's ratio of net debt to annualized adjusted funds flow was 3.6 to 1 (December 31, 2017 – 2.5 to 1). In the current depressed and volatile commodity environment, Crew plans to limit capital expenditures to approximate adjusted funds flow. With only 25% drawn on the Company's $235 million Facility and the senior unsecured notes termed out to 2024, the Company's financial position remains strong. The Company will continue to monitor this ratio, and if necessary, it will consider divesting of non-core properties, will further adjust its annual capital expenditure program or may consider other forms of financing to further strengthen its financial position.

($ thousands, except ratio)	**December 31, 2018**	December 31, 2017
Working capital surplus (deficit)	**11,984**	(29,143)
Bank loan	**(59,904)**	(21,977)
Senior unsecured notes	**(294,885)**	(293,862)
Net debt	**(342,805)**	(344,982)
Fourth quarter adjusted funds flow (1)	**23,712**	34,087
Annualized	**94,848**	136,348
Net debt to annualized adjusted funds flow (1)	**3.6**	2.5

Note:
(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.

Contractual Obligations

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

($ thousands)	Total	2019	2020	2021	2022	2023	Thereafter
Bank Loan (note 1)	59,904	-	59,904	-	-	-	-
Senior unsecured notes (note 2)	300,000	-	-	-	-	-	300,000
Operating leases	2,742	1,175	1,175	392	-	-	-
Firm transportation agreements	242,420	46,575	49,454	27,456	26,862	23,024	69,049
Firm processing agreement	112,192	17,634	16,337	12,354	12,354	12,354	41,159
Total	**717,258**	**65,384**	**126,870**	**40,202**	**39,216**	**35,378**	**410,208**

Note 1 – Based on the existing terms of the Company's Facility the first possible repayment date may come in 2020. However, it is expected that the Facility will be extended and no repayment will be required in the near term.
Note 2 – Matures on March 14, 2024.

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

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

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

GUIDANCE

The Company's Board of Directors has approved a $95-$105 million exploration and development budget for 2019 that is forecasted to approximate adjusted funds flow for the year. This budget will focus predominantly on Crew's plan to increase condensate volumes while positioning Crew to achieve forecasted annual average production of 22,000 to 23,000 boe per day. Crew entered 2019 with seven (7.0 net) drilled but uncompleted wells ("DUCs"), which will accelerate condensate production. Drilling and completions activity will continue to target liquids-rich opportunities with the Company planning to drill six (6.0 net) and complete ten (10.0 net) UCR wells at West Septimus. The Company also plans to drill one Montney lease retention well and one exploratory horizontal Montney well in 2019. Crew has also allocated capital to our heavy oil business, planning to drill three multi-leg horizontal wells which are expected to maintain production volumes.

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 2018**	Sep. 30 2018	June 30 2018	Mar. 31 2018	Dec. 31 2017	Sep. 30 2017	June 30 2017	Mar. 31 2017
Total daily production (boe/d)	**22,383**	23,680	23,583	25,939	25,270	23,251	20,468	23,231
Exploration and development expenditures	**33,174**	23,656	12,468	33,921	36,413	90,069	36,656	75,164
Property acquisitions/(dispositions)	**175**	9	17	(10,007)	(1,709)	(144)	(45,701)	(352)
Average wellhead price ($/boe)	**24.69**	24.82	25.18	25.46	25.87	22.36	26.25	27.40
Petroleum and natural gas sales	**50,838**	54,080	54,040	59,427	60,146	47,824	48,886	57,298
Cash provided by operating activities	**22,878**	19,095	31,304	15,885	43,484	15,258	31,359	27,189
Adjusted funds flow	**23,712**	20,107	21,804	26,373	34,087	24,970	21,353	27,719
Per share – basic	**0.16**	0.13	0.14	0.18	0.23	0.17	0.14	0.19
– diluted	**0.16**	0.13	0.14	0.17	0.22	0.17	0.14	0.18
Net income (loss)	**18,771**	(939)	(9,181)	4,148	2,342	2,127	21,880	8,056
Per share – basic	**0.12**	(0.01)	(0.06)	0.03	0.02	0.01	0.15	0.05
– diluted	**0.12**	(0.01)	(0.06)	0.03	0.02	0.01	0.14	0.05

Over the past eight quarters, the Company continued to invest the majority of its capital expenditures in northeastern British Columbia, including the completion of the West Septimus facility expansion in the fourth quarter of 2017, resulting in significant production growth and infrastructure development in the area. Average wellhead pricing began to recover in the latter part of 2016, prompting the Company to increase its capital expenditures at Greater Septimus and Tower. Commodity pricing continued to strengthen in the latter part of 2016 and stabilize in early 2017, where the Company further expanded it capital program and infrastructure spending to allow for the growth realized in the second half of 2017 and early 2018. Beginning in the third quarter of 2017 and extending throughout 2018 the Canadian oil and gas industry has experienced volatile commodity prices with a significant declines in Canadian natural gas prices and quarter to quarter volatility in the price of Canadian oil, condensate and natural gas liquids.

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 negatively been impacted. This has resulted in reduced spending on exploration and development and has led to a reduction in production levels over the last three quarters of 2018.

Over the past two years, low commodity prices have also led to the assessment and realization of impairment of the carrying value of the Lloydminster CGU. In the fourth quarter of 2016 and the second quarter of 2017, the Company incurred impairment charges of $44.4 million and $16.7 million, respectively. In the second quarter of 2017, the Company realized a $37.9 million gain on divesture as it continues to monetize non-core properties to fund future growth.

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

($ thousands, except per share amounts)	**Year ended Dec. 31, 2018**	Year ended Dec. 31, 2017	Year ended Dec. 31, 2016
Petroleum and natural gas sales	**218,385**	214,154	174,719
Cash provided by operating activities	**89,162**	117,290	77,478
Adjusted funds flow	**91,996**	108,129	78,674
Per share -basic	**0.61**	0.73	0.55
-diluted	**0.61**	0.72	0.54
Net income (loss)	**12,799**	34,405	(64,926)
Per share -basic	**0.08**	0.23	(0.45)
-diluted	**0.08**	0.23	(0.45)
Daily production (boe/d)	**23,885**	23,061	22,844
Crew average sales price ($/boe)	**25.05**	25.44	20.90
Total assets	**1,451,923**	1,388,120	1,239,040
Working capital surplus (deficiency) (1)	**11,984**	(29,143)	(10,006)
Bank loan	**59,904**	21,977	88,036
Senior unsecured notes	**294,885**	293,862	147,329
Total other long-term liabilities	**142,246**	130,795	113,492

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

Over the last three years, a volatile commodity price environment has impacted revenue, cash provided by operating activities, adjusted funds flow and net income (loss). The overall decline in forecasted future commodity prices has also led to the assessment and realization of impairment charges on certain CGUs in each of 2016 and 2017.

New Accounting Pronouncements

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

a) IFRS 9 Financial Instruments:

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

b) IFRS 15 Revenue from Contracts with Customers:

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

c) IFRS 16 Leases:

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

- Account for leases with a remaining term of less than 12 months at January 1, 2019 as short-term leases;
- 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;
- All right of use assets will be equal to the corresponding lease liability at transition date; 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 date of transition.

Management has identified right of use assets and lease liabilities relating primarily to office space and field vehicles. The impact to the consolidated financial statements will be as follows:

- Lower general and administrative expenses and operating costs;
- Higher finance expenses due to the interest recognized on the lease obligations; and
- Higher depletion and depreciation expense relating to the right of use assets.

As at December 31, 2018, the Company is in the process of finalizing the full financial impact of IFRS 16 and developing and implementing polices, internal controls and processes.

Application of Critical Accounting Estimates

Crew's significant accounting policies are disclosed in note 3 to the December 31, 2018 consolidated financial statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Crew continuously refines its management and reporting systems to ensure that accurate, timely and useful information is gathered and disseminated. Crew's financial and operating results incorporate certain estimates including the following:

- Estimated accruals for revenues, royalties, operating expenses and general administrative expenses where actual revenues and costs have not been received;
- Estimated capital expenditures where actual costs have not been received or for projects that are in progress;
- Estimated depletion, depreciation and amortization charges are based on estimates of oil and gas reserves that Crew expects to recover in the future. As a key component in the depletion, depreciation and amortization calculation, the reserve estimates have a significant impact on net earnings and the Company's financial results could differ if there is a revision in our estimate of reserve quantities;
- Estimated future recoverable value of property, plant and equipment and any related impairment charges or recoveries are assessed for impairment when circumstances suggest the carrying amount may exceed its recoverable amount. The recoverable amount calculation requires the use of estimates which are subject to change as new information becomes available. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets;

- Estimated fair values of derivative contracts, which are used to manage commodity price, foreign currency and interest rate swaps, are determined using valuation models which require assumptions regarding the amount and timing of future cash flows and discount rates. As the Company's assumptions rely on external market data, the resulting fair value estimates may not be indicative of the amounts realized or settled and are therefore subject to market uncertainty;
- Decommissioning obligations are based on assumptions which take into consideration current economic factors and experience to date which we believe are reasonable. The actual cost of the Company's decommissioning obligations may change in response to numerous factors;
- Estimated deferred income tax assets and liabilities are based on current tax interpretations, regulations and legislation which are subject to change. As a result, there are usually a number of tax matters under review and therefore income taxes are subject to measurement uncertainty.

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

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

The Company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's disclosure controls and procedures at the financial year end of the Company and have concluded that the Company's disclosure controls and procedures are effective at the financial year end of the Company for the foregoing purposes.

The Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Utilizing the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") Internal Control – Integrated Framework (2013), such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal controls over financial reporting at the financial year end of the Company and concluded that the Company's internal controls over financial reporting are effective, at the financial year end of the Company, for the foregoing purpose. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on October 1, 2018 and ended on December 31, 2018 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

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

Dated as of March 4, 2019

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 4, 2019

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, 2018 and December 31, 2017

− 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, 2018 and December 31, 2017, 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.

Chartered Professional Accountants

Calgary, Canada

March 4, 2019

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(thousands)	**December 31, 2018**	December 31, 2017
Assets		
Current Assets:		
Accounts receivable	**$ 70,522**	$ 40,930
Derivative financial instruments (note 6)	**8,382**	1,666
	78,904	42,596
Other long-term assets	**-**	4,788
Property, plant and equipment (note 7)	**1,373,019**	1,340,736
	$ 1,451,923	$ 1,388,120
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 58,538**	$ 70,073
Derivative financial instruments (note 6)	**-**	1,319
	58,538	71,392
Bank loan (note 9)	**59,904**	21,977
Senior unsecured notes (note 10)	**294,885**	293,862
Decommissioning obligations (note 11)	**89,448**	88,368
Deferred tax liability (note 13)	**52,798**	42,427
Shareholders' Equity		
Share capital (note 12)	**1,468,986**	1,458,086
Contributed surplus	**75,715**	73,158
Deficit	**(648,351)**	(661,150)
	896,350	870,094
Commitments (note 18)		
Subsequent event (note 6,19)		
	$ 1,451,923	$ 1,388,120

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, 2018**	Year ended December 31, 2017
Revenue		
Petroleum and natural gas sales (note 14)	**$ 218,385**	$ 214,154
Royalties	**(15,123)**	(15,152)
Realized (loss) gain on derivative financial instruments	**(10,645)**	10,018
Unrealized gain on derivative financial instruments	**8,035**	19,737
Other revenue (note 14)	**11,989**	4,981
	212,641	233,738
Expenses		
Operating	**58,341**	52,933
Transportation	**16,007**	19,096
Marketing	**2,914**	-
General and administrative	**12,090**	11,914
Share-based compensation	**7,076**	8,650
Depletion and depreciation (note 7)	**77,373**	75,131
	173,801	167,724
Income from operations	**38,840**	66,014
Financing (note 15)	**25,216**	32,655
Impairment of property, plant and equipment (note 8)	**-**	16,710
Gain on divestiture of property, plant and equipment (note 7)	**(9,546)**	(33,951)
Income before income taxes	**23,170**	50,600
Deferred tax expense (note 13)	**10,371**	16,195
Net income and comprehensive income	**$ 12,799**	$ 34,405
Net income per share (note 12)		
Basic	**$ 0.08**	$ 0.23
Diluted	**$ 0.08**	$ 0.23

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(thousands)	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 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**

(thousands)	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 2017	146,812	$1,442,284	$ 74,960	$ (695,555)	$ 821,689
Net income for the year	-	-	-	34,405	34,405
Share-based compensation expensed	-	-	8,650	-	8,650
Share-based compensation capitalized	-	-	7,690	-	7,690
Issued on vesting of share awards	3,440	19,053	(19,053)	-	-
Tax deduction on excess value of share awards	-	-	911	-	911
Shares purchased and cancelled (note 12)	(924)	(3,251)	-	-	(3,251)
Balance, December 31, 2017	**149,328**	**$1,458,086**	**$ 73,158**	**$ (661,150)**	**$ 870,094**

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands)	**Year ended December 31, 2018**	Year ended December 31, 2017
Cash provided by (used in):		
Operating activities:		
Net income	**$ 12,799**	$ 34,405
Adjustments:		
Unrealized gain on derivative financial instruments	**(8,035)**	(19,737)
Share-based compensation	**7,076**	8,650
Depletion and depreciation (note 7)	**77,373**	75,131
Financing expenses (note 15)	**25,216**	32,655
Interest expense (note 15)	**(22,235)**	(20,961)
Impairment of property, plant and equipment (note 8)	**-**	16,710
Gain on divestiture of property, plant and equipment (note 7)	**(9,546)**	(33,951)
Deferred tax expense (note 13)	**10,371**	16,195
Decommissioning obligations settled (note 11)	**(1,194)**	(513)
Change in non-cash working capital (note 17)	**(2,663)**	8,706
	89,162	117,290
Financing activities:		
Increase (decrease) in bank loan	**37,927**	(66,059)
Issuance of senior notes, net of financing costs (note 10)	**-**	293,055
Redemption of senior notes (note 10)	**-**	(156,282)
Shares purchased and cancelled (note 12)	**-**	(3,251)
	37,927	67,463
Investing activities:		
Property, plant and equipment expenditures (note 7)	**(101,878)**	(238,302)
Property acquisitions	**(201)**	(3,827)
Property dispositions	**10,007**	51,733
Purchase of other long-term assets	**-**	(4,788)
Change in non-cash working capital (note 17)	**(35,017)**	10,431
	(127,089)	(184,753)
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, 2018 and 2017

(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 statement 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.

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

The financial statements were authorized for issuance by Crew's Board of Directors on March 4, 2019.

3. Significant accounting policies:

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

(a) Basis of consolidation:

(i) Subsidiaries:

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

(ii) Jointly owned assets:

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

(iii) Transactions eliminated on consolidation:

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

(b) Foreign currency:

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

(c) Financial instruments:

(i) Non-derivative financial instruments:

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

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

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

(ii) Derivative financial instruments:

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

(iii) Share capital:

Common shares are classified as equity. Incremental costs directly attributable to the issuance of common shares 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 statement of income (loss) as incurred.

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

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

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

Development and production costs:

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

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

(ii) Subsequent costs:

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

(iii) Depletion and depreciation:

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

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

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

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

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

Office equipment	5 years

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

(iv) Assets held for sale:

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

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

(e) Leased assets:

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

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

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

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

(f) Impairment:

(i) Financial assets:

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

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

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

All impairment losses are recognized in profit or loss.

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

(ii) Non-financial assets:

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

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

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

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

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

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

(g) Share based payments:

The grant date fair value of restricted and performance 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 profit or loss using the effective interest method. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Company's outstanding borrowings during the period.

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

(k) Income tax:

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

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

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

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

(l) Earnings per share:

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

(m) Flow-through shares:

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

(n) Inventory:

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

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

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

Critical judgments in applying accounting policies:

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

(i) Identification of CGUs

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

(ii) Impairment of petroleum and natural gas assets

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

(iii) Exploration and evaluation assets

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

(iv) Deferred income taxes

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

Key sources of estimation uncertainty:

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

(i) Reserves

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

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

(ii) Decommissioning obligations

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

(iii) Business combinations

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

(iv) Share-based payments

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

(v) Income taxes

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

(vi) Derivatives

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

4. Determination of fair values:

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

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

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

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

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

The fair value of cash and cash equivalents, accounts receivable, accounts payable, bank loans and the senior unsecured notes are estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2018 and December 31, 2017, 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, 2018 and December 31, 2017, the carrying value of the unsecured notes approximated fair value.

(iii) Derivatives:

The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and published forward price curves as at the statement of financial position date, using the remaining contracted volumes and a credit adjusted interest rate. The fair value of options and costless collars is based on option models that use published information with respect to volatility, prices and interest rates.

(iv) Restricted and performance awards:

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

5. Change in accounting policies:

(i) Adoption of IFRS 9 – Financial Instruments:

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

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

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

The additional disclosures required by IFRS 15, including those required for the cumulative effect method, are disclosed in note 14.

(iii) Future adoption of IFRS 16 – Leases:

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

- Account for leases with a remaining term of less than 12 months at January 1, 2019 as short-term leases;
- 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 ROU assets will be measured at the amount equal to the lease liability on date of transition.

Management has identified right of use assets and lease liabilities relating primarily to office space and field vehicles. The impact to the consolidated financial statements will be as follows:

- Lower general and administrative expenses and operating costs;
- Higher finance expenses due to the interest recognized on the lease obligations; and
- Higher depletion and depreciation expense relating to the right of use assets.

As at December 31, 2018, the Company is in the process of finalizing the full financial impact of IFRS 16 and developing and implementing polices, internal controls and processes.

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, 2018		December 31, 2017
Trade and other receivables	**$**	**70,522**	$	40,930
Derivative financial assets		**8,382**		1,666
	$	**78,904**	$	42,596

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 2018, 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, 2018, the Company's receivables consisted of $23.9 million (December 31, 2017 - $27.2 million) of receivables from petroleum and natural gas marketers, of which all have been subsequently collected, $34.6 million (December 31, 2017 - $3.8 million) from partners within jointly owned assets and operations of which $0.1 million has been subsequently collected, and $12.0 million (December 31, 2017 - $9.9 million) of deposits, prepaids and other accounts receivable, which includes a $9.6 million government grant credit earned through the completion of the construction of the Pine River pipeline, of which $0.1 million has subsequently been collected. The Company does not consider any receivables to be past due.

(b) Market risk:

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

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

Foreign currency exchange rate risk:

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

Interest rate risk:

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its bank loan which bears a floating rate of interest. Average bank debt outstanding during the year ending December 31, 2018 was $46.1 million (December 31, 2017 - $26.8 million). For the year ended December 31, 2018, a 1.0 percent change to the effective interest rate would have a $0.5 million impact on net income (December 31, 2017 - $0.3 million). The interest rate on the senior unsecured notes is fixed and is not subject to interest rate risk.

Commodity price risk:

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

Derivative assets:

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

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, 2018, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value
Gas	22,500 mmbtu/day	January 1, 2019 - December 31, 2019	Chicago Citygate	$3.54/mmbtu	Swap	$ (1,054)
Gas	5,000 mmbtu/day	January 1, 2019 - December 31, 2019	Dawn Daily index	$3.56/mmbtu	Swap	(113)
Gas	7,500 mmbtu/day	January 1, 2019 - December 31, 2019	US$ Nymex Henry Hub	$2.98 US/mmbtu	Swap	653
Oil	250 bbl/day	January 1, 2019 - June 30, 2019	CDN$ WTI	$83.80/bbl	Swap	926
Oil	500 bbl/day	January 1, 2019 - June 30, 2019	CDN$ WCS	$52.93/bbl	Swap	1,272
Oil	250 bbl/day	January 1, 2019 - June 30, 2019	CDN$ WCS - WTI Differential	($25.75)/bbl	Swap	(56)
Oil	1,750 bbl/day	January 1, 2019 - December 31, 2019	CDN$ WTI	$75.44/bbl	Swap	6,754
Total						**$ 8,382**

As at December 31, 2018, a 10% change in future commodity prices applied against these contracts would have a $6.8 million impact on net income.

Subsequent to December 31, 2018, the Company entered into the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Gas	2,500 mmbtu/day	April 1, 2019 - October 31, 2019	Chicago Citygate	$3.44/mmbtu	Swap
Gas	2,500 mmbtu/day	April 1, 2019 - October 31, 2019	Dawn Daily index	$3.52 US/mmbtu	Swap
Gas	2,500 mmbtu/day	April 1, 2019 - October 31, 2019	US$ Nymex Henry Hub	$2.85 US/mmbtu	Swap
Oil	500 bbl/day	July 1, 2019 - December 31, 2019	CDN$ WCS - WTI Differential	($25.23)/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 9, which is subject to annual renewal by the lenders and has a contractual maturity in 2019. In addition, the Company issued $300 million in senior unsecured notes in 2017 that are scheduled to mature in 2024, as discussed in note 10.

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.

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

The Company monitors this ratio and endeavours to maintain it at or below 2.0 to 1.0. During periods of increased capital expenditures, acquisitions or low commodity prices, this ratio will increase over the Company's target. As shown below, as at December 31, 2018, the Company's ratio of net debt to annualized adjusted funds flow was 3.6 to 1 (December 31, 2017 – 2.5 to 1). In the current depressed and volatile commodity price environment, Crew plans to limit capital expenditures to approximate adjusted funds flow. With only 25% drawn on the Company's $235 million Facility and the senior unsecured notes termed out to 2024, the Company's financial position remains strong. The Company will continue to monitor this ratio and, if necessary, it will consider divesting of non-core properties, will further adjust its annual capital expenditure program or may consider other forms of financing to further strengthen its financial position.

	December 31, 2018	December 31, 2017
Net debt:		
Accounts receivable	**$ 70,522**	$ 40,930
Accounts payable and accrued liabilities	**(58,538)**	(70,073)
Working capital surplus (deficiency)	**$ 11,984**	$ (29,143)
Bank loan	**(59,904)**	(21,977)
Senior unsecured notes	**(294,885)**	(293,862)
Net debt	**$ (342,805)**	$ (344,982)
Fourth quarter annualized adjusted funds flow:		
Cash provided by operating activities	**$ 22,878**	$ 43,484
Decommissioning obligations settled	**237**	29
Change in non-cash working capital	**843**	(9,165)
Accretion of deferred financing charges	**(246)**	(261)
Fourth quarter adjusted funds flow	**$ 23,712**	$ 34,087
Annualized	**$ 94,848**	$ 136,348
Net debt to annualized adjusted funds flow	**3.6**	2.5

Neither the Company nor any of its subsidiaries are subject to externally imposed capital requirements. The Facility is subject to a semi-annual review of the Borrowing Base which is directly impacted by the value of the oil and natural gas reserves (Bank loan – note 9).

7. Property, plant and equipment:

Cost or deemed cost	Total
Balance, January 1, 2017	$ 2,181,279
Additions	238,302
Acquisitions	6,827
Divestitures	(22,626)
Change in decommissioning obligations	2,853
Capitalized share-based compensation	7,690
Balance, December 31, 2017	$ 2,414,325
Additions	103,219
Acquisitions	201
Divestitures	(875)
Change in decommissioning obligations	730
Capitalized share-based compensation	6,381
Balance, December 31, 2018	**$ 2,523,981**

Accumulated depletion and depreciation	Total
Balance, January 1, 2017	$ 981,827
Depletion and depreciation expense	75,131
Divestitures	(79)
Impairment	16,710
Balance, December 31, 2017	$ 1,073,589
Depletion and depreciation expense	77,373
Balance, December 31, 2018	**$ 1,150,962**

Net book value	Total
Balance, December 31, 2018	**$ 1,373,019**
Balance, December 31, 2017	$ 1,340,736

Included in property, plant and equipment additions for the year ended December 31, 2018 is $1.3 million of pipe inventory transferred from other long-term assets upon the construction of the West Septimus pipeline to the TransCanada Pipeline Saturn meter station.

The calculation of depletion for the three months ended December 31, 2018 included estimated future development costs of $1,894.4 million (December 31, 2017 - $1,764.2 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $70.5 million (December 31, 2017 - $70.0 million) and undeveloped land of $159.3 million (December 31, 2017 - $161.6 million) related to future development acreage, with no associated reserves.

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

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

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

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

8. Impairment:

	Year Ended December 31, 2018	Year Ended December 31, 2017
Impairment losses:		
PP&E	**$ -**	$ 16,710
	$ -	$ 16,710

Assessment:

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. At December 31, 2017, the Company identified indicators of impairment and completed impairment testing for the northeast British Columbia CGU, but did not identify indicators of impairment for the Lloydminster CGU.

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, 2018, the Company used value in use, discounted at pre-tax rates between 10% and 30% (December 31, 2017 – 10% and 20%) dependent on the risk profile of the reserve category and CGU. At Q2 2017, the fair value less cost to sell was determined to be the appropriate measure for the Lloydminster 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 2018 assessment:

The following estimates were used in determining whether an impairment or reversal to the carrying value of the CGU 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.

(b) Results of 2017 assessment:

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

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

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

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

9. Bank loan:

As at December 31, 2018, the Company's bank facility consists of a revolving line of credit of $210 million and an operating line of credit of $25 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 5, 2019. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 per cent and all outstanding advances thereunder will become repayable in one year from the extension date. The available lending limits of the Facility (the "Borrowing Base") are reviewed semi-annually and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled Borrowing Base review on or before June 5, 2019. The Facility is secured by a floating charge debenture and a general securities agreement on the assets of the Company.

Advances under the Facility are available by way of prime rate loans with interest rates between 0.50 percent and 2.50 percent over the bank's prime lending rate and bankers' acceptances and LIBOR loans, which are subject to stamping fees and margins ranging from 1.50 percent to 3.50 percent depending upon the debt to EBITDA ratio of the Company calculated at the Company's previous quarter end. Standby fees are charged on the undrawn Facility at rates ranging from 0.338 percent to 0.788 percent depending upon the debt to EBITDA ratio. As at December 31, 2018, the Company's applicable pricing included a 0.50 percent margin on prime lending, a 1.50 percent stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.338 percent per annum standby fee on the portion of the Facility that is not drawn. Borrowing margins and fees are reviewed annually as part of the bank syndicate's annual renewal.

At December 31, 2018, the Company had issued letters of credit totaling $20.9 million (December 31, 2017 - $7.7 million).

10. Senior unsecured notes:

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

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

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

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

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

In connection with the issuance of the 2024 Notes, on March 23, 2017 the Company redeemed all of the previously issued and outstanding $150 million of 8.375% senior unsecured notes, due October 21, 2020 (the "2020 Notes") at a redemption price of $1,041.88 per $1,000 of principal amount, plus accrued and unpaid interest. A redemption premium of $6.3 million and unamortized deferred financing costs of $2.5 million were recorded in financing expense as a result of the 2020 Notes redemption (Financing – note 15).

At December 31, 2018, the carrying value of the 2024 Notes was net of deferred financing costs of $5.1 million (December 31, 2017 – $6.1 million).

11. Decommissioning obligations:

	As at December 31, 2018	As at December 31, 2017
Decommissioning obligations, beginning of year	**$ 88,368**	$ 85,859
Obligations incurred	**1,523**	4,557
Obligations settled	**(1,194)**	(513)
Obligations divested	**(414)**	(1,765)
Change in estimated future cash outflows	**(793)**	(1,704)
Accretion of decommissioning obligations	**1,958**	1,934
Decommissioning obligations, end of year	**$ 89,448**	$ 88,368

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning obligations to be $89.4 million as at December 31, 2018 (December 31, 2017 - $88.4 million) based on an inflation adjusted undiscounted total future liability of $117.8 million (December 31, 2017 - $118.9 million). These payments are expected to be made over the next 40 years with the majority of costs to be incurred between 2020 and 2035. The inflation rate applied to the liability is 2% (December 31, 2017 – 2%). The discount factor, being the risk-free rate related to the liability, is 2.13% (December 31, 2017 –

2.22%). The $0.8 million (December 31, 2017 - $1.7 million) change in estimated future cash outflows is a result of a change in the discount factor and estimated future obligations.

12. Share capital:

At December 31, 2018, the Company was authorized to issue an unlimited number of common shares with the holders of common shares entitled to one vote per share.

From May 25, 2017 to May 24, 2018, the Company executed under a normal course issuer bid (the "NCIB") the purchase of 924,100 common shares for cancellation for a total cost of $3.3 million that were removed from share capital in the year ended December 31, 2017. The Company did not purchase any common shares for cancellation under the NCIB in 2018 prior to the expiry of the NCIB.

Restricted and Performance Award Incentive Plan:

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

Subject to terms and conditions of the RPAP, each RA and PA entitles the holder to an award value to be typically paid as to one-third on each of the first, second and third anniversaries of the date of grant. For the purpose of calculating share-based compensation, the fair value of each award is determined at the grant date using the closing price of the common shares. For the year ended December 31, 2018, the fair value of awards granted was calculated using an estimated forfeiture rate of 9% (December 31, 2017 – 8%). The weighted average fair value of awards granted for the year ended December 31, 2018 was $2.34 (December 31, 2017 - $5.11). In the case of PAs, the award value is adjusted for a payout multiplier which can range from 0.0 to 2.0 and is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. On the vesting dates, the Company has the option of settling the award value in cash or common shares of the Company. Since the inception of the RPAP, the Company has settled all awards through the issuance of common shares from treasury. For RAs and PAs granted subsequent to May 21, 2018, the Company currently intends to settle the award value with common shares purchased in the open market as the Company no longer has the ability, in the absence of further shareholder approval being obtained, to settle the award values associated with such awards with common shares issued from treasury. Through the vesting of 729,000 RAs and 989,000 PAs, when taking into account the earned multipliers for PAs, 2,402,000 common shares of the Company were issued for the year ended December 31, 2018.

The number of RAs and PAs outstanding are as follows:

	Number of RAs	Number of PAs
Balance January 1, 2017	1,699	2,537
Granted	902	1,309
Vested	(808)	(1,316)
Forfeited	(177)	(309)
Balance December 31, 2017	1,616	2,221
Granted	2,628	3,427
Vested	(729)	(989)
Forfeited	(78)	(164)
Balance December 31, 2018	**3,437**	**4,495**

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, 2018 was 151,095,000 (December 31, 2017 – 148,603,000).

In computing diluted earnings per share for the year ended December 31, 2018, 725,000 (December 31, 2017 – 2,467,000) 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 8,773,000 (December 31, 2017 – 2,316,000) 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 $1.95 during the year ended December 31, 2018 (December 31, 2017 - $4.63).

13. 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, 2018		Year ended December 31, 2017
Income before income taxes	**$**	**23,170**	$	50,600
Combined federal and provincial income tax rate		**27.0%**		26.6%
Computed "expected" income tax expense	**$**	**6,256**	$	13,460
Increase (decrease) in income taxes resulting from:				
Change in income tax rates		**-**		832
Flow-through share renunciation		**-**		3,989
Non-deductible expenses and other		**63**		2,316
Change in share-based compensation estimate		**4,052**		(2,983)
	$	**10,371**	$	17,614
Premium on flow-through shares		**-**		(1,419)
Deferred income tax expense	**$**	**10,371**	$	16,195

(b) Deferred income tax liability:

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

		December 31, 2018		December 31, 2017
Deferred tax liabilities:				
Property, plant and equipment	**$**	**158,926**	$	132,749
Derivative financial instruments		**2,263**		94
Other		**6,362**		2,852
Deferred tax assets:				
Decommissioning obligations	**$**	**(24,151)**	$	(23,859)
Non-capital losses		**(90,602)**		(69,409)
Deferred income tax liability	**$**	**52,798**	$	42,427

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

	January 1, 2018	Recognized in equity	Recognized in other	Recognized in profit or loss	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**

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

The Company's assets have an approximate tax basis of $1,081.9 million at December 31, 2018 (December 31, 2017 - $1,080.0 million) available for deduction against future taxable income. The following table summarizes the tax pools:

	December 31, 2018	December 31, 2017
Cumulative Canadian Exploration Expense	**$ 291,400**	$ 290,400
Cumulative Canadian Development Expense	**238,800**	276,000
Undepreciated Capital Costs	**202,800**	234,800
Non-capital losses	**335,600**	257,100
Share issue costs	**5,300**	7,800
Other	**8,000**	13,900
Estimated tax basis	**$ 1,081,900**	$ 1,080,000

Non-capital losses will begin expiring in 2028. The estimated income tax pools for 2018 have been reduced by the estimated deferred partnership income for 2018.

14. Revenue:

Petroleum and natural gas sales:

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

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

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

	Year ended December 31, 2018	Year ended December 31, 2017
Light crude oil	**$ 6,582**	$ 10,541
Heavy crude oil	**25,548**	30,254
Condensate	**62,731**	46,360
Other natural gas liquids	**14,900**	14,059
Natural gas	**108,624**	112,940
	$ 218,385	$ 214,154

The adoption of IFRS 15 resulted in the Company evaluating its arrangement with third parties and partners to determine if the Company is the principal or agent. Based on the focus of control of the specified good or service, the Company identified arrangements for processing services where the Company is considered the principal and not a result of collaborative arrangements with partners in jointly owned assets. As a result of this change, the Company has reclassified $4.0 million for the year months ended December 31, 2017 from operating expenses to processing revenue included in other revenue.

Other revenue:

The following table summarizes the Company's other revenue:

	Year ended December 31, 2018	Year ended December 31, 2017
Marketing revenue	**$ 6,855**	$ -
Processing revenue	**4,134**	3,981
Other	**1,000**	1,000
	$ 11,989	$ 4,981

15. Financing:

	Year ended December 31, 2018	Year ended December 31, 2017
Interest expense	**$ 22,235**	$ 20,961
Accretion of deferred financing costs	**1,023**	968
Accretion of decommissioning obligations	**1,958**	1,934
Premium paid on redemption of 2020 Notes (note 10)	**-**	6,282
Deferred financing costs expensed on 2020 Notes (note 10)	**-**	2,510
	$ 25,216	$ 32,655

16. Key personnel expenses:

The aggregate payroll expense of key personnel was as follows:

	Year ended December 31, 2018	Year ended December 31, 2017
Short-term benefits	**$ 3,545**	$ 3,136
Long-term benefits	**6,836**	8,837
	$ 10,381	$ 11,973

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.

17. Supplemental cash flow information:

Changes in non-cash working capital is comprised of:

	Year ended December 31, 2018	Year ended December 31, 2017
Changes in non-cash working capital:		
Accounts receivable	**$ (29,592)**	$ (1,342)
Accounts payable and accrued liabilities	**(11,535)**	20,479
Other long-term assets	**3,447**	-
	$ (37,680)	$ 19,137
Operating activities	**$ (2,663)**	$ 8,706
Investing activities	**(35,017)**	10,431
	$ (37,680)	$ 19,137
Interest paid	**$ (22,167)**	$ (16,701)

18. Commitments:

	Total	2019	2020	2021	2022	2023	Thereafter
Operating leases	$ 2,742	$ 1,175	$ 1,175	$ 392	$ -	$ -	$ -
Firm transportation agreements	242,420	46,575	49,454	27,456	26,862	23,024	69,049
Firm processing agreement	112,192	17,634	16,337	12,354	12,354	12,354	41,159
Total	**$ 357,354**	**$65,384**	**$66,966**	**$40,202**	**$39,216**	**$35,378**	**$ 110,208**

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

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

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

19. Subsequent event:

Subsequent to December 31, 2018, the Company disposed of non-core land with no associated production or assigned reserves, for gross proceeds of $17.5 million.

DIRECTORS & OFFICERS

OFFICERS

Dale O. Shwed
President and Chief Executive Officer

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

James Taylor
Chief Operating Officer

Jamie L. Bowman
Senior Vice President, Marketing & Originations

Kurtis Fischer
Vice President, Business Development

Paul Dever
Vice President, Government & Stakeholder Relations

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

Mark Miller
Vice President, Land and Negotiations

BOARD OF DIRECTORS

John A. Brussa
Chairman Independent Director

Jeffery E. Errico
Lead Director Independent Director

Dennis L. Nerland
Independent Director

Karen Nielsen
Independent Director

Ryan Shay, CPA, CA
Independent Director

Dale O. Shwed
President, Crew Energy Inc.

David G. Smith
Independent Director

Corporate Secretary

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

ABBREVIATIONS

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