crew energy inc.

# BUILDING OUR FUTURE IN THE MONTNEY

'16

CREW ENERGY INC.

annual review

# ABOUT CREW

Crew Energy Inc. is a dynamic, growth-oriented energy company, focused on the development of our world-class Montney resource. Our goals are to reduce or control costs, improve our netbacks and increase reserves, production and cash flow on a per share basis. Crew's three year plan forecasts production growth to over 60,000 boe per day by the end of 2019, while maintaining a strong balance sheet.

Based in Calgary, Alberta, Crew is a leading holder of Montney acreage in northeast British Columbia with approximately 300,000 net acres. We utilize evolving technologies to increase individual well production and maximize overall rates of return, while simultaneously reducing costs and minimizing our environmental footprint. Crew's committed and experienced team has a proven track record of value creation and seeks to manage ongoing financial risk by maintaining a strong balance sheet, an active hedging program and focusing on market diversity. Crew's common shares trade on TSX under ticker 'CR'.

## Corporate Information

**AUDITORS**
KPMG LLP

**LEGAL COUNSEL**
Burnet, Duckworth & Palmer LLP

**RESERVE ENGINEERS**
Sproule Associates Ltd.

**TRANSFER AGENT**
Computershare Trust Company of Canada

**BANKERS**
Toronto-Dominion Bank

Alberta Treasury Branches

Bank of Montreal

National Bank of Canada

Bank of Nova Scotia

JPMorgan Chase Bank

Business Development Bank of Canada

## Investor Contact

**INVESTOR RELATIONS**
Crew Energy Inc.
Phone: (403) 266-2088
Email: investor@crewenergy.com
Web: www.crewenergy.com

**EXCHANGE LISTING**
TSX: CR

## Head Office

Suite 800, 250 - 5th Street S.W.
Calgary, Alberta
Canada T2P 0R4
Phone: (403) 266-2088

# CREW ENERGY INC. 2016 ANNUAL REVIEW

Crew Energy Inc. (TSX: CR) ("Crew" or the "Company") is pleased to provide our operating and financial results for the three and twelve month periods ended December 31, 2016.

## 2016 FULL YEAR AND Q4 HIGHLIGHTS

- Annual production averaged 22,844 boe per day, an increase of 23% over 2015, reflecting ongoing growth in Montney production with capital spending that was 30% lower than the prior year.

- Success at Septimus and West Septimus ("Greater Septimus") continued through 2016 with area production increasing 59% year over year to 17,797 boe per day, and increasing 21% to 17,307 boe per day in the fourth quarter of 2016 over the same period in 2015.

- Fourth quarter 2016 funds from operations were $27.9 million ($0.19 per diluted share), 42% higher than the same quarter in 2015 primarily attributable to materially lower costs and improved natural gas pricing.

- Fourth quarter corporate operating netbacks were $17.03 per boe, 23% higher than the same period in 2015 and 21% higher than the previous quarter, as a result of lower operating costs combined with higher realized pricing in the quarter.

- Operating costs per boe were reduced by 29% in 2016 compared to 2015 and averaged $5.88 per boe, compared to $8.31 per boe in 2015. Operating costs in the fourth quarter averaged $5.35 per boe, a reduction of 22% compared to the same period in 2015 and a further five percent reduction from the prior quarter.

- Operating costs per boe at Greater Septimus averaged $3.34 per boe in the fourth quarter, a further 7% reduction from the previous quarter and 31% lower than the same period in 2015, contributing to Greater Septimus fourth quarter operating netbacks of $18.22 per boe.

- Balance sheet strength and ongoing financial flexibility were maintained in 2016 as year-end net debt totaled $245.4 million, including working capital deficiency, representing a 2.2 times net debt to annualized fourth quarter 2016 funds from operations ratio, and a draw of 38% on our credit facility.

- On February 24, 2017, we announced the refinancing of our existing high yield term debt, replacing it with $300 million of new high yield term debt bearing interest at 6.5% and maturing in 2024. This transaction is scheduled to close on or about March 14, 2017.

- As announced on February 9, 2017, Crew reported strong Montney reserves growth in the Company's 2016 year end independent reserves evaluation (the "Reserves Report") with attractive capital efficiencies. Net of production, proved plus probable ("2P") reserves increased by 24%, total proved ("1P") reserves by 26%, and proved developed producing ("PDP") reserves by 11% resulting in reserves per share increases of 19% on 2P, 21% on 1P and 7% on PDP.

- On a 2P basis, finding and development ("F&D") costs were $5.65 per boe generating a recycle ratio of 3.0 times while 1P F&D costs were $6.30 per boe, resulting in a recycle ratio of 2.7 times, all including changes in future development capital ("FDC").

## FINANCIAL & OPERATING HIGHLIGHTS:

| FINANCIAL<br>($ thousands, except per share amounts) | **Three months ended Dec. 31, 2016** | Three months ended Dec. 31, 2015 | **Year ended Dec. 31, 2016** | Year ended Dec. 31, 2015 |
|---|---|---|---|---|
| **Petroleum and natural gas sales** | **55,051** | 34,532 | **174,719** | 153,934 |
| **Funds from operations**(1) | **27,879** | 19,601 | **78,674** | 82,363 |
| Per share - basic | **0.19** | 0.14 | **0.55** | 0.60 |
| - diluted | **0.19** | 0.14 | **0.54** | 0.60 |
| **Net loss** | **(40,030)** | (8,167) | **(64,926)** | (55,355) |
| Per share - basic | **(0.28)** | (0.06) | **(0.45)** | (0.40) |
| - diluted | **(0.28)** | (0.06) | **(0.45)** | (0.40) |
| **Exploration and Development expenditures** | **37,612** | 42,067 | **108,202** | 246,418 |
| **Property acquisitions** (net of dispositions) | **3,099** | (36,644) | **3,973** | (85,441) |
| **Net capital expenditures** | **40,711** | 5,423 | **112,175** | 160,977 |

| **Capital Structure**<br>($ thousands) | **As at Dec. 31, 2016** | As at Dec. 31, 2015 |
|---|---|---|
| Working capital deficiency(2) | **10,006** | 10,737 |
| Bank loan | **88,036** | 80,980 |
| | **98,042** | 91,717 |
| Senior Unsecured Notes | **147,329** | 146,679 |
| **Total Net Debt** | **245,371** | 238,396 |
| **Debt Capacity**(3) | **385,000** | 400,000 |
| **Common Shares Outstanding** (thousands) | **146,812** | 141,067 |

Notes:

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

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

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

| **Operations** | **Three months ended Dec. 31, 2016** | Three months ended Dec. 31, 2015 | **Year ended Dec. 31, 2016** | Year ended Dec. 31, 2015 |
|---|---|---|---|---|
| **Daily production** | | | | |
| Light crude oil (bbl/d) | **540** | 340 | **335** | 441 |
| Heavy crude oil (bbl/d) | **2,188** | 2,849 | **2,459** | 3,834 |
| Natural gas liquids (bbl/d) | **3,402** | 3,437 | **3,349** | 2,521 |
| Natural gas (mcf/d) | **97,501** | 84,479 | **100,203** | 70,474 |
| Total (boe/d @ 6:1) | **22,380** | 20,706 | **22,844** | 18,542 |
| **Average prices** (1) | | | | |
| Light crude oil ($/bbl) | **57.49** | 48.75 | **49.89** | 53.10 |
| Heavy crude oil ($/bbl) | **41.44** | 31.92 | **33.39** | 40.40 |
| Natural gas liquids ($/bbl) | **38.83** | 27.87 | **31.83** | 30.28 |
| Natural gas ($/mcf) | **3.53** | 2.04 | **2.71** | 2.37 |
| Oil equivalent ($/boe) | **26.74** | 18.13 | **20.90** | 22.74 |

Notes:

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

| | **Three months ended Dec. 31, 2016** | Three months ended Dec. 31, 2015 | **Year ended Dec. 31, 2016** | Year ended Dec. 31, 2015 |
|---|---|---|---|---|
| **Netback** ($/boe) | | | | |
| Revenue | **26.74** | 18.13 | **20.90** | 22.74 |
| Royalties | **(1.92)** | (1.23) | **(1.27)** | (2.01) |
| Realized commodity hedging (loss)/gain | **(0.35)** | 5.82 | **1.42** | 6.05 |
| Operating costs | **(5.35)** | (6.89) | **(5.88)** | (8.31) |
| Transportation costs | **(2.09)** | (1.96) | **(2.25)** | (1.90) |
| Operating netback (1) | **17.03** | 13.87 | **12.92** | 16.57 |
| G&A | **(1.33)** | (1.42) | **(1.41)** | (1.95) |
| Interest on long-term debt | **(2.15)** | (2.16) | **(2.10)** | (2.45) |
| Funds from operations | **13.55** | 10.29 | **9.41** | 12.17 |
| | | | | |
| **Drilling Activity** | | | | |
| Gross wells | **8** | 6 | **21** | 33 |
| Working interest wells | **7.7** | 6.0 | **19.7** | 31.4 |
| Success rate, net wells (%) | **91** | 83 | **96** | 97 |

Notes:

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

## OVERVIEW

Throughout 2016, Crew continued to demonstrate the success of our Montney-focused strategy with positive growth across our core Greater Septimus area and advancement of our future development plans at Groundbirch. While commodity prices remained very weak through the first half of the year, we benefitted from lower costs and improved operational efficiencies and had access to our required drilling and completions services. With foresight into the potential for ramp-up in industry activity and given our development plans for the next three years, Crew took the opportunity to lock-in major service costs through the end of 2017 and remains well positioned to advance our long-range growth plan.

Given the commodity price environment that prevailed through 2016, we are very pleased with both our financial and operating results for the year. In addition to generating exciting results from wells drilled in our ultra condensate-rich area at Greater Septimus, we also expanded our future potential development with our first wells into new zones including the Lower Montney and the Lower "B" Interval of the Upper Montney. We will continue to drill and develop these zones, and potentially others, while we build-out our infrastructure to accommodate additional production growth.

The success of our 2016 operational activities was reflected in positive reserves increases – on an absolute and per share basis – which we achieved at attractive capital efficiency metrics. We posted meaningful improvements in our three year average F&D costs, which improved 17% and 12%, respectively, on a 1P and 2P basis compared to 2015, and were 37% and 25% lower, respectively, than in 2014. This demonstrates the continued efficiency gains we have realized through the implementation of pad drilling, reductions in drilling days, and overall efficiency improvements. Our conservative capital program in 2016 was responsive to commodity price changes and during the year we increased the program from $70 million to $112 million in light of strengthening commodity prices, lower service costs and to further support the phased development of our multi-year plan to achieve 60,000 boe per day by the end of 2019. Under this plan, Crew will schedule our drilling and completions activities to coincide with both processing capacity as well as our firm transportation arrangements, while ensuring our balance sheet remains strong with ample liquidity.

While a sale of our Lloydminster heavy oil asset did not conclude by the end of 2016, we are continuing with this process and remain confident that we will be able to transact and ensure optimal value for shareholders.

## FINANCIAL

A challenging first half commodity price environment resulted in the 2016 Canadian dollar WTI benchmark average crude price ending the year 8% lower than in 2015, while AECO natural gas prices in 2016 averaged 20% lower than in 2015. However, as the year progressed, limited first half drilling, supportive summer weather and the announcement of a 2017 Organization of Petroleum Exporting Countries ("OPEC") production curtailment agreement all provided pricing support for oil and natural gas. During the fourth quarter, crude oil prices improved with the Canadian dollar WTI benchmark price increasing 17% over the same period in 2015. Natural gas prices also strengthened in the fourth quarter, with the AECO daily natural gas benchmark price increasing 33% compared to the third quarter of 2016 and 26% over the same quarter in 2015.

Crew's natural gas prices were positively impacted through the year as a result of our marketing team's active natural gas marketing program, the diversification in our transportation and sales points, and the approximately 19% higher heat content of our Montney natural gas relative to the AECO benchmark. In the fourth quarter, our realized natural gas price increased by 73% over the same period in 2015 to $3.53 per mcf. Our overall per boe realized price improved 47% to $26.74 per boe in the fourth quarter compared to the same period in 2015, while our 2016 realized price per boe was $20.90 per boe, a decline of 8% year over year.

With improved commodity pricing and a favorable service cost environment, Crew moved forward with an expanded capital program in the second half of 2016 which included net capital expenditures totaling $78.3 million or 70% of the total 2016 net capital expenditures of $112.2 million. Expenditures were largely directed to drilling and completing wells in the Greater Septimus area, the completion of wells at Tower that had been previously drilled but uncompleted and initiating the expansion of the West Septimus facility from the current 60 mmcf per day to 120 mmcf per day.

Despite the increased capital program, the Company remained focused on maintaining its strong financial position exiting the year with net debt of $245.4 million or 2.2 times annualized fourth quarter funds from operations, a 27% improvement from the 3.0 times multiple at the end of 2015. The Company's strong financial position is enhanced by the financial liquidity provided by the Company's 62% undrawn bank facility at year-end. The facility's total $235 million borrowing base capacity was well supported by the 11% increase in the Company's 2016 PDP reserves, which had a net present value discounted at 10% of $459 million. Additionally, subsequent to the end of 2016, we announced the refinancing of our 2020 maturing, $150 million senior unsecured 8.375% notes. These notes will be redeemed and replaced by a new senior unsecured note offering totaling $300 million, bearing interest at 6.5% maturing in 2024. Closing of this transaction is expected to occur on or about March 14, 2017, subject to satisfaction of customary closing conditions. The excess proceeds from the refinancing transaction will be directed to repayment of outstanding indebtedness under our bank facility and for general corporate purposes, including the ongoing development of our high quality Montney asset base. This refinancing transaction is expected to further enhance Crew's financial flexibility, and supports our Montney development and infrastructure build-out that underpins the Company's long-range growth plan.

The improved commodity price environment and Crew's continued focus on reducing costs contributed to fourth quarter funds from operations of $27.9 million or $0.19 per diluted share, an increase of 42% over the fourth quarter of 2015. Even with positive cost impacts, lower average commodity prices through most of 2016 resulted in a 4% reduction in annual funds from operations to $78.7 million or $0.54 per diluted share. Crew's fourth quarter and full year 2016 earnings were impacted by unrealized losses incurred on the Company's risk management program and a non-cash impairment charge against the Company's heavy oil property.

Crew continued to reduce operating costs per boe through 2016, which averaged $5.88 per boe or 29% lower than in 2015, which helped to support our netback in a low price environment. In the fourth quarter of 2016, operating costs averaged $5.35 per boe or 22% lower than the same period the prior year. The quarterly and annual reductions are a result of overall industry cost improvements, enhanced operational efficiencies, and the impact of increased volumes from our lower-cost Greater Septimus area.

## TRANSPORTATION, MARKETING & HEDGING

Through 2016, Crew's strategy to further diversify our natural gas transportation and sales points coupled with the higher heat content of our gas has resulted in our realized sales price outperforming industry benchmarks. Crew will continue to seek out opportunities to enhance our diversification as we continue to grow. One of the many advantages of our Montney land base is that we are situated with access to all three major export pipeline systems which affords substantial optionality to access markets across North America. We successfully renewed contracts that will provide continued exposure to the Chicago City Gate, AECO, Alliance ATP and Station 2 markets through 2017. In April of 2017, our transportation on the Spectra pipeline system increases from 13 mmcf per day to 30 mmcf per day, providing the ability to move additional natural gas into the Station 2 and Sumas, Washington markets. In early 2018, we have also secured 60 mmcf per day of capacity on the TransCanada pipeline system ("TCPL"), affording improved market diversity for natural gas from our Greater Septimus and Groundbirch areas. As well, in mid-2019, we have an additional 60 mmcf per day of firm capacity on the TCPL system.

With an improved outlook for longer-dated natural gas futures prices, Crew continued to systematically add 2017 natural gas hedges throughout the fourth quarter and the early part of 2017 to help mitigate price volatility. For 2017, Crew's total natural gas hedged position is approximately 48% of our forecast 2017 gas sales at a transportation-adjusted equivalent price of $2.92 per gj, which when adjusting for the higher heat content of Crew's gas, equates to $3.62 per mcf. For liquids, we have approximately 43% of our 2017 light oil and natural gas liquids sales hedged at an average price of CDN$68.17 per bbl.

## OPERATIONS

### NE BC Montney – Greater Septimus Overview

Our Greater Septimus activities are supported by improving well results, continued cost reductions and enhanced pricing through our diversified market portfolio. Crew's fourth quarter and full year 2016 average production at Greater Septimus totaled 17,307 boe per day and 17,797 boe per day, respectively. Production volumes were 59% higher than in 2015 and 21% higher than the fourth quarter of 2015 due to continued drilling and completions activities focused in the ultra condensate-rich region, where Crew is able to generate very attractive returns in the current commodity price environment. These production volumes were achieved despite an eight day full system shut-down of the Alliance Pipeline which resulted in all of our Montney operations being shut-in, reducing production for the quarter by approximately 1,750 boe per day. Crew has continued to realize increases in condensate production in proportion to other liquids production, as total natural gas liquids ("NGL") volumes in 2016 were 33% higher than in 2015. Operating costs per boe at Greater Septimus declined 7% from the third quarter to $3.34 per boe as a result of improved economies of scale and continued cost reduction initiatives. Project economics at Greater Septimus remain compelling, particularly within the ultra condensate-rich area at West Septimus which was a focal area for Crew during the last half of 2016.

**Greater Septimus**

| **Production & Drilling** | **Q4 2016** | Q3 2016 | Q2 2016 | Q1 2016 |
|---|---|---|---|---|
| Average Daily Production (boe/d) | **17,307** | 18,592 | 17,131 | 18,149 |
| Wells drilled (gross / net) | **8 / 7.7** | 8 / 7.0 | - | 4 / 4.0 |
| Wells completed | **5** | 7 | 7 | 3 |

| **Operating Netback** ($ per boe) | **Q4 2016** | Q3 2016 | Q2 2016 | Q1 2016 |
|---|---|---|---|---|
| Revenue | **25.10** | 20.56 | 16.06 | 16.69 |
| Royalties | **(1.47)** | (0.94) | (0.69) | (0.79) |
| Realized commodity hedge (loss)/gain | **(0.39)** | 1.11 | 3.24 | 1.34 |
| Operating costs | **(3.34)** | (3.61) | (4.02) | (4.43) |
| Transportation costs | **(1.68)** | (1.59) | (1.97) | (2.21) |
| Operating netback | **18.22** | 15.53 | 12.62 | 10.60 |

During 2016, Crew's primary focus was on the continued development of our liquids-rich West Septimus area, where we realized 1P and 2P reserves increases of 66% to 81.0 mmboe and 53% to 154.8 mmboe, respectively, compared to year end 2015.

The ongoing delineation of Crew's significant Montney land base continued in 2016 with successful results from new stratigraphic intervals of the Montney, and confirmation of an ultra condensate-rich window that is approximately six times the condensate level Crew had previously encountered. Combined with the improved efficiency in our operations during 2016, the Company was able to progress our completion technology while achieving record low all-in well costs.

Crew has two Upper Montney Lower "B" wells in the Greater Septimus area, one of which has been on production for 250 days and produced at an average rate of 1,000 boe per day. The second Lower "B" well has been on production for 60 days and produced at an average rate of 1,475 boe per day. The two wells were assigned an average 2P estimated ultimate recovery ("EUR") of 1.2 million boe per well by Crew's independent reserves evaluator in the Reserves Report, 16% higher than our current Septimus undeveloped EUR assignments. The improved performance that we have experienced at West Septimus illustrates the prospectivity of the multiple zones within the Montney, the importance of geo-steering which allows for targeted zonal drilling and the benefits of higher intensity fracture treatments. With continued exploitation of the Lower "B" interval and the Company's ongoing focus on technology enhancements and implementation, we expect continued strong well performance from our legacy Septimus asset.

Crew's original Lower Montney well at Septimus continues to perform well, producing ahead of the 5.6 bcf type curve for booked undeveloped locations used in the Reserves Report. We believe the largely unbooked Lower Montney resource will be a significant focus within our multi-year growth plan and are continuing to explore optimal completion designs for the Lower Montney to be applied to our future pad developments.

At West Septimus our new ultra condensate-rich wells continue to exceed expectations with our initial two wells producing a total of 30,500 bbls and 52,000 bbls of condensate in 90 and 145 days, respectively, at an average condensate gas ratio of 153 and 192 bbls per mmcf, respectively. These results contributed to an initial reserve booking in the Reserves Report of 41 undeveloped locations with an average 2P EUR of 3.7 bcf of natural gas and 239 mbbls of condensate. The total capital cost for each of these wells was $4.3 million including a 40-stage open hole completion with an increased two tonnes per metre sand loading. Crew is excited about further delineation of this liquids-rich resource with two six-well pads planned for the second and third quarters of 2017. Subject to further delineation of the local reservoir quality and productivity, our internal assessment would indicate up to 165 potential drilling opportunities within this ultra condensate-rich window.

Through the end of 2016, the design basis for the West Septimus facility expansion to 120 mmcf per day was finalized. The plant's front end liquids design specifications were increased to incorporate significantly higher condensate and NGL loading from our newly discovered ultra condensate-rich region. During the fourth quarter, we placed orders for the longest lead items to ensure a delivery schedule in time for a projected start-up scheduled for the fourth quarter of 2017. The net cost to the Company for the expansion is expected to be between $12 and $15 million based on Crew's current 28% working interest in our Greater Septimus natural gas processing complex. Crew also began to survey the right of way for a 43 kilometre pipeline system from Crew's existing West Septimus infrastructure through our future 120 mmcf per day Groundbirch facility site and down to the existing TransCanada Saturn meter station. With completion of this pipeline system in early 2018, Crew will have achieved a major milestone in our diverse transportation and marketing strategy by having physical access to all three major pipeline systems out of the Western Canadian Sedimentary Basin.

**NE BC Montney – Tower Overview**

In 2014, Crew drilled four wells in our Tower light oil play, and in 2016, proceeded with completing two of the four drilled and uncompleted wells utilizing a plug and perf completion system and two tonnes per metre sand loading. To date the wells have produced 30,500 and 11,000 bbls of light oil in 90 and 60 days, respectively, at average oil to gas ratios of 243 and 150 bbls per mmcf, respectively. Crew is currently in the process of completing the remaining two wells and is continuing to optimize our completion techniques in the ultra condensate-rich gas and oil hydrocarbon windows to determine the most economic technique to be applied to full-scale field development.

**Lloydminster, AB/SK Overview**

In light of the ongoing sales process at Lloydminster through the fourth quarter of 2016, Crew was directing minimal capital toward the area and production volumes declined during the last half of 2016, averaging 2,191 boe per day in the fourth quarter and 2,486 boe per day during 2016. The Lloydminster area provides significant leverage to improving oil prices while continuing to have a low and competitive cost structure.

## OUTLOOK

In 2017, we will continue to build upon Crew's existing core developments and delineate additional acreage in the liquids-rich window at West Septimus and at Groundbirch. Our 300,000 acre land position and over 110 TCFE of Total Petroleum Initially In Place Montney resource comprised of 8 billion barrels of oil and 60 Tcf of natural gas affords Crew access to oil and liquids-rich natural gas and the optionality to optimize commodity type, transportation systems and sales markets. We have been successful in steadily improving our netback by reducing operating costs and targeting greater condensate and oil in our production mix. Given the current outlook for natural gas, we will concentrate on the development of oil and condensate-rich natural gas assets in our portfolio. Crew currently has three rigs running in the Montney and has 13 wells drilled and awaiting completion. In addition, we have five wells currently flowing back after being completed.

From this strong base, we continue to advance our multi-year growth plan, staged with access to processing and transportation infrastructure that will allow Crew to have the capacity to meet its targeted growth of over 60,000 boe per day over the next three years. With larger size and scale, Crew anticipates being able to fund our growth with a combination of funds from operations, our new senior unsecured notes, draws on the bank facility as it expands, other financing alternatives or potential future asset sales. We are committed to executing our growth plan with a priority of maintaining a strong balance sheet through this period as we have done in the past.

Our $200 million capital budget for 2017 anticipates drilling 28 new Montney wells, completing 39 wells, and finalizing the West Septimus facility expansion in the fourth quarter. Our Greater Septimus gas processing complex has incremental processing capacity to manage our near term production additions, and the planned expansion later in 2017 is expected to support growth to over 35,000 boe per day. Based on current forecast commodity price assumptions, 2017 annual production is anticipated to range between 25,000 and 27,000 boe per day, while exit production is expected to be greater than 30,000 boe per day. We are commencing work on the engineering design for the planned 120 mmcf per day greenfield Groundbirch processing facility, expected to be commissioned in the fourth quarter of 2018, as well as the interconnecting pipeline system from West Septimus through Groundbirch to our new TCPL sales point at Saturn. By 2019, Crew anticipates being in a strong position with a total of 300 mmcf per day of total processing capacity paired with 275 mmcf per day of firm and priority interruptible transportation capacity. Post 2019, Crew is actively working to secure additional processing and takeaway capacity to continue to grow our Montney production base.

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

**Cautionary Statements**

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

*Information presented herein in respect of reserves and related information is based on our independent reserves evaluation for the year ended December 31, 2016 prepared by Sproule Associates Limited, details of which were provided in our press release issued on February 9, 2017. Our oil and gas reserves statement for the year ended December 31, 2016, which will include complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, will be contained within our Annual Information Form which will be available on our SEDAR profile at www.sedar.com. The recovery and reserve estimates contained herein are estimates only and there is no guarantee that the estimated reserves will be recovered. In relation to the disclosure of estimates for individual properties, such estimates may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. The Company's belief that it will establish additional reserves over time with conversion of probable undeveloped reserves into proved reserves is a forward-looking statement and is based on certain assumptions and is subject to certain risks, as discussed below under the heading "Forward-Looking Information and Statements".*

*This report contains metrics commonly used in the oil and natural gas industry, such as "finding and development costs" and "operating netbacks". The term "EUR" is the estimated raw quantity of gas or oil that is potentially recoverable or has already been recovered from a* *well. Reference is made to Crew's press release dated February 9, 2017 for definitions and details of the calculation of such metrics used herein. These terms do not have standardized meanings or standardized methods of calculation and therefore may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included herein to provide readers with additional information to evaluate the Company's performance, however such metrics should not be unduly relied upon.*

*F&D 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 report 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 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.*

*This report contains references to estimates of oil and gas classified as Total Petroleum Initially In Place ("**TPIIP**") in Crew's Montney region in northeast British Columbia which are not, and should not, be confused with, oil and gas reserves. Such estimates are based upon an independent resource evaluation effective as at December 31, 2015, prepared for Crew in accordance with the Canadian Oil & Gas Evaluation Handbook, complete details of which evaluation were set forth in Crew's previously disseminated press release dated May 5, 2016 (the "**Resource Report Press Release**"). Such resource estimates are broken into the requisite categories and are subject to a number of cautionary statements, assumptions, risks, positive and negative factors relative to the estimates and contingencies, all of which details are set forth in the Resource Report Press Release, all of which is incorporated by reference herein.*

**Forward-Looking Information and Statements**

*This report contains certain forward–looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "project", "should", "believe", "plans", "intends" "forecast" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this report contains forward-looking information and statements pertaining to the following: the estimated volumes and product mix of Crew's oil and gas production; the potential opportunity for expanded drilling in the Lower Montney; future oil and natural gas prices and Crew's commodity risk management programs; marketing and transportation plans; future liquidity and financial capacity; future results from operations and operating metrics including potential rates of return; 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); estimated drilling locations at Greater Septimus and potential impact thereof; the amount and timing of capital projects including the planned expansion of our West Septimus facility and the timing and estimated cost thereof; the potential sale of our heavy oil assets in Saskatchewan and Alberta; long-term growth strategy including drilling, completion and infrastructure plans and associated timing and costs; methods of funding our capital program including possible non-core asset divestitures and asset swaps; the anticipated completion of the senior unsecured note refinancing transaction, the timing thereof, and the anticipated use of proceeds including the redemption of the Company's currently outstanding notes; and Crew's 2017 budget and production estimates including 2017 annual year-end and exit rates and three year production targets.*

*In this report, reference is made to the Company's long range potential Montney growth scenario. Such information reflects internal projections used by management for the purposes of making capital investment decisions and for internal long range planning and budget preparation. This information is based upon a variety of assumptions that may prove to be incorrect and, accordingly, long range targets are not intended to reflect estimates or forecasts of metrics that may actually be achieved. Accordingly, undue reliance should not be placed on the same.*

*The recovery and reserve estimates of Crew's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. In addition, forward-looking statements or information are based on a number of material factors, expectations or assumptions of Crew which have been used to develop such statements and information but which may prove to be incorrect. Although Crew believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because Crew can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified herein, assumptions have been made regarding, among other things: that Crew will continue to conduct its operations in a manner consistent with past operations; results from drilling and development activities consistent with past operations; the quality of the reservoirs in which Crew operates and continued performance from existing wells; the continued and timely development of infrastructure in areas of new production; the accuracy of the estimates of Crew's reserve volumes; certain commodity price and other cost assumptions; continued availability of debt and equity financing and cash flow to fund Crew's current and future plans and expenditures; the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; the general continuance of current industry conditions; the timely receipt of any required regulatory approvals; the ability of Crew to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects in which Crew has an interest in to operate the field in a safe, efficient and effective manner; the ability of Crew to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and cost of pipeline, storage and facility construction and expansion and the ability of Crew to secure adequate product transportation; future commodity prices; currency, exchange and interest rates; regulatory framework regarding* *royalties, taxes and environmental matters in the jurisdictions in which Crew operates; and the ability of Crew to successfully market its oil and natural gas products.*

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

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

**Test Results and Initial Production Rates**

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

**BOE equivalent**

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

# YEAR END 2016

Management's Discussion and Analysis

&

Financial Statements

# MANAGEMENT'S DISCUSSION AND ANALYSIS

## FINANCIAL & OPERATING HIGHLIGHTS

| **Financial**<br>($ thousands, except per share amounts) | **Year ended**<br>**December 31, 2016** | Year ended<br>December 31, 2015 |
|---|---|---|
| **Petroleum and natural gas sales** | **174,719** | 153,934 |
| **Cash provided by operations** | **77,478** | 74,698 |
| **Funds from operations** [(1)] | **78,674** | 82,363 |
| Per share -basic | **0.55** | 0.60 |
| -diluted | **0.54** | 0.60 |
| **Net loss** | **(64,926)** | (55,355) |
| Per share -basic | **(0.45)** | (0.40) |
| -diluted | **(0.45)** | (0.40) |
| **Exploration and development expenditures** | **108,202** | 246,418 |
| **Property acquisitions** (net of dispositions) | **3,973** | (85,441) |
| **Net capital expenditures** | **112,175** | 160,977 |

| **Capital structure**<br>($ thousands) | **As at**<br>**December 31, 2016** | As at<br>December 31, 2015 |
|---|---|---|
| Working capital deficiency [(2)] | **10,006** | 10,737 |
| Bank loan | **88,036** | 80,980 |
| | **98,042** | 91,717 |
| Senior unsecured notes | **147,329** | 146,679 |
| **Total net debt** | **245,371** | 238,396 |
| **Debt capacity**[(3)] | **385,000** | 400,000 |
| **Common shares outstanding** (thousands) | **146,812** | 141,067 |

| **Operations** | **Year ended**<br>**December 31, 2016** | Year ended<br>December 31, 2015 |
|---|---|---|
| **Daily production** | | |
| Light crude oil (bbl/d) | **335** | 441 |
| Heavy crude oil (bbl/d) | **2,459** | 3,834 |
| Natural gas liquids (bbl/d) | **3,349** | 2,521 |
| Natural gas (mcf/d) | **100,203** | 70,474 |
| Oil equivalent (boe/d @ 6:1) | **22,844** | 18,542 |
| **Average prices** [(4)] | | |
| Light crude oil ($/bbl) | **49.89** | 53.10 |
| Heavy crude oil ($/bbl) | **33.39** | 40.40 |
| Natural gas liquids ($/bbl) | **31.83** | 30.28 |
| Natural gas ($/mcf) | **2.71** | 2.37 |
| Oil equivalent ($/boe) | **20.90** | 22.74 |
| **Netback** ($/boe) | | |
| Operating netback [(5)] | **12.92** | 16.57 |
| G&A | **(1.41)** | (1.95) |
| Interest on long-term debt | **(2.10)** | (2.45) |
| Funds from operations | **9.41** | 12.17 |
| **Drilling activity** | | |
| Gross wells | **21** | 33 |
| Working interest wells | **19.7** | 31.4 |
| Success rate, net wells | **96%** | 97% |

Notes:

(1) Funds from operations 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. Funds from operations is used to analyze the Company's operating performance and leverage. Funds from operations does not have a standardized measure prescribed by International Financial Reporting Standards, and therefore, may not be comparable with the calculations of similar measures for other companies.

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

(3) Includes the maximum available under the Company's bank facility combined with the total face value of the $150 million senior unsecured notes due in October 2020.

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

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

## ADVISORIES

Management's discussion and analysis ("MD&A") is the explanation of the financial performance for the period covered by the financial statements along with an analysis of the financial position for Crew Energy Inc. ("Crew" or 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, 2016 and 2015. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). All figures provided herein and in the December 31, 2016 audited consolidated financial statements are reported in Canadian dollars. This MD&A is dated March 2, 2017.

**Forward Looking Statements**

This MD&A contains forward looking statements. Management's assessment of future plans and operations, drilling plans and the timing thereof, plans for the completion and tie-in of wells, facility and pipeline construction, commissioning and the timing thereof, capital expenditures, timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, the completion of the Offering of the 2024 Notes on the terms anticipated, or at all, the anticipated use of the proceeds, including the redemption of the 2020 Notes and the timing of closing of the offering, production estimates including 2017 average, 2017 exit forecasts and 2019 exit production targets, expected commodity mix and prices, future operating costs, future transportation costs, expected royalty rates, expected general and administrative expenses, expected interest rates, debt levels, funds from operations and the timing of and impact of implementing accounting policies, estimates regarding undeveloped land position and estimated future drilling, recompletion or reactivation locations and anticipated impact of potential future transactions may constitute forward looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, the inability to fully realize the benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and inability to access sufficient capital from internal and external sources. As a consequence, the Company's actual results may differ materially from those expressed in, or implied by, the forward looking statements. Forward looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Crew believes that the expectations reflected in such forward looking statements or information are reasonable, undue reliance should not be placed on forward looking statements because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document and other documents filed by the Company, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Company has an interest in to operate the field in a safe, efficient and effective manner; Crew's ability to obtain financing on acceptable terms; changes in the Company's banking facility; field production rates and decline rates; the ability to reduce operating costs; the ability to replace and expand oil and natural gas reserves through acquisition, development or exploration; the timing and costs of pipeline, storage and facility construction and expansion; the ability of the Company to secure adequate product transportation; future petroleum and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company operates; and Crew's ability to successfully market its petroleum and natural gas products. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) or at the Company's website (www.crewenergy.com). Furthermore, the forward looking statements contained in this document are made as at the date of this document and the Company does not undertake any obligation to update publicly or to revise any of the included forward looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

**Conversions**

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

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

**Non-IFRS Measures**

Funds from Operations

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

| ($ thousands) | **Three months ended December 31, 2016** | Three months ended December 31, 2015 | **Year ended December 31, 2016** | Year ended December 31, 2015 |
|---|---|---|---|---|
| Cash provided by operating activities | **19,900** | 12,373 | **77,478** | 74,698 |
| Decommissioning obligations settled | **763** | 43 | **1,411** | 736 |
| Change in operating non-cash working capital | **7,394** | 7,300 | **435** | 7,498 |
| Accretion of deferred financing costs | **(178)** | (115) | **(650)** | (569) |
| Funds from operations | **27,879** | 19,601 | **78,674** | 82,363 |

Debt to EBITDA

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

Operating Netback

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

Working Capital and Net Debt

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

| ($ thousands) | **December 31, 2016** | December 31, 2015 |
|---|---|---|
| Current assets | **39,588** | 34,417 |
| Current liabilities | **(68,494)** | (38,217) |
| Marketable securities | **-** | (1,160) |
| Derivative financial instruments | **18,900** | (5,777) |
| Working capital deficit | **(10,006)** | (10,737) |

| ($ thousands) | **December 31, 2016** | December 31, 2015 |
|---|---|---|
| Bank loan | **(88,036)** | (80,980) |
| Senior unsecured notes | **(147,329)** | (146,679) |
| Working capital deficit | **(10,006)** | (10,737) |
| Net debt | **(245,371)** | (238,396) |

## RESULTS OF OPERATIONS

**Overview**

In 2016, Crew continued to focus on the economic development of its vast Montney resource and was encouraged by the continued improvement of the capital and operating cost structure as well as the significant improvements in well productivity. A systemic approach to our hedging program, diversity of sales points for our products and an improved commodity price environment have allowed Crew to pursue a more aggressive growth strategy while maintaining financial strength. Crew achieved average annual production of 22,844 boe per day, an increase of 23% over 2015 levels. A successful drilling and completion program at the Company's Septimus and West Septimus ("Greater Septimus") areas drove Crew's production growth which included an increase of 59% in the Company's Montney production to 17,797 boe per day and a 33% increase in ngl production to 3,349 bbl per day.

The first half of 2016 was plagued by the worst commodity price environment in Crew's history. During the worst of the downturn, the Company remained committed to maintaining a strong financial position by executing a conservative capital spending program and relying on our structured risk management program to provide support to our cash flow from operations. Cash flow during the year was also supported by the Company's diversified marketing strategy that helped to maximize oil, ngl and natural gas revenues by providing exposure to various pricing points. In particular, the Company's natural gas benefited from being significantly exposed to the Chicago City Gate market which proved to be one of the strongest natural gas markets in North America in 2016.

Through the first half of 2016, Crew spent $32.9 million on exploration and development expenditures predominantly on drilling and completing wells at Greater Septimus in order to fill the Company's processing capacity in the area. As commodity pricing increased through the last half of the year, Crew accelerated its capital expenditures to total $112.2 million for 2016. Included in these expenditures was $16.5 million in infrastructure spending predominantly at West Septimus where the Company commenced its facility expansion to increase the processing capacity from 60 mmcf per day to 120 mmcf per day. The facility expansion is expected to be complete in the fourth quarter of 2017 and will provide the Company with 180 mmcf per day of processing capacity in the area. In 2016, Crew's drilling and completion activity was focused on the development of its Montney play where the Company drilled 20 (18.6 net) wells and completed 22 (20.3 net) wells. The Company continues to be encouraged with its drilling success, increasing production rates and reduced costs driving attractive economics at Greater Septimus.

Crew has been actively managing its costs throughout the organization. Greater efficiencies and increased production have decreased annual operating costs per boe 29% to average $5.88 per boe in 2016. This was highlighted by the Company's Greater Septimus operating costs decreasing 32% throughout the year from $4.86 per boe in the fourth quarter of 2015 to $3.34 per boe in the fourth quarter of 2016. The Company has also been proactive in reducing its general and administrative expenses and successfully decreased its total costs by 11% and costs per boe by 28% to average $1.41 per boe in 2016.

Crew exited 2016 with net debt of $245 million, which included $88 million drawn on the Company's bank facility. At this debt level, the Company's debt to annualized fourth quarter 2016 funds from operations was 2.2 times, representing continued improvement over the 2.7 times ratio at the end of the third quarter of 2016. Subsequent to the end of 2016, the Company announced a refinancing of its high yield notes whereby the existing notes, bearing interest at 8.375% and maturing in 2020, will be replaced with $300 million of notes bearing interest at 6.5% and maturing in 2024 as discussed in the Capital Funding section below. The transaction is expected to close late in the first quarter of 2017. With no near term maturities, an increasing reserve base and substantial liquidity, Crew is strongly positioned to manage its long-term plan of production growth, targeting 60,000 boe per day by the end of 2019.

**Production**

| | **Three months ended December 31, 2016** | | | | Three months ended December 31, 2015 | | | |
|---|---|---|---|---|---|---|---|---|
| | **Oil (bbl/d)** | **Ngl (bbl/d)** | **Nat. gas (mcf/d)** | **Total (boe/d)** | Oil (bbl/d) | Ngl (bbl/d) | Nat. gas (mcf/d) | Total (boe/d) |
| Northeast British Columbia | **540** | **3,402** | **97,481** | **20,189** | 340 | 3,437 | 84,218 | 17,813 |
| Lloydminster | **2,188** | **-** | **20** | **2,191** | 2,849 | - | 261 | 2,893 |
| Total | **2,728** | **3,402** | **97,501** | **22,380** | 3,189 | 3,437 | 84,479 | 20,706 |

In the fourth quarter of 2016, production increased 8% over the same period in 2015 as the Company continued to achieve strong drilling and completion results from its Montney liquids rich natural gas operations in the Greater Septimus area in Northeast British Columbia. In addition, the Company increased its oil production with the completion of two light oil wells in the fourth quarter of 2016 at Tower, British Columbia. This production increase was partially offset by a decline in heavy oil production as the Company did not drill any heavy oil wells in the fourth quarter and significantly curtailed well reactivations in the Lloydminster area during 2016 in order to focus on the development of Crew's higher rate of return Montney projects. In addition, an eight day Alliance pipeline shut-down in October negatively impacted natural gas and associated liquids production at Greater Septimus by approximately 1,750 boe per day during the fourth quarter of 2016.

| | **Year ended December 31, 2016** | | | | Year ended December 31, 2015 | | | |
|---|---|---|---|---|---|---|---|---|
| | **Oil (bbl/d)** | **Ngl (bbl/d)** | **Nat. gas (mcf/d)** | **Total (boe/d)** | Oil (bbl/d) | Ngl (bbl/d) | Nat. gas (mcf/d) | Total (boe/d) |
| Northeast British Columbia | **335** | **3,349** | **100,041** | **20,358** | 441 | 2,521 | 70,185 | 14,660 |
| Lloydminster | **2,459** | **-** | **162** | **2,486** | 3,834 | - | 289 | 3,882 |
| Total | **2,794** | **3,349** | **100,203** | **22,844** | 4,275 | 2,521 | 70,474 | 18,542 |

Production in 2016 increased 23% as compared to the same period in 2015 as the Company executed a strong drilling and completion program in Northeast British Columbia where production increased 39%. This production increase was partially offset by declines in Lloydminster heavy oil production as the Company continues to shift its capital spending to Montney liquids rich natural gas production at Greater Septimus.

**Revenue**

| | **Three months ended December 31, 2016** | Three months ended December 31, 2015 | **Year ended December 31, 2016** | Year ended December 31, 2015 |
|---|---|---|---|---|
| **Revenue ($ thousands)** | | | | |
| Light crude oil | **2,856** | 1,523 | **6,108** | 8,538 |
| Heavy crude oil | **8,343** | 8,366 | **30,052** | 56,536 |
| Natural gas liquids | **12,151** | 8,812 | **39,008** | 27,857 |
| Natural gas | **31,701** | 15,831 | **99,551** | 61,003 |
| Total | **55,051** | 34,532 | **174,719** | 153,934 |
| | | | | |
| **Crew average prices** | | | | |
| Light crude oil ($/bbl) | **57.49** | 48.75 | **49.89** | 53.10 |
| Heavy crude oil ($/bbl) | **41.44** | 31.92 | **33.39** | 40.40 |
| Natural gas liquids ($/bbl) | **38.83** | 27.87 | **31.83** | 30.28 |
| Natural gas ($/mcf) | **3.53** | 2.04 | **2.71** | 2.37 |
| Oil equivalent ($/boe) | **26.74** | 18.13 | **20.90** | 22.74 |
| | | | | |
| **Benchmark pricing** | | | | |
| Light crude oil – WTI (Cdn $/bbl) | **65.73** | 56.22 | **57.26** | 62.14 |
| Heavy crude oil – WCS (Cdn $/bbl) | **46.61** | 36.88 | **38.96** | 44.83 |
| Natural gas liquids – Condensate @ Edmonton (Cdn $/bbl) | **64.49** | 55.61 | **56.22** | 58.98 |
| Natural Gas: | | | | |
| AECO 5A daily index (Cdn $/mcf) | **3.09** | 2.46 | **2.16** | 2.70 |
| Chicago City Gate at ATP (Cdn $/mcf) | **3.22** | 2.15 | **2.54** | 2.78 |
| Alliance 5A (Cdn $/mcf)(1) | **3.12** | 0.91 | **2.35** | 1.04 |

(1) Alliance 5A is represented by the NGX AECO + APC – ATP 5A benchmark price commencing December 1, 2015 prior thereto, Alliance spot prices are reflected as AECO + CREC 4A.

In the fourth quarter of 2016, Crew's revenue increased 59% over the same period in 2015 as a result of the increase in realized commodity prices combined with the increase in the Company's fourth quarter production at Greater Septimus and Tower. Crew's realized light oil price increased 18% in the fourth quarter which was comparable to the 17% increase in the Company's Cdn$ West Texas Intermediate ("WTI") benchmark for the same period. The Company's heavy oil price increased 30% in the quarter which was slightly higher than the 26% increase in the Company's Western Canadian Select ("WCS") benchmark as a result of the Company securing short term sales contracts when WCS differentials were narrower than the average market trade for the same period. The Company's natural gas liquids ("ngl") price increased 39% in the fourth quarter of 2016 over the same period in 2015 which was significantly higher than the 16% increase in the Condensate at Edmonton benchmark price. The Company's ngl production includes propane and butane in its realized price, both of which yield a price that disproportionately increased as compared to the increase in the Company's condensate benchmark price. In addition, increased higher valued condensate production in proportion to total ngl production boosted the Company's total ngl price in the fourth quarter of 2016, as compared to the fourth quarter of 2015. The Company's natural gas price increased 73% as a result of the significant increase in the Company's benchmark pricing over the same period in 2015. For the fourth quarter of 2016, the AECO 5A, Chicago City Gate at ATP and Alliance 5A benchmarks increased 26%, 50% and 243%, respectively, over the same period in 2015. In the fourth quarter of 2016, the Company's natural gas sales benefited from the diversity of pricing points, as outlined below, compared to 2015 when sales were predominately at Alliance spot prices. The Company's natural gas price is further enhanced by the high heat content of its Montney natural gas which is approximately 19% richer than the Alliance standard heat content.

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

- 40% - Chicago City Gate at ATP
- 30% - AECO
- 19% - Alliance 5A
- 9% - Station 2
- 2% - Sumas, WA

For 2016, the Company's revenue increased 14% over the same period in 2015 as a result of the 23% increase in production offset partially by the 8% decline in realized wellhead pricing for the same period. Crew's realized light oil price decreased 6% which was similar to the 8% decline in the Company's WTI benchmark price for 2016. The Company's heavy oil price decreased 17% which was slightly higher than the 13% decrease in the WCS benchmark as a result of securing short term contracts that were slightly lower than the average market trade for the period. Crew's realized ngl price increased 5% as compared to the 5% decrease in the Condensate at Edmonton benchmark price over the same period last year. This is a result of increased higher valued condensate production from the Greater Septimus area coupled with an increase in propane and butane realized pricing as compared to 2015. For 2016, the Company's natural gas price increased 14% over 2015 as a result of the significant increase in the Company's Alliance 5A benchmark pricing which increased 126% over the same period last year. This increase was partially offset by the decline in the AECO 5A and Chicago City Gate at ATP benchmarks which decreased 20% and 9%, respectively. These three benchmarks represent the primary markets for the sale of the majority of the Company's natural gas.

**Royalties**

| ($ thousands, except per boe) | **Three months ended December 31, 2016** | Three months ended December 31, 2015 | **Year ended December 31, 2016** | Year ended December 31, 2015 |
|---|---|---|---|---|
| Royalties | **3,952** | 2,348 | **10,614** | 13,611 |
| Per boe | **1.92** | 1.23 | **1.27** | 2.01 |
| Percentage of revenue | **7.2%** | 6.8% | **6.1%** | 8.8% |

In the fourth quarter of 2016, royalties and royalties as a percentage of revenue increased as compared to same period in 2015 as a result of the increased oil production at Tower, which attracts a higher royalty rate, combined with an increase in the Company's realized wellhead pricing yielding higher royalty rates which are price sensitive. This was partially offset by increased production at Greater Septimus where the Company's royalty rate is lower than the corporate average due to new well deep gas royalty credit programs in British Columbia combined with a decline in heavy oil production which attracts a higher royalty rate relative to the corporate average. For 2016, royalties as a percentage of revenue decreased as compared to 2015, as a result of increased Montney production which yields lower royalty rates as compared to the corporate average. Crew expects royalties as a percentage of revenue to average between 6% and 8% in 2017.

**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 loss and comprehensive loss:

| ($ thousands) | **Three months ended December 31, 2016** | Three months ended December 31, 2015 | **Year ended December 31, 2016** | Year ended December 31, 2015 |
|---|---|---|---|---|
| Realized (loss) gain on derivative financial instruments | **(720)** | 11,083 | **11,851** | 40,929 |
| Per boe | **(0.35)** | 5.82 | **1.42** | 6.05 |
| Unrealized loss on financial instruments | **(15,807)** | (6,493) | **(24,867)** | (32,589) |

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

| Subject of Contract | Notional Quantity | Term | Reference | Strike Price | Option Traded | Fair Value ($000s) |
|---|---|---|---|---|---|---|
| Gas | 22,500 gj/day | January 1, 2017 - December 31, 2017 | AECO C Monthly Index | $2.83 | Swap | (3,527) |
| Gas | 10,000 gj/day | January 1, 2017 - December 31, 2017 | AECO C Daily Index | $3.08 | Swap | (661) |
| Gas | 22,500 mmbtu/day | January 1, 2017 - December 31, 2017 | Chicago Citygate | $3.88 | Swap | (8,055) |
| Gas | 2,500 mmbtu/day | January 1, 2017 - December 31, 2018 | Chicago Citygate | $4.25 | Swap | (441) |
| Gas | 5,000 gj/day | January 1, 2018 - December 31, 2018 | AECO C Monthly Index | $3.00 | Call | (613) |
| Oil | 750 bbl/day | January 1, 2017 - June 30, 2017 | CDN$ WTI | $67.58 | Swap | (965) |
| Oil | 1,750 bbl/day | January 1, 2017 - December 31, 2017 | CDN$ WTI | $68.02 | Swap | (4,760) |
| Oil | 250 bbl/day | January 1, 2017 - December 31, 2017 | CDN$ WTI | $71.00 | Call Swaption(1) | (368) |
| **Total** | | | | | | **(19,390)** |

(1) The referenced contract is a European call swaption, which the counterparty will accept or decline by June 30, 2017.

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

| Subject of Contract | Notional Quantity | Term | Reference | Strike Price | Option Traded |
|---|---|---|---|---|---|
| Oil | 500 bbl/day | February 1, 2017 - June 30, 2017 | CDN$ WCS - WTI differential | ($19.40) | Swap |
| Oil | 250 bbl/day | February 1, 2017 - June 30, 2017 | CDN$ WTI | $73.00 | Swap |
| Gas | 2,500 gj/day | April 1, 2017 - October 31, 2017 | AECO C Daily Index | $2.55 | Swap |
| Gas | 2,500 mmbtu/day | February 1, 2017 - December 31, 2018 | Chicago Citygate | $4.20 | Swap |
| Gas | 2,500 gj/day | January 1, 2018 - December 31, 2018 | AECO C Daily Index | $2.62 | Swap |

**Operating Costs**

| ($ thousands, except per boe) | **Three months ended December 31, 2016** | Three months ended December 31, 2015 | **Year ended December 31, 2016** | Year ended December 31, 2015 |
|---|---|---|---|---|
| Operating costs | **11,021** | 13,134 | **49,148** | 56,242 |
| Per boe | **5.35** | 6.89 | **5.88** | 8.31 |

For the fourth quarter of 2016 and the year ended December 31, 2016, the Company's operating costs per boe decreased 22% and 29%, respectively, over the same periods in 2015 as a result of the significant increase of lower cost production in the Greater Septimus area combined with the decline in higher cost heavy oil production in the Lloydminster area. At Greater Septimus, in the fourth quarter of 2016 and for the year ended December 31, 2016, the Company's operating costs per boe decreased by 32% and 20%, respectively, due to operational efficiencies, reduced trucking costs and increased production. The Company forecasts operating costs to average $5.50 to $6.00 per boe in 2017.

**Transportation Costs**

| ($ thousands, except per boe) | **Three months ended December 31, 2016** | Three months ended December 31, 2015 | **Year ended December 31, 2016** | Year ended December 31, 2015 |
|---|---|---|---|---|
| Transportation costs | **4,308** | 3,730 | **18,812** | 12,884 |
| Per boe | **2.09** | 1.96 | **2.25** | 1.90 |

For the fourth quarter of 2016, the Company's transportation costs and transportation costs per boe slightly increased as a result of increased Greater Septimus condensate production, a portion of which is trucked to alternative sales markets in order to maximize the price received, coupled with an increase in Tower oil production which is currently being trucked to sales markets.

Transportation costs per boe increased in 2016 as compared to 2015 as a result of higher unutilized demand charges from decreased other British Columbia non-Montney production where the Company had firm processing and transportation costs through the majority of 2016. In the fourth quarter of 2016, the Company reduced its firm processing and transportation commitments which significantly reduced its unutilized demand charges on the Spectra system. The Company expects transportation costs per boe to range between $2.25 and $2.50 per boe for 2017.

**Operating Netbacks**

| ***Q4 2016*** <br> *($/boe)* | **Greater Septimus** | **Heavy Oil** | **Other** | **Three months ended December 31, 2016** | Three months ended December 31, 2015 |
|---|---|---|---|---|---|
| Revenue | **25.10** | **41.42** | **25.42** | **26.74** | 18.13 |
| Royalties | **(1.47)** | **(4.74)** | **(2.43)** | **(1.92)** | (1.23) |
| Realized commodity hedging loss/gain | **(0.39)** | **-** | **(0.38)** | **(0.35)** | 5.82 |
| Operating costs | **(3.34)** | **(22.43)** | **(4.47)** | **(5.35)** | (6.89) |
| Transportation costs | **(1.68)** | **(1.00)** | **(5.43)** | **(2.09)** | (1.96) |
| Operating netbacks | **18.22** | **13.25** | **12.71** | **17.03** | 13.87 |
| Production (boe/d) | **17,307** | **2,191** | **2,882** | **22,380** | 20,706 |

Operating netbacks for the fourth quarter of 2016 increased over the same period in 2015 as a result of stronger realized wellhead pricing and lower operating costs, partially offset by a realized commodity hedging loss and higher royalty and transportation costs. Fourth quarter netbacks were also positively impacted by the addition of new light oil and natural gas production from the Tower area, which is currently grouped under the Other category.

| ***2016*** | | | | | |
|---|---|---|---|---|---|
| *($/boe)* | **Greater Septimus** | **Heavy Oil** | **Other** | **Year ended December 31, 2016** | Year ended December 31, 2015 |
| Revenue | **19.61** | **33.13** | **17.98** | **20.90** | 22.74 |
| Royalties | **(0.97)** | **(3.30)** | **(1.36)** | **(1.27)** | (2.01) |
| Realized commodity hedging gain/(loss) | **1.59** | **(0.15)** | **1.73** | **1.42** | 6.05 |
| Operating costs | **(3.85)** | **(18.15)** | **(8.07)** | **(5.88)** | (8.31) |
| Transportation costs | **(1.86)** | **(0.98)** | **(6.21)** | **(2.25)** | (1.90) |
| Operating netbacks | **14.52** | **10.55** | **4.07** | **12.92** | 16.57 |
| Production (boe/d) | **17,797** | **2,486** | **2,561** | **22,844** | 18,542 |

For the year ended 2016, operating netbacks decreased over the same period in 2015 as a result of lower commodity prices in the first half of 2016, reduced realized commodity hedging gains and higher transportation costs, partially offset by a decrease in royalties and operating costs.

**General and Administrative Costs**

| ($ thousands, except per boe) | **Three months ended December 31, 2016** | Three months ended December 31, 2015 | **Year ended December 31, 2016** | Year ended December 31, 2015 |
|---|---|---|---|---|
| Gross costs | **4,552** | 3,715 | **18,438** | 19,710 |
| Operator's recoveries | **(198)** | (219) | **(385)** | (544) |
| Capitalized costs | **(1,620)** | (800) | **(6,285)** | (5,986) |
| General and administrative expenses | **2,734** | 2,696 | **11,768** | 13,180 |
| Per boe | **1.33** | 1.42 | **1.41** | 1.95 |

Gross general and administrative ("G&A") and capitalized costs increased in the fourth quarter of 2016 as compared to the same period in 2015 as the Company eliminated all provisions for 2015 cash bonuses to executive and management personnel in the fourth quarter of 2015, due to the weakening commodity price environment that existed at the time. Net G&A costs per boe decreased 6% during the fourth quarter due to the increased capitalized compensation costs and higher production levels as compared with the same period in 2015. Net annual 2016 G&A costs and costs per boe have decreased as compared to the same period in 2015, due to the start of a new office lease in 2016 significantly reducing the Company's office rent for the year. Crew forecasts G&A costs per boe to average between $1.25 and $1.50 in 2017.

**Share-Based Compensation**

| ($ thousands) | **Three months ended December 31, 2016** | Three months ended December 31, 2015 | **Year ended December 31, 2016** | Year ended December 31, 2015 |
|---|---|---|---|---|
| Gross costs | **3,739** | 2,852 | **16,495** | 14,577 |
| Capitalized costs | **(1,802)** | (1,349) | **(7,696)** | (6,995) |
| Total share-based compensation | **1,937** | 1,503 | **8,799** | 7,582 |

In the fourth quarter of 2016 and for the year ended December 31, 2016, the Company's share-based compensation expense increased as compared to the same periods in 2015, due to additional compensation expense recorded as a result of an increase in the previously estimated performance multiplier applied to certain outstanding performance awards, recognizing the Company's positive operational performance in 2015.

**Depletion and Depreciation**

| ($ thousands, except per boe) | **Three months ended December 31, 2016** | Three months ended December 31, 2015 | **Year ended December 31, 2016** | Year ended December 31, 2015 |
|---|---|---|---|---|
| Depletion and depreciation | **18,923** | 20,234 | **85,403** | 93,084 |
| Per boe | **9.19** | 10.62 | **10.21** | 13.75 |

In the fourth quarter of 2016 and for the year ended December 31, 2016, depletion and depreciation costs per boe decreased by 13% and 26%, respectively, when compared to the same periods in 2015. These decreases were due to increased proved plus probable reserve bookings at Greater Septimus, where improved drilling and completion efficiencies have reduced costs, combined with increased production in these areas where depletion rates are lower than the corporate average. The Company increased proved plus probable reserves by 24% to 323.9 mmboe during 2016, highlighted by a 28% increase in Greater Septimus proved plus probable reserves. Additionally, lower depletion was recognized on the Lloydminster property due to an impairment write down in 2015 that reduced the carrying value of the CGU.

**Impairment**

At December 31, 2016, due to the ongoing reduced heavy oil price environment combined with the Company's future heavy oil development plans in the area and the existing heavy oil transaction market, the Company tested its Lloydminster cash generating unit ("CGU") for impairment. It was determined that the carrying value of the Lloydminster heavy oil CGU exceeded its recoverable amount and a $44.4 million impairment charge was recorded. There were no indicators of impairment for the Company's northeast British Columbia CGU, and therefore an impairment test was not performed.

During 2015, as a result of the significantly lower commodity price environment, management performed an impairment test on its CGUs which resulted in the carrying value of the Lloydminster heavy oil CGU exceeding its recoverable amount and a $55.4 million impairment charge was recorded.

**Gain on Divestiture of Property**

During the third quarter of 2015, the Company disposed of certain Lloydminster heavy oil properties with a net book value of $21.2 million and associated decommissioning obligations of $4.9 million for cash proceeds of $50.1 million. A gain of $33.8 million was recognized on the disposition's closing.

In a separate unrelated transaction during the third quarter of 2015, the Company exchanged undeveloped land in northeast British Columbia with a net book value of $5.5 million for land with a fair value of $13.6 million resulting in a gain of $8.1 million.

**Finance Expenses**

| ($ thousands, except per boe) | **Three months ended December 31, 2016** | Three months ended December 31, 2015 | **Year ended December 31, 2016** | Year ended December 31, 2015 |
|---|---|---|---|---|
| Interest on bank loan | **1,093** | 825 | **4,342** | 3,452 |
| Interest on senior notes | **3,166** | 3,166 | **12,562** | 12,562 |
| Accretion of deferred financing charges | **178** | 115 | **650** | 569 |
| Accretion of the decommissioning obligation | **461** | 418 | **1,768** | 1,841 |
| Total finance expense | **4,898** | 4,524 | **19,322** | 18,424 |
| Average debt level | **242,396** | 196,783 | **239,908** | 201,585 |
| Average drawings on bank loan | **92,396** | 46,783 | **89,908** | 51,585 |
| Effective interest rate on bank loan | **4.7%** | 7.0% | **4.8%** | 6.7% |
| Effective interest rate on senior notes | **8.4%** | 8.4% | **8.4%** | 8.4% |
| Effective interest rate on long-term debt | **7.0%** | 8.0% | **7.0%** | 7.9% |
| Interest on long-term debt per boe | **2.15** | 2.16 | **2.10** | 2.45 |

Average corporate debt levels increased in both the fourth quarter of 2016 and for the year ended December 31, 2016 as compared to the same periods in 2015, as capital expenditures over the past twelve months were partially funded by increased drawings on the bank loan. The effective interest rate on the Company's bank loan was lower in both the fourth quarter of 2016 and for the year ended December 31, 2016 as compared to the same periods in 2015, due to reduced standby fees incurred as a result of increased drawings on the Company's bank facility in 2016. Crew forecasts the effective interest rate on its long-term debt to average between 6.5% and 7.5% for 2017.

**Deferred Income Taxes**

In the fourth quarter of 2016, the provision for deferred taxes was a recovery of $13.7 million compared to a recovery of $1.0 million for the same period in 2015. The increased recovery is a result of a higher pre-tax loss experienced during the fourth quarter of 2016 due to an impairment charge incurred in the quarter. For 2016, the provision for deferred taxes was a recovery of $20.8 million compared to a recovery of $11.8 million for 2015. The higher recovery in 2016 was a result of the Company having an increased pre-tax loss in 2016, due primarily to the $44.4 million impairment charge on the Lloydminster CGU in the fourth quarter of 2016 and lower income from operations due to lower commodity prices and the loss booked on derivative financial instruments.

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

| ($ thousands) | **December 31, 2016** | December 31, 2015 |
|---|---|---|
| Cumulative Canadian Exploration Expense | **280,500** | 250,500 |
| Cumulative Canadian Development Expense | **276,700** | 433,400 |
| Undepreciated Capital Cost | **178,300** | 212,900 |
| Non-capital losses | **218,600** | 21,500 |
| Share issue costs | **4,300** | 6,300 |
| | **958,400** | 924,600 |

The estimated income tax pools for 2016 have been reduced by the estimated deferred partnership income for 2016. The Company did not pay cash taxes in 2016 and estimates it has sufficient tax pools to shelter estimated income until 2019 or beyond.

**Cash, Funds from Operations and Net Loss**

| ($ thousands, except per share amounts) | | **Three months ended December 31, 2016** | Three months ended December 31, 2015 | **Year ended December 31, 2016** | Year ended December 31, 2015 |
|---|---|---|---|---|---|
| Cash provided by operating activities | | **19,900** | 12,373 | **77,478** | 74,698 |
| Funds from operations | | **27,879** | 19,601 | **78,674** | 82,363 |
| Per share | -basic | **0.19** | 0.14 | **0.55** | 0.60 |
| | -diluted | **0.19** | 0.14 | **0.54** | 0.60 |
| Net loss | | **(40,030)** | (8,167) | **(64,926)** | (55,355) |
| Per share | -basic | **(0.28)** | (0.06) | **(0.45)** | (0.40) |
| | -diluted | **(0.28)** | (0.06) | **(0.45)** | (0.40) |

For the fourth quarter of 2016, the increase in cash provided by operating activities and funds from operations was a result of increased production and higher operating netbacks as compared to the same period in 2015. For 2016, the decrease in funds from operations was due to lower realized prices and lower realized commodity hedging gains while the increase in cash provided by operating activities was a result of a reduced decrease in operating non-cash working capital. The increased net loss in the fourth quarter and year ended December 31, 2016 was a result of the impairment charge recorded for the Lloydminster CGU in 2016. In 2015, the impairment charge was partially offset by the Lloydminster disposition gain on sale recorded in the third quarter of 2015.

**Capital Expenditures, Property Acquisitions and Dispositions**

During the fourth quarter of 2016, the Company drilled eight (7.7 net) wells resulting in seven (7.0 net) natural gas wells and one (0.7 net) dry and abandoned well. The Company also completed five (4.0 net) wells and recompleted six (6.0 net) wells in the quarter. The Company also completed a minor acquisition in the fourth quarter for $3.0 million which included a minor amount of non-Montney production and reserves in Crew's operating areas in northeast British Columbia, but more importantly, included field infrastructure that will support current and future Montney operations.

In 2016, the Company drilled a total of 21 (19.7 net) wells resulting in one (1.0 net) oil wells, 19 (18.0 net) gas wells, and one (0.7 net) dry and abandoned well. During the year, the Company completed 23 (21.3 net) wells and recompleted 17 (15.0 net) wells. The Company continued to execute on a successful drilling and completion program in the Greater Septimus area where Crew is encouraged by increasing new well production rates and reduced drilling and completion costs. In addition, the Company has commenced equipment procurement for the planned expansion of the Company's West Septimus facility which is scheduled to be in service in the fourth quarter of 2017.

Total net capital expenditures are detailed below:

| ($ thousands) | **Three months ended December 31, 2016** | Three months ended December 31, 2015 | **Year ended December 31, 2016** | Year ended December 31, 2015 |
|---|---|---|---|---|
| Land | **1,294** | 984 | **3,689** | 3,034 |
| Seismic | **254** | 2,973 | **832** | 8,861 |
| Drilling and completions | **25,925** | 16,529 | **80,585** | 114,189 |
| Facilities, equipment and pipelines | **8,437** | 20,665 | **16,500** | 113,842 |
| Other | **1,702** | 916 | **6,596** | 6,492 |
| Total exploration and development | **37,612** | 42,067 | **108,202** | 246,418 |
| Property acquisitions (dispositions) | **3,099** | (36,644) | **3,973** | (85,441) |
| Total | **40,711** | 5,423 | **112,175** | 160,977 |

The Company's Board of Directors has approved a $200 million exploration and development budget for 2017. This budget will focus predominantly on drilling and completions at Greater Septimus, allowing forecasted production to exceed 30,000 boe per day by the fourth quarter of 2017. The Company plans to execute a 28 well Montney drill program, and the completion of 39 wells which is forecasted to achieve a 40% increase in Montney production year over year. In addition, $40 million of capital will be directed to key infrastructure projects including the expansion of the Company's West Septimus gas facility.

## LIQUIDITY AND CAPITAL RESOURCES

### Capital Funding

As at December 31, 2016, the Company's bank facility consists of a revolving line of credit of $205 million and an operating line of credit of $30 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 6, 2017. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 per cent and all outstanding advances thereunder will become repayable in one year from the extension date. The available lending limits of the Facility (the "Borrowing Base") are reviewed semi-annually and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. The credit agreement requires the Company to maintain a debt to EBITDA ratio of 4:1 and a secured debt to EBITDA ratio of 3:1 at the end of each fiscal quarter. Debt consists of the Company's bank debt and senior unsecured notes while secured debt consists of the Company's bank debt. At December 31, 2016, these ratios were 2.4:1 and 0.9:1, respectively. EBITDA is a non-GAAP measure and is defined in the credit agreement as earnings before interest, taxes, depreciation and amortization, unrealized gains or losses on financial instruments, share-based compensation, all other non-cash items and EBITDA from disposed properties and acquisitions for the most recent twelve month period. Other non-cash items include impairment, gains or losses on divestitures, premium on flow-through shares and unrealized gains or losses on marketable securities for the most recent twelve month period. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled Borrowing Base review on or before June 6, 2017. The Facility is secured by a floating charge debenture and a general securities agreement on the assets of the Company.

In October 2013, the Company issued $150 million of 8.375% senior unsecured notes, due October 21, 2020 (the "2020 Notes"). These notes are guaranteed, jointly and severally, on an unsecured basis, by each of the Company's current and future restricted subsidiaries. Interest on the notes accrues at the rate of 8.375% per year and is payable semi-annually. The Company may redeem all or part of the notes at the redemption prices set forth below plus any accrued and unpaid interest:

| Year[1] | Percentage |
|---|---|
| 2016 | 104.188% |
| 2017 | 102.792% |
| 2018 | 101.396% |
| 2019 | 100.000% |

(1) For the 12 month period beginning on October 21 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.

On February 24, 2017, the Company entered into an underwriting agreement to sell, on a private placement basis (the "Offering"), $300 million of senior unsecured notes, with a coupon of 6.5%, that will be due for repayment in 2024 (the "2024 Notes"). Subject to the closing of the Offering, the net proceeds will be used to redeem all of the Company's existing 2020 Notes, of which an aggregate principal amount of $150 million is currently outstanding, and the excess proceeds will be used for a non-permanent repayment of current indebtedness under the Company's existing Facility and for general corporate purposes, including the ongoing development of the Company's Montney asset base. Closing of the offering is expected to occur on or before March 14, 2017, subject to satisfaction of customary closing conditions.

In connection with the proposed redemption of the 2020 Notes, the Company issued a notice of conditional redemption to redeem the 2020 Notes at CDN$1,041.88 per $1,000.00 of principal amount redeemed, plus accrued and unpaid interest to, but not including, the redemption date which is March 23, 2017. Redemption of the 2020 Notes is conditional on completion of the Offering and is expected to result in a loss on redemption of $6.3 million related to the premium paid on early redemption of the 2020 Notes, and the recognition of $2.7 million in financing costs, related to the outstanding deferred financing costs of the 2020 Notes as at December 31, 2016.

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

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

**Working Capital**

The capital intensive nature of Crew's activities generally results in the Company carrying a working capital deficit. Working capital deficiency includes cash and cash equivalents and accounts receivable less accounts payable and accrued liabilities. Included in the working capital deficit is an accounts receivable of $10.0 million for a government incentive credit earned through the completion of the construction of the Pine River pipeline. The collection of the grant is realized through the reduction of future royalties payable to the British Columbia government.

The Company maintains sufficient unused bank credit lines to satisfy working capital deficiencies. At December 31, 2016, the Company's working capital deficiency totaled $10.0 million which, when combined with the drawings on its bank loan, represented 42% of its bank facility at December 31, 2016.

**Share Capital**

During 2016, the Company closed a private placement offering of 1,845,100 common shares at a price of $8.13 per share for gross proceeds of $15.0 million. The shares were issued on a flow-through basis, with an issuance premium to the common share trading value at the time of issuance of $1.4 million. Pursuant to the provisions of the Income Tax Act (Canada) and the terms of the offering, the Company is committing to renounce to the subscribers Canadian Development Expenses incurred by the Company of $7.5 million by each of January 31, 2017 and March 31, 2017, respectively.

On March 3, 2015, the Company issued, under a short form prospectus offering, 16,667,000 common shares of the Company, on a bought deal basis, at a price of $6.00 per share for aggregate gross proceeds of $100 million.

Crew is authorized to issue an unlimited number of common shares. As at March 2, 2017, there were 146,821,668 common shares and options to acquire 1,430,083 common shares of the Company issued and outstanding. In addition, there were 1,692,539 restricted awards and 2,534,801 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, 2016.

**Capital Structure**

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

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

The Company monitors this ratio and endeavours to maintain it at or below 2.0 to 1.0. During periods of increased capital expenditures, acquisitions or during periods of low commodity prices, this ratio will increase over short-term periods. As shown below, as at December 31, 2016, the Company's ratio of net debt to annualized funds from operations was 2.20 to 1 (December

31, 2015 – 3.04 to 1). While this ratio has improved over the past year, the Company continues to closely monitor its financial position. With the Facility only 38% drawn at the end of 2016 and the forward market for oil and natural gas prices signaling an improvement over average prices received during 2016, the Company's financial position is strong. If the Company believes it is necessary to improve its financial position, it will consider divesting of non-core properties, will further adjust its annual capital expenditure program or may consider other forms of financing.

| ($ thousands, except ratio) | **December 31, 2016** | December 31, 2015 |
|---|---|---|
| Working capital deficit | **(10,006)** | (10,737) |
| Bank loan | **(88,036)** | (80,980) |
| Senior unsecured notes | **(147,329)** | (146,679) |
| Net debt | **(245,371)** | (238,396) |
| | | |
| Fourth quarter funds from operations | **27,879** | 19,601 |
| Annualized | **111,516** | 78,404 |
| | | |
| Net debt to annualized funds from operations ratio | **2.20** | 3.04 |

**Contractual Obligations**

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

| ($ thousands) | Total | 2017 | 2018 | 2019 | 2020 | 2021 | Thereafter |
|---|---|---|---|---|---|---|---|
| Bank Loan (note 1) | 88,036 | - | 88,036 | - | - | - | - |
| Senior unsecured notes (note 2) | 150,000 | - | - | - | 150,000 | - | - |
| Operating leases | 4,700 | 783 | 1,175 | 1,175 | 1,175 | 392 | - |
| Capital commitments | 33,670 | 33,670 | - | - | - | - | - |
| Firm transportation agreements | 139,184 | 30,923 | 30,311 | 29,739 | 26,509 | 3,570 | 18,132 |
| Firm processing agreements | 96,327 | 12,895 | 12,637 | 12,637 | 11,336 | 7,395 | 39,427 |
| **Total** | **511,917** | **78,271** | **132,159** | **43,551** | **189,020** | **11,357** | **57,559** |

Note 1 – Based on the existing terms of the Company's Facility the first possible repayment date may come in 2018. However, it is expected that the revolving bank facility will be extended and no repayment will be required in the near term.
Note 2 – Matures on October 21, 2020.

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

Capital commitments includes expansion costs of the Septimus complex natural gas processing facility and Canadian Development Expenses to be incurred under the Company's flow through obligation.

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

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

## GUIDANCE

The Company's $200 million capital budget for 2017 anticipates drilling 28 Montney wells, completing 39 wells and completing the West Septimus facility expansion in the fourth quarter. The Greater Septimus gas processing complex has incremental processing capacity to manage near term production additions and the planned expansion later in 2017 is expected to support growth to over 35,000 boe per day. The Company's 2017 annual production is anticipated to range between 25,000 and 27,000 boe per day, while exit production is expected to be greater than 30,000 boe per day. Through 2017 Crew anticipates commencing work on the engineering design for the planned 120 mmcf per day Groundbirch processing facility, expected to be commissioned in the fourth quarter of 2018, as well as an interconnecting pipeline system from West Septimus through Groundbirch to a new TCPL sales point at Saturn.

## 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 2016** | Sep. 30 2016 | June 30 2016 | Mar. 31 2016 | Dec. 31 2015 | Sep. 30 2015 | June 30 2015 | Mar. 31 2015 |
|---|---|---|---|---|---|---|---|---|---|
| Total daily production (boe/d) | | **22,380** | 23,211 | 21,950 | 23,832 | 20,706 | 16,773 | 17,656 | 19,035 |
| Exploration and development expenditures | | **37,612** | 37,731 | 15,096 | 17,763 | 42,067 | 58,565 | 54,694 | 91,092 |
| Property acquisitions/ (dispositions) | | **3,099** | (98) | 16 | 956 | (36,644) | (50,281) | 1,226 | 258 |
| Average wellhead price ($/boe) | | **26.74** | 22.05 | 18.14 | 16.76 | 18.13 | 22.54 | 27.81 | 23.31 |
| Petroleum and natural gas sales | | **55,051** | 47,093 | 36,232 | 36,343 | 34,532 | 34,784 | 44,678 | 39,940 |
| Cash provided by operations | | **19,900** | 25,940 | 12,047 | 19,591 | 12,373 | 22,091 | 23,013 | 17,221 |
| Funds from operations | | **27,879** | 23,033 | 16,048 | 11,714 | 19,601 | 17,273 | 24,769 | 20,720 |
| Per share | -basic | **0.19** | 0.16 | 0.11 | 0.08 | 0.14 | 0.12 | 0.18 | 0.16 |
| | -diluted | **0.19** | 0.16 | 0.11 | 0.08 | 0.14 | 0.12 | 0.18 | 0.16 |
| Net loss | | **(40,030)** | (1,286) | (16,815) | (6,795) | (8,167) | (18,179) | (13,239) | (15,770) |
| Per share | -basic | **(0.28)** | (0.01) | (0.12) | (0.05) | (0.06) | (0.13) | (0.09) | (0.12) |
| | -diluted | **(0.28)** | (0.01) | (0.12) | (0.05) | (0.06) | (0.13) | (0.09) | (0.12) |

Beginning in 2014, Crew embarked on a plan to refocus the Company towards its Montney assets in northeast British Columbia. In 2015, the Company invested the majority of its capital expenditures in Greater Septimus and Tower, increasing production by 57% from the first quarter of 2015 to the fourth quarter of 2016. In the fourth quarter of 2015 and into the first half of 2016, commodity prices significantly declined forcing the Company to decrease capital expenditures in the first half of 2016. As prices began their recovery in the latter part of 2016, the Company subsequently increased its capital expenditures at Greater Septimus and Tower. Despite the conservative first half of 2016 capital program, the Company's 2016 production remained fairly stable throughout the year with limited planned growth.

The significant fluctuations in commodity prices have impacted cash provided by operations, funds from operations and net loss. Crew has moderated the financial impact of volatile commodity prices by entering into derivative and physical risk management contracts which can cause significant fluctuations in net loss due to unrealized gains and losses recognized on a quarterly basis. The Company has also attempted to mitigate the lower price environment by reducing its controllable costs. In 2015 and into 2016, low commodity prices have also led to the assessment and realization of impairment of the carrying value of the Lloydminster CGU. In 2015, the Company incurred $55.4 million in impairment charges and in 2016, the Company also incurred $44.4 million of impairment charges. These losses have been partially offset by gains on the sale of certain properties in 2015.

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

| ($ thousands, except per share amounts) | **Year ended Dec. 31, 2016** | Year ended Dec. 31, 2015 | Year ended Dec. 31, 2014 |
|---|---|---|---|
| Petroleum and natural gas sales | **174,719** | 153,934 | 425,424 |
| Cash provided by operations | **77,478** | 74,698 | 169,207 |
| Funds from operations | **78,674** | 82,363 | 171,592 |
| Per share -basic | **0.55** | 0.60 | 1.40 |
| -diluted | **0.54** | 0.60 | 1.39 |
| Net loss | **(64,926)** | (55,355) | (349,714) |
| Per share -basic | **(0.45)** | (0.40) | (2.86) |
| -diluted | **(0.45)** | (0.40) | (2.86) |
| Daily production (boe/d) | **22,844** | 18,542 | 24,205 |
| Crew average sales price ($/boe) | **20.90** | 22.74 | 48.15 |
| Total assets | **1,239,040** | 1,244,283 | 1,225,065 |
| Working capital deficiency (1) | **10,006** | 10,737 | 57,722 |
| Bank loan | **88,036** | 80,980 | 49,904 |
| Senior unsecured notes | **147,329** | 146,679 | 146,110 |
| Total other long-term liabilities | **113,492** | 132,711 | 143,344 |

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

Over the last three years, a declining commodity price environment has negatively impacted revenue, cash provided by operations, funds from operations and net loss. The decline in forecasted future commodity prices has also led to the assessment and realization of impairment charges on certain CGUs from 2014 to 2016. In addition, the Company recorded losses on the disposition of certain assets in 2014.

**New Accounting Pronouncements**

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

(a) IFRS 15 Revenue from Contracts with Customers:

As of January 1, 2018, the Company will be required to adopt IFRS 15 Revenue from Contracts with Customers. The new standard replaces IAS 11 Construction Contracts; IAS 18 Revenue, IFRIC 13 Customer Loyalty Programmes, IFRIC 15 Agreements for the Construction of Real Estate, IFRIC 18 Transfers of Assets from Customers and SIC 31 Revenue-Barter Transactions Involving Advertising Services. The new standard dictates the recognition and measurement requirements for reporting the nature, amount, timing and uncertainty of revenue resulting from an entity's contracts with customers. As of December 31, 2016 Crew is still determining the impact that the adoption of this standard will have on its financial statements.

(b) IFRS 9 Financial Instruments:

As of January 1, 2018, the Company will be required to adopt IFRS 9 Financial Instruments, which is the result of the first phase of the IASB project to replace IAS 39 Financial Instruments: Recognition and Measurement. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has two classification categories: amortized cost and fair value. In addition, updates have also been applied surrounding hedge accounting requirements which are now more aligned with an entity's risk management activities. As of December 31, 2016 Crew is still determining the impact that the adoption of this standard will have on its financial statements.

(c) IFRS 16 Leases:

As of January 1, 2019, the Company will be required to adopt IFRS 16 Leases, which will replace IFRS 17 Leases. For lessees applying the new standard, a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. As of December 31, 2016 Crew is still determining the impact that the adoption of this standard will have on its financial statements.

**Application of Critical Accounting Estimates**

Crew's significant accounting policies are disclosed in note 3 to the December 31, 2016 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 DD&A 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, 2016 and ended on December 31, 2016 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

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

**Dated as of March 2, 2017**

# MANAGEMENT'S REPORT

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

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

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

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

((signed))

Dale O. Shwed

President and Chief Executive Officer

((signed))

John G. Leach

Senior Vice-President and Chief Financial Officer

March 2, 2017

# AUDITORS' REPORT

To the Shareholders of Crew Energy Inc.,

We have audited the accompanying consolidated financial statements of Crew Energy Inc., which comprise the consolidated statements of financial position as at December 31, 2016 and December 31, 2015, the consolidated statements of loss and comprehensive loss, changes in shareholders' equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

*Management's Responsibility for the Consolidated Financial Statements*

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

*Auditors' Responsibility*

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

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

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

*Opinion*

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Crew Energy Inc. as at December 31, 2016 and December 31, 2015, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

((signed))

"KPMG LLP"
Chartered Professional Accountants
March 2, 2017
Calgary, Canada

# CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

| (thousands) | **December 31, 2016** | December 31, 2015 |
|---|---|---|
| **Assets** | | |
| Current Assets: | | |
| Accounts receivable | **$ 39,588** | $ 26,697 |
| Marketable securities (note 6) | **-** | 1,160 |
| Derivative financial instruments (note 13) | **-** | 6,560 |
| | **39,588** | 34,417 |
| Property, plant and equipment (note 7) | **1,199,452** | 1,209,866 |
| | **$ 1,239,040** | $ 1,244,283 |
| **Liabilities and Shareholders' Equity** | | |
| Current Liabilities: | | |
| Accounts payable and accrued liabilities | **$ 49,594** | $ 37,434 |
| Derivative financial instruments (note 13) | **18,900** | 783 |
| | **68,494** | 38,217 |
| Derivative financial instruments (note 13) | **490** | 300 |
| Bank loan (note 9) | **88,036** | 80,980 |
| Senior unsecured notes (note 10) | **147,329** | 146,679 |
| Decommissioning obligations (note 11) | **85,859** | 85,822 |
| Deferred premium on flow-through shares (note 12) | **1,419** | - |
| Deferred tax liability (note 14) | **25,724** | 46,589 |
| **Shareholders' Equity** | | |
| Share capital (note 12) | **1,442,284** | 1,398,698 |
| Contributed surplus | **74,960** | 77,627 |
| Deficit | **(695,555)** | (630,629) |
| | **821,689** | 845,696 |
| Commitments (note 17) | | |
| Subsequent event (note 13,19) | | |
| | **$ 1,239,040** | $ 1,244,283 |

*See accompanying notes to the consolidated financial statements.*

On behalf of the Board

((signed)) ((signed))

David G. Smith — Dennis L. Nerland

Director — Director

# CONSOLIDATED STATEMENTS OF LOSS AND COMPREHENSIVE LOSS

| (thousands, except per share amounts) | **Year ended December 31, 2016** | Year ended December 31, 2015 |
|---|---|---|
| **Revenue** | | |
| Petroleum and natural gas sales | **$ 174,719** | $ 153,934 |
| Royalties | **(10,614)** | (13,611) |
| Realized gain on derivative financial instruments (note 13) | **11,851** | 40,929 |
| Unrealized loss on derivative financial instruments (note 13) | **(24,867)** | (32,589) |
| | **151,089** | 148,663 |
| **Expenses** | | |
| Operating | **49,148** | 56,242 |
| Transportation | **18,812** | 12,884 |
| General and administrative | **11,768** | 13,180 |
| Share-based compensation | **8,799** | 7,582 |
| Depletion and depreciation | **85,403** | 93,084 |
| | **173,930** | 182,972 |
| Loss from operations | **(22,841)** | (34,309) |
| Financing (note 16) | **19,322** | 18,424 |
| (Gain) loss on marketable securities (note 6) | **(955)** | 892 |
| Impairment on property, plant and equipment (note 8) | **44,432** | 55,376 |
| Loss (gain) on divestiture of property, plant and equipment (note 7) | **130** | (41,877) |
| Loss before income taxes | **(85,770)** | (67,124) |
| Deferred tax recovery (note 14) | **(20,844)** | (11,769) |
| Net loss and comprehensive loss | **$ (64,926)** | $ (55,355) |
| Net loss per share (note 12) | | |
| Basic | **$ (0.45)** | $ (0.40) |
| Diluted | **$ (0.45)** | $ (0.40) |

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

| (thousands) | Number of shares | Share capital | Contributed surplus | Deficit | Total Shareholders' equity |
|---|---|---|---|---|---|
| Balance January 1, 2015 | 123,429 | $1,292,693 | $ 72,951 | $ (575,274) | $ 790,370 |
| Net loss | - | - | - | (55,355) | (55,355) |
| Share-based compensation expensed | - | - | 7,582 | - | 7,582 |
| Share-based compensation capitalized | - | - | 6,995 | - | 6,995 |
| Transfer to share capital for exercised options | - | 75 | (75) | - | - |
| Issued on exercise of options | 28 | 157 | - | - | 157 |
| Issued on vesting of share awards | 943 | 9,826 | (9,826) | - | - |
| Issuance of common shares | 16,667 | 100,002 | - | - | 100,002 |
| Share issue costs, net of tax of $1,414 | - | (4,055) | - | - | (4,055) |
| **Balance December 31, 2015** | **141,067** | **$1,398,698** | **$ 77,627** | **$ (630,629)** | **$ 845,696** |

*See accompanying notes to the consolidated financial statements.*

# CONSOLIDATED STATEMENTS OF CASH FLOWS

| (thousands) | **Year ended December 31, 2016** | Year ended December 31, 2015 |
|---|---|---|
| **Cash provided by (used in):** | | |
| **Operating activities:** | | |
| Net loss | **$ (64,926)** | $ (55,355) |
| Adjustments: | | |
| Unrealized loss on derivative financial instruments (note 13) | **24,867** | 32,589 |
| Share-based compensation | **8,799** | 7,582 |
| Depletion and depreciation | **85,403** | 93,084 |
| Financing expenses (note 16) | **19,322** | 18,424 |
| Interest expense (note 16) | **(16,904)** | (16,014) |
| Impairment of property, plant and equipment (note 8) | **44,432** | 55,376 |
| (Gain) loss on sale of marketable securities (note 6) | **(955)** | 892 |
| Loss (gain) on divestiture of property, plant and equipment (note 7) | **130** | (41,877) |
| Deferred tax recovery (note 14) | **(20,844)** | (11,769) |
| Decommissioning obligations settled (note 11) | **(1,411)** | (736) |
| Change in non-cash working capital (note 15) | **(435)** | (7,498) |
| | **77,478** | 74,698 |
| **Financing activities:** | | |
| Increase in bank loan | **7,056** | 31,076 |
| Proceeds from exercise of options | **10,899** | 157 |
| Proceeds from issuance of flow-through shares (note 12) | **15,001** | - |
| Proceeds from issuance of common shares (note 12) | **-** | 100,002 |
| Share issue costs | **(78)** | (5,469) |
| | **32,878** | 125,766 |
| **Investing activities:** | | |
| Property, plant and equipment expenditures (note 7) | **(108,202)** | (246,418) |
| Property acquisitions | **(4,077)** | (1,607) |
| Property dispositions | **104** | 87,048 |
| Proceeds on marketable securities disposed (note 6) | **2,115** | - |
| Change in non-cash working capital (note 15) | **(296)** | (39,487) |
| | **(110,356)** | (200,464) |
| 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, 2016 and 2015

*(Tabular amounts in thousands)*

**1. Reporting entity:**

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

**2. Basis of preparation:**

These financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. A summary of the significant accounting policies and method of computation is presented in note 3.

The financial statements have been prepared on the historical cost basis except for derivative financial instruments and marketable securities which are measured at fair value. The methods used to measure fair values are discussed in note 5.

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

The financial statements were authorized for issuance by Crew's Board of Directors on March 2, 2017.

**3. Significant accounting policies:**

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

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

(a) Basis of consolidation:

(i) Subsidiaries:

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

(ii) Jointly owned assets:

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

(iii) Transactions eliminated on consolidation:

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

(b) Foreign currency:

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

(c) Financial instruments:

(i) Non-derivative financial instruments:

Non-derivative financial instruments are comprised of cash and cash equivalents, accounts receivable, marketable securities, 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.

Marketable securities are classified as held-for-trading. They are considered level 1 financial instruments and are measured at fair value through profit or loss based on quoted market prices in an active market.

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

(ii) Derivative financial instruments:

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

(iii) Share capital:

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

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

(i) Recognition and measurement:

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

Pre-license costs are recognized in the statement of 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 related cash-generating units ("CGUs").

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 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 net 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.

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 options and restricted and performance units granted to employees is recognized as compensation expense, with a corresponding increase in contributed surplus over the vesting period. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options and restricted and performance units that vest. A performance multiplier is estimated on the grant date for performance units and adjusted to reflect the number of performance units that 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 oil and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer which is usually when legal title passes to the external party.

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

(j) Finance income and expenses:

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

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

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

(k) Income tax:

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

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

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

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

(l) Earnings per share:

Basic earnings per share is calculated by dividing the profit or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted earnings per share is determined by adjusting the profit or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options and 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) Critical accounting judgments and key sources of estimation uncertainty:

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

*Critical judgments in applying accounting policies:*

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

*(i) Identification of CGUs*

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

*(ii) Impairment of petroleum and natural gas assets*

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

*(iii) Exploration and evaluation assets*

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

*(iv) Deferred income taxes*

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

*Key sources of estimation uncertainty:*

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

*(i) Reserves*

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

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

*(ii) Decommissioning obligations*

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

*(iii) Business combinations*

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

*(iv) Share-based payments*

All equity-settled, share-based awards issued by the Company are recorded at fair value. The fair value of stock option awards are estimated using the Black-Scholes option-pricing model while 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 expected volatility in share price, option life, dividend yield, risk-free rate, estimated forfeitures at the initial grant date and 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. Future accounting policies:**

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

(a) IFRS 15 Revenue from Contracts with Customers:

As of January 1, 2018, the Company will be required to adopt IFRS 15 Revenue from Contracts with Customers. The new standard replaces IAS-11 Construction Contracts; IAS 18 Revenue, IFRIC 13 Customer Loyalty Programmes, IFRIC 15 Agreements for the Construction of Real Estate, IFRIC 18 Transfers of Assets from Customers and SIC 31 Revenue-Barter Transactions Involving Advertising Services. The new standard dictates the recognition and measurement requirements for reporting the nature, amount, timing and uncertainty of revenue resulting from an entity's contracts with customers. As of December 31, 2016, Crew is still determining the impact that the adoption of this standard will have on its financial statements.

(b) IFRS 9 Financial Instruments:

As of January 1, 2018, the Company will be required to adopt IFRS 9 Financial Instruments, which is the result of the first phase of the IASB project to replace IAS 39 Financial Instruments: Recognition and Measurement. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has two classification categories: amortized cost and fair value. In addition, updates have also been applied surrounding hedge accounting requirements which are now more aligned with an entity's risk management activities. As of December 31, 2016, Crew is still determining the impact that the adoption of this standard will have on its financial statements.

(c) IFRS 16 Leases:

As of January 1, 2019, the Company will be required to adopt IFRS 16 Leases, which will replace IFRS 17 Leases. For lessees applying the new standard, a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. As of December 31, 2016, Crew is still determining the impact that the adoption of this standard will have on its financial statements.

**5. 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, 2016 and December 31, 2015, 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, 2016, the carrying value of the unsecured notes approximated fair value.

(iii) Marketable securities:

The fair value of marketable securities is determined using quoted prices in an active market.

(iv) 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.

(v) Stock options:

The fair value of employee stock options is measured using a Black Scholes option pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility (based on weighted average historic volatility), weighted average expected life of the instruments (based on historical experience and general option holder behaviour), expected dividends, and the risk-free interest rate (based on government bonds).

(vi) 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.

**6. Marketable securities:**

The Company previously held 1,415,094 common shares of a public company trading on the TSX Venture exchange. The shares were valued at $0.82 per common share for a total value of approximately $1.2 million at December 31, 2015. In the second quarter of 2016, all 1,415,094 common shares were sold for proceeds of approximately $2.1 million, resulting in a gain of $0.9 million (December 31, 2015 - $0.9 million unrealized loss) being recorded in the Company's financial statements for the year ended December 31, 2016.

## 7. Property, plant and equipment:

| Cost or deemed cost | Total |
|---|---|
| Balance, January 1, 2015 | $ 1,851,036 |
| Additions | 246,418 |
| Acquisitions | 15,147 |
| Divestitures | (65,778) |
| Change in decommissioning obligations | 8,040 |
| Capitalized share-based compensation | 6,995 |
| Balance, December 31, 2015 | $ 2,061,858 |
| Additions | 108,202 |
| Acquisitions | 4,097 |
| Divestitures | (254) |
| Change in decommissioning obligations | (320) |
| Capitalized share-based compensation | 7,696 |
| **Balance, December 31, 2016** | **$ 2,181,279** |

| Accumulated depletion and depreciation | Total |
|---|---|
| Balance, January 1, 2015 | $ 704,440 |
| Depletion and depreciation expense | 93,084 |
| Divestitures | (908) |
| Impairment (net) | 55,376 |
| Balance, December 31, 2015 | $ 851,992 |
| Depletion and depreciation expense | 85,403 |
| Impairment (net) | 44,432 |
| **Balance, December 31, 2016** | **$ 981,827** |

| Net book value | Total |
|---|---|
| **Balance, December 31, 2016** | **$ 1,199,452** |
| Balance, December 31, 2015 | $ 1,209,866 |

The calculation of depletion for the three months ended December 31, 2016 included estimated future development costs of $1,603.2 million (December 31, 2015 - $1,316.2 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $67.3 million (December 31, 2015 - $64.0 million) and undeveloped land of $182.3 million (December 31, 2015 - $218.9 million) related to future development acreage, with no associated reserves.

During 2015, the Company disposed of certain petroleum and natural gas properties with a net book value of $21.2 million, and associated decommissioning obligations of $4.9 million for proceeds of cash of $50.1 million. A gain of $33.8 million was recognized on the disposition's closing. In a separate unrelated transaction, the Company exchanged undeveloped land with a net book value of $5.5 million for land with a fair value of $13.6 million, resulting in a gain of $8.1 million.

## 8. Impairment:

| | **Year Ended December 31, 2016** | Year Ended December 31, 2015 |
|---|---|---|
| Impairment losses: | | |
| PP&E | $ 44,432 | $ 55,376 |
| | **$ 44,432** | **$ 55,376** |

Assessment:

At December 31, 2016 and 2015, the Company tested the Lloydminster CGU for impairment as well as the potential reversal of prior period impairments where indicators were present. There were no indicators of impairment for the Company's northeast British Columbia CGU, and therefore an impairment test was not performed. For the purpose of impairment testing, the recoverable amounts 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. In 2015, the Company used value in use, discounted at pre-tax rates between 10% and 25% dependent on the risk profile of the reserve category. During 2016, fair value less costs to sell has been determined to be the appropriate measure for the current period.

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 2016 assessment:

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

| | WTI Oil (US$/bbl) | WCS ($CDN/bbl) | AECO Gas ($CDN/mmbtu) | $CDN/$US |
|---|---|---|---|---|
| 2017 | 55.00 | 53.12 | 3.44 | 0.780 |
| 2018 | 65.00 | 61.85 | 3.27 | 0.820 |
| 2019 | 70.00 | 64.94 | 3.22 | 0.850 |
| 2020 | 71.40 | 66.93 | 3.91 | 0.850 |
| 2021 | 72.83 | 68.27 | 4.00 | 0.850 |
| 2022 | 74.28 | 69.64 | 4.10 | 0.850 |
| 2023 | 75.77 | 71.03 | 4.19 | 0.850 |
| 2024 | 77.29 | 72.45 | 4.29 | 0.850 |
| 2025 | 78.83 | 73.90 | 4.40 | 0.850 |
| 2026 | 80.41 | 75.38 | 4.50 | 0.850 |
| 2027 | 82.02 | 76.88 | 4.61 | 0.850 |
| Remainder | +2.0%/yr | +2.0%/yr | +2.0%/yr | 0.85 thereafter |

At December 31, 2016, due to the ongoing reduced heavy oil price environment combined with the Company's future heavy oil development plans in the area and the existing heavy oil transaction market, the Company tested its Lloydminster CGU for impairment. It was determined that the carrying value of the Lloydminster heavy oil CGU exceeded its recoverable amount and a $44.4 million impairment charge was recorded.

(b) Results of 2015 assessment:

The following estimates were used in determining whether an impairment or reversal to the carrying value of the CGUs existed at December 31, 2015:

| | WTI Oil (US$/bbl) | WCS ($CDN/bbl) | AECO Gas ($CDN/mmbtu) | $CDN/$US |
|---|---|---|---|---|
| 2017 | 45.00 | 45.26 | 2.25 | 0.75 |
| 2018 | 60.00 | 57.96 | 2.95 | 0.80 |
| 2019 | 70.00 | 65.88 | 3.42 | 0.83 |
| 2020 | 80.00 | 75.11 | 3.91 | 0.85 |
| 2021 | 81.20 | 77.03 | 4.20 | 0.85 |
| 2022 | 82.42 | 78.19 | 4.28 | 0.85 |
| 2023 | 83.65 | 79.36 | 4.35 | 0.85 |
| 2024 | 84.91 | 80.55 | 4.43 | 0.85 |
| 2025 | 86.18 | 81.76 | 4.51 | 0.85 |
| 2026 | 87.48 | 82.99 | 4.59 | 0.85 |
| 2027 | 88.79 | 84.23 | 4.67 | 0.85 |
| Remainder | +1.5%/yr | +1.5%/yr | +1.5%/yr | 0.85 thereafter |

During 2015, as a result of the significantly lower commodity price environment, management performed an impairment test of its CGUs. A decrease in the West Texas Intermediate ("WTI"), Western Canadian Select ("WCS") future oil price and AECO natural gas price forecasts as compared to those used in the prior year assessment resulted in the carrying value of the Lloydminster heavy oil CGU exceeding its recoverable amount and a $55.4 million impairment charge was recorded.

## 9. Bank loan:

As at December 31, 2016, the Company's bank facility consists of a revolving line of credit of $205 million and an operating line of credit of $30 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 6, 2017. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 per cent and all outstanding advances thereunder will become repayable in one year from the extension date. The available lending limits of the Facility (the "Borrowing Base") are reviewed semi-annually and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. The credit agreement requires the Company to maintain a debt to EBITDA ratio of 4:1 and a secured debt to EBITDA ratio of 3:1 at the end of each fiscal quarter. Debt consists of the Company's bank debt and senior unsecured notes while secured debt consists of the Company's bank debt. At December 31, 2016, these ratios were 2.4:1 and 0.9:1, respectively. EBITDA is a non-GAAP measure and is defined in the credit agreement as earnings before interest, taxes, depreciation and amortization, unrealized gains or losses on financial instruments, share-based compensation, all other non-cash items and EBITDA from disposed properties and acquisitions for the most recent twelve month period. Other non-cash items include impairment, gains or losses on divestitures, premium on flow-through shares and unrealized gains or losses on marketable securities for the most recent twelve month period. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled Borrowing Base review on or before June 6, 2017. The Facility is secured by a floating charge debenture and a general securities agreement on the assets of the Company.

Advances under the Facility are available by way of prime rate loans with interest rates between 1.00 percent and 2.50 percent over the bank's prime lending rate and bankers' acceptances and LIBOR loans, which are subject to stamping fees and margins ranging from 2.00 percent to 3.50 percent depending upon the secured debt to EBITDA ratio of the Company calculated at the Company's previous quarter end. Standby fees are charged on the undrawn Facility at rates ranging from 0.50 percent to 0.875 percent depending upon the debt to EBITDA ratio. As at December 31, 2016, the Company's applicable pricing included a 1.25 percent margin on prime lending, a 2.25 percent stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.56 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, 2016, the Company had issued letters of credit totaling $13.6 million (December 31, 2015 - $7.8 million). The effective interest rate on the Company's borrowings under its Facility for the year ended December 31, 2016 was 4.8% (2015 – 6.7%).

## 10. Senior unsecured notes:

In October 2013, the Company issued $150 million of 8.375% senior notes, due October 21, 2020. These notes are guaranteed, jointly and severally, on an unsecured basis, by each of the Company's current and future restricted subsidiaries. Interest on the notes accrues at the rate of 8.375% per year and is payable semi-annually. The Company may redeem all or part of the notes at the redemption prices set forth below plus any accrued and unpaid interest:

| Year[(1)] | Percentage |
|---|---|
| 2016 | 104.188% |
| 2017 | 102.792% |
| 2018 | 101.396% |
| 2019 | 100.000% |

(1) For the 12 month period beginning on October 21 of each year.

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

At December 31, 2016, the carrying value of the senior unsecured notes was net of deferred financing costs of $2.7 million (December 31, 2015 - $3.3 million).

## 11. Decommissioning obligations:

| | **As at December 31, 2016** | As at December 31, 2015 |
|---|---|---|
| Decommissioning obligations, beginning of year | **$ 85,822** | $ 82,836 |
| Obligations incurred | **1,344** | 6,696 |
| Obligations acquired | **4,061** | - |
| Obligations settled | **(1,411)** | (736) |
| Obligations divested | **-** | (6,159) |
| Change in estimated future cash outflows | **(5,725)** | 1,344 |
| Accretion of decommissioning obligations | **1,768** | 1,841 |
| Decommissioning obligations, end of year | **$ 85,859** | $ 85,822 |

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning obligations to be $85.9 million as at December 31, 2016 (December 31, 2015 - $85.8 million) based on an inflation adjusted undiscounted total future liability of $113.4 million (December 31, 2015 - $113.9 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% (2015 – 2%). The discount factor, being the risk-free rate related to the liability, is 2.21% (December 31, 2015 – 2.03%). The $5.7 million (December 31, 2015 - $1.3 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, 2016, the Company was authorized to issue an unlimited number of common shares with the holders of common shares entitled to one vote per share.

During 2016, the Company closed a private placement offering of 1,845,100 common shares at a price of $8.13 per share for gross proceeds of $15.0 million. The shares were issued on a flow-through basis, with an issuance premium to the common share trading value at the time of issuance of $1.4 million. Pursuant to the provisions of the Income Tax Act (Canada) and the terms of the offering, the Company is committing to renounce to the subscribers Canadian Development Expenses incurred by the Company of $7.5 million by each of January 31, 2017 and March 31, 2017, respectively.

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

**Share based payments:**

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

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

| | Number of options | Weighted average exercise price |
|---|---|---|
| Balance January 1, 2015 | 5,206 | $ 7.65 |
| Exercised | (28) | 5.65 |
| Forfeited | (593) | 9.06 |
| Expired | (802) | 12.04 |
| Balance December 31, 2015 | 3,783 | $ 6.51 |
| Exercised | (1,903) | 5.73 |
| Forfeited | (113) | 6.99 |
| Expired | (337) | 8.32 |
| **Balance December 31, 2016** | **1,430** | **$ 7.08** |

The weighted average trading price of the Company’s common shares was $5.48 during the year ended December 31, 2016 (December 31, 2015 - $5.14).

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

| Range of exercise prices | Outstanding at Dec 31, 2016 | Weighted average remaining life (years) | Weighted average exercise price | Exercisable at Dec 31, 2016 | Weighted average exercise price |
|---|---|---|---|---|---|
| $ 5.58 to $ 5.65 | 24 | 0.8 | $ 5.58 | 24 | $ 5.58 |
| $ 5.66 to $ 7.16 | 156 | 0.3 | 6.58 | 156 | 6.58 |
| $ 7.17 to $ 7.25 | 1,250 | 0.3 | 7.17 | 1,246 | 7.17 |
| | **1,430** | **0.3** | **$ 7.08** | **1,426** | **$ 7.08** |

**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, 2016, the fair value of awards granted was calculated using an estimated forfeiture rate of 12% (December 31, 2015 – 13%). The weighted average fair value of awards granted for the year ended December 31, 2016 was $3.88 (December 31, 2015 - $4.98). In the case of PAs, the award value is adjusted for a payout multiplier which can range from 0.0 to 2.0 and is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. Through the vesting of 492,000 restricted awards and 759,000 performance awards, when taking into account the earned multipliers for performance awards, 1,997,000 common shares of the Company were issued for the year ended December 31, 2016. On the vesting dates, the Company has the option of settling the award value in cash or common shares of the Company. To date the Company has not settled any awards with cash.

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

| | Number of restricted awards | Number of performance awards |
|---|---|---|
| Balance January 1, 2015 | 759 | 968 |
| Granted | 730 | 1,041 |
| Vested | (270) | (348) |
| Forfeited | (132) | (115) |
| Balance December 31, 2015 | 1,087 | 1,546 |
| Granted | 1,209 | 1,862 |
| Vested | (492) | (759) |
| Forfeited | (105) | (112) |
| **Balance December 31, 2016** | **1,699** | **2,537** |

**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, 2016 was 143,087,000 (December 31, 2015 – 137,948,000).

In computing diluted earnings per share for the year ended December 31, 2016, nil (December 31, 2015 – nil) shares were added to the weighted average common shares outstanding to account for the dilution of stock options and restricted and performance awards. There were 1,430,000 (December 31, 2015 – 3,783,000) stock options and 4,236,000 (December 31, 2015 – 2,633,000) restricted and performance awards that were not included in the diluted earnings per share calculation because they were anti-dilutive.

**13. 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, marketable securities and counterparties to derivative financial assets. The maximum exposure to credit risk at year-end is as follows:

| | | **December 31, 2016** | | December 31, 2015 |
|---|---|---|---|---|
| Trade and other receivables | **$** | **39,588** | $ | 26,697 |
| Marketable securities | | **-** | | 1,160 |
| Derivative financial assets | | **-** | | 6,560 |
| | **$** | **39,588** | $ | 34,417 |

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 2016, 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, 2016 the Company's receivables consisted of $24.6 million (December 31, 2015 - $18.5 million) of receivables from petroleum and natural gas marketers, of which all have been subsequently collected, $2.0 million (December 31, 2015 - $3.9 million) from partners within jointly owned assets and operations of which $0.4 million has been subsequently collected, and $13.0 million (December 31, 2015 - $4.2 million) of deposits, prepaids and other accounts receivable, of which $0.4 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, 2016 was $89.9 million (December 31, 2015 - $51.6 million). For the year ended December 31, 2016, a 1.0 percent change to the effective interest rate would have a $0.8 million impact on net loss (December 31, 2015 - $0.4 million). The interest rate on the senior unsecured notes is fixed and is not subject to interest rate risk.

Commodity price risk:

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

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 loss.

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

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

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

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

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

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

| Subject of Contract | Notional Quantity | Term | Reference | Strike Price | Option Traded | Fair Value ($000s) |
|---|---|---|---|---|---|---|
| Gas | 22,500 gj/day | January 1, 2017 - December 31, 2017 | AECO C Monthly Index | $2.83 | Swap | (3,527) |
| Gas | 10,000 gj/day | January 1, 2017 - December 31, 2017 | AECO C Daily Index | $3.08 | Swap | (661) |
| Gas | 22,500 mmbtu/day | January 1, 2017 - December 31, 2017 | Chicago Citygate | $3.88 | Swap | (8,055) |
| Gas | 2,500 mmbtu/day | January 1, 2017 - December 31, 2018 | Chicago Citygate | $4.25 | Swap | (441) |
| Gas | 5,000 gj/day | January 1, 2018 - December 31, 2018 | AECO C Monthly Index | $3.00 | Call | (613) |
| Oil | 750 bbl/day | January 1, 2017 - June 30, 2017 | CDN$ WTI | $67.58 | Swap | (965) |
| Oil | 1,750 bbl/day | January 1, 2017 - December 31, 2017 | CDN$ WTI | $68.02 | Swap | (4,760) |
| Oil | 250 bbl/day | January 1, 2017 - December 31, 2017 | CDN$ WTI | $71.00 | Call Swaption[(1)] | (368) |
| **Total** | | | | | | **(19,390)** |

(1) The referenced contract is a European call swaption, which the counterparty will accept or decline by June 30, 2017.

As at December 31, 2016, a 10% change in future commodity prices applied against these contracts would have an $11.1 million impact on net loss.

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

| Subject of Contract | Notional Quantity | Term | Reference | Strike Price | Option Traded |
|---|---|---|---|---|---|
| Oil | 500 bbl/day | February 1, 2017 - June 30, 2017 | CDN$ WCS - WTI differential | ($19.40) | Swap |
| Oil | 250 bbl/day | February 1, 2017 - June 30, 2017 | CDN$ WTI | $73.00 | Swap |
| Gas | 2,500 gj/day | April 1, 2017 - October 31, 2017 | AECO C Daily Index | $2.55 | Swap |
| Gas | 2,500 mmbtu/day | February 1, 2017 - December 31, 2018 | Chicago Citygate | $4.20 | Swap |
| Gas | 2,500 gj/day | January 1, 2018 - December 31, 2018 | AECO C Daily Index | $2.62 | 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 2017. In addition, the Company issued $150 million in senior unsecured notes in 2013 that are scheduled to mature in 2020 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's objective when managing capital is to maintain a flexible capital structure which will allow it to execute on its capital expenditure program, which includes expenditures on oil and gas activities which may or may not be successful. Therefore, the Company monitors the level of risk incurred in its capital expenditures to balance the proportion of debt and equity in its capital structure.

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

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

The Company monitors this ratio and endeavours to maintain it at or below 2.0 to 1.0. During periods of increased capital expenditures, acquisitions or during periods of low commodity prices, this ratio will increase over short-term periods. As shown below, as at December 31, 2016, the Company's ratio of net debt to annualized funds from operations was 2.20 to 1 (December 31, 2015 – 3.04 to 1). While this ratio has improved over the past year, the Company continues to closely monitor its financial position. With the Facility only 38% drawn and the forward market for oil and natural gas prices signaling an improvement over average prices received during 2016, the Company's financial position is strong. If the Company feels it is necessary to improve its financial position, it will consider divesting of non-core properties, will further adjust its annual capital expenditure program or may consider other forms of financing.

| | **December 31, 2016** | December 31, 2015 |
|---|---|---|
| Net debt: | | |
| Accounts receivable | **$ 39,588** | $ 26,697 |
| Accounts payable and accrued liabilities | **(49,594)** | (37,434) |
| Working capital deficiency | **$ (10,006)** | $ (10,737) |
| Bank loan | **(88,036)** | (80,980) |
| Senior unsecured notes | **(147,329)** | (146,679) |
| Net debt | **$ (245,371)** | $ (238,396) |
| Fourth Quarter Annualized funds from operations: | | |
| Cash provided by operating activities | **$ 19,900** | $ 12,373 |
| Decommissioning obligations settled | **763** | 43 |
| Change in non-cash working capital | **7,394** | 7,300 |
| Accretion of deferred financing charges | **(178)** | (115) |
| Fourth Quarter Funds from operations | **$ 27,879** | $ 19,601 |
| Annualized | **$ 111,516** | $ 78,404 |
| Net debt to annualized funds from operations | **2.20** | 3.04 |

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

**14. Income taxes:**

(a) Deferred income tax recovery:

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

| | **Year ended December 31, 2016** | Year ended December 31, 2015 |
|---|---|---|
| Loss before income taxes | **$ (85,770)** | $ (67,124) |
| Combined federal and provincial income tax rate | **26.6%** | 26.2% |
| Computed "expected" income tax recovery | **$ (22,806)** | $ (17,559) |
| Increase in income taxes resulting from: | | |
| Non-deductible expenses | **2,474** | 2,494 |
| Change in income tax rates | **-** | 2,705 |
| Flow-through share renunciation | **-** | 2,576 |
| Other | **(512)** | 417 |
| | **$ 20,844)** | $ 9,367) |
| Premium on flow-through shares | **-** | (2,402) |
| Deferred income tax recovery | **$ (20,844)** | $ (11,769) |

(b) Deferred income tax liability:

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

| | **December 31, 2016** | December 31, 2015 |
|---|---|---|
| Deferred tax liabilities: | | |
| Property, plant and equipment | **$ 112,573** | $ 74,036 |
| Derivative financial instruments | **-** | 1,461 |
| Deferred tax assets: | | |
| Decommissioning obligations | **$ (22,907)** | $ (22,595) |
| Non-capital losses | **(58,324)** | (5,512) |
| Derivative financial instruments | **(5,173)** | - |
| Other | **(445)** | (801) |
| Deferred income tax liability | **$ 25,724** | $ 46,589 |

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

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

| | January 1, 2015 | Recognized in equity | Recognized in other | Recognized in profit or loss | December 31, 2015 |
|---|---|---|---|---|---|
| Property, plant and equipment | $ 74,756 | $ - | $ 2,402 | $ (3,122) | $ 74,036 |
| Decommissioning obligations | (21,245) | - | - | (1,350) | (22,595) |
| Derivative financial instruments | 9,730 | - | - | (8,269) | 1,461 |
| Non-capital losses | (5,488) | - | - | (24) | (5,512) |
| Other | (383) | (1,414) | - | 996 | (801) |
| | **$ 57,370** | **$ (1,414)** | **$ 2,402** | **$ (11,769)** | **$ 46,589** |

The Company's assets have an approximate tax basis of $958 million at December 31, 2016 (December 31, 2015 - $925 million) available for deduction against future taxable income. The following table summarizes the tax pools:

| | **December 31, 2016** | December 31, 2015 |
|---|---|---|
| Cumulative Canadian Exploration Expense | **$ 280,500** | $ 250,500 |
| Cumulative Canadian Development Expense | **276,700** | 433,400 |
| Undepreciated Capital Costs | **178,300** | 212,900 |
| Non-capital losses | **218,600** | 21,500 |
| Share issue costs | **4,300** | 6,300 |
| Estimated tax basis | **$ 958,400** | $ 924,600 |

Non-capital losses will begin expiring in 2028. The estimated income tax pools for 2016 have been reduced by the estimated deferred partnership income for 2016.

## 15. Supplemental cash flow information:

Changes in non-cash working capital is comprised of:

| | Year ended December 31, 2016 | Year ended December 31, 2015 |
|---|---|---|
| Changes in non-cash working capital: | | |
| Accounts receivable | **$ (12,891)** | $ 8,696 |
| Accounts payable and accrued liabilities | **12,160** | (55,681) |
| | **$ (731)** | $ (46,985) |
| Operating activities | **$ (435)** | $ (7,498) |
| Investing activities | **(296)** | (39,487) |
| | **$ (731)** | $ (46,985) |
| Interest paid | **$ (15,366)** | $ (16,523) |

## 16. Financing:

| | Year ended December 31, 2016 | Year ended December 31, 2015 |
|---|---|---|
| Interest expense | **$ 16,904** | $ 16,014 |
| Accretion of deferred financing costs | **650** | 569 |
| Accretion of decommissioning obligations | **1,768** | 1,841 |
| | **$ 19,322** | $ 18,424 |

## 17. Commitments:

| | Total | 2017 | 2018 | 2019 | 2020 | 2021 | Thereafter |
|---|---|---|---|---|---|---|---|
| Operating leases | $ 4,700 | $ 783 | $ 1,175 | $ 1,175 | $ 1,175 | $ 392 | $ - |
| Capital commitments | 33,670 | 33,670 | - | - | - | - | - |
| Firm transportation agreements | 139,184 | 30,923 | 30,311 | 29,739 | 26,509 | 3,570 | 18,132 |
| Firm processing agreement | 96,327 | 12,895 | 12,637 | 12,637 | 11,336 | 7,395 | 39,427 |
| **Total** | **$273,881** | **$78,271** | **$44,123** | **$43,551** | **$39,020** | **$11,357** | **$ 57,559** |

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

Capital commitments includes expansion costs of the Septimus complex natural gas processing facility and Canadian Development Expenses to be incurred under the Company's flow through obligation (Share Capital – note 12).

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

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

## 18. Personnel expenses:

The aggregate payroll expense of key management personnel was as follows:

| | **Year ended December 31, 2016** | Year ended December 31, 2015 |
|---|---|---|
| Short-term benefits | **$ 3,872** | $ 2,568 |
| Long-term benefits | **8,518** | 7,394 |
| | **$ 12,390** | $ 9,962 |

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

## 19. Subsequent event:

On February 24, 2017, the Company entered into an underwriting agreement to sell (the "Offering"), on a private placement basis, $300 million senior unsecured notes, with a coupon of 6.5%, that will be due for repayment in 2024 (the "2024 Notes"). Subject to closing of the Offering, the net proceeds will be used to redeem all of the Company's existing 8.375% senior unsecured notes due 2020 (the "2020 Notes"), of which an aggregate principal amount of $150 million is currently outstanding, and the excess proceeds will be used for a non-permanent repayment of current indebtedness under the Company's existing Facility and for general corporate purposes, including the ongoing development of the Company's Montney asset base. Closing of the offering is expected to occur on or before March 14, 2017, subject to satisfaction of customary closing conditions.

In connection with the Offering, the Company issued a notice of conditional redemption to redeem the 2020 Notes at $1,041.88 per $1,000.00 of principal amount redeemed, plus accrued and unpaid interest to, but not including, the redemption date which is March 23, 2017. The redemption of the 2020 Notes is conditional upon completion of the Offering and the Company's deposit with the paying agent of sufficient funds to pay the aggregate redemption price. Redemption of the 2020 Notes is expected to result in a loss on redemption of $6.3 million related to the premium paid on early redemption of the 2020 Notes, and the recognition of $2.7 million in financing costs, related to the outstanding deferred financing costs of the 2020 Notes as at December 31, 2016.

# DIRECTORS & OFFICERS

## OFFICERS

Dale O. Shwed
*President and Chief Executive Officer*
John G. Leach, CA
*Senior Vice President and Chief Financial Officer*
Rob Morgan, P.Eng.
*Senior Vice President and Chief Operating Officer*
Ken Truscott
*Senior Vice President, Business Development and Land*
Jamie L. Bowman
*Vice President, Marketing*
Kurtis Fischer
*Vice President, Business Development*
Shawn A. Van Spankeren, CMA
*Vice President, Finance and Administration*

## BOARD OF DIRECTORS

John A. Brussa,
*Chairman Independent Director*
Jeffery E. Errico,
*Lead Director Independent Director*
Dennis L. Nerland
*Independent Director*
Dale O. Shwed
*President, Crew Energy Inc.*
David G. Smith
*Independent Director*

## Corporate Secretary

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

## ABBREVIATIONS

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