crew energy inc.

MONTNEY: JUST KEEPS GETTING BETTER

’15 CREW ENERGY INC.

annual review

ABOUT CREW

Crew Energy Inc. is a dynamic, growth-oriented exploration and production company, focused on increasing our long-term production, reserves and cash flow through the development of our world-class Montney resource in northeast British Columbia. We are committed to the pursuit of long-term, sustainable per share growth through a balanced mix of responsible exploration and development, complemented by accretive strategic acquisitions.

Based in Calgary, Alberta, Crew is a leading holder of Montney acreage, with approximately 474 net sections. We continue to adopt new and evolving technologies to increase individual well production and enhance overall rates of return, while simultaneously reducing costs. Our committed and experienced team has a proven track record of value creation and seeks to manage ongoing risk by maintaining a strong balance sheet and responsible hedging program. Crew's common shares are listed for trading on TSX under ticker 'CR'.

Corporate Information

AUDITORS
KPMG LLP

LEGAL COUNSEL
Burnet, Duckworth & Palmer LLP

RESERVE ENGINEERS
Sproule Associates Limited

TRANSFER AGENT
Computershare Trust Company of Canada

BANKERS
Toronto-Dominion Bank
Union Bank
Bank of Montreal
Bank of Nova Scotia
Alberta Treasury Branches
National Bank of Canada
JPMorgan Chase Bank

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CREW ENERGY INC. 2015 ANNUAL REVIEW

Crew Energy Inc. (TSX: CR) of Calgary, Alberta ("Crew" or the "Company") is pleased to provide our operating and financial results for the three and twelve month periods ended December 31, 2015.

2015 HIGHLIGHTS

- Fourth quarter 2015 funds from operations were $19.6 million or $0.14 per diluted share and contributed to full year 2015 funds from operations of $82.4 million or $0.60 per diluted share;
- Fourth quarter volumes increased 23% over third quarter, averaging 20,706 boe per day as processing at the West Septimus facility increased concurrent with our firm transportation arrangement on the Alliance Pipeline system ("Alliance") on December 1, 2015. Annual average production was 18,542 boe per day;
- Exit production volumes in 2015 from our Northeast British Columbia ("NE BC") Montney areas increased 71% over the same period in 2014 largely attributable to improving well performance, strong West Septimus and Septimus drilling results, and the increased volumes through the West Septimus facility;
- Operating costs per boe decreased 19% quarter over quarter and 30% year over year to $6.89 reflecting the ongoing focus on cost reduction and lower operating costs associated with the Company's growing Montney operations;
- All-in cash costs per boe (including royalties, operating, transportation, general and administrative and interest expenses) decreased by 36% in 2015 compared to 2014 and by 22% in the fourth quarter of 2015 compared to the third quarter, reflecting the Company's continued initiatives to reduce our cost structure in response to the prevailing commodity price environment;
- Net 2015 capital expenditures totaled $161.0 million, reflecting exploration and development investments of $246.4 million focused on our Montney assets, and net of $85.4 million recovered in property dispositions;
- Net debt at year end 2015 was 6% lower than year end 2014, and totaled $238.4 million, with approximately $170 million undrawn on a $250 million bank credit facility. Net debt also includes $150 million in long-term senior notes with a maturity in October 2020;
- As announced on February 17, 2016, Crew reported strong reserves growth with record capital efficiencies, including proved developed producing ("PDP") reserves increasing by 51% net of production, and by 21% on a debt-adjusted per share basis. On a proved plus probable ("2P") basis, reserves increased to 260.6 mmboe, replacing 694% of annual production;
- Estimated year-end reserve value less total debt was $9.87 per diluted share, based on the net present value of estimated future net revenues attributed to Crew's 2P reserves before income tax and discounted at 10% as reflected in the year end independent reserves evaluation; and
- Crew strengthened our Montney asset base with the completion of two transactions during the year including an innovative petroleum and natural gas rights exchange with the Province of BC, and the $50 million sale of certain heavy oil assets in Lloydminster; both of which facilitated the allocation of capital to high-return Montney projects.

FINANCIAL & OPERATING HIGHLIGHTS

FINANCIAL ($ thousands, except per share amounts)	Three months ended Dec. 31, 2015	Three months ended Dec. 31, 2014	Year ended Dec. 31, 2015	Year ended Dec. 31, 2014
Petroleum and natural gas sales	**34,532**	72,295	**153,934**	425,424
Funds from operations(1)	**19,601**	33,035	**82,363**	171,592
Per share -basic	**0.14**	0.27	**0.60**	1.40
-diluted	**0.14**	0.27	**0.60**	1.39
Net income (loss)	**(8,167)**	(28,424)	**(55,355)**	(349,714)
Per share -basic	**(0.06)**	(0.23)	**(0.40)**	(2.86)
-diluted	**(0.06)**	(0.23)	**(0.40)**	(2.86)
Exploration and Development expenditures	**42,067**	81,447	**246,418**	306,775
Property acquisitions (net of dispositions)	**(36,644)**	1,901	**(85,441)**	(252,478)
Net capital expenditures	**5,423**	83,348	**160,977**	54,297

Capital Structure ($ thousands)	As at Dec. 31, 2015	As at Dec. 31, 2014
Working capital deficiency(2)	**10,737**	57,722
Bank loan	**80,980**	49,904
	91,717	107,626
Senior Unsecured Notes	**146,679**	146,110
Total Net Debt	**238,396**	253,736
Debt Capacity(3)	**400,000**	430,000
Common Shares Outstanding (thousands)	**141,067**	123,429

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) 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.

Operations	Three months ended Dec. 31, 2015	Three months ended Dec. 31, 2014	Year ended Dec. 31, 2015	Year ended Dec. 31, 2014
Daily production(1)				
Light crude oil (bbl/d)	**340**	1,228	**441**	429
Heavy crude oil (bbl/d)	**2,849**	5,867	**3,834**	5,897
Natural gas liquids (bbl/d)	**3,437**	2,041	**2,521**	1,640
Natural gas (mcf/d)	**84,479**	70,397	**70,474**	63,300
Subtotal (boe/d)	**20,706**	20,869	**18,542**	18,516
Properties sold (boe/d) (1)	**-**	-	**-**	5,689
Oil equivalent (boe/d)	**20,706**	20,869	**18,542**	24,205
Average prices (1, 2)				
Light & medium crude oil ($/bbl)	**48.75**	69.79	**53.10**	75.27
Heavy crude oil ($/bbl)	**31.92**	61.47	**40.40**	72.64
Natural gas liquids ($/bbl)	**27.87**	39.37	**30.28**	55.26
Natural gas ($/mcf)	**2.04**	3.66	**2.37**	4.78
Oil equivalent ($/boe)	**18.13**	37.65	**22.74**	48.15

	Three months ended Dec. 31, 2015	Three months ended Dec. 31, 2014	**Year ended Dec. 31, 2015**	Year ended Dec. 31, 2014
Netback(3,4) ($/boe)				
Revenue	**18.13**	37.65	**22.74**	48.15
Royalties	**(1.23)**	(6.46)	**(2.01)**	(9.35)
Realized commodity hedging gain / (loss)	**5.82**	1.83	**6.05**	(2.63)
Operating costs	**(6.89)**	(9.79)	**(8.31)**	(10.77)
Transportation costs	**(1.96)**	(1.73)	**(1.90)**	(1.51)
Operating netback	**13.87**	21.50	**16.57**	23.89
G&A	**(1.42)**	(2.28)	**(1.95)**	(2.15)
Interest on long-term debt	**(2.16)**	(2.02)	**(2.45)**	(2.32)
Funds from operations	**10.29**	17.20	**12.17**	19.42
Drilling Activity				
Gross wells	**6**	24	**33**	77
Working interest wells	**6.0**	23.3	**31.4**	72.7
Success rate, net wells (%)	**83**	100%	**97**	99%

Notes:

(1) Amounts for the year ended December 31, 2014 include 2,260 bbl/d of oil, 737 bbl/d of ngl and 16,149 mcf/d of natural gas which was sold during 2014.

(2) Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments. Average prices for light oil, natural gas liquids and natural gas have been adjusted to reflect the impact of the production volumes sold as shown in Note 1.

(3) Netback figures for the three and twelve months ended December 31, 2014 are as previously reported and have not been adjusted for Properties Sold.

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

OVERVIEW

Throughout 2015, Crew continued to execute on our focused business model of profitably developing and advancing our significant Montney resource base. As a result of numerous strategic decisions made through 2015, the Company is well positioned from an operational and financial standpoint despite a very difficult commodity price environment. We met our targeted exit production volume of over 26,000 boe per day in early December as a result of our successful drilling program leading to increased throughput at our West Septimus facility. Crew's fourth quarter production averaged 20,706 boe per day while full year production averaged 18,542 boe per day reflecting the Company's prudent decision to shut-in volumes during the second half of the year due to extremely weak natural gas prices in NE BC and the impact of a third party pipeline issue which curtailed production in the third quarter. Beginning December 1, 2015, Crew's firm service arrangement with Alliance came into effect providing secure egress for our increased production and exposure to multiple markets and improved pricing.

During 2015, we invested $246.4 million into exploration and development expenditures, or $209.5 million net of the sale of a portion of our West Septimus facility to our infrastructure partner, further offset by proceeds of $50.1 million from our heavy oil disposition. Activities during 2015 were focused on the advancement of our Montney assets including completion of the West Septimus facility, drilling 27 gross (25.3 net) wells in NE BC and completing and tying-in 25 wells, which included both 2015 and 2014 drills. The Company also exited the year with an inventory of 15 wells in NE BC that were drilled but uncompleted that will provide support for first half 2016 production. During the second half of 2015, the Company also commenced construction on the installation of a pipeline beneath the Pine River (the "Pine River Pipeline") which will connect the West Septimus and Septimus plants, reduce condensate transportation costs, facilitate future expansion of the West Septimus facility, enhance longer term market access and position Crew as the only operator with pipeline connections that span the Pine River.

Two strategic transactions completed in 2015 further supported our Montney focus. In July 2015, Crew closed an innovative petroleum and natural gas rights exchange with the Province of British Columbia, adding 53 net sections of land featuring prospective Upper and Lower Montney zones that are contiguous to our Groundbirch property. Crew received this acreage in exchange for surrendering 66 net sections of undeveloped land that had been subject to restricted development since 2004. In September, Crew closed a $50.1 million cash disposition of a minor portion of producing Lloydminster heavy oil assets. This disposition further strengthened the balance sheet by reducing debt outstanding on the credit facility.

Evidence of the high quality of Crew's asset base and our operational efficiencies is clearly demonstrated by our strong 2015 reserves growth, coupled with the lowest finding and development ("F&D") and finding, development and acquisition ("FD&A") costs in the Company's history. These low costs across all reserves categories contributed to strong recycle ratios, even in the context of a very weak commodity price environment. Crew increased 2P reserves to 260.6 million boe with a replacement ratio of 694%, and achieved all-in 2P FD&A costs of $3.86 per boe, with a recycle ratio of 4.3 times.

Crew has been actively working to further reduce costs in all areas of the organization, and has benefitted from a combination of capital cost reductions across the broader industry as well as internal efficiency improvements. The implementation of pad drilling across our core areas has helped to reduce costs and enhance operational efficiencies. Well costs have declined from over $5.0 million in 2014 with recent pad drills averaging $4.0 million per well while also generating improved results. With the increase in throughput at our West Septimus facility in December and our ongoing cost reduction initiatives, Crew's operating costs in the fourth quarter were 19% lower than in the previous quarter, and are forecast to be reduced by 24% or approximately $2.00 per boe in 2016 compared to 2015.

The quality, prospectivity and future potential of the Montney resource continues to improve with time and technology. Crew's achievements through 2015 are evidence of our success in building a strong and growing Company that reflects the Montney: it just keeps getting better.

FINANCIAL

Crew's strong financial position and ongoing strategy to preserve our balance sheet strength have afforded the Company flexibility to make decisions that are in the long-term interests of the Company and our shareholders. In March 2015, we closed a $100 million equity financing which strengthened the balance sheet and provided Crew with the ability to invest in high return projects despite persistent volatility in commodity prices. The Company exited 2015 with $238.4 million of total debt, including working capital deficiency and the Company's $150 million ($146.7 million net of deferred financing costs) senior unsecured notes that are not due for repayment until the last quarter of 2020. At year-end, Crew had drawn approximately $81.0 million or 32% of our $250 million bank facility. With no near-term maturities, an increasing reserve base and substantial liquidity, Crew is strongly positioned to manage through this ongoing commodity weakness. Our priority continues to be on preserving balance sheet strength while meeting transportation arrangements.

Weak commodity prices prevailed through the fourth quarter of 2015 as the price of oil continued to be impacted by OPEC's persistent resolve to regain global market share by eliminating quotas which had previously operated to support a higher price. We also endured a weakening natural gas market as North America remained abundantly supplied by constantly improving drilling efficiencies, while demand was impacted by extremely moderate early winter weather patterns. More specifically, Crew's natural gas sales were impacted by ongoing regional price discounts through October and November due to pipeline constraints in northwest Alberta and NE BC. Despite these challenges, Crew was able to increase fourth quarter funds from operations to $19.6 million, a 24% improvement over the third quarter due to a 23% increase in production and a significant drop in our overall cost structure. Fourth quarter cash costs per boe were reduced by 22% compared to the third quarter 2015, highlighted by a 47% reduction in royalty charges, a 19% drop in operating costs, and a 31% decline in G&A costs.

Net capital expenditures during the fourth quarter totaled $5.4 million which included exploration and development expenditures of $42.1 million, offset by the recovery of $36.8 million from our facility partner for their share of the cost to build the West Septimus gas processing facility. Exploration and development expenditures during the quarter included the drilling of six gross (6.0 net) wells and the completion of seven (6.0 net) wells in West Septimus and Septimus. Expenditures include an incremental $9 million of capital that was added to our fourth quarter 2015 budget as we took advantage of the exceptional fall weather and the efficiencies and cost savings offered by maintaining one rig drilling through to the middle of December. The Company continued operations to install the Pine River Pipeline during the quarter. The majority of the cost of the Pine River Pipeline project was incurred as planned in 2015, against which an $11 million Government of British Columbia infrastructure credit is expected to be earned upon project completion. This credit was originally forecast to be recognized in the fourth quarter but has been deferred along with the expected completion of the project into the first quarter of 2016.

TRANSPORTATION AND MARKETING

Crew's firm transportation arrangement on Alliance took effect on December 1, 2015 securing takeaway capacity to various markets, enabling Crew to capture more favorable pricing. Concurrent with the start of the Company's firm Alliance transportation service Crew also entered into several marketing arrangements diversifying the Company's market exposure for natural gas. Starting December 1, 2015 approximately 40% of our natural gas is sold at Chicago City-gate pricing, while 50% is priced at an AECO equivalent. Currently 10% of Crew's volumes are exposed to the Spectra Energy ("Spectra") system. Longer term, Crew has committed to expansions of takeaway capacity on both the Spectra and TransCanada Pipeline systems, positioning the Company for future growth and provides the ability to continue to actively manage our market and operational diversification. In addition, Crew has secured firm service arrangements on the Pembina Pipeline system to transport produced liquids from the greater Septimus area through our 100% owned LACT (Lease Automatic Custody Transfer) unit.

Crew's risk management strategy is designed to partially protect cash flows against significant declines in commodity prices, while partially safeguarding a funding source for our capital program. In 2015 the Company realized a $40.9 million, or $6.05 per boe, hedging gain. In 2016, the Company has protected a portion of our funds from operations and helped to support ongoing financial stability with approximately 44% of our estimated 2016 natural gas volumes currently hedged with a floor price of approximately $2.73 per gj or approximately $2.88 per mcf. For 2017, the Company has 7% of our estimated 2017 natural gas volumes hedged at a price of $2.90 per gj or approximately $3.06 per mcf.

OPERATIONS UPDATE

The significant growth potential and prospectivity of Crew's Montney asset base was clearly reflected in our 2015 operational performance and year end reserves report. We continued to generate positive drilling results providing over 40 mmcf per day of productive capacity in the first phase of our West Septimus growth plan. Construction of the 60 mmcf per day West Septimus facility was completed in early August and brought on-stream at approximately half capacity as budgeted, with increased throughput taking effect December 1, 2015 concurrent with the commencement of our firm transportation arrangements. A combination of our well performance and the ramp-up of the facility contributed to reaching our 2015 exit production rate of over 26,000 boe per day in December.

Crew's capital efficiencies improved markedly in 2015 as demonstrated by our top quartile F&D and FD&A costs and recycle ratios. A portion of these record low costs stem from Crew's strategic decision to maintain an established inventory of drilled wellbores which allowed the Company to complete and tie-in volumes in an efficient and timely manner to meet transportation arrangements and grow production. This strategy continues into 2016 as Crew had a total of 15 (14.3 net) wells drilled in inventory at the end of 2015. Our Montney well costs have declined substantially since 2014 with recent 2016 per well costs totaling approximately $4.0 million to drill, complete and tie-in with further improvements in cost structure anticipated. This achievement is meaningfully lower than the $4.3 million Septimus / West Septimus undeveloped well cost included in our 2015 year end reserve report.

The operational success realized at West Septimus in 2015 confirmed the substantial opportunity for further drilling and area expansion. At West Septimus, 2P reserve bookings increased 110%, achieving significantly higher gas rates as well as liquids reserves that were 300% higher than 2014. Crew drilled six (6.0 net) wells in the fourth quarter, accelerating the drilling of the first four of an eight well pad at West Septimus originally planned for the first quarter of 2016 to capitalize on efficiencies and favorable weather. This operational momentum has continued into the first quarter, as Crew completed and tested two wells at West Septimus. The first of these wells achieved a production test rate of 12 mmcf per day after a nine day clean-up period with 56 bbls per mmcf of wellhead condensate at a flowing casing pressure of 1,335 psi. The second well achieved a production test rate of 10 mmcf per day after a six day clean-up period with wellhead condensate of 42 bbls per mmcf at a flowing casing pressure of 1,340 psi.

At Septimus, Crew increased throughput volumes at our Septimus facility concurrent with our Alliance transportation arrangement on December 1, 2015 and the plant achieved a new record throughput in excess of 11,600 boe per day (65.6 mmcf/day inlet volumes) during December 2015. In addition, the Company realized positive results from our first Lower Montney well at Septimus which averaged 4.4 mmcf per day over the first 60 days of production with 34 bbls per mmcf of field condensate. At Septimus, our first Lower Montney reserves were assigned covering approximately three (2.0 net) sections.

Inclusive of the one existing net section that had previously been assigned Lower Montney reserves at Attachie, Crew's total Lower Montney reserves represent only 0.6% of our overall Montney land base, confirming that the Lower Montney represents an additional substantial opportunity for expanded future drilling.

Activity at Crew's other key Montney areas at Attachie / Groundbirch and Tower were limited during the latter half of 2015 as the Company elected to focus on areas offering more attractive economics in the current commodity price environment. Crew drilled a vertical stratigraphic test well at Tower in Q4 2015 for the purpose of gathering specific reservoir information that will be used in the design and optimization of future completions within the Montney oil window, which represents approximately 33% of Crew's overall land base. These areas offer significant oil and liquids growth potential, which the Company plans on developing with improved commodity prices.

At our Lloydminster heavy oil property, the Company successfully divested of a non-core heavy oil asset package for $50.1 million, which bolstered the balance sheet. Crew continued to employ a conservative approach at Lloydminster through 2015, including electing not to restart wells that did not meet stringent economic criteria contributing to a 13% reduction in area operating costs which averaged $16.74 per boe. Current area production is approximately 2,800 boe per day with approximately 600 boe per day of production offline awaiting more favorable pricing.

RESERVES VALUE PER DILUTED SHARE

Following is a calculation of Crew's estimated reserves value per diluted share less debt at December 31, 2015. This value is based on the net present value ("NPV") of estimated future net revenues attributed to Crew's 2P reserves before income tax and discounted at 10% as reflected in the independent corporate reserves evaluation prepared by Sproule Associates Limited. ("Sproule") with an effective date of December 31, 2015.

	$000s	$ per share(4)
2P NPV(1)(2)	1,656,797	
Estimated net debt(3)	(238,396)	
Reserves value less debt (diluted)	1,418,401	$9.87

Notes:
(1) Evaluated by Sproule as at December 31, 2015. NPV of future net revenue does not represent fair market value of the reserves.
(2) NPV before taxes based on Sproule's forecast prices and costs as of December 31, 2015 are stated prior to provision for interest, debt service charges or general administrative expenses and after deduction of royalties, operating costs, estimated well abandonment and reclamation costs and estimated future capital expenditures.
(3) Net debt as at December 31, 2015, including working capital deficit.
(4) Per share figures based on 143.7 million diluted shares including "in the money" stock options and incentive awards outstanding as at December 31, 2015.

OUTLOOK

In 2016, Crew will prioritize the preservation of our balance sheet strength while managing production volumes to optimize netbacks. We have reduced our previously released 2016 capital budget by $4 million to $70 million to reflect expenditures incurred in 2015 that were originally planned for 2016 and confirm Crew's previous 2016 average production guidance of 23,000 to 25,000 boe per day. As the year progresses, we will continue to monitor the impact of changing commodity prices and plan to adjust capital spending to approximate estimated funds from operations. Our 2016 program anticipates growth in annual average production of over 25% year-over-year, a result of the additional production capacity in our new West Septimus gas plant and a very active and highly successful 2015 drilling program. Crew's sustainability has continued to improve, with over 100 Montney wells on production that support a PDP decline rate of 28%, which is a seven percent reduction from the 30% decline rate the previous year. Maintaining operational flexibility is critical in this environment and our readiness will enable efficient increases in activity and investment when commodity prices improve. Crew's 2016 drilling and development capital will continue to be allocated to our high return areas at West Septimus and Septimus where we continue to drive costs down. We remain committed to our Montney development and in 2016 plan to complete and bring on-stream the inventory of 15 wells that were drilled in 2015, as well as drill, complete and tie-in seven gross (6.0 net) additional wells.

Despite very challenging market conditions through 2015 and into 2016, Crew has continued to stick to our plan to cut costs and efficiently grow our production. Full cycle capital efficiencies are expected to improve in 2016 as Crew invested $113.8 million in infrastructure during 2015 and does not plan material expenditures on infrastructure in 2016. In an environment of low prices and severely constrained funds from operations, we have successfully:

- Achieved record capital efficiencies with 2P FD&A of $3.86 per boe leading to a recycle ratio of 4.3 times;
- Increased 2P reserves by 21% to 260.6 mmboe, a 10% increase on a debt adjusted per share basis;
- Increased production to 26,000 boe per day in December compared to the annual average of 18,542 boe per day;
- Achieved full-cycle on-stream capital efficiencies of $15,000 per flowing boe on $210 million of capital;
- Reduced year end net debt by 6%;
- Commissioned a new 60 mmcf per day gas processing facility;
- Increased our Montney land position to 474 net sections after the impact of an innovative land swap;
- Secured 100 mmcf per day of firm transportation service on the Alliance Pipeline; and
- Enhanced our focused Montney position through a $50 million heavy oil disposition.

We will continue to pursue the optimization of well designs and focus on the development of our Montney assets, while seeking to provide long-term profitable growth for our shareholders. With further advances in technology and the ongoing development of our Montney resource, Crew's position as a growing Montney producer continues to improve year after year.

We would like to thank all of Crew's employees, management, consultants and our Board of Directors for their hard work and unwavering dedication, and we sincerely thank our shareholders for your continued support of Crew's Montney focused strategy.

CAUTIONARY STATEMENTS

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 volume and product mix of Crew's oil and gas production; production estimates including 2016 forecast average production; future decline rates; future oil and natural gas prices and Crew's commodity risk management programs; future liquidity and financial capacity; future results from operations and operating metrics; potential for further reductions in operating costs and potential to improve ultimate recoveries and initial production rates; future costs, expenses and royalty rates; future interest costs; the exchange rate between the $US and $Cdn; future development, exploration, acquisition, development and infrastructure activities and related capital expenditures and the timing thereof; the number of wells to be drilled, completed and tied-in and the timing thereof; the amount and timing of capital projects including anticipated timing of completion of the Pine River Pipeline and expected recovery of the majority of this expenditure through the BC infrastructure credit; the total future capital associated with development of reserves and resources; and methods of funding our capital, including possible non-core asset divestitures and asset swaps.

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: the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; 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; the ability of Crew to successfully market its oil and natural gas products. There are a number of assumptions associated with the potential *of reserve and resource volumes assigned to the evaluated areas including the quality of the Montney reservoir, future drilling programs and the funding thereof, continued performance from existing wells and performance of new wells, the growth of infrastructure, well density per section, and recovery factors and discovery and development necessarily involves known and unknown risks and uncertainties, including those identified in this report.*

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; the potential for variation in the quality of the Montney formation; changes in the demand for or supply of Crew's products; 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 and resource 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.

Information Regarding Disclosure on Oil and Gas Reserves and Operational Information

Information presented herein in respect of reserves and related information is based on our independent reserves evaluation for the year ended December 31, 2015 prepared by Sproule Associates Limited, details of which were provided in our press release issued on February 17, 2016. Our oil and gas reserves statement for the year ended December 31, 2015, 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 above under the heading "Forward-Looking Information and Statements".

This report contains metrics commonly used in the oil and natural gas industry, such as "recycle ratio", "finding and development costs", "recycle ratio", "finding, development and acquisition costs", "operating netbacks", "reserves replacement", and "reserve life index". Reference is made to Crew's press release dated February 17, 2016 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.

Both F&D and FD&A costs take into account reserves revisions during the year on a per boe basis. The aggregate of the costs incurred in the financial year and changes during that year in estimated FDC may not reflect total F&D costs related to reserves additions for that year. Finding and development costs both including and excluding acquisitions and dispositions have been presented in this 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.

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 a 6:1 conversion basis may be misleading as an indication of value.

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.

YEAR END 2015

Management's Discussion and Analysis

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Financial Statements

MANAGEMENT'S DISCUSSION AND ANALYSIS

FINANCIAL & OPERATING HIGHLIGHTS

Financial ($ thousands, except per share amounts)	**Year ended** **December 31, 2015**	Year ended December 31, 2014
Petroleum and natural gas sales	**153,934**	425,424
Cash provided by operations	**74,698**	169,207
Funds from operations [(1)]	**82,363**	171,592
Per share -basic	**0.60**	1.40
-diluted	**0.60**	1.39
Net loss	**(55,355)**	(349,714)
Per share -basic	**(0.40)**	(2.86)
-diluted	**(0.40)**	(2.86)
Exploration and development expenditures	**246,418**	306,775
Property acquisitions (net of dispositions)	**(85,441)**	(252,478)
Net capital expenditures	**160,977**	54,297

Capital Structure ($ thousands)	**As at** **December 31, 2015**	As at December 31, 2014
Working capital deficiency [(2)]	**10,737**	57,722
Bank loan	**80,980**	49,904
	91,717	107,626
Senior unsecured notes	**146,679**	146,110
Total Net debt	**238,396**	253,736
Debt capacity[(3)]	**400,000**	430,000
Common Shares Outstanding (thousands)	**141,067**	123,429

Operations	**Year ended** **December 31, 2015**	Year ended December 31, 2014
Daily production		
Light crude oil (bbl/d)	**441**	429
Heavy crude oil (bbl/d)	**3,834**	5,897
Natural gas liquids (bbl/d)	**2,521**	1,640
Natural gas (mcf/d)	**70,474**	63,300
Subtotal (boe/d)	**18,542**	18,516
Properties sold (boe/d) [(4)]	**-**	5,689
Oil equivalent (boe/d @ 6:1)	**18,542**	24,205
Average prices [(5)]		
Light crude oil ($/bbl)	**53.10**	75.27
Heavy crude oil ($/bbl)	**40.40**	72.64
Natural gas liquids ($/bbl)	**30.28**	55.26
Natural gas ($/mcf)	**2.37**	4.78
Oil equivalent ($/boe)	**22.74**	48.15
Netback ($/boe)		
Operating netback [(6)]	**16.57**	23.89
G&A	**(1.95)**	(2.15)
Interest on long-term debt	**(2.45)**	(2.32)
Funds from operations	**12.17**	19.42
Drilling Activity		
Gross wells	**33**	77
Working interest wells	**31.4**	72.7
Success rate, net wells	**97%**	99%

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) Amounts for the year ended December 31, 2014 include 2,260 bbl/d of crude oil, 737 bbl/d of ngl and 16,149 mcf/d of natural gas which was sold during 2014.

(5) Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments. Average prices for light crude oil, natural gas liquids and natural gas have been adjusted to reflect the impact of the production volumes sold as shown in Note 2.

(6) 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 Company's explanation of its financial performance for the period covered by the financial statements along with an analysis of the Company's financial position. Comments relate to and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2015 and 2014. The consolidated financial statements for the year ended December 31, 2015 have been prepared in accordance with International Financial Reporting Standards ("IFRS"). All figures provided herein and in the December 31, 2015 audited consolidated financial statements are reported in Canadian dollars.

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 tie-in and completion of wells, facility and pipeline construction, commissioning and the timing thereof, capital expenditures including the Company's planned 2016 exploration and development budget, timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, the anticipated recoveries of a portion of the Pine River pipeline expenditures through government infrastructure credit, production estimates including 2016 average production growth forecasts, 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 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, 2015**	Three months ended December 31, 2014	**Year ended December 31, 2015**	Year ended December 31, 2014
Cash provided by operating activities	**12,373**	37,714	**74,698**	169,207
Decommissioning obligations settled	**43**	249	**736**	768
Change in operating non-cash working capital	**7,300**	(4,773)	**7,498**	2,104
Accretion of deferred financing costs	**(115)**	(155)	**(569)**	(487)
Funds from operations	**19,601**	33,035	**82,363**	171,592

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 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, 2015**	December 31, 2014
Current assets	**34,417**	78,469
Current liabilities	**(38,217)**	(95,337)
Marketable securities	**(1,160)**	(2,052)
Derivative financial instruments	**(5,777)**	(38,802)
Working capital deficit	**(10,737)**	(57,722)

($ thousands)	**December 31, 2015**	December 31, 2014
Bank loan	**(80,980)**	(49,904)
Senior unsecured notes	**(146,679)**	(146,110)
Working capital deficit	**(10,737)**	(57,722)
Net debt	**(238,396)**	(253,736)

RESULTS OF OPERATIONS

Overview

Throughout 2015, Crew continued to execute on its focused business model of developing and advancing the Company's significant Montney resource base. As a result of numerous strategic decisions made during the past year, the Company is operationally and financially well positioned despite a very difficult commodity price environment. Crew exceeded its exit production volume target of over 26,000 boe per day in early December as a result of successful drilling results and higher throughput at our West Septimus facility. Crew's annual average volume of 18,542 boe per day reflected the Company's prudent decision to shut-in volumes during the second half of the year due to extremely weak natural gas prices in northeast British Columbia and the impact of third party pipeline issues which curtailed production in the last half of 2015.

Crew's strong financial position and ongoing strategy to preserve our balance sheet has afforded the Company flexibility to make decisions that are in the best long-term interests of Crew and our shareholders. In March 2015, the Company closed a $100 million equity financing which strengthened the balance sheet and provided Crew with the ability to invest in high return projects despite continued volatility in commodity prices, which fell by more than 40% during 2015. The Company is less than one third drawn on a $250 million credit facility, leaving it with approximately $170 million of available credit capacity. The balance of the net debt is comprised of a working capital deficiency and $150 million in long-term senior unsecured notes that mature in October 2020. With no near term maturities, an increasing reserve base and substantial liquidity, Crew is strongly positioned to manage through the current environment. Our priority continues to be on preserving balance sheet strength while managing transportation and processing commitments.

During 2015, Crew invested $246 million into exploration and development expenditures, which was offset by proceeds of $85 million from dispositions, including a non-core heavy oil disposition and the sale of a portion of our West Septimus facility to an infrastructure partner. Activities during 2015 were focused on the advancement of Crew's Montney assets including completion of the West Septimus facility, drilling 33 (31.4 net) wells, and completing and tying-in 32 (31.0 net) wells. Crew accelerated approximately $9 million of capital spending that was originally budgeted for first quarter 2016 into 2015 to capture operational efficiencies. During the second half of 2015, the Company also commenced construction on the installation of a pipeline beneath the Pine River which will connect the West Septimus and Septimus plants, reduce condensate transportation costs, facilitate future expansion of the West Septimus facility and enhance longer term market access. The majority of the cost of this project was incurred in 2015 as planned and for which an $11 million Government of British Columbia infrastructure credit will be earned upon completion. The infrastructure credit is recognized as a reduction of the Company's capital expenditures when the project is completed, which was delayed into the first quarter of 2016.

Two strategic transactions completed in 2015 further supported the Company's Montney focus. In July 2015, Crew closed an innovative petroleum and natural gas rights exchange with the Province of British Columbia, adding 53 net sections of land featuring prospective Upper and Lower Montney zones that are contiguous to the Company's Groundbirch property. Crew received this acreage in exchange for surrendering 66 net sections of undeveloped land that had been subject to restricted development since 2004. In September, Crew closed a $50.1 million disposition of a minor portion of producing Lloydminster heavy oil assets. This disposition further strengthened the balance sheet by reducing debt outstanding on the credit facility.

Crew has been actively working to further reduce costs in all areas of the organization and has benefitted from a combination of capital cost reductions across the broader industry and an improvement in efficiencies. The implementation of pad drilling across our core areas has also helped to reduce costs and enhance operational efficiencies. As a result of the increase in throughput at our West Septimus facility in December, Crew's operating costs in the fourth quarter were 19% lower than in the previous quarter, and are forecast to average 22% lower in 2016 as compared to 2015.

Crew's firm transportation arrangement on the Alliance system took effect on December 1, 2015 and offers numerous benefits over and above increased production and reduced operating costs. Strategically, this arrangement provides secured takeaway capacity and consistent transportation to multiple higher value markets, enabling Crew to capture more favorable pricing. The Company continues to be very well positioned with access to infrastructure, including optionality for future Montney growth through cost-effective facility expansions or new builds depending on commodity prices.

2014 Strategic Transactions

On May 30, 2014, Crew disposed of approximately 7,000 boe per day (75% natural gas) focused primarily in the Deep Basin of Alberta for approximately $234 million, before closing adjustments (the "Alberta Gas Disposition").

On September 30, 2014, Crew disposed of approximately 3,650 boe per day of production (78% oil) in the Princess area of Alberta for approximately $150 million, before closing adjustments (the "Princess Disposition").

These transactions (the "2014 Dispositions") have had a significant impact on the comparison of the Company's results for the year ended December 31, 2015 to the results for the same period in 2014. The impact is outlined in detail below and in the Company's Management Discussion and Analysis for the year ended December 31, 2014.

Production

	Three months ended December 31, 2015				Three months ended December 31, 2014			
	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	**340**	**3,437**	**84,218**	**17,813**	1,228	2,041	70,135	14,958
Lloydminster	**2,849**	**-**	**261**	**2,893**	5,867	-	262	5,911
Total	**3,189**	**3,437**	**84,479**	**20,706**	7,095	2,041	70,397	20,869

In the fourth quarter of 2015, production slightly decreased over the same period in 2014 due to heavy oil production reductions as the Company continued to curtail new drilling and reduce workover and well servicing activity until commodity prices recover. The heavy oil production decrease was partially offset by incremental liquids rich natural gas production at Septimus and West Septimus where the Company increased production by 19% over the same period in 2014 as a result of the success of the continued Montney development. This increase in Montney production was tempered by pipeline service restrictions and curtailments that carried over from the prior quarter which resulted in restricted access and significantly depressed prices on third party pipeline systems in northeast British Columbia. The Company continued to manage its natural gas production levels to effectively match to its firm fixed sales commitments. In December 2015, Crew's firm transportation commitment contracts on the Alliance pipeline commenced providing the Company alternative markets, thus mitigating the weak natural gas pricing environment experienced in the previous months and allowing Crew to increase its liquids rich natural gas production at Septimus and West Septimus.

	Year ended December 31, 2015				Year ended December 31, 2014			
	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	**441**	**2,521**	**70,185**	**14,660**	429	1,640	63,088	12,584
Lloydminster	**3,834**	**-**	**289**	**3,882**	5,897	-	212	5,932
Properties sold	**-**	**-**	**-**	**-**	2,260	737	16,149	5,689
Total	**4,275**	**2,521**	**70,474**	**18,542**	8,586	2,377	79,449	24,205

Production in 2015 decreased 23% as compared to 2014 as a result of the 2014 Dispositions combined with production declines in Lloydminster from reduced capital investment as a result of the weak commodity pricing during this period. This production decrease was partially offset by growth in the Company's Montney production in northeast British Columbia as a result of a strong drilling program combined with added processing capacity from the commissioning of the new West Septimus gas facility in the second half of the year.

Revenue

	Three months ended December 31, 2015	Three months ended December 31, 2014	**Year ended December 31, 2015**	Year ended December 31, 2014
Revenue ($ thousands)				
Light crude oil	**1,523**	7,924	**8,538**	11,784
Heavy crude oil	**8,366**	33,181	**56,536**	156,346
Natural gas liquids	**8,812**	7,483	**27,857**	33,084
Natural gas	**15,831**	23,707	**61,003**	110,558
Properties sold	**-**	-	**-**	113,652
Total	**34,532**	72,295	**153,934**	425,424
Crew average prices(1)				
Light crude oil ($/bbl)	**48.75**	69.79	**53.10**	75.27
Heavy crude oil ($/bbl)	**31.92**	61.47	**40.40**	72.64
Natural gas liquids ($/bbl)	**27.87**	39.37	**30.28**	55.26
Natural gas ($/mcf)	**2.04**	3.66	**2.37**	4.78
Oil equivalent ($/boe)	**18.13**	37.65	**22.74**	48.15
Benchmark pricing				
Light crude oil – WTI (Cdn $/bbl)	**56.22**	82.94	**62.14**	102.49
Heavy crude oil – WCS (Cdn $/bbl)	**36.88**	66.72	**44.83**	81.07
Natural gas liquids – Condensate @ Edmonton (Cdn $/bbl)	**55.61**	78.31	**58.98**	100.26
Natural Gas – AECO 2A daily index (Cdn $/mcf)	**2.48**	3.61	**2.70**	4.49
Spectra Natural Gas – NGX Station #2 day ahead index (Cdn $/mcf)	**1.09**	3.11	**1.79**	4.12
NGX APC - AECO 5a less ATP(2)	**1.75**	-	**1.75**	-

(1) 2014 comparative average prices for light crude oil, natural gas liquids and natural gas have been adjusted to reflect the impact of the 2014 disposition.

(2) NGX APC - AECO 5a less ATP benchmark price commenced December 1, 2015 and does not represent the average benchmark price for the fourth quarter or year ended December 31, 2015.

In the fourth quarter of 2015, Crew's revenue decreased 52% as compared to the same period in 2014 as a result of the significant decline in commodity prices experienced in 2015 and a shift to a higher weighting of natural gas in the Company's fourth quarter production. Crew's realized light oil price decreased 30% in the fourth quarter which was comparable to the 32% decline in the Company's Cdn$ West Texas Intermediate ("WTI") benchmark for the same period. Heavy oil decreased 48% in the quarter which was slightly higher than the 45% decrease in the Company's Western Canadian Select ("WCS") benchmark as a result of the Company securing short term sales contracts when WCS differentials were wider than the average market trade for the same period. The Company's natural gas liquids ("ngl") price decreased 29% in the fourth quarter of 2015 over the same period in 2014 which was comparable to the decline in the Condensate at Edmonton benchmark price for the same period.

During the fourth quarter, the Company's natural gas price declined 44% as compared to a decline of 31% in the AECO benchmark and a 65% decline in the Spectra benchmark. From January through November of 2015, Crew sold its natural gas into the Spectra Station 2 or Alliance CREC market. These markets saw significant price discounts during this period, relative to the AECO market, due to regional pipeline restrictions that negatively impacted the supply/demand dynamic at the Spectra and Alliance pricing points. Crew successfully offset a portion of this discount by forward selling a portion of its January through November Alliance natural gas sales at a fixed differential that was substantially better than the average traded Alliance differential for the period.

On December 1, 2015, Crew began transporting natural gas under a new firm service arrangement on the Alliance pipeline and selling the majority of its natural gas under new sales contracts that are linked to Chicago Citygate pricing or AECO referenced pricing. As a result of Crew's contracts commencing in December, the Company's realized natural gas price for the first two months of the fourth quarter was 32% lower than the Company's AECO 2A benchmark price while the Company's realized natural gas price was 6% higher than the AECO 2A benchmark for the month of December. The Company's natural gas price is expected to closely track the change in the new NGX APC – AECO 5a less ATP benchmark price commencing in 2016.

For 2015, revenue decreased 64% over the same period in 2014 as a result of the 2014 Dispositions combined with the 53% decrease in realized commodity pricing. The Company's light oil price decreased 29% which outperformed the 39% decline in the Company's CDN WTI benchmark as a result of the benchmark being an average for the year whereas the majority of the Company's 2014 light oil revenue was earned during the fourth quarter when 2014 prices were at their lowest point. Crew's heavy oil price decreased 44% in 2015 as compared to 2014 which was consistent with the 45% decline in the WCS benchmark price for the same period. The Company's ngl price decreased 45% which was slightly higher than the 41% decrease in the Condensate at Edmonton benchmark price as the Company's ngl production includes propane and butane in the ngl price, both of which yield a price that is disproportionately lower as compared to the condensate benchmark price. For 2015, the Company's natural gas price decreased 50% over 2014 as compared to the 40% decrease in the Company's AECO 2A benchmark and 57% decrease in the Company's Spectra benchmark. The Company's 2015 natural gas sales were impacted by the Spectra Station 2 and Alliance price weakness, as described earlier.

Royalties

($ thousands, except per boe)	**Three months ended December 31, 2015**	Three months ended December 31, 2014	**Year ended December 31, 2015**	Year ended December 31, 2014
Royalties	**2,348**	12,410	**13,611**	82,621
Per boe	**1.23**	6.46	**2.01**	9.35
Percentage of revenue	**6.8%**	17.2%	**8.8%**	19.4%

In the fourth quarter and year ended December 31, 2015, royalties and royalties as a percentage of revenue were significantly lower than the same periods of 2014 as a result of the increased production at Septimus and West Septimus which attract lower royalty rates as a result of new well deep gas royalty credit programs in British Columbia. Royalties in 2015 were also impacted by lower commodity prices attracting a lower royalty rate and the previously mentioned 2014 Dispositions which attracted higher royalty rates. Crew expects royalties as a percentage of revenue to average between 7% and 9% in 2016.

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, 2015**	Three months ended December 31, 2014	**Year ended December 31, 2015**	Year ended December 31, 2014
Realized gain (loss) on derivative financial instruments	**11,083**	3,523	**40,929**	(23,262)
Per boe	**5.82**	1.83	**6.05**	(2.63)
Unrealized gain (loss) on financial instruments	**(6,493)**	43,770	**(32,589)**	53,406

As at December 31, 2015, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Oil	500 bbl/day	January 1, 2016 – June 30, 2016	US$ WCS – WTI diff	$(14.95)	Swap	(188)
Oil	500 bbl/day	January 1, 2016 – December 31, 2016	CDN$ WTI	$116.50	Call	(15)
Oil	250 bbl/day	January 1, 2016 – December 31, 2016	CDN$ WTI	$78.25	Swap	1,908
Gas	20,000 gj/day	January 1, 2016 – December 31, 2016	AECO C Monthly Index	$2.60	Swap	1,387
Gas	2,500 gj/day	April 1, 2016 – October 31, 2016	AECO C Monthly Index	$2.14	Swap	(130)
Gas	20,000 mmbtu/day	January 1, 2016 – December 31, 2016	CDN$ Chicago Citygate	$3.79	Swap	2,440
Gas	5,000 mmbtu/day	January 1, 2016 – December 31, 2016	Nymex Henry Hub – AECO C ($US/mmbtu)	Nymex less US$-0.5025/mmbtu	Basis Swap[(1)]	375
Gas	2,500 gj/day	January 1, 2017 – December 31, 2017	AECO C Monthly Index	$2.73	Swap	(6)
Gas	5,000 gj/day	January 1, 2017 – December 31, 2017	AECO C Monthly Index	$2.90	Call Swaption[(2)]	(294)
Total						5,477

(1) Crew receives NYMEX Henry Hub "Last Day" Settlement minus applicable spread; Crew pays AECO C (US$/mmbtu)
(2) The referenced contract is a European call swaption, which the counterparty will accept or decline by December 22, 2016.

Subsequent to December 31, 2015, the Company entered into the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Gas	5,000 mmbtu/day	January 1, 2017 - December 31, 2017	CDN$ Chicago Citygate	$3.89	Swap
Gas	2,638 gj/day	February 1, 2016 - December 31, 2016	AECO C Monthly Index	$2.75	Swap
Gas	2,638 gj/day	April 1, 2016 – December 31, 2016	AECO C Monthly Index	$2.03	Swap

Subsequent to December 31, 2015, the Company unwound the following derivative commodity contracts for net proceeds of approximately $2.0 million:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Gas	2,500 mmbtu/day	February 1, 2016 - December 31, 2016	Nymex Henry Hub - AECO C ($US/mmbtu)	NYMEX minus US$-0.55/mmbtu	Basis Swap
Oil	250 bbl/day	February 1, 2016 - December 31, 2016	CDN$ WTI	$78.25	Swap
Gas	2,500 mmbtu/day	April 1, 2016 - December 31, 2016	Nymex Henry Hub - AECO C ($US/mmbtu)	NYMEX minus US$-0.46/mmbtu	Basis Swap

Operating Costs

($ thousands, except per boe)	**Three months ended December 31, 2015**	Three months ended December 31, 2014	**Year ended December 31, 2015**	Year ended December 31, 2014
Operating costs	**13,134**	18,790	**56,242**	95,128
Per boe	**6.89**	9.79	**8.31**	10.77

For the fourth quarter of 2015, the Company's operating costs per unit decreased 30% over the same period in 2014 as a result of the significant increase of lower cost production in Septimus and West Septimus combined with the decrease in higher cost heavy oil production in the Lloydminster area. For 2015, operating costs per unit decreased 23% over the same period in 2014 as a result of the increased lower cost Septimus and West Septimus area production combined with the Princess Disposition and the decline in Lloydminster production, both of which attracted higher costs per unit as compared to the corporate average. Crew's cost structure also continues to benefit from strategic operational efficiencies and industry wide cost reductions. The Company forecasts operating costs to average $6.00 to $6.75 per boe for 2016.

Transportation Costs

($ thousands, except per boe)	**Three months ended December 31, 2015**	Three months ended December 31, 2014	**Year ended December 31, 2015**	Year ended December 31, 2014
Transportation costs	**3,730**	3,325	**12,884**	13,314
Per boe	**1.96**	1.73	**1.90**	1.51

For the fourth quarter of 2015, the Company's transportation costs and transportation costs per boe increased as a result of significant new West Septimus condensate production which currently requires long haul trucking to market. Additionally, in December of 2015, natural gas transportation costs increased as the Company commenced its firm transportation arrangements on the Alliance pipeline which improves the Company's natural gas realized pricing. The Company partially offset the increase in transportation costs with the installation of the lease automatic custody transfer unit ("LACT") in the third quarter of 2015 at the Septimus gas facility whereby the facility is tied into a condensate sales pipeline. The Company expects condensate trucking costs to decrease further once construction of the Pine River pipeline is completed in 2016 allowing condensate production from West Septimus to be pipeline connected to the LACT unit.

Transportation costs per unit increased in 2015 as compared to 2014 as a result of the 2014 Dispositions that yielded lower transportation costs per unit, the aforementioned additional costs to transport West Septimus condensate and the new Alliance pipeline transportation charges. The Company expects transportation costs per boe to range between $2.50 and $2.80 per boe for 2016.

Operating Netbacks

($/boe)	**Three months ended December 31, 2015**	Three months ended December 31, 2014	**Year ended December 31, 2015**	Year ended December 31, 2014
Revenue	**18.13**	37.65	**22.74**	48.15
Royalties	**(1.23)**	(6.46)	**(2.01)**	(9.35)
Realized commodity hedging gain/(loss)	**5.82**	1.83	**6.05**	(2.63)
Operating costs	**(6.89)**	(9.79)	**(8.31)**	(10.77)
Transportation costs	**(1.96)**	(1.73)	**(1.90)**	(1.51)
Operating netbacks	**13.87**	21.50	**16.57**	23.89

Operating netbacks for the fourth quarter and year ended December 31, 2015 decreased over the same periods in 2014 as a result of the significant decline in the Company's realized pricing and increase in transportation costs. This was partially offset by realized hedging gains from the Company's risk management program and lower royalty and operating costs in the current period.

General and Administrative Costs

($ thousands, except per boe)	**Three months ended December 31, 2015**	Three months ended December 31, 2014	**Year ended December 31, 2015**	Year ended December 31, 2014
Gross costs	**3,715**	7,392	**19,710**	29,636
Operator's recoveries	**(219)**	(329)	**(544)**	(631)
Capitalized costs	**(800)**	(2,680)	**(5,986)**	(9,969)
General and administrative expenses	**2,696**	4,383	**13,180**	19,036
Per boe	**1.42**	2.28	**1.95**	2.15

In the fourth quarter of 2015 and for the year ended December 31, 2015, gross and net (after recoveries and capitalized costs) general and administrative costs and costs per boe have decreased as compared to the same periods in 2014 due to reduced staffing levels as a result of the 2014 Dispositions and a reduction in the Company's compensation program prompted by the substantial decline in commodity prices. Crew forecasts the general and administrative costs per boe to average between $1.40 and $1.60 in 2016.

Share-Based Compensation

($ thousands)	**Three months ended December 31, 2015**	Three months ended December 31, 2014	**Year ended December 31, 2015**	Year ended December 31, 2014
Gross costs	**2,852**	3,404	**14,577**	13,437
Capitalized costs	**(1,349)**	(2,073)	**(6,995)**	(6,889)
Total share-based compensation	**1,503**	1,331	**7,582**	6,548

In the fourth quarter of 2015, the Company's share-based compensation expense slightly increased compared to the same period in 2014 due to lower capitalized costs from reduced capital activity in the period. For the year ended December 31, 2015, the Company's share-based compensation expense has increased compared to the same period in 2014 from additional compensation expense recorded in the first quarter of 2015, which was due to an increase in the performance multiplier applied to performance awards recognizing the Company's positive 2014 performance.

Depletion and Depreciation

($ thousands, except per boe)	**Three months ended December 31, 2015**	Three months ended December 31, 2014	**Year ended December 31, 2015**	Year ended December 31, 2014
Depletion and depreciation	**20,234**	31,184	**93,084**	158,835
Per boe	**10.62**	16.24	**13.75**	17.98

In the fourth quarter of 2015, depletion and depreciation costs and costs per boe decreased as compared to the same period in 2014 as a result of increased proved plus probable reserve bookings from the Company's successful Montney drilling and completion program combined with the lower book value on the Lloydminster CGU from the impairment write-down taken in the third quarter of 2015. For the 2015 year, depletion costs and costs per boe were lower due to the removal of higher depletion rate assets from the property, plant and equipment from the 2014 Dispositions combined with the aforementioned Lloydminster impairment and increased proved plus probable reserve bookings from the year-end third party reserve report.

Impairment

During the third quarter of 2015, as a result of the significantly lower commodity price environment, management updated the 2014 year end external reserve report with the third party price forecast and management's best estimates of changes in the operations of the Company. These estimates were used in performing an impairment assessment on the Company's CGUs at September 30, 2015. A decrease in the WTI and WCS future oil price and AECO natural gas price forecasts as compared to those used in the December 31, 2014 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.

At December 31, 2015, with an updated external reserve report and further weakening of the commodity price environment, the Company tested its CGUs for impairment and it was determined that the carrying value approximated the value in use and therefore no additional impairment existed.

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, 2015**	Three months ended December 31, 2014	**Year ended December 31, 2015**	Year ended December 31, 2014
Interest on bank loan	**825**	554	**3,452**	7,422
Interest on senior notes	**3,166**	3,166	**12,562**	12,562
Accretion of deferred financing charges	**115**	155	**569**	487
Accretion of the decommissioning obligation	**418**	575	**1,841**	2,836
Total finance expense	**4,524**	4,450	**18,424**	23,307
Average debt level	**196,783**	165,009	**201,585**	285,176
Average drawings on bank loan	**46,783**	15,009	**51,585**	135,176
Effective interest rate on bank loan	**7.0%**	14.6%	**6.7%**	5.4%
Effective interest rate on senior notes	**8.4%**	8.4%	**8.4%**	8.4%
Effective interest rate on long-term debt	**8.0%**	9.0%	**7.9%**	7.0%
Interest on long-term debt per boe	**2.16**	2.02	**2.45**	2.32

For the fourth quarter of 2015, average debt levels increased over the same period in 2014 as a result of the Company's active capital program during the year which the Company partially funded with the proceeds from the Princess Disposition received at the end of the third quarter of 2014. Average debt levels for 2015 decreased over the same period in 2014 as a result of the common share issuances discussed below in the *Share Capital* section combined with proceeds from the disposition of the Lloydminster heavy oil properties and the disposition of 50% of the gas processing facility discussed in the *Capital Expenditures* section below. The effective interest rate on the bank loan was lower in the fourth quarter of 2015 as compared to the same period in 2014, due to lower standby fees incurred on the Company's bank facility in the fourth quarter of 2015 resulting from increased drawings on a reduced available facility. For the year ended December 31, 2015, the effective interest rate on the bank loan was higher as compared to the same period in 2014 due to higher standby fees incurred on the Company's bank facility throughout 2015 resulting from decreased drawings on the facility. Crew forecasts the effective interest rate on it long-term debt to average between 6.5% and 8.5% for 2016.

Deferred Income Taxes

In the fourth quarter of 2015, the provision for deferred taxes was a recovery of $1.0 million compared to a recovery of $9.0 million for the same period in 2014. The reduced recovery is a result of a higher pre-tax loss experienced during the fourth quarter of 2014 due to impairment charges incurred in the quarter. For the year ended December 31, 2015, the provision for deferred taxes was a recovery of $11.8 million compared to a recovery of $116.0 million for 2014. The higher recovery in 2014 was a result of the Company having an increased pre-tax loss related to the loss recorded on the Princess Disposition in 2014 and reduced property impairment charges in 2015.

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

($ thousands)	**December 31, 2015**	December 31, 2014
Cumulative Canadian Exploration Expense	**250,500**	200,700
Cumulative Canadian Development Expense	**433,400**	453,500
Undepreciated Capital Cost	**212,900**	172,400
Non-capital losses	**21,500**	21,500
Share issue costs	**6,300**	3,900
	924,600	852,000

The estimated income tax pools for 2015 have been reduced by qualifying exploration expenditures renounced in 2014 under the flow-through share offering as well as the estimated deferred partnership income for 2015. The Company did not pay cash taxes in 2015 and estimates it has sufficient tax pools to shelter estimated income until 2017 or beyond.

Cash, Funds from Operations and Net Income

($ thousands, except per share amounts)	**Three months ended December 31, 2015**	Three months ended December 31, 2014	**Year ended December 31, 2015**	Year ended December 31, 2014
Cash provided by operating activities	**12,373**	37,714	**74,698**	169,207
Funds from operations	**19,601**	33,035	**82,363**	171,592
Per share -basic	**0.14**	0.27	**0.60**	1.40
-diluted	**0.14**	0.27	**0.60**	1.39
Net loss	**(8,167)**	(28,424)	**(55,355)**	(349,714)
Per share -basic	**(0.06)**	(0.23)	**(0.40)**	(2.86)
-diluted	**(0.06)**	(0.23)	**(0.40)**	(2.86)

The decrease in cash provided by operating activities and funds from operations in the fourth quarter of 2015 and full 2015 year as compared to the same periods in 2014 was a result of reduced income from the 2014 Dispositions and the decline in Lloydminster production and lower 2015 commodity prices partially offset by an increase in Septimus and West Septimus area production. The decreased net loss in 2015 was a result of the losses incurred on the 2014 Dispositions and reduced property impairment charges in 2015 as compared to the same period in 2014.

Capital Expenditures, Property Acquisitions and Dispositions

During the fourth quarter of 2015, the Company drilled six (6.0 net) wells resulting in five (5.0 net) natural gas wells and one (1.0 net) dry and abandoned well. The Company also completed seven (6.0 net) wells and recompleted eight (7.5 net) wells in the quarter. In addition, during the fourth quarter the Company spent $20.7 million on infrastructure upgrades in northeast British Columbia, which included the Pine River pipeline project.

In 2015, the Company drilled a total of 33 (31.4 net) wells resulting in 8 (8.0 net) oil wells, 24 (22.4 net) gas wells, and one (1.0 net) dry and abandoned stratigraphic test well. During the year, the Company completed 32 (31.0 net) wells and recompleted 48 (43.9 net) wells. Crew's infrastructure spending was predominantly related to the West Septimus facility as well as the Pine River pipeline connecting the Septimus and West Septimus facilities and various other pipeline, battery and well equipping projects in northeast British Columbia.

In 2015, the Company closed the disposition of certain Lloydminster heavy oil properties. Consideration consisted of $50.1 million and the disposition included production of approximately 225 boe per day and 11,670 net acres of land. In addition, the Company completed a non-cash land swap with the Province of British Columbia in which Crew received 53 net sections of land contiguous to its existing land base in exchange for 66 net sections of undeveloped land situated within the Peace Moberly Tract.

During the fourth quarter of 2015, the Company sold 50% of its working interest in a gas processing facility in northeast British Columbia. The disposed interest in the facility had a net book value of $37.8 million, and associated decommissioning obligations of $0.9 million. As part of this transaction, the Company equalized the working interests of the remaining partner in the Septimus and West Septimus facilities ("Septimus Complex"). As a result of the disposition and equalization, Crew retained a 28% working interest in the Septimus Complex and the Company may re-purchase the other party's equalized interest in 2020, for a pre-determined cost, if either party exercises its option.

Total net capital expenditures are detailed below:

($ thousands)	**Three months ended December 31, 2015**	Three months ended December 31, 2014	**Year ended December 31, 2015**	Year ended December 31, 2014
Land	**984**	920	**3,034**	4,150
Seismic	**2,973**	1,516	**8,861**	5,985
Drilling and completions	**16,529**	61,406	**114,189**	231,100
Facilities, equipment and pipelines	**20,665**	14,748	**113,842**	54,463
Other	**916**	2,857	**6,492**	11,077
Total exploration and development	**42,067**	81,447	**246,418**	306,775
Property acquisitions (dispositions)	**(36,644)**	1,901	**(85,441)**	(252,478)
Total	**5,423**	83,348	**160,977**	54,297

The Company's Board of Directors has approved a $70 million exploration and development budget for 2016.

LIQUIDITY AND CAPITAL RESOURCES

Capital Funding

The Company has a credit facility with a syndicate of lending banks (the "Syndicate") which includes a revolving line of credit of $220 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, 2016. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 percent and all outstanding balances under the Facility 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 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 under 4:1 and a secured debt to EBITDA ratio under 3:1 at the end of each fiscal quarter. At December 31, 2015, these ratios were 2.3:1 and 0.8:1, respectively. EBITDA is a non-GAAP measure and 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 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. 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, 2016. At December 31, 2015, the Company had drawings of $81.0 million on the Facility and had issued letters of credit totaling $7.8 million.

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. Prior to October 21 2016, the Company may redeem up to 35% of the aggregate principal amount with the cash proceeds from certain equity issues at a redemption price of 108.375%, plus accrued and unpaid interest. In addition, at any time prior to October 21, 2016, the Company may redeem all or part of the notes at a price equal to 100% of the principal amount plus a "make-whole" premium and any accrued and unpaid interest. At any time on or after October 21, 2016, 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.

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. The Company maintains sufficient unused bank credit lines to satisfy working capital deficiencies. At December 31, 2015, the Company's working capital deficiency totaled $10.7 million which, when combined with the drawings on its bank loan, represented 37% of its bank facility at December 31, 2015.

Share Capital

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.

During 2014, the Company closed a non-brokered private placement offering of 944,524 common shares at a price of $12.60 per share for gross proceeds of $11.9 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 $3.0 million. Pursuant to the provisions of the Income Tax Act (Canada), the Company renounced to the subscribers Canadian Exploration Expenses incurred by the Company after September 26, 2014 and prior to December 31, 2015 totaling $11.9 million. The Company renounced the Canadian Exploration Expenses such that the full proceeds were deductible against the subscribers' income for the fiscal year ended December 31, 2014. At December 31, 2015, the Company has incurred the entire $11.9 million in qualifying expenditures under this flow-through share offering.

Crew is authorized to issue an unlimited number of common shares. As at March 3, 2016, there were 141,071,097 common shares and options to acquire 3,689,106 common shares of the Company issued and outstanding. In addition, there were 1,066,443 restricted awards and 1,531,758 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, 2015.

Capital Structure

The Company considers its capital structure to include working capital, the bank loan, the 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 on-going basis in order to maintain the flexibility needed to achieve the Company's long-term objectives. To manage the capital structure the Company may adjust capital spending, hedge future revenue and costs, issue new equity, issue new debt, amend, revise or extend the terms of the existing bank facility 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 the Company's bank loan, senior unsecured notes and net working capital, divided by annualized funds from operations for the most recent quarter.

The Company monitors this ratio and strives 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. As shown below, as at December 31, 2015, the Company's ratio of net debt to annualized funds from operations was 3.04 to 1 (December 31, 2014 – 1.92 to 1). In 2015, as a result of the significant decline in commodity prices, the Company increased its financial flexibility through the issuance of additional common shares and the strategic divestiture of non-core properties. The Company plans to closely monitor commodity prices and, if felt necessary to maintain a strong financial position, will continue its strategy of divesting of non-core properties, will adjust its annual capital expenditure program or may consider other forms of financing.

($ thousands, except ratio)	**December 31, 2015**	December 31, 2014
Working capital deficit	**(10,737)**	(57,722)
Bank loan	**(80,980)**	(49,904)
Senior unsecured notes	**(146,679)**	(146,110)
Net debt	**(238,396)**	(253,736)
Fourth quarter funds from operations	**19,601**	33,035
Annualized	**78,404**	132,140
Net debt to annualized funds from operations ratio	**3.04**	1.92

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	2016	2017	2018	2019	2020	Thereafter
Bank Loan (note 1)	80,980	-	80,980	-	-	-	-
Senior unsecured notes	150,000	-	-	-	-	150,000	-
Operating leases	6,750	1,658	1,175	1,175	1,175	1,175	392
Firm transportation agreements	164,893	30,658	29,347	29,686	29,406	26,224	19,572
Firm processing agreements	64,659	13,361	13,325	13,325	13,325	11,323	-
Total	467,282	45,677	124,827	44,186	43,906	188,722	19,964

(1) Based on the existing terms of the Company's bank facility the first possible repayment date may come in 2017. However, it is expected that the revolving bank facility will be extended and no repayment will be required in the near term.

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

The firm transportation agreements include commitments to third parties to transport natural gas and natural gas liquids from gas processing facilities in northeastern British Columbia.

The firm processing agreements include commitments to process natural gas through third party owned gas processing facilities in northeastern British Columbia.

GUIDANCE

Through 2016, Crew will continue to prioritize the preservation of its balance sheet strength while managing production volumes to optimize netbacks. The Company's 2016 capital budget is currently set at $70 million but the Company intends to closely monitor the impact of weak commodity prices on its business and will further adjust capital spending, if necessary, to approximate funds from operations. Crew is anticipating growth in annual average production of approximately 25% year over year as a result of the additional production capacity in the new West Septimus gas plant and an active 2015 drilling program. Crew's 2016 drilling and development capital will continue to be allocated to higher rate of return areas focused at West Septimus and Septimus, where further investment is supported under current commodity prices. The Company remains committed to Montney development and currently plans to complete and bring on-stream the inventory of 15 wells that were drilled in 2015, as well as drill, complete and tie-in seven (6.3 net) additional wells in 2016.

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 2015**	Sept 30 2015	June 30 2015	Mar. 31 2015	Dec. 31 2014	Sep. 30 2014	June 30 2014	Mar. 31 2014
Total daily production (boe/d)		**20,706**	16,773	17,656	19,035	20,869	20,846	27,200	28,021
Exploration and development expenditures		**42,067**	58,565	54,694	91,092	81,447	106,405	52,783	66,140
Property acquisitions/ (dispositions)		**(36,644)**	(50,281)	1,226	258	1,901	(141,796)	(215,115)	102,532
Average wellhead price ($/boe)		**18.13**	22.54	27.81	23.31	37.65	50.51	50.86	51.69
Petroleum and natural gas sales		**34,532**	34,784	44,678	39,940	72,295	96,879	125,882	130,368
Cash provided by operations		**12,373**	22,091	23,013	17,221	37,714	37,566	43,589	50,338
Funds from operations		**19,601**	17,273	24,769	20,720	33,035	39,023	47,724	51,810
Per share	-basic	**0.14**	0.12	0.18	0.16	0.27	0.32	0.39	0.43
	-diluted	**0.14**	0.12	0.18	0.16	0.27	0.31	0.38	0.42
Net income (loss)		**(8,167)**	(18,179)	(13,239)	(15,770)	(28,424)	(195,389)	3,792	(129,693)
Per share	-basic	**(0.06)**	(0.13)	(0.09)	(0.12)	(0.23)	(1.60)	0.03	(1.07)
	-diluted	**(0.06)**	(0.13)	(0.09)	(0.12)	(0.23)	(1.60)	0.03	(1.07)

Beginning in 2014, Crew embarked on a plan to refocus the Company towards its Montney assets in northeast British Columbia. The new focus began with the 2014 Dispositions which resulted in the sale of a significant portion of the Company's existing production and the realization of losses on the sale of these properties. The proceeds from these sales have been used over the past two years to partially fund organic Montney production growth through the Company's exploration and development program.

During the past two years, the oil and gas industry has seen a significant decrease in commodity prices that has also negatively impacted revenue. The impact of this has reduced cash provided by operations, funds from operations and net income. The substantial and ongoing decline in commodity prices has also led to the assessment and realization of impairment of the carrying value of certain CGUs. In 2015, the Company incurred $55.4 million in impairment charges and in 2014, the Company also incurred $233.7 million of impairment charges. These losses have been partially offset by gains from the Company's risk management program over the periods.

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

($ thousands, except per share amounts)	**Year ended Dec. 31, 2015**	Year ended Dec. 31, 2014	Year ended Dec. 31, 2013
Petroleum and natural gas sales	**153,934**	425,424	430,627
Cash provided by operations	**74,698**	169,207	161,949
Funds from operations	**82,363**	171,592	172,438
Per share -basic	**0.60**	1.40	1.42
-diluted	**0.60**	1.39	1.42
Net income (loss)	**(55,355)**	(349,714)	(79,311)
Per share -basic	**(0.40)**	(2.86)	(0.65)
-diluted	**(0.40)**	(2.86)	(0.65)
Daily production (boe/d)	**18,542**	24,205	27,451
Crew average sales price ($/boe)	**22.74**	48.15	42.98
Total assets	**1,244,283**	1,225,065	1,843,027
Working capital deficiency (1)	**10,737**	57,722	40,098
Bank loan	**80,980**	49,904	197,688
Senior unsecured notes	**146,679**	146,110	145,623
Total other long-term liabilities	**132,711**	143,344	280,945

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

Over the last three years, a significant decrease in commodity prices has negatively impacted revenue, cash provided by operations, funds from operations and net income. The decline in forecasted future commodity prices has also led to the assessment and realization of impairment charges on certain CGUs from 2013 to 2015. The substantial decrease in the Company's total assets and other long-term liabilities from 2013 to 2014 was the result of the 2014 Dispositions as part of the refocus on Crew's Montney assets and net impairment charges in 2013 of $71.3 million and the 2014 impairment charges as referenced above.

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 11 Joint Arrangements:

As of January 1, 2016, the Company will be required to adopt amendments to IFRS-11 Joint Arrangements. The amendments to this standard will require entities acquiring an interest in a joint operation to apply the principles of IFRS-3 as it relates to business combinations. As of December 31, 2015 the new standard has been adopted, it is not anticipated to have a material impact on the Company.

(b) IFRS 15 Revenue from Contracts with Customers:

As of January 1, 2017, 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, 2015 Crew is still determining the impact that the adoption of this standard will have on its financial statements.

(c) 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, 2015 Crew is still determining the impact that the adoption of this standard will have on its financial statements.

(d) 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 January 1, 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, 2015 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, 2015 and ended on December 31, 2015 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 3, 2016

MANAGEMENT’S REPORT

Management, in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, has prepared the accompanying consolidated financial statements of Crew Energy Inc. 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 of Crew’s internal control systems as they considered necessary and included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with International Financial Reporting Standards.

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 3, 2016

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, 2015 and December 31, 2014, 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, 2015 and December 31, 2014, 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
Calgary, Canada
March 3, 2016

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(thousands)	**December 31, 2015**	December 31, 2014
Assets		
Current Assets:		
Accounts receivable	**$ 26,697**	$ 35,393
Marketable securities (note 6)	**1,160**	2,052
Derivative financial instruments (note 13)	**6,560**	41,024
	34,417	78,469
Property, plant and equipment (note 7)	**1,209,866**	1,146,596
	$ 1,244,283	$ 1,225,065
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 37,434**	$ 93,115
Derivative financial instruments (note 13)	**783**	2,222
	38,217	95,337
Derivative financial instruments (note 13)	**300**	736
Bank loan (note 9)	**80,980**	49,904
Senior unsecured notes (note 10)	**146,679**	146,110
Decommissioning obligations (note 11)	**85,822**	82,836
Deferred premium on flow-through shares (note 12)	**-**	2,402
Deferred tax liability (note 14)	**46,589**	57,370
Shareholders' Equity		
Share capital (note 12)	**1,398,698**	1,292,693
Contributed surplus	**77,627**	72,951
Deficit	**(630,629)**	(575,274)
	845,696	790,370
Commitments (note 17)		
Subsequent event (note 13)		
	$ 1,244,283	$ 1,225,065

See accompanying notes to the consolidated financial statements.

On behalf of the Board

(signed)

David G. Smith
Director

(signed)

Dennis L. Nerland
Director

CONSOLIDATED STATEMENTS OF LOSS AND COMPREHENSIVE LOSS

(thousands, except per share amounts)	**Year ended December 31, 2015**	Year ended December 31, 2014
Revenue		
Petroleum and natural gas sales	**$ 153,934**	$ 425,424
Royalties	**(13,611)**	(82,621)
Realized gain (loss) on derivative financial instruments (note 13)	**40,929**	(23,262)
Unrealized gain (loss) on derivative financial instruments (note 13)	**(32,589)**	53,406
	148,663	372,947
Expenses		
Operating	**56,242**	95,128
Transportation	**12,884**	13,314
General and administrative	**13,180**	19,036
Share-based compensation	**7,582**	6,548
Depletion and depreciation	**93,084**	158,835
	182,972	292,861
Income (loss) from operations	**(34,309)**	80,086
Financing (note 16)	**18,424**	23,307
Unrealized loss on marketable securities (note 6)	**892**	948
Impairment on property, plant and equipment (note 8)	**55,376**	233,719
Loss (gain) on divestiture of property, plant and equipment (note 7)	**(41,877)**	287,836
Loss before income taxes	**(67,124)**	(465,724)
Deferred tax recovery (note 14)	**(11,769)**	(116,010)
Net loss and comprehensive loss	**$ (55,355)**	$ (349,714)
Net loss per share (note 12)		
Basic	**$ (0.40)**	$ (2.86)
Diluted	**$ (0.40)**	$ (2.86)

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, 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 of share-based compensation on exercise of 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

	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 2014	121,635	$1,275,910	$ 63,106	$ (225,560)	$ 1,113,456
Net loss	-	-	-	(349,714)	(349,714)
Share-based compensation expensed	-	-	6,548	-	6,548
Share-based compensation capitalized	-	-	6,889	-	6,889
Transfer of share-based compensation on exercise of options	-	1,883	(1,883)	-	-
Issued on exercise of options	605	4,271	-	-	4,271
Issued on vesting of share awards	244	1,709	(1,709)	-	-
Issued on private placement of flow-through shares	945	11,901	-	-	11,901
Deferred premium on flow-through shares	-	(2,961)	-	-	(2,961)
Share issue costs, net of tax of $6	-	(20)	-	-	(20)
Balance December 31, 2014	123,429	$1,292,693	$ 72,951	$ (575,274)	$ 790,370

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands)	Year ended December 31, 2015	Year ended December 31, 2014
Cash provided by (used in):		
Operating activities:		
Net loss	**$ (55,355)**	$ (349,714)
Adjustments:		
Unrealized (gain) loss on derivative financial instruments	**32,589**	(53,406)
Share-based compensation	**7,582**	6,548
Depletion and depreciation	**93,084**	158,835
Financing expenses	**18,424**	23,307
Interest expense (note 16)	**(16,014)**	(19,984)
Unrealized loss on marketable securities	**892**	948
Impairment of property, plant and equipment	**55,376**	233,719
(Gain) loss on divestiture of property, plant and equipment	**(41,877)**	287,836
Deferred tax recovery	**(11,769)**	(116,010)
Decommissioning obligations settled (note 11)	**(736)**	(768)
Change in non-cash working capital (note 15)	**(7,498)**	(2,104)
	74,698	169,207
Financing activities:		
Increase (decrease) in bank loan	**31,076**	(147,784)
Proceeds from exercise of options	**157**	4,271
Proceeds from issuance of flow-through shares	**-**	11,901
Proceeds from issuance of common shares	**100,002**	-
Share issue costs	**(5,469)**	(26)
	125,766	(131,638)
Investing activities:		
Property, plant and equipment expenditures	**(246,418)**	(306,775)
Property acquisitions	**(1,607)**	(138,868)
Property dispositions	**87,048**	388,346
Change in non-cash working capital (note 15)	**(39,487)**	19,728
	(200,464)	(37,569)
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, 2015 and 2014

(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, 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 issue by the Board of Directors on March 3, 2016.

3. Significant accounting policies:

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

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

(a) Basis of consolidation:

(i) Subsidiaries:

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

(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 issue 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 expenditures:

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

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

Exploration and evaluation 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, exploration and evaluation 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 exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation 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 income in the period measured. Non-current assets and disposal groups held for sale are presented in current assets and liabilities on the statement of financial position.

(e) Leased assets:

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 the finance expenses and the reduction of the outstanding liability. The finance expenses are allocated to each year during the lease term so as 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 exploration and evaluation 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 cash-generating units

Crew's assets are aggregated into cash-generating units, 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 11 Joint Arrangements:

As of January 1, 2016, the Company will be required to adopt amendments to IFRS-11 Joint Arrangements. The amendments to this standard will require entities acquiring an interest in a joint operation to apply the principles of IFRS-3 as it relates to business combinations. As of January 1, 2016 the new standard has been adopted and is not anticipated to have a material impact on the Company.

(b) IFRS 15 Revenue from Contracts with Customers:

As of January 1, 2017, 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, 2015 Crew is still determining the impact that the adoption of this standard will have on its financial statements.

(c) 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, 2015 Crew is still determining the impact that the adoption of this standard will have on its financial statements.

(d) 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, 2015 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, 2015 and December 31, 2014, 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, 2015 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 holds 1,415,094 common shares of a public company trading on the TSX Venture Exchange. The shares were valued at $1.45 per common share for a total value of $2.1 million at December 31, 2014. As at December 31, 2015 the fair market value of the marketable securities was $0.82 per common share for a total value of approximately $1.2 million, which resulted in an unrealized loss of $0.9 million (December 31, 2014 - $0.9 million unrealized loss) being recorded in the Company's financial statements for the year ended December 31, 2015.

7. Property, plant and equipment:

Cost or deemed cost	Total
Balance, January 1, 2014	$ 2,705,206
Additions	306,775
Acquisitions	155,750
Divestitures	(1,335,760)
Change in decommissioning obligations	12,176
Capitalized share-based compensation	6,889
Balance, December 31, 2014	$ 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**

Accumulated depletion and depreciation	Total
Balance, January 1, 2014	$ 927,612
Depletion and depreciation expense	158,835
Divestitures	(615,726)
Impairment (net)	233,719
Balance, December 31, 2014	$ 704,440
Depletion and depreciation expense	93,084
Divestitures	(908)
Impairment (net)	55,376
Balance, December 31, 2015	**$ 851,992**

Net book value	Total
Balance, December 31, 2015	**$ 1,209,866**
Balance, December 31, 2014	$ 1,146,596

The calculation of depletion for the three months ended December 31, 2015 included estimated future development costs of $1,316.2 million (December 31, 2014 - $1,295.7 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $64.0 million (December 31, 2014 - $67.1 million) and undeveloped land of $218.9 million (December 31, 2014 - $218.1 million) related to future development acreage.

During the third quarter of 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.

During the fourth quarter of 2015, the Company sold 50% of its working interest in a gas processing facility in northeast British Columbia. The disposed interest in the facility had a net book value of $37.8 million, and associated decommissioning obligations of $0.9 million. As part of this transaction, the Company equalized the working interests of the remaining partner in the Septimus and West Septimus facilities ("Septimus Complex"). As a result of the disposition and equalization, Crew retained a 28% working interest in the Septimus Complex and the Company may re-purchase the other party's equalized interest in 2020, for a pre-determined cost, if either party exercises its option.

8. Impairment:

	Year Ended December 31, 2015	Year Ended December 31, 2014
Impairment losses:		
PP&E	**$ 55,376**	$ 80,180
Assets held for sale	**-**	153,539
	$ 55,376	$ 233,719

Assessment:

At December 31, 2015 and 2014, the Company tested its CGUs for impairment as well as the potential reversal of prior period impairments where indicators were present. 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. During 2015, the Company used pre-tax discount rates between 10% and 25% dependent on the risk profile of the reserve category. In prior years Crew used fair value less costs to sell, discounted at a pre-tax rate of 10%, to calculate impairment; however, in 2015, value in use has been determined to be the appropriate measure for the current period due to a lack of comparable market metrics.

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 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
2016	45.00	45.26	2.25	0.75
2017	60.00	57.96	2.95	0.80
2018	70.00	65.88	3.42	0.83
2019	80.00	75.11	3.91	0.85
2020	81.20	77.03	4.20	0.85
2021	82.42	78.19	4.28	0.85
2022	83.65	79.36	4.35	0.85
2023	84.91	80.55	4.43	0.85
2024	86.18	81.76	4.51	0.85
2025	87.48	82.99	4.59	0.85
2026	88.79	84.23	4.67	0.85
Remainder	+1.5%/yr	+1.5%/yr	+1.5%/yr	0.85 thereafter

During the third quarter of 2015, as a result of the significantly lower commodity price environment, management updated the 2014 year end external reserve report with the third party price forecast and management's best estimates of changes in the operations of the Company. These estimates were used in performing an impairment assessment on the Company's CGUs at September 30, 2015. A decrease in the West Texas Intermediate ("WTI") and Western Canadian Select ("WCS") future oil price and AECO natural gas price forecasts as compared to those used in the December 31, 2014 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.

At December 31, 2015, with an updated external reserve report and further weakening of the commodity price environment, the Company tested its CGUs for impairment and it was determined that the carrying value approximated the value in use for all CGUs and therefore no additional impairment existed.

(b) Results of 2014 assessment:

The following estimates were used in determining whether an impairment or reversal to the carrying value of the CGUs existed at December 31, 2014:

	WTI Oil (US$/bbl)	WCS ($Cdn/bbl)	AECO Gas ($Cdn/mmbtu)	$Cdn/$US
2015	65.00	60.50	3.32	0.85
2016	80.00	75.13	3.71	0.87
2017	90.00	84.52	3.90	0.87
2018	91.35	85.79	4.47	0.87
2019	92.72	87.07	5.05	0.87
2020	94.11	89.31	5.13	0.87
2021	95.52	90.65	5.22	0.87
2022	96.96	92.01	5.31	0.87
2023	98.41	93.39	5.40	0.87
2024	99.89	94.79	5.49	0.87
2025	101.38	96.21	5.58	0.87
Remainder	+1.5%/yr	+1.5%/yr	+1.5%/yr	0.87 thereafter

At December 31, 2014, it was determined that indicators of impairment existed and impairment tests were performed on the Company's CGUs. The decrease in the WCS price estimate, as well as negative technical reserve revisions resulting from lower than expected performance from certain heavy oil wells, resulted in the carrying value of the Lloydminster heavy oil CGU exceeding its recoverable amount and an $80.2 million impairment charge was recorded. During 2014, the assets included in the Alberta Gas Disposition were classified as held for sale and hence tested for impairment. As a result of the test, it was determined that the carrying value of the assets exceeded the fair value less costs to sell of $260.1 million and a $153.5 million impairment charge was recorded. A one per cent increase in the assumed discount rate would result in an additional impairment of $6.3 million.

9. Bank loan:

The Company's bank facility as at December 31, 2015 consisted of a revolving line of credit of $220 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, 2016. 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 under 4:1 and a secured debt to EBITDA ratio under 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, 2015, these ratios were 2.3:1 and 0.8:1, respectively. EBITDA is a non-GAAP measure and 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. 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, 2016. 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 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, 2015, the Company's applicable pricing included a 1.0 percent margin on prime lending and a 2.0 percent stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.50 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, 2015, the Company had issued letters of credit totaling $7.8 million (December 31, 2014 - $2.4 million). The effective interest rate on the Company's borrowings under its bank facility for the year ended December 31, 2015 was 6.7% (2014 – 5.4%).

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. Prior to October 21, 2016, the Company may redeem up to 35% of the aggregate principal amount, with the cash proceeds from certain equity issues, at a redemption price of 108.375%, plus accrued and unpaid interest. In addition, at any time prior to October 21, 2016, the Company may redeem all or part of the notes at a price equal to 100% of the principal amount plus a "make-whole" premium and any accrued and unpaid interest. At any time on or after October 21, 2016, 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, 2015, the carrying value of the senior unsecured notes was net of deferred financing costs of $3.3 million (December 31, 2014 - $3.9 million).

11. Decommissioning obligations:

	As at December 31, 2015	As at December 31, 2014
Decommissioning obligations, beginning of year	**$ 82,836**	$ 108,118
Obligations incurred	**6,696**	6,134
Obligations acquired	**-**	16,882
Obligations settled	**(736)**	(768)
Obligations divested	**(6,159)**	(56,408)
Change in estimated future cash outflows	**1,344**	6,042
Accretion of decommissioning obligations	**1,841**	2,836
Decommissioning obligations, end of year	**$ 85,822**	$ 82,836

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 $85.8 million as at December 31, 2015 (December 31, 2014 - $82.8 million) based on an inflation adjusted undiscounted total future liability of $113.9 million (December 31, 2014 - $108.7 million). These payments are expected to be made over the next 25 years with the majority of costs to be incurred between 2020 and 2035. The inflation rate applied to the liability is 2% (2014 – 2%). The discount factor, being the risk-free rate related to the liability, is 2.03% (December 31, 2014 – 2.24%). The $1.3 million (December 31, 2014 - $6.0 million) change in estimated future cash outflows is a result of the change in the discount factor.

12. Share capital:

At December 31, 2015, the Company was authorized to issue an unlimited number of common shares with the holders of common shares entitled to one vote per share.

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

During 2014, the Company closed a non-brokered private placement offering of 944,524 common shares at a price of $12.60 per share for gross proceeds of $11.9 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 $3.0 million. Pursuant to the provisions of the Income Tax Act (Canada), the Company is committed to renounce to the subscribers Canadian Exploration Expenses incurred by the Company after September 26, 2014 and prior to December 31, 2015 totaling $11.9 million. The Company renounced the Canadian Exploration Expenses such that the full proceeds was deductible against the subscribers' income for the fiscal year ended December 31, 2014. At December 31, 2015, the Company has incurred the entire $11.9 million in qualifying expenditures under this flow-through share offering.

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, 2014	7,978	$ 9.03
Granted	5	$ 7.25
Exercised	(605)	$ 7.06
Forfeited	(626)	$ 9.03
Expired	(1,546)	$ 14.48
Balance December 31, 2014	5,206	$ 7.65
Exercised	(28)	$ 5.65
Forfeited	(593)	$ 9.06
Expired	(802)	$ 12.04
Balance December 31, 2015	**3,783**	**$ 6.51**

The weighted average trading price of the Company's common shares was $5.14 during the year ended December 31, 2015 (December 31, 2014 - $8.93).

The following table summarizes information about the stock options outstanding at December 31, 2015:

Range of exercise prices	Outstanding at Dec 31, 2015	Weighted average remaining life (years)	Weighted average exercise price	Exercisable at Dec 31, 2015	Weighted average exercise price
$ 5.16 to $ 7.01	2,180	0.5	$ 5.72	2,105	$ 5.70
$ 7.02 to $ 9.94	1,473	1.2	$ 7.18	978	$ 7.18
$ 9.95 to $13.03	130	0.1	$ 12.09	130	$ 12.09
	3,783	0.8	$ 6.51	3,213	$ 6.41

The fair value of the options was estimated using a Black Scholes model with the following weighted average inputs:

Assumptions	**Year ended December 31, 2015**	Year ended, December 31, 2014
Risk free interest rate (%)	-	1.3
Expected life (years)	-	4.0
Expected volatility (%)	-	43
Forfeiture rate (%)	-	15.6
Weighted average fair value of options	-	$ 2.57

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, 2015, the fair value of awards granted was calculated using an estimated forfeiture rate of 13% (December 31, 2014 – 9%). The weighted average fair value of awards granted for the year ended December 31, 2015 was $4.98 (December 31, 2014 - $11.44). 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 270,000 restricted awards and 348,000 performance awards, when taking into account the earned multipliers for performance awards, 943,000 common shares of the Company were issued for the year ended December 31, 2015. 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, 2014	296	320
Granted	732	901
Vested	(91)	(102)
Forfeited	(178)	(151)
Balance December 31, 2014	759	968
Granted	730	1,041
Vested	(270)	(348)
Forfeited	(132)	(115)
Balance December 31, 2015	**1,087**	**1,546**

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, 2015 was 137,948,000 (December 31, 2014 – 122,395,000).

In computing diluted earnings per share for the year ended December 31, 2015, NIL (December 31, 2014 – 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 3,783,000 (December 31, 2014 – 5,206,000) stock options and 2,633,000 (December 31, 2014 – 1,727,000) 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, 2015	December 31, 2014
Trade and other receivables	**$ 26,697**	$ 35,393
Marketable securities	**1,160**	2,052
Derivative financial assets	**6,560**	41,024
	$ 34,417	$ 78,469

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 2015, three third party purchasers were responsible for at least 40% 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, 2015 the Company's receivables consisted of $18.5 million (December 31, 2014 - $21.4 million) of receivables from petroleum and natural gas marketers which has subsequently been collected, $3.9 million (December 31, 2014 - $5.8 million) from partners within jointly owned assets and operations of which $1.1 million has been subsequently collected, and $4.2 million (December 31, 2014 - $8.2 million) of deposits, prepaids and other accounts receivable, of which $2.6 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, 2015 was $51.6 million (December 31, 2014 - $135.2 million). For the year ended December 31, 2015, a 1.0 percent change to the effective interest rate would have a $0.4 million impact on net income (December 31, 2014 - $1.6 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 income.

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

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

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

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

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

At December 31, 2015, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Oil	500 bbl/day	January 1, 2016 – June 30, 2016	US$ WCS - WTI diff	$(14.95)	Swap	(188)
Oil	500 bbl/day	January 1, 2016 - December 31, 2016	CDN$ WTI	$116.50	Call	(15)
Oil	250 bbl/day	January 1, 2016 - December 31, 2016	CDN$ WTI	$78.25	Swap	1,908
Gas	20,000 gj/day	January 1, 2016 - December 31, 2016	AECO C Monthly Index	$2.60	Swap	1,387
Gas	2,500 gj/day	April 1, 2016 - October 31, 2016	AECO C Monthly Index	$2.14	Swap	(130)
Gas	20,000 mmbtu/day	January 1, 2016 - December 31, 2016	CDN$ Chicago Citygate	$3.79	Swap	2,440
Gas	5,000 mmbtu/day	January 1, 2016 – December 31, 2016	Nymex Henry Hub - AECO C ($US/mmbtu)	NYMEX minus US$-0.5025/mmbtu	Basis Swap(1)	375
Gas	2,500 gj/day	January 1, 2017 - December 31, 2017	AECO C Monthly Index	$2.73	Swap	(6)
Gas	5,000 gj/day	January 1, 2017 - December 31, 2017	AECO C Monthly Index	$2.90	Call Swaption(2)	(294)
Total						5,477

(1) Crew receives NYMEX Henry Hub "Last Day" Settlement minus applicable spread; Crew pays AECO C(US$/mmbtu)

(2) The referenced contract is a European call swaption, which the counterparty will accept or decline by December 22, 2016.

As at December 31, 2015, a 10% decrease to the price outlined in the contracts above would result in a $3.9 million increase in net income.

Subsequent to December 31, 2015, the Company entered into the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Gas	5,000 mmbtu/day	January 1, 2017 - December 31, 2017	CDN$ Chicago Citygate	$3.89	Swap
Gas	2,638 gj/day	February 1, 2016 - December 31, 2016	AECO C Monthly Index	$2.75	Swap
Gas	2,638 gj/day	April 1, 2016 – December 31, 2016	AECO C Monthly Index	$2.03	Swap

Subsequent to December 31, 2015, the Company unwound the following derivative commodity contracts for net proceeds of approximately $2.0 million:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Gas	2,500 mmbtu/day	February 1, 2016 - December 31, 2016	Nymex Henry Hub - AECO C ($US/mmbtu)	NYMEX minus US$-0.55/mmbtu	Basis Swap
Oil	250 bbl/day	February 1, 2016 - December 31, 2016	CDN$ WTI	$78.25	Swap
Gas	2,500 mmbtu/day	April 1, 2016 - December 31, 2016	Nymex Henry Hub - AECO C ($US/mmbtu)	NYMEX minus US$-0.46/mmbtu	Basis 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, that is subject to renewal annually 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 the 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, 2015, the Company's ratio of net debt to annualized funds from operations was 3.04 to 1 (December 31, 2014 – 1.92 to 1). As a result of the significant decline in commodity prices during the year, the Company increased its financial flexibility through the issuance of additional equity (Share Capital – note 12) and the strategic divesture of non-core properties. The Company plans to closely monitor commodity prices and, if felt necessary to maintain a strong financial position, will continue its strategy of divesting of non-core properties, will adjust its annual capital expenditure program or may consider other forms of financing.

	December 31, 2015	December 31, 2014
Net debt:		
Accounts receivable	**$ 26,697**	$ 35,393
Accounts payable and accrued liabilities	**(37,434)**	(93,115)
Working capital deficiency	**$ (10,737)**	$ (57,722)
Bank loan	**(80,980)**	(49,904)
Senior unsecured notes	**(146,679)**	(146,110)
Net debt	**$ (238,396)**	$ (253,736)
Fourth Quarter Annualized funds from operations:		
Cash provided by operating activities	**$ 12,373**	$ 37,714
Decommissioning obligations settled	**43**	249
Change in non-cash working capital	**7,300**	(4,773)
Accretion of deferred financing charges	**(115)**	(155)
Fourth Quarter Funds from operations	**$ 19,601**	$ 33,035
Annualized	**$ 78,404**	$ 132,140
Net debt to annualized funds from operations	**3.04**	1.92

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, 2015	Year ended December 31, 2014
Loss before income taxes	**$ (67,124)**	$ (465,724)
Combined federal and provincial income tax rate	**26.2%**	25.6%
Computed "expected" income tax recovery	**$ (17,559)**	$ (119,039)
Increase in income taxes resulting from:		
Non-deductible expenses	**2,494**	1,733
Change in income tax rates	**2,705**	1,015
Flow-through share renunciation	**2,576**	574
Other	**417**	266
	(9,367)	(115,451)
Premium on flow-through shares	**(2,402)**	(559)
Deferred income tax recovery	**$ (11,769)**	$ (116,010)

The income tax rate change is due to a change in the applied weighting of statutory provincial income tax rates and the increase in the Alberta provincial corporate tax rate from 10% to 12% in 2015.

(b) Deferred income tax liability:

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

	December 31, 2015	December 31, 2014
Deferred tax liabilities:		
Property, plant and equipment	**$ 74,036**	$ 74,756
Derivative financial instruments	**1,461**	9,730
Deferred tax assets:		
Decommissioning obligations	**$ (22,595)**	$ (21,245)
Non-capital losses	**(5,512)**	(5,488)
Other	**(801)**	(383)
Deferred income tax liability	**$ 46,589**	$ 57,370

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

	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

	January 1, 2014	Recognized in equity	Recognized in profit or loss	December 31, 2014
Property, plant and equipment	$ 210,387	$ -	$ (135,631)	$ 74,756
Decommissioning obligations	(27,472)	-	6,227	(21,245)
Derivative financial instruments	(3,898)	-	13,628	9,730
Non-capital losses	(5,464)	-	(24)	(5,488)
Other	(726)	(6)	349	(383)
	$ 172,827	$ (6)	$ (115,451)	$ 57,370

The Company's assets have an approximate tax basis of $925 million at December 31, 2015 (December 31, 2014 - $852 million) available for deduction against future taxable income. The following table summarizes the tax pools:

	December 31, 2015	December 31, 2014
Cumulative Canadian Exploration Expense	**$ 250,500**	$ 200,700
Cumulative Canadian Development Expense	**433,400**	453,500
Undepreciated Capital Costs	**212,900**	172,400
Non-capital losses	**21,500**	21,500
Share issue costs	**6,300**	3,900
Estimated tax basis	**$ 924,600**	$ 852,000

Non-capital losses will begin expiring in 2028. The estimated income tax pools for 2015 have been reduced by the estimated deferred partnership income for 2015.

15. Supplemental cash flow information:

Changes in non-cash working capital is comprised of:

	Year ended December 31, 2015	Year ended December 31, 2014
Changes in non-cash working capital:		
Accounts receivable	**$ 8,696**	$ 14,484
Accounts payable and accrued liabilities	**(55,681)**	3,140
	$ (46,985)	$ 17,624
Operating activities	**$ (7,498)**	$ (2,104)
Investing activities	**(39,487)**	19,728
	$ (46,985)	$ 17,624
Interest paid	**$ (16,523)**	$ (20,682)

16. Financing:

	Year ended December 31, 2015	Year ended December 31, 2014
Interest expense	**$ 16,014**	$ 19,984
Accretion of deferred financing costs	**569**	487
Accretion of decommissioning obligations	**1,841**	2,836
	$ 18,424	$ 23,307

17. Commitments:

	Total	2016	2017	2018	2019	2020	Thereafter
Operating leases	$ 6,750	$ 1,658	$ 1,175	$ 1,175	$ 1,175	$ 1,175	$ 392
Firm transportation agreements	164,893	30,658	29,347	29,686	29,406	26,224	19,572
Firm processing agreement	64,659	13,361	13,325	13,325	13,325	11,323	-
Total	$236,302	$45,677	$43,847	$44,186	$43,906	$38,722	$ 19,964

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

The firm transportation agreements include commitments to third parties to transport natural gas and natural gas liquids from gas processing facilities in northeastern British Columbia.

The firm processing agreements include commitments to process natural gas through third party owned gas processing facilities in northeastern British Columbia.

18. Personnel expenses:

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

	Year ended December 31, 2015	Year ended December 31, 2014
Short-term benefits	**$ 2,568**	$ 4,766
Long-term benefits	**7,394**	4,767
	$ 9,962	$ 9,533

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. In addition, share-based compensation provided to key management personnel includes awards offered under Crew's long-term incentive plans. The 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.

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