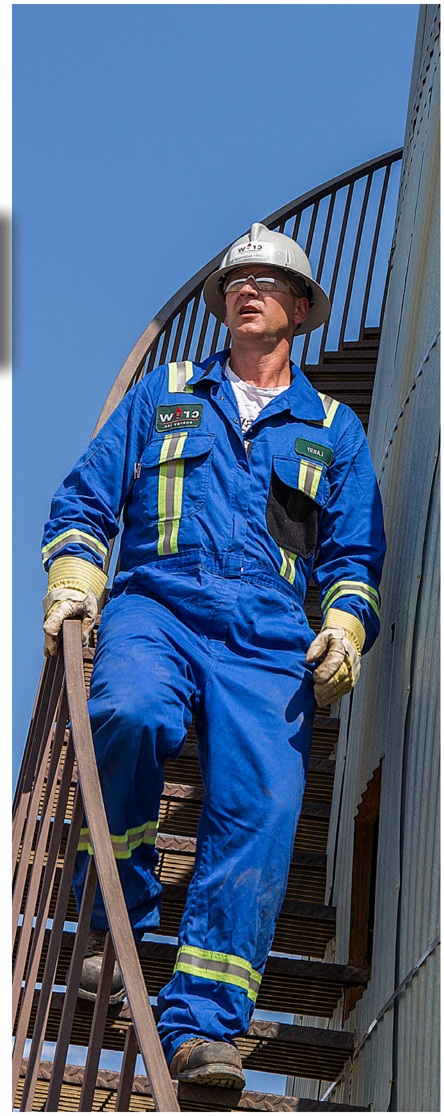
crew energy inc.

SHARPENING OUR FOCUS >>



'14 | 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 487 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 Ltd.

TRANSFER AGENT
Valiant Trust Company

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

Investor Contact

INVESTOR RELATIONS
Crew Energy Inc.
Phone: (403) 266-2088
Fax: (403) 266-6259
Email: investor@crewenergy.com
Web: www.crewenergy.com

EXCHANGE LISTING
TSX: CR

Head Office

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

CREW ENERGY INC. 2014 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, 2014.

2014 HIGHLIGHTS

- Our fourth quarter 2014 funds from operations were $33.0 million or $0.27 per diluted share and contributed to full year 2014 funds from operations of $171.6 million or $1.39 per diluted share;
- We undertook several transactions during the year to sharpen our focus on the Montney in Northeast British Columbia ("BC"), including acquiring an additional 110 net sections, bringing our total Montney acreage position to 487 net sections. Of this sizeable land base, only 9% had been assigned reserves as at year end 2014, which offers Crew significant future potential;
- Through the disposition of two Alberta-based asset packages, we sold more than 10,600 boe per day, or 39% of Crew's 2013 average production, and realized total cash proceeds of $372 million, strengthening our balance sheet;
- Average production in 2014 was 24,205 boe per day, with fourth quarter volumes averaging 20,869 boe per day. On a debt-adjusted basis, 2014 production per share numbers were consistent with 2013 which were as planned and reflected the significant dispositions and the overall transformation of our asset base;
- Production from our Northeast BC areas averaged 14,958 boe per day in the fourth quarter of 2014, a 44% increase over the same period in 2013, largely attributable to improving well performance and strong drilling results, including the addition of 2,400 boe per day at Tower during the quarter;
- Exploration and development expenditures totaled $306.8 million, including $231.1 million directed to drilling and completions, with 77 gross (72.7 net) wells drilled during the year with 99% success. Given the increased focus on our Montney assets, 75% of the total exploration and development capital was directed to activities at Septimus / West Septimus, Groundbirch and Tower;
- As announced in our year end reserves release, Crew's proved plus probable ("2P") reserves increased 25% on a debt-adjusted per share basis, with the successful addition of 108.4 mmboe of 2P reserves, resulting in attractive finding and development ("F&D") costs of $9.64 per boe (including changes in future development capital ("FDC")), and a recycle ratio of 2.5 times;
- Crew's all in cash costs per boe (including royalties, operating, transportation, general and administration and interest expenses) decreased by 18% in the fourth quarter compared to the previous quarter, reflecting the impact of our more focused Montney asset base, as well as weaker overall commodity prices that have more recently contributed to reductions in the cost structure;
- We continued with our proactive risk management program by hedging approximately 39% of our 2015 projected natural gas production at CDN$3.92 per mcf, approximately 27% of projected liquids production at CDN$102.82 per bbl and locking-in WCS differentials on 2,000 bbl per day at CDN$21.59;
- Our year-end net debt was approximately $130 million lower relative to 2013 and totaled $253.7 million; and
- Subsequent to year end on March 3, 2015, we completed a bought deal financing for gross proceeds of $100 million by issuing 16.7 million Common Shares, which further strengthened our balance sheet and positioned the Company very well to effectively manage the business through a weak commodity price environment, plus sets the stage for growth once the economic environment improves.

FINANCIAL & OPERATING HIGHLIGHTS

FINANCIAL ($ thousands, except per share amounts)	**Three months ended Dec. 31, 2014**	Three months ended Dec. 31, 2013	**Year ended Dec. 31, 2014**	Year ended Dec. 31, 2013
Petroleum and natural gas sales	**72,295**	110,394	**425,424**	430,627
Funds from operations(1)	**33,035**	48,128	**171,592**	172,438
Per share - basic	**0.27**	0.40	**1.40**	1.42
- diluted	**0.27**	0.40	**1.39**	1.42
Net income (loss)	**(28,424)**	(58,429)	**(349,714)**	(79,311)
Per share - basic	**(0.23)**	(0.48)	**(2.86)**	(0.65)
- diluted	**(0.23)**	(0.48)	**(2.86)**	(0.65)
Exploration and Development expenditures	**81,447**	55,996	**306,775**	220,031
Property acquisitions (net of dispositions)	**1,901**	(1,931)	**(252,478)**	40,218
Net capital expenditures	**83,348**	54,065	**54,297**	260,249

Capital Structure ($ thousands)	**As at Dec. 31, 2014**	As at Dec. 31, 2013
Working capital deficiency(2)	**57,722**	40,098
Bank loan	**49,904**	197,688
	107,626	237,786
Senior Unsecured Notes	**146,110**	145,623
Total Net Debt	**253,736**	383,409
Bank facility	**280,000**	420,000
Common Shares Outstanding (thousands)	**123,429**	121,635

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.

Operations	**Three months ended Dec. 31, 2014**	Three months ended Dec. 31, 2013	**Year ended Dec. 31, 2014**	Year ended Dec. 31, 2013
Daily production (1)				
Light & medium oil (bbl/d)	**1,228**	464	**559**	460
Princess oil (bbl/d)	**-**	3,547	**2,130**	3,894
Lloydminster oil (bbl/d)	**5,867**	6,645	**5,897**	6,024
Natural gas liquids (bbl/d)	**2,041**	3,105	**2,377**	3,022
Natural gas (mcf/d)	**70,397**	89,528	**79,449**	84,306
Oil equivalent (boe/d @ 6:1)	**20,869**	28,682	**24,205**	27,451
Average prices (1, 2)				
Light & medium oil ($/bbl)	**70.15**	77.88	**79.48**	84.82
Princess oil ($/bbl)	**-**	66.62	**83.80**	72.54
Lloydminster oil ($/bbl)	**61.47**	60.49	**72.64**	65.90
Natural gas liquids ($/bbl)	**39.86**	59.03	**55.23**	55.97
Natural gas ($/mcf)	**3.66**	3.82	**4.82**	3.47
Oil equivalent ($/boe)	**37.65**	41.84	**48.15**	42.98

	Three months ended Dec. 31, 2014	Three months ended Dec. 31, 2013	**Year ended Dec. 31, 2014**	Year ended Dec. 31, 2013
Netback ($/boe)				
Revenue	**37.65**	41.84	**48.15**	42.98
Realized commodity hedging gain / (loss)	**1.83**	(0.11)	**(2.63)**	(1.54)
Royalties	**(6.46)**	(7.78)	**(9.35)**	(8.53)
Operating costs	**(9.79)**	(10.62)	**(10.77)**	(11.14)
Transportation costs	**(1.73)**	(1.21)	**(1.51)**	(1.25)
Operating netback (3)	**21.50**	22.12	**23.89**	20.52
G&A	**(2.28)**	(1.87)	**(2.15)**	(1.86)
Interest on long-term debt	**(2.02)**	(1.99)	**(2.32)**	(1.45)
Funds from operations	**17.20**	18.26	**19.42**	17.21
Drilling Activity				
Gross wells	**24**	16	**77**	95
Working interest wells	**23.3**	15.6	**72.7**	91.8
Success rate, net wells (%)	**100%**	100%	**99%**	99%

Notes:

(1) Princess, Alberta oil (20^0 to 26^0 API oil) has historically been classified as medium or conventional oil. Effective December 31, 2012 Crew's reserves attributable to its Princess property have been classified as heavy oil to accord with definitions in the royalty regulations in Alberta. Princess and other oil production and pricing are shown separately from Lloydminster heavy oil volumes for clarity and comparison with historical classification.

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

(3) 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

The past twelve months have been a transformational period for Crew, as we took deliberate steps to sharpen the focus on our high-quality Montney acreage position in northeast BC. Through several key transactions, we added 110 net sections in the Montney, and sold two developed producing assets (Alberta Gas and Princess) resulting in the disposition of over 10,600 boe per day of production and 76.4 mmboe of 2P reserves. Since our Montney assets are still in the early stages of development, proceeds from the two sales helped to strengthen our balance sheet and enable the Company to increase the capital spending directed to the ongoing delineation and development of this expanding resource.

Of our 487 net Montney sections, only 9% have been assigned reserves to date, affording the Company significant long-term running room. Through our measured exploration and development capital program, we are focused on the continued conversion of our Montney resource to proved and probable reserves. For context, while our Septimus area represents 73% of Crew's overall corporate proved developed producing reserves and is our most developed Montney asset, the developed land base in that area represents only 2% of our total Montney acreage. Further, Septimus offers high quality acreage that generates attractive rates of return, even in lower commodity price environments.

Both of our fourth quarter and full year 2014 production volumes were lower than during the same periods in 2013. For the full year volumes, this is attributable to the previously noted asset sales, while the fourth quarter was impacted by both the asset sales, plus approximately 1,000 boe per day of heavy oil and non-Montney gas production that became uneconomic in the current commodity price environment and was shut-in during the quarter. Our successful drilling at Septimus and Tower, coupled with the acquisitions at Septimus and Groundbirch, allowed Crew to increase production from our Northeast BC assets by 45% year over year, which partially offset the asset dispositions.

The strength of our focused strategy was demonstrated in 2014 as we significantly expanded our Montney reserves and production through drilling and achieved a 2P reserves replacement ratio of 362% with attractive capital efficiencies of $9.64 per boe (F&D including FDC) which were lower than our three year average. Further, a significant portion of our increased reserves are due to pool extensions and improved recoveries in the Montney which drove a 10% increase in our 2P reserves per share and a 25% increase in reserves per share on a debt-adjusted basis.

FINANCIAL

As a result of the significant transition in Crew's asset base through the year, our fourth quarter 2014 funds from operations were lower than the previous quarter as well as the fourth quarter of 2013 by 15% and 31%, respectively. A combination of production volumes that were sold in the second and third quarters, as well as softening commodity prices impacted Crew's fourth quarter funds from operations. However, funds from operations for the full year 2014 remained consistent with 2013, and totaled $171.2 million or $1.39 per fully diluted share. Our 2014 annual netbacks increased as compared to the same period in 2013 as a result of stronger pricing year over year.

In the fourth quarter of 2014 the Company spent $61.4 million on drilling and completions including the drilling of 24 (23.3 net) wells resulting in 14 (14.0 net) oil wells and 10 (9.3 net) natural gas wells. In addition, the Company completed 9 (8.3 net) wells and recompleted 11 (9.8 net) wells in the quarter. The Company also spent $14.7 million directed to infrastructure predominately on the Company's West Septimus facility currently planned for commissioning in Q3 2015. In 2014, Crew invested $306.8 million of exploration and development capital, of which 75% was focused towards northeast BC, 17% towards Lloydminster and the remaining 8% toward other sold properties. Of the total corporate exploration and development expenditures, $231.1 million was spent drilling 77 (72.7 net) wells resulting in 50 (46.4 net) oil wells, 26 (25.3 net) gas wells, and one (1.0 net) dry and abandoned well and completing 51 (47.2 net) wells and recompleting 72 (67.6 net) wells. Crew's infrastructure spending was predominantly related to the West Septimus facility as well as pipeline, battery and various well equipping costs in northeast British Columbia.

Commodity prices experienced a significant and volatile decline commencing in the fourth quarter of 2014. Through the first nine months of the year, West Texas Intermediate ("WTI") oil prices were strong and averaged over CDN$109 per barrel. However, during the fourth quarter, the market experienced an over-supply of oil, causing WTI to average CDN$82.94 per barrel, and by year end it had fallen to CDN$61 per barrel. Concurrent with the significant decline in WTI, the WCS heavy oil discount to WTI also narrowed to CDN$16.22 per barrel, maintaining a 20% discount to WTI. Increased refinery demand, ongoing increases in crude-by-rail shipments, as well as pipeline and infrastructure expansion projects continue to be positive catalysts for the WCS differential to WTI.

Consistent with WTI price movements, natural gas prices were stronger during the first nine months of the year reflecting reduced storage levels as the AECO benchmark price averaged $4.54 per gj, 57% higher than the previous year. North American supply growth combined with warm early winter temperatures across North America drove the AECO benchmark price down to $3.42 per gj in the fourth quarter. Despite this decrease, the annual AECO benchmark price for 2014 averaged $4.26 or 32% above 2013 levels.

Crew maintains a risk management strategy designed to partially protect our cash flows against significant declines in commodity prices, while safeguarding our funding source for our ongoing capital program. For the first nine months of 2014, due to a strong commodity price environment, Crew incurred realized losses on its financial instruments of $26.8 million or $3.87 per boe. In the fourth quarter, with the precipitous decline in commodity prices, the Company realized a $3.5 million hedging gain. Moving into 2015, we have protected a portion of our cash flow and have supported our ongoing financial stability with 33,800 gj per day of natural gas volumes currently hedged at an average price of $3.71 per gj ($3.92 per mcf), 2,122 bbl per day of liquids volumes hedged at an average price of CDN$102.82 per bbl, and 2,000 bbl per day of WCS differentials locked in at CDN$21.59.

Crew exited 2014 with $253.7 million of net debt including working capital deficiency and the Company's $150 million senior unsecured notes that are not due for repayment until 2020. At year-end, Crew had drawn approximately $49.9 million or 18% of our $280 million bank facility. The completion of our $100 million bought deal financing on March 3rd enhances our liquidity, and provides us with significant financial flexibility.

In response to the weaker commodity price environment, Crew has been working with all of our service providers to achieve cost reductions across many areas of our business. We are pleased to have secured reductions in field costs from various providers and will continue to seek additional opportunities to lower costs and enhance efficiencies.

OPERATIONS UPDATE

Septimus / West Septimus - Montney, NE BC

Crew continues to be very pleased with the progression and development of our Septimus / West Septimus properties. In 2014, through the drilling of 23 wells (22.3 net), we successfully increased our 2P reserves by 60% to 134.4 mmboe. Our type well performance at Septimus specifically continued to improve due to enhanced completion techniques and infrastructure optimization, with our average 2P reserves per booked location increasing by 16% to 5.0 bcf per well on average compared to 2013.

With our sharpened focus and increased drilling and development of our Montney assets, we are also actively managing our infrastructure planning and implementation. Early in 2015, we began designing the necessary surface equipment and pipeline tie-in to eliminate the trucking of condensate from our Septimus facility reducing transportation costs in the area by approximately $4.00 per bbl once completed in the second quarter. In addition, construction on the new West Septimus facility began in 2014, and by year end, Crew had incurred approximately 60% of its forecasted net total expenditure on the facility, with target completion in the third quarter of 2015. Crew pre-drilled twelve wells in West Septimus in 2014 intended to supply gas to the new West Septimus facility, and those wells are anticipated to be completed in the first and second quarter of 2015.

At Septimus, Crew is currently completing the drilling of a five well pad in order to fully optimize costs and efficiencies related to pad development. Since drilling and casing wells represents the smallest portion (approximately 40%) of the overall cost of a new well, we are maintaining our capital flexibility to defer completion of new wells until the commodity market strengthens and project economics justify further investment. Crew continues to monitor the broader pricing environment and we remain committed to ensuring economics are not sacrificed in pursuit of production growth.

Groundbirch / Attachie – Montney, NE BC

The success of our activities at Groundbirch and Attachie through 2014 is reflected by the significant 2P reserves increases reported at both properties relative to the prior year. At Groundbirch, we drilled two new horizontal wells which confirmed the highly over-pressured nature of the reservoir in this area and the high liquids content of the production. Our 2P reserves in the area increased from 1.1 mmboe last year to 26.2 mmboe. We are in the process of acquiring 28 square miles of 3D seismic at Groundbirch which will aid in further delineation of its potential. At Attachie, we drilled an exploration well which successfully validated reservoir prospectivity of this property and our 2P reserves increased over 100% year over year from 13.2 mmboe to 26.7 mmboe. The prospectivity of Crew's lands in both of these areas continues to be validated by a combination of our operations and activities as well as competitor activity.

Tower Oil – Montney, NE BC

Development at our light oil property at Tower focused on drilling five wells in 2014, primarily from pad locations, resulting in Crew adding new production of approximately 2,400 boe per day in the fourth quarter and 13.7 mmboe of 2P reserves. We also completed construction of the first phase of our Tower oil battery with new production from the area flowing into the facility. With the evolution of both drilling and completions practices at Tower, we have successfully increased our exposure to light oil and condensate. In early 2015 we completed the drilling of the last two wells of a four well pad at Tower offering an opportunity to accelerate oil and condensate development as commodity prices and project economics warrant.

Lloydminster Oil - Alberta/Saskatchewan

Production at our heavy oil Lloydminster property averaged 5,933 boe per day during 2014 and 2P reserves remained stable at 12,606 mboe with the drilling of 36 (33 net) wells. Into 2015 we plan to maintain activity levels on our effective recompletion and workover program and will defer new drilling until commodity prices recover sufficiently to provide more attractive rates of return.

OUTLOOK

We are very pleased with our progress in 2014 as we sharpened Crew's focus on our world-class Montney resource through the transformation of our asset base. This period has resulted in Crew successfully assembling 487 net sections of Montney lands on which we have exposure to all three hydrocarbon windows and are ideally situated near infrastructure that allows us to access both existing and new potential markets. With our success through 2014 in efficiently adding reserves and production we have evolved to become a leading operator in the Montney. Our independent evaluator previously assigned resource to 352 out of our 487 net sections, estimated at 109 trillion cubic feet equivalent ("TCFE") of total petroleum initially in place ("TPIIP"), and we have the potential to further increase resource estimates with the completion of our 2015 independent resource evaluation anticipated in the second quarter. Our strategy of focusing on the Montney and divesting of non-core assets unfolded during 2014 with the divestiture of Alberta Gas and Princess Assets for $372 million. We were able to reduce net debt by $130 million, add 110 net sections of Montney rights, replace 83 mmboe of sold reserves and add 23 mmboe of reserves within a seven month period at a very attractive F&D cost (including FDC) of $9.62 per boe. We also replaced a significant portion of our sold oil production with a higher quality, more valuable light oil / condensate product from our Tower area.

The combination of our 2015 hedge position and a strengthened balance sheet following closing of our $100 million offering, affords Crew greater liquidity and financial flexibility to manage our business prudently during this period of uncertain commodity prices. Without a clear line of sight to an improved pricing environment, Crew continues to diligently review our operations and capital projects to ensure they meet corporate objectives and economic hurdles. Our 2015 capital program of up to $185 million is structured to allow us to maintain financial strength while enabling the Company to move quickly and adjust our activities as project economics warrant and prove additional prospectivity for future development. The Company continues to monitor capital spending in the current depressed commodity price environment and believes that lower projected costs could lead to improving efficiencies. Crew has 22 net Montney wells drilled which provide an inventory of wellbores that can be completed and brought on-production at the Company's discretion depending on commodity prices and other factors. Crew is forecasting average production for 2015 of 20,000 to 22,000 boe per day and a 2015 exit rate of 24,000 to 25,000 boe per day based on a net capital budget of up to $185 million.

Corporately, Crew announces the planned retirement of Mr. Gary Smith, Vice President Exploration following his successful 32 year career in the oil and gas industry. Mr. Smith joined Crew in 2007 and has significantly contributed to the Company's success over the past eight years including the assembly and early development of our prominent Montney land position. Prior to joining Crew Mr. Smith held increasing roles of responsibility with Greenbank Energy, Storm Energy, Canadian Hunter Exploration, Union Pacific Resources and Chevron Canada Resources. Crew's Board of Directors, Executive team and employees wish to thank Gary for his invaluable contributions to Crew's success and wish him well in his post career endeavors

Despite the challenging market conditions we face today, Crew is still in the early stages of the development of our Montney resource and we believe we have built the right platform and team to increase production, enhance recoveries and reserves, and provide our shareholders with long-term profitable growth. We appreciate the ongoing hard work and dedication of all Crew's consultants, employees, management and our Board of Directors and we sincerely thank our shareholders for your continued support of Crew's 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 2015 forecast average and exit production; 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; anticipated 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 the West Septimus facilities; the total future capital associated with development of reserves and resources; and methods of funding our capital program, 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 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, 2014 prepared by Sproule Associates Limited, details of which were provided in our press release issued on February 18, 2015. Our oil and gas reserves statement for the year ended December 31, 2014, 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".*

Resource Estimates

This report contains references to estimates of oil and gas classified as Total Petroleum Initially-In-Place ("TPIIP") in the Montney region in northeastern British Columbia which are not, and should not be confused with, oil and gas reserves. Such estimates are based upon an independent resource evaluation effective as at April 30, 2014 prepared in accordance with the Canadian Oil and Gas Evaluation Handbook. Such estimates are subject to a number of cautionary statements, assumptions, risks, positive and negative factors relevant to the estimates and contingencies, the details of which, along with the complete details of the resource evaluation itself, were set forth in Crew's previously disseminated press release dated May 7, 2014. Accordingly, readers are referred to and encouraged to review the sections entitled "Northeast British Columbia Montney Resource Evaluation", "Definitions of Oil and Gas Resources and Reserves" and "Information Regarding Disclosure on Oil and Gas Reserves, Resources and Operational Information" in the May 7, 2014 press release for applicable definitions, cautionary language, explanations and discussion of resources estimated herein, all of which is incorporated herein by reference.

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.

MANAGEMENT'S DISCUSSION AND ANALYSIS

FINANCIAL & OPERATING HIGHLIGHTS

FINANCIAL *($ thousands, except per share amounts)*	**Year ended December 31, 2014**	Year ended December 31, 2013
Petroleum and natural gas sales	**425,424**	430,627
Cash provided by operations	**169,207**	161,949
Funds from operations (note 1)	**171,592**	172,438
Per share - basic	**1.40**	1.42
- diluted	**1.39**	1.42
Net loss	**(349,714)**	(79,311)
Per share - basic	**(2.86)**	(0.65)
- diluted	**(2.86)**	(0.65)
Exploration and development expenditures	**306,775**	220,031
Property acquisitions (net of dispositions)	**(252,478)**	40,218
Net capital expenditures	**54,297**	260,249

CAPITAL STRUCTURE *($ thousands)*	**As at December 31, 2014**	As at December 31, 2013
Working capital deficiency (note 2)	**57,722**	40,098
Bank loan	**49,904**	197,688
	107,626	237,786
Senior unsecured notes	**146,110**	145,623
Total Net debt	**253,736**	383,409
Bank facility	**280,000**	420,000
Common Shares Outstanding *(thousands)*	**123,429**	121,635

OPERATIONS	**Year ended December 31, 2014**	Year ended December 31, 2013
Daily production (note 5)		
Light/medium oil (bbl/d)	**559**	460
Princess oil (bbl/d)	**2,130**	3,894
Lloydminster oil (bbl/d)	**5,897**	6,024
Natural gas liquids (bbl/d)	**2,377**	3,022
Natural gas (mcf/d)	**79,449**	84,306
Oil equivalent (boe/d @ 6:1)	**24,205**	27,451
Average prices (note 3,5)		
Light/medium oil ($/bbl)	**79.48**	84.82
Princess oil ($/bbl)	**83.80**	72.54
Lloydminster oil ($/bbl)	**72.64**	65.90
Natural gas liquids ($/bbl)	**55.23**	55.97
Natural gas ($/mcf)	**4.82**	3.47
Oil equivalent ($/boe)	**48.15**	42.98
Netback ($/boe)		
Operating netback (note 4)	**23.89**	20.52
G&A	**2.15**	1.86
Interest on long-term debt	**2.32**	1.45
Funds from operations	**19.42**	17.21
Drilling Activity		
Gross wells	**77**	95
Working interest wells	**72.7**	91.8
Success rate, net wells	**99%**	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 only accounts receivable less accounts payable and accrued liabilities.

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

(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.

(5) The Princess, Alberta property, which is an area that produces crude oil and associated liquids (ranging from 20^0 to 26^0 API), has historically been classified as medium oil by Crew's previous independent reserve evaluators. Effective December 31, 2012, Crew's reserves attributable to its Princess property have been classified by Crew's independent reserve evaluator as heavy oil to accord with definitions contained in the Canadian Oil and Gas Evaluation Handbook, specifically the guidelines related to heavy oil designations contained in the royalty regulations for the Province of Alberta. We have presented Princess and other oil production and revenue separately from our Lloydminster heavy oil in this MD&A for greater clarity as they have historically been classified separately.

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, 2014 and 2013. The consolidated financial statements for the year ended December 31, 2014 have been prepared in accordance with International Financial Reporting Standards ("IFRS"). All figures provided herein and in the December 31, 2014 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 construction, commissioning and the timing thereof, capital expenditures, timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, production estimates including 2015 average and 2015 exit 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, 2014**	Three months ended December 31, 2013	**Year ended December 31, 2014**	Year ended December 31, 2013
Cash provided by operating activities	**37,714**	48,850	**169,207**	161,949
Decommissioning obligations settled	**249**	379	**768**	4,333
Change in operating non-cash working capital	**(4,773)**	(940)	**2,104**	6,317
Accretion of deferred financing costs	**(155)**	(161)	**(487)**	(161)
Funds from operations	**33,035**	48,128	**171,592**	172,438

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, 2014**	December 31, 2013
Current assets	**78,469**	49,877
Current liabilities	**(95,337)**	(105,315)
Marketable securities	**(2,052)**	-
Derivative financial instruments	**(38,802)**	15,340
Working capital deficit	**(57,722)**	(40,098)

($ thousands)	**December 31, 2014**	December 31, 2013
Bank loan	**(49,904)**	(197,688)
Senior unsecured notes	**(146,110)**	(145,623)
Working capital deficit	**(57,722)**	(40,098)
Net debt	**(253,736)**	(383,409)

RESULTS OF OPERATIONS

Overview

Throughout 2014, Crew continued to sharpen its focus on developing and expanding the long-term, high growth potential of its Montney resource in northeast British Columbia ("BC"). By way of three transactions completed in late March and July 2014, The Company purchased approximately 110 net sections of highly prospective Montney rights in the Septimus and Groundbirch areas of operation in northeast BC for approximately $120 million. In May of 2014, Crew closed the disposition of petroleum and natural gas assets (approximately 7,000 boe per day, weighted 75% to natural gas) focused primarily in the Deep Basin of Alberta (the "Alberta Gas Disposition") for gross proceeds of approximately $234 million in cash before closing adjustments. In conjunction with this transaction, Crew acquired approximately 400 bbls per day of heavy oil production for gross proceeds of approximately $12 million. On September 30th, the Company closed the disposition of petroleum and natural gas assets in the Princess area of southeast Alberta, which included production of approximately 3,650 boe per day, for proceeds of approximately $150 million, before closing adjustments (the "Princess Disposition"). These transactions enabled Crew to reduce its debt by approximately $267 million (before closing adjustments), which strengthened the balance sheet and positioned Crew to continue the development of its significantly expanded Montney resource.

Crew's 2014 production averaged 24,205 boe per day, a decrease over 2013 due to the Alberta Gas Disposition and the Princess Disposition. However, a successful drilling and completion program in northeast BC increased the Company's 2014 production in that area by 45% over the prior year. During the year, Crew increased its exposure to light oil through a successful drilling program at Tower, BC which added over 2,400 boe per day of production in the fourth quarter of 2014. The Company's heavy oil property at Lloydminster continued to generate free cash flow and averaged 5,933 boe per day during the year.

West Texas Intermediate ("WTI") oil prices were strong through the first nine months of the year averaging over CDN$109 per barrel. Increased supply, particularly from North America, and moderating global demand led to a rapid price decline in WTI during the last three months of 2014, with prices averaging CDN$82.94 per barrel in the fourth quarter, and further dropping to CDN$61 per barrel by the end of the year. The discount for Canadian heavy oil, measured as the Western Canadian Select ("WCS") price differential to WTI, encountered its normal seasonal swings but averaged CDN$21.42 per bbl, a 21% discount to WTI, which resulted in stronger WCS pricing than realized over the past few years. In the fourth quarter, concurrent with the significant decline in WTI oil prices, the discount for heavy oil narrowed to CDN$16.22 per barrel but remained at a 20% discount to WTI. Increased refinery demand, ongoing increases in crude-by-rail shipments, as well as pipeline and infrastructure expansion projects continue to be positive catalysts for the WCS differential to WTI.

In late 2013 and early 2014, an extended cold winter across North America reduced natural gas storage levels to 52% below the prior year's level and 55% below the five year average level. For the first nine months of 2014, natural gas prices reflected the reduced storage levels as the AECO benchmark price averaged $4.54 per gj, 57% higher than the previous year. In the fourth quarter, concerns over increased North American supply combined with robust natural gas storage inventory levels decreased the AECO benchmark price to $3.42 per gj. Despite the fourth quarter decrease, the annual AECO benchmark price for 2014 averaged $4.26 per gj or 42% above 2013 levels.

Crew's risk management strategy is designed to partially protect its cash flows against significant declines in commodity prices, while safeguarding its funding source for the Company's ongoing capital program. For the first nine months of 2014, due to a strong commodity price environment, Crew incurred realized losses on its financial instruments of $26.8 million or $3.87 per boe. In the fourth quarter, with the precipitous decline in commodity prices, the Company realized a $3.5 million, or $1.85 per boe, hedging gain. Moving into 2015, the Company has protected a portion of its cash flow and helped to support its ongoing financial stability with 33,800 gj per day of natural gas volumes currently hedged at an average price of $3.71 per gj; 2,122 bbls per day of liquids volumes hedged at an average price of CDN$102.82 per bbl; and 2,000 bbls per day of WCS differentials locked in at CDN$21.59.

In 2014, Crew strengthened its financial position with the execution of the Alberta Gas Disposition and Princess Disposition. The Company exited 2014 with $253.7 million of net debt, including working capital deficiency, which includes the Company's $150 million senior unsecured notes that are not due for repayment until 2020. At year-end, Crew had drawn approximately $49.9 million or 18% of its $280 million bank facility. In early March 2015, the Company closed a $100 million bought deal financing, whereby Crew issued 16,667,000 common shares at a price of $6.00 per share to further solidify its financial position as the Company navigates through the challenging commodity price environment that it is facing in early 2015.

Total net capital expenditures during 2014 were $54.3 million which included the Septimus and Groundbirch acquisitions and proceeds from the Alberta Gas Disposition and Princess Disposition. Exploration and development expenditures totaled $306.8 million and were focused on the Company's Montney development in northeast BC where Crew spent $231 million at Septimus/West Septimus, Groundbirch and Tower. In addition, $52 million was directed towards heavy oil development at Lloydminster in both Saskatchewan and Alberta, and $24 million was spent on other minor properties throughout Alberta that were sold during the year.

Impact of Strategic Transactions

On March 30, 2014, Crew closed the Septimus and Groundbirch acquisitions. These acquisitions added approximately 1,400 boe per day of production (98% natural gas). The revenue, royalties and operating costs on a per unit basis associated with this newly acquired production are similar to the Company's existing northeast BC production. This new production does attract higher transportation costs per unit as the natural gas is produced into a third party owned gathering and processing infrastructure which has an all-in fee charged for gathering, processing and transmission through this system which is included in transportation expense.

On May 30, 2014 Crew closed the Alberta Gas Disposition. Production from this disposition attracted operating costs and royalties which are below the corporate average, which subsequently increased the Company's 2014 operating costs per boe and royalties as a percentage of revenue.

On September 30, 2014, Crew closed the Princess Disposition which included approximately 3,650 boe per day of 78% liquids production. This production attracted a higher royalty rate and higher operating costs per boe in comparison to the Company's remaining production.

Results for 2014 reflect the Septimus and Groundbirch acquisitions closing on March 30, 2014, the Alberta Gas Disposition closing on May 30, 2014 and the Princess Disposition closing on September 30, 2014.

Production

	Three months ended December 31, 2014				Three months ended December 31, 2013			
	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	**1,228**	**2,041**	**70,135**	**14,958**	93	1,807	51,138	10,423
Lloydminster	**5,867**	**-**	**262**	**5,911**	6,645	-	207	6,680
Princess	**-**	**-**	**-**	**-**	3,547	102	6,535	4,738
Other Alberta	**-**	**-**	**-**	**-**	371	1,196	31,648	6,841
Total	**7,095**	**2,041**	**70,397**	**20,869**	10,656	3,105	89,528	28,682

In the fourth quarter of 2014, production decreased 27% over the same period in 2013 as the result of the Alberta Gas Disposition and the Princess Disposition. The decreased production due to these transactions was partially offset by a 44% increase in production from northeast British Columbia due to the Septimus and Groundbirch acquisitions completed in March and focused capital spending to develop the Company's liquids rich natural gas play at Septimus and its emerging light oil play at Tower. At Lloydminster, heavy oil production decreased as the Company reduced workover and routine well servicing activity and began shutting-in uneconomic volumes in response to declining oil prices.

	Year ended December 31, 2014				Year ended December 31, 2013			
	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	**429**	**1,640**	**63,088**	**12,584**	118	1,374	43,170	8,687
Lloydminster	**5,897**	**-**	**212**	**5,933**	6,024	-	326	6,078
Princess	**2,130**	**63**	**3,673**	**2,805**	3,894	109	6,677	5,116
Other Alberta	**130**	**674**	**12,476**	**2,883**	342	1,539	34,133	7,570
Total	**8,586**	**2,377**	**79,449**	**24,205**	10,378	3,022	84,306	27,451

Production in 2014 decreased 12% as compared to 2013 as a result of the aforementioned strategic dispositions partially offset by the Septimus and Groundbirch acquisitions completed in March and a successful drilling and completion program in northeast British Columbia. During 2014, the Company increased its exposure to light oil with approximately 2,400 boe per day coming on production in the fourth quarter at Tower.

Revenue

	Three months ended December 31, 2014	Three months ended December 31, 2013	**Year ended December 31, 2014**	Year ended December 31, 2013
Revenue ($ thousands)				
Light/medium oil	**7,924**	3,305	**16,228**	14,137
Princess oil	**-**	21,744	**65,156**	103,089
Lloydminster oil	**33,181**	36,990	**156,346**	144,995
Natural gas liquids	**7,483**	16,862	**47,919**	61,726
Natural gas	**23,707**	31,493	**139,775**	106,680
Total	**72,295**	110,394	**425,424**	430,627
Crew average prices				
Light/medium oil ($/bbl)	**70.15**	77.88	**79.48**	84.82
Princess oil ($/bbl)	**-**	66.62	**83.80**	72.54
Lloydminster oil ($/bbl)	**61.47**	60.49	**72.64**	65.90
Natural gas liquids ($/bbl)	**39.86**	59.03	**55.23**	55.97
Natural gas ($/mcf)	**3.66**	3.82	**4.82**	3.47
Oil equivalent ($/boe)	**37.65**	41.84	**48.15**	42.98
Benchmark pricing				
Princess and Lloydminster oil – WCS (Cdn $/bbl)	**66.72**	68.41	**81.07**	74.97
Light/medium oil and ngl – Cdn$ WTI (Cdn $/bbl)	**82.94**	102.30	**102.49**	100.96
Natural Gas – AECO C daily index (Cdn $/mcf)	**3.61**	3.57	**4.49**	3.22

In the fourth quarter of 2014, Crew's revenue decreased 35% as a result of the Deep Basin and Princess dispositions, combined with a 10% decrease in commodity pricing as compared with the same quarter in 2013. Crew's realized natural gas price decreased 4% in the quarter compared to the AECO C benchmark increase of 1% as the Company experienced wider differentials between AECO pricing and the prices realized for natural gas sold in British Columbia on the Alliance pipeline system, which is the primary market for Crew's Septimus natural gas production. As the Company disposed of the Princess property in the third quarter, the fourth quarter light oil was predominantly new Tower light oil which attracts a higher market price. The Company's benchmark for this light oil is Cdn$ WTI for which the Company received a value of approximately 85% of Cdn$ WTI during the quarter which is within the Company's expectations. Crew's fourth quarter Lloydminster oil price increased 2% which outperformed the decrease in the WCS benchmark. The Company actively manages its heavy oil sales by entering into physical contracts throughout the months to reduce the volatility of revenues and as such, successfully marketed its heavy crude oil during periods when WCS differentials were narrower than the average market trade for the quarter. The Company's natural gas liquids ("ngl") price decreased 32% over the same period last year, as compared to a 19% decrease in the Cdn$ WTI benchmark. During the fourth quarter, there was extreme volatility experienced in liquids pricing and in particular, the Company's ethane and propane pricing disproportionately decreased in the fourth quarter as compared to the WTI benchmark.

The Company's 2014 revenue slightly decreased over 2013 as a result of the Alberta Gas Disposition combined with the Princess Disposition but was partially offset by the increase in production at Septimus and Tower and the 12% increase in commodity pricing year over year. The Company's Princess oil price increased 16% while the Lloydminster oil price increased 10% in 2014. The larger variance for Princess oil, over the 8% increase in the WCS benchmark, is a result of the realized price only consisting of the first nine months of 2014. The larger variance for Lloydminster oil is due to the Company marketing its oil during periods when WCS differentials were narrower than the average market price. The Company's natural gas price was consistent with benchmark pricing while ngl prices were subject to the aforementioned disproportionate decrease in ethane and propane prices.

Royalties

($ thousands, except per boe)	**Three months ended December 31, 2014**	Three months ended December 31, 2013	**Year ended December 31, 2014**	Year ended December 31, 2013
Royalties	**12,410**	20,541	**82,621**	85,464
Per boe	**6.46**	7.78	**9.35**	8.53
Percentage of revenue	**17.2%**	18.6%	**19.4%**	19.8%

In the fourth quarter and year ended 2014, royalties and royalties as a percentage of revenue were lower than the same periods of 2013 as a result of the increased production at Septimus and Tower which attract a lower royalty rate than the corporate historical average and the previously aforementioned dispositions of Deep Basin and Princess properties which attracted higher royalty rates. Crew expects its royalty as a percentage of revenue to average between 16% and 18% in 2015.

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, 2014**	Three months ended December 31, 2013	**Year ended December 31, 2014**	Year ended December 31, 2013
Realized gain (loss) on derivative financial instruments	**3,523**	(301)	**(23,262)**	(15,436)
Per boe	**1.83**	(0.11)	**(2.63)**	(1.54)
Unrealized gain (loss) on financial instruments	**43,770**	(4,592)	**53,406**	(8,170)

As at December 31, 2014, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Oil	750 bbl/day	January 1, 2015 – June 30, 2015	CDN$ WTI	$103.80	Swap	5,400
Oil	1,750 bbl/day	January 1, 2015 – December 31, 2015	CDN$ WTI	$102.62	Swap	23,092
Oil	2,000 bbl/day	January 1, 2015 – December 31, 2015	CDN$ WCS – WTI diff	($21.59)	Swap	(1,984)
Gas	30,000 gj/day	January 1, 2015 – December 31, 2015	AECO C Monthly Index	$3.75	Swap	11,590
Gas	7,500 gj/day	July 1, 2015 – December 31, 2015	AECO C Monthly Index	$3.41	Swap	942
Gas	2,500 gj/day	January 1, 2015 – March 31, 2015	US$ Chicago Citygate	$4.15	Swap(1)	(238)
Oil	500 bbl/day	January 1, 2016 – December 31, 2016	CDN$ WTI	$116.50	Call	(324)
Oil	250 bbl/day	January 1, 2016 – December 31, 2016	CDN$ WTI	$88.00 – $100.00	Call(2)	(412)
Total						38,066

(1) The referenced contract is associated with the cost of make-up gas resulting from processing a portion of the Company's natural gas liquids sales.
(2) The referenced contract is a structured call which is only triggered if the average CDN$ WTI trades above $100 per bbl for a given month during the term.

Operating Costs

($ thousands, except per boe)	**Three months ended December 31, 2014**	Three months ended December 31, 2013	**Year ended December 31, 2014**	Year ended December 31, 2013
Operating costs	**18,790**	28,032	**95,128**	111,569
Per boe	**9.79**	10.62	**10.77**	11.14

For the fourth quarter and year ended December 31, 2014, the Company's operating costs per unit decreased 8% and 3%, respectively, over the same period in 2013. This is a result of increased production in the Septimus area which yields lower operating costs as compared to the corporate average and the disposition of higher cost production in the Princess area. This was partially offset by the disposition of lower cost Deep Basin production and incremental higher cost Montney oil production from Tower in British Columbia. The Company forecasts operating costs to average $9.50 to $10.25 per boe for 2015.

Transportation Costs

($ thousands, except per boe)	**Three months ended December 31, 2014**	Three months ended December 31, 2013	**Year ended December 31, 2014**	Year ended December 31, 2013
Transportation costs	**3,325**	3,197	**13,314**	12,572
Per boe	**1.73**	1.21	**1.51**	1.25

In the fourth quarter and year ended December 31, 2014, the Company's transportation costs and transportation costs per boe increased as compared to the same periods in 2013 as a result of the first quarter acquisition of northeast British Columbia natural gas production, which attracts an all-in fee for gathering and processing at a third party facility, and new production from the Tower oil property in the fourth quarter in which both yield a higher transportation cost per unit. In addition, the cost per unit was further impacted by the disposition of lower transportation cost per unit production from Princess and Deep Basin. The Company expects transportation costs per boe to range between $1.85 and $2.25 per boe for 2015.

Operating Netbacks

($/boe)	**Three months ended December 31, 2014**	Three months ended December 31, 2013	**Year ended December 31, 2014**	Year ended December 31, 2013
Revenue	**37.65**	41.84	**48.15**	42.98
Royalties	**(6.46)**	(7.78)	**(9.35)**	(8.53)
Realized commodity hedging gain/(loss)	**1.83**	(0.11)	**(2.63)**	(1.54)
Operating costs	**(9.79)**	(10.62)	**(10.77)**	(11.14)
Transportation costs	**(1.73)**	(1.21)	**(1.51)**	(1.25)
Operating netbacks	**21.50**	22.12	**23.89**	20.52

Operating netbacks for the fourth quarter of 2014 decreased over the same period in 2013 as the Company's natural gas and ngl prices decreased combined with the sale of the higher netback production at Princess. This was partially offset by realized hedging gains on our risk management program. 2014 annual netbacks increased as compared to the same period in 2013 as a result of higher commodity prices year over year.

General and Administrative Costs

($ thousands, except per boe)	**Three months ended December 31, 2014**	Three months ended December 31, 2013	**Year ended December 31, 2014**	Year ended December 31, 2013
Gross costs	**7,392**	7,797	**29,636**	29,514
Operator's recoveries	**(329)**	(187)	**(631)**	(826)
Capitalized costs	**(2,680)**	(2,667)	**(9,969)**	(10,059)
General and administrative expenses	**4,383**	4,943	**19,036**	18,629
Per boe	**2.28**	1.87	**2.15**	1.86

General and administrative costs decreased in the fourth quarter of 2014 compared to the same period in 2013 due to reduced staffing levels as a result of the Alberta Gas Disposition and the Princess Disposition. General and administrative costs after recoveries and capitalization slightly increased in 2014 due to lower operator recoveries from reduced capital activity with industry partners. General and administrative costs per boe increased in the fourth quarter and year as compared to the same periods in 2013 as a result of decreased production volumes resulting from the Alberta Gas and Princess Dispositions. The Company expects general and administrative costs per boe to average $2.25 to $2.50 in 2015.

Share-Based Compensation

($ thousands)	**Three months ended December 31, 2014**	Three months ended December 31, 2013	**Year ended December 31, 2014**	Year ended December 31, 2013
Gross costs	**3,404**	2,619	**13,437**	9,113
Capitalized costs	**(2,073)**	(1,351)	**(6,889)**	(4,660)
Total share-based compensation	**1,331**	1,268	**6,548**	4,453

In the fourth quarter and year ended December 31, 2014, the Company's share-based compensation expense has increased compared to the same periods in 2013 due to additional higher valued restricted and performance awards granted in the second quarter of 2014.

Depletion and Depreciation

($ thousands, except per boe)	**Three months ended December 31, 2014**	Three months ended December 31, 2013	**Year ended December 31, 2014**	Year ended December 31, 2013
Depletion and depreciation	**31,184**	49,001	**158,835**	190,176
Per boe	**16.24**	18.57	**17.98**	18.98

Depletion and depreciation costs have decreased both in the fourth quarter and for the year ended December 31, 2014 as a result of the Alberta Gas and Princess Dispositions removing assets from the Company's property, plant and equipment that carried a higher per unit depletion rate. In addition, depletion and depreciation costs per boe have decreased in the fourth quarter and year ended December 31, 2014 compared to the same periods in 2013 due to increased proved plus probable reserve bookings from the Company's annual reserve evaluation.

Impairment

At December 31, 2014, as a result of the significantly lower commodity price environment, it was determined that indicators of impairment existed for the Company's Cash Generating Units ("CGUs"). The decrease in the future WCS price estimate as well as negative technical reserve revisions resulting from lower than expected performance from certain heavy oil wells, resulted in the book value of the Lloydminster heavy oil CGU exceeding its future 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 were tested for impairment. As a result of the test, it was determined that the fair value less costs to sell of $260.1 million exceeded the carrying value of the assets and a $153.5 million impairment charge was recorded.

At December 31, 2013, it was determined that indicators of impairment existed and impairment tests were performed on the Company's CGUs. In the Alberta Gas CGU, reduced forward natural gas price forecasts resulted in the net book value of the CGU exceeding the estimated recoverable amount and Crew recognized a $16.3 million impairment charge. In the Company's Princess CGU, a lower estimated fair value in undeveloped land coupled with the extension in timing of cash-flows, from the deferral of planned waterflood projects, resulted in an impairment charge of $107.1 million. Offsetting these impairments was a reversal of prior period impairment charges of $52.2 million in the Company's Lloydminster heavy oil CGU. The reversal was determined appropriate as the 2013 drilling and recompletion program had resulted in improved well performance, adding additional reserves to the Company's pre-existing reserve base through extensions and infill drilling. In addition, operational results on certain pre-existing wells were better than historical results and, during 2013, a more favourable outlook on future Western Canadian Select heavy oil pricing was recognized by the Company's independent reserves evaluator.

As the recoverable amount of the CGUs are sensitive to a decrease in commodity prices, further impairment charges could be recorded in future periods. Alternatively, an improvement of commodity prices could reverse any impairment charges recorded to date, less applicable depletion and depreciation charges.

Loss on Divestiture of Property

The Company's efforts to focus on accelerated growth of our highly economic northeast British Columbia Montney projects resulted in the strategic sale of the Company's Princess and Alberta gas properties.

During the third quarter of 2014, the Company closed the Princess Disposition comprised of assets which had a carrying value of $463.1 million, including $15.6 million of exploration and evaluation costs, and associated decommissioning obligations of $26.7 million. Consideration consisted of cash of $150 million before closing adjustments. A loss of $288.4 million has been recognized on disposal.

During the second quarter of 2014, the Company closed the Alberta Gas Disposition comprised of assets which had a carrying value of $263.1 million and associated decommissioning obligations of $29.2 million. Consideration consisted of cash of $234 million, before closing adjustments. A loss of $8.1 million was recognized on the disposition's closing. In conjunction with this transaction, Crew acquired approximately 400 bbls per day of heavy oil production for gross proceeds of approximately $12 million.

Crew's decision to sell the Princess and Alberta gas properties for lower than their carrying values, and resulting in the realized impairment charges and losses on these sales, was predicated on the Company's ability to reinvest the net cash proceeds of $372 million into Montney projects that will offset production lost from the sale of these properties and is expected to generate higher future rates of return.

Finance Expenses

($ thousands, except per boe)	**Three months ended December 31, 2014**	Three months ended December 31, 2013	**Year ended December 31, 2014**	Year ended December 31, 2013
Interest on bank loan	**554**	2,682	**7,422**	11,949
Interest on senior notes	**3,166**	2,409	**12,562**	2,409
Accretion of deferred financing charges	**155**	161	**487**	161
Accretion of the decommissioning obligation	**575**	696	**2,836**	2,707
Total finance expense	**4,450**	5,948	**23,307**	17,226
Average debt level	**165,009**	344,498	**285,176**	304,585
Average drawings on bank loan	**15,009**	228,738	**135,176**	295,491
Effective interest rate on bank loan	**14.6%**	4.9%	**5.4%**	4.4%
Effective interest rate on senior notes	**8.4%**	8.4%	**8.4%**	8.4%
Effective interest rate on long-term debt	**9.0%**	6.0%	**7.0%**	4.8%
Interest on long-term debt per boe	**2.02**	1.99	**2.32**	1.45

For the fourth quarter and year ended December 31, 2014, average debt levels decreased over the same periods in 2013 as a result of receiving the proceeds from the Alberta Gas and Princess Dispositions. The effective interest rate on the Company's bank loan increased in both the fourth quarter and for the year ended December 31, 2014, as compared with the same periods in 2013, due to higher standby fees incurred on the Company's bank facility in 2014 resulting from a significant decrease in drawings on the facility following the issuance of the senior unsecured notes in the fourth quarter of 2013 and receipt of proceeds from the Alberta Gas and Princess Dispositions in 2014. After taking into account the effect of the proceeds received from the recent equity offering, which closed on March 3, 2015, the Company expects its effective interest rate on long-term debt will average approximately 8.5% to 9.5% in 2015 due to higher standby fees on forecasted reduced drawings on the bank facility.

Deferred Income Taxes

In the fourth quarter of 2014, the provision for deferred taxes was a recovery of $9.0 million compared to a recovery of $19.3 million for the same period in 2013. The reduced recovery is a result of a reduced pre-tax loss experienced during the fourth quarter of 2014. For the year ended December 31, 2014, the provision for deferred taxes was a recovery of $116.0 million compared to a recovery of $23.7 million for 2013. The higher recovery in 2014 is a result of the Company having an increased pre-tax loss related to the loss recorded on the Princess Disposition in the third quarter and the impairment charge incurred in the first quarter of 2014 related to the Alberta Gas Disposition and the impairment charge on the Lloydminster CGU in the fourth quarter of 2014.

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

($ thousands)	**December 31, 2014**	December 31, 2013
Cumulative Canadian Exploration Expense	**200,700**	179,200
Cumulative Canadian Development Expense	**453,500**	498,400
Cumulative Canadian Oil and Gas Property Expense	**-**	81,600
Undepreciated Capital Cost	**172,400**	184,000
Non-capital losses	**21,500**	21,500
Share issue costs	**3,900**	2,300
	852,000	967,000

The estimated income tax pools for 2014 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 2014. The Company did not pay cash taxes in 2014 and estimates it has sufficient tax pools to shelter estimated income until 2016 or beyond.

Cash, Funds from Operations and Net Income

($ thousands, except per share amounts)	**Three months ended December 31, 2014**	Three months ended December 31, 2013	**Year ended December 31, 2014**	Year ended December 31, 2013
Cash provided by operating activities	**37,714**	48,850	**169,207**	161,949
Funds from operations	**33,035**	48,128	**171,592**	172,438
Per share - basic	**0.27**	0.40	**1.40**	1.42
- diluted	**0.27**	0.40	**1.39**	1.42
Net loss	**(28,424)**	(58,429)	**(349,714)**	(79,311)
Per share - basic	**(0.23)**	(0.48)	**(2.86)**	(0.65)
- diluted	**(0.23)**	(0.48)	**(2.86)**	(0.65)

The decrease in cash provided by operating activities and funds from operations in the fourth quarter of 2014 was a result of reduced production due to the Alberta Gas Disposition in the second quarter, the Princess Disposition in the third quarter of 2014 and lower commodity prices in the fourth quarter of 2014. The increase in cash provided by operating activities in 2014 was due to reduced decommissioning obligations settled in 2014. The decrease in net loss in the fourth quarter 2014 was a result of reduced depletion costs resulting from increased proved and probable reserves at December 31, 2014 and the Princess Disposition in the third quarter of 2014. The increased net loss for the year ended December 31, 2014 was a result of higher impairment charges and the loss recognized on the Princess Disposition.

Capital Expenditures, Property Acquisitions and Dispositions

During the fourth quarter of 2014, the Company drilled 24 (23.3 net) wells resulting in 14 (14.0 net) oil wells and 10 (9.3 net) natural gas wells. In addition, the Company completed 9 (8.3 net) wells and recompleted 11 (9.8 net) wells in the quarter. The Company spent $14.7 million directed to infrastructure predominately on the Company's West Septimus facility currently planned for commissioning in Q3 2015.

In 2014, the Company drilled a total of 77 (72.7 net) wells resulting in 50 (46.4 net) oil wells, 26 (25.3 net) gas wells, and one (1.0 net) dry and abandoned well. During the year, the Company completed 51 (47.2 net) wells and recompleted 72 (67.6 net) wells. Crew's infrastructure spending was predominantly related to the West Septimus facility as well as pipeline, battery and various well equipping costs in northeast British Columbia.

During 2014, Crew purchased approximately 110 net sections of highly prospective Montney rights as well as 1,400 boe per day of natural gas production in the Septimus and Groundbirch areas of operation in northeast British Columbia for approximately $120 million.

In 2014, the Company closed the Princess Disposition. Consideration included $150 million in cash, before closing adjustments. The assets sold included production of approximately 3,650 boe per day and 259,000 net acres of land. In addition, the Company closed the Alberta Gas Disposition. Consideration included approximately $234 million in cash, before closing adjustments. The assets sold included production of approximately 7,000 boe per day of 75% natural gas production and 254,000 net acres of land. In conjunction with this transaction, Crew acquired 2,750 net acres of mineral rights with approximately 400 bbls per day of heavy oil production in the Lloydminster area for gross proceeds of approximately $12 million.

During the year, the Company also sold non-core undeveloped land in northeast British Columbia for proceeds of $11 million consisting of cash of $8 million and 1.4 million shares of a TSX-V listed company.

Total net capital expenditures are detailed below:

($ thousands)	**Three months ended December 31, 2014**	Three months ended December 31, 2013	**Year ended December 31, 2014**	Year ended December 31, 2013
Land	**920**	2,631	**4,150**	7,639
Seismic	**1,516**	459	**5,985**	4,015
Drilling and completions	**61,406**	34,742	**231,100**	157,488
Facilities, equipment and pipelines	**14,748**	15,206	**54,463**	39,475
Other	**2,857**	2,958	**11,077**	11,414
Total exploration and development	**81,447**	55,996	**306,775**	220,031
Property acquisitions (dispositions)	**1,901**	(1,931)	**(252,478)**	40,218
Total	**83,348**	54,065	**54,297**	260,249

The Company's Board of Directors has approved a net $185 million exploration and development budget for 2015.

LIQUIDITY AND CAPITAL RESOURCES

Capital Funding

The Company has a credit facility with a syndicate of lending banks (the "Syndicate"). The credit facility includes a revolving line of credit of $250 million and an operating line of credit of $30 million (the "Facility"). This amount reflects adjustments made in the fourth quarter to reflect the net effect of the Alberta Gas Disposition and the Princess Disposition as well as the mid-year engineering review. The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 8, 2015. 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 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 of 4:1 and a secured debt to EBITDA ratio of 3:1 at the end of each fiscal quarter. At December 31, 2014, these ratios were 1.4:1 and 0.4:1, respectively. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled borrowing base review on or before June 8, 2015. At December 31, 2014, the Company had drawings of $49.9 million on the Facility and had issued letters of credit totaling $2.4 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.

A substantial decline in both oil and natural gas prices in the fourth quarter of 2014 negatively impacted cash flow. With the low commodity price environment persisting into the early part of 2015, the Company has elected to increase its financial flexibility through the issuance of additional equity on a bought deal basis as discussed in note 21 in the Company's 2014 annual financial statements. On February 9, 2015, the Company entered into an agreement with a syndicate of underwriters who agreed to purchase 16,667,000 Common Shares of the Company at a price of $6.00 per Common Share for aggregate gross proceeds of approximately $100 million. The equity offering closed on March 3, 2015.

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, 2014, the Company's working capital deficiency totaled $57.7 million which, when combined with the drawings on its bank loan, represented 38% of its bank facility at December 31, 2014.

Share Capital

In September 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 implied premium of $3.0 million. Pursuant to the provisions of the Income Tax Act (Canada), the Company is committing 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 will renounce the Canadian Exploration Expenses such that the full proceeds will be deductible against the subscribers' income for the fiscal year ended December 31, 2014. At December 31, 2014, the Company has incurred $2.2 million in qualifying expenditures under this flow-through share offering.

Crew is authorized to issue an unlimited number of common shares. As at March 6, 2015, there were 140,099,762 common shares and options to acquire 5,204,003 common shares of the Company issued and outstanding. In addition, there were 749,600 restricted awards and 964,118 performance awards outstanding.

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 over short-term periods. As shown below, as at December 31, 2014, the Company's ratio of net debt to annualized funds from operations was 1.92 to 1 (December 31, 2013 – 1.99 to 1). As discussed above in *Capital Funding*, the Company has elected to increase its flexibility through the issuance of additional equity. In addition, the Company plans to continue its strategy of divesting of non-core properties, will adjust its annual capital expenditure program, if necessary, or may consider other forms of financing in order to maintain its financial flexibility.

($ thousands, except ratio)	**December 31, 2014**	December 31, 2013
Working capital deficit	**(57,722)**	(40,098)
Bank loan	**(49,904)**	(197,688)
Senior unsecured notes	**(146,110)**	(145,623)
Net debt	**(253,736)**	(383,409)
Fourth quarter funds from operations	**33,035**	48,128
Annualized	**132,140**	192,512
Net debt to annualized funds from operations ratio	**1.92**	1.99

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	2015	2016	2017	2018	2019	Thereafter
Bank Loan (note 1)	49,904	-	49,904	-	-	-	-
Senior unsecured notes (note 2)	150,000	-	-	-	-	-	150,000
Operating leases	5,119	2,494	2,625	-	-	-	-
Firm transportation agreements	140,072	5,596	25,675	26,031	26,031	26,031	30,708
Firm processing agreements	55,125	12,029	10,556	9,114	8,509	8,228	6,689
Capital commitment	9,655	9,655	-	-	-	-	-
Total	409,875	29,774	88,760	35,145	34,540	34,259	187,397

Note 1 – Based on the existing terms of the Company's bank facility the first possible repayment date may come in 2016. However, it is expected that the revolving bank facility will be extended and no repayment will be required in the near term.
Note 2 – Matures on October 21, 2020.

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

The 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 the Septimus area.

The capital commitment represents the Canadian Exploration Expenses to be incurred and renounced to subscribers of the shares as discussed in *Share Capital* above.

GUIDANCE

The Company's 2015 hedge position and a strengthened balance sheet, following the closing of the $100 million equity offering, affords Crew greater liquidity and financial flexibility to manage its business prudently during this period of uncertain commodity prices. Without a clear line of sight to an improved pricing environment, Crew continues to diligently review its operations and capital projects to ensure they meet corporate objectives and economic hurdles. The Company's 2015 capital program of up to $185 million is structured to allow Crew to maintain financial strength while enabling the Company to move quickly and adjust its projects as economics warrant. The Company continues to monitor capital spending in the current depressed commodity price environment and believes that lower costs could lead to improved efficiencies. Crew expects 2015 production to average between 20,000 and 22,000 boe per day with a 2015 exit rate between 24,000 and 25,000 boe per day.

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 2014	Sept 30 2014	June 30 2014	Mar. 31 2014	Dec. 31 2013	Sept. 30 2013	June 30 2013	Mar. 31 2013
Total daily production (boe/d)	20,869	20,846	27,200	28,021	28,682	28,016	27,109	25,961
Exploration and development expenditures	81,447	106,405	52,783	66,140	55,996	68,435	30,348	65,252
Property acquisitions/(dispositions)	1,901	(141,796)	(215,115)	102,532	(1,931)	33,203	(5,717)	14,663
Average wellhead price ($/boe)	37.65	50.51	50.86	51.69	41.84	45.85	44.91	39.06
Petroleum and natural gas sales	72,295	96,879	125,882	130,368	110,394	118,173	110,793	91,267
Cash provided by operations	37,714	37,566	43,589	50,338	48,850	42,698	44,486	25,917
Funds from operations	33,035	39,023	47,724	51,810	48,128	42,035	48,087	34,188
Per share – basic	0.27	0.32	0.39	0.43	0.40	0.35	0.40	0.28
– diluted	0.27	0.31	0.38	0.42	0.40	0.35	0.40	0.28
Net income (loss)	(28,424)	(195,389)	3,792	(129,693)	(58,429)	(843)	2,008	(22,047)
Per share – basic	(0.23)	(1.60)	0.03	(1.07)	(0.48)	(0.01)	0.02	(0.18)
– diluted	(0.23)	(1.60)	0.03	(1.07)	(0.48)	(0.01)	0.02	(0.18)

Over the past eight quarters, fluctuations in petroleum and natural gas sales have resulted from volatility in commodity prices as well as variations in production volumes. Funds from operations are further affected by related royalty impacts as well as realized gains and losses on risk management contracts, while net income is additionally affected by unrealized gains and losses on risk management contracts as well as net impairments on property, plant and equipment and gains and losses on dispositions of assets.

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

($ thousands, except per share amounts)	**Year ended Dec. 31, 2014**	Year ended Dec. 31, 2013	Year ended Dec. 31, 2012
Petroleum and natural gas sales	**425,424**	430,627	417,763
Cash provided by operations	**169,207**	161,949	213,591
Funds from operations	**171,592**	172,438	186,604
Per share - basic	**1.40**	1.42	1.54
- diluted	**1.39**	1.42	1.54
Net income (loss)	**(349,714)**	(79,311)	21,542
Per share - basic	**(2.86)**	(0.65)	0.18
- diluted	**(2.86)**	(0.65)	0.18
Daily production (boe/d)	**24,205**	27,451	27,963
Crew average sales price ($/boe)	**48.15**	42.98	40.82
Total assets	**1,225,065**	1,843,027	1,833,802
Working capital deficiency (note 1)	**57,722**	40,098	48,522
Bank loan	**49,904**	197,688	242,834
Senior unsecured notes	**146,110**	145,623	-
Total other long-term liabilities	**143,344**	280,945	305,308

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

Crew's petroleum and natural gas sales, cash provided by operations, funds from operations and net income are all impacted by production levels and commodity pricing. These performance measures have all fluctuated throughout 2012 to 2014 as a result of volatile oil and natural gas prices combined with the increased cost of the Company's operations. Over the last three years, net income has largely been affected by fluctuating net impairment charges. In 2014, the Company incurred $233.7 million in impairment charges and in 2013, the Company incurred $123.5 million of impairment charges on certain CGUs. In 2012, the Company incurred $122.8 million of impairment charges, $52.2 million of which were reversed in 2013.

New Accounting Pronouncements

On January 1, 2014, the Company adopted International Financial Reporting Interpretations Committee ("IFRIC") Interpretation 21 - Levies, which addresses payments to government bodies. There was no impact on the Company as a result of adopting the new standard.

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

(a) IFRS-9 Financial Instruments:

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, 2014 Crew is still determining the impact that the adoption of this standard will have on its financial statements.

(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, 2014 Crew is still determining the impact that the adoption of this standard will have on its financial statements.

(c) 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, 2014 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, 2014 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 and operating costs 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 (1992), 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, 2014 and ended on December 31, 2014 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 6, 2015

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 6, 2015

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, 2014 and December 31, 2013, 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, 2014 and December 31, 2013, 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 Accountants
Calgary, Canada
March 6, 2015

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(thousands)		**December 31, 2014**		December 31, 2013
Assets				
Current Assets:				
Accounts receivable	**$**	**35,393**	$	49,877
Marketable securities (note 7)		**2,052**		-
Derivative financial instruments (note 15)		**41,024**		-
		78,469		49,877
Exploration and evaluation assets (note 8)		**-**		15,556
Property, plant and equipment (note 9)		**1,146,596**		1,777,594
	$	**1,225,065**	$	1,843,027
Liabilities and Shareholders' Equity				
Current Liabilities:				
Accounts payable and accrued liabilities	**$**	**93,115**	$	89,975
Derivative financial instruments (note 15)		**2,222**		15,340
		95,337		105,315
Derivative financial instruments (note 15)		**736**		-
Bank loan (note 11)		**49,904**		197,688
Senior unsecured notes (note 12)		**146,110**		145,623
Decommissioning obligations (note 13)		**82,836**		108,118
Deferred premium on flow-through shares (note 14)		**2,402**		-
Deferred tax liability (note 16)		**57,370**		172,827
Shareholders' Equity				
Share capital (note 14)		**1,292,693**		1,275,910
Contributed surplus		**72,951**		63,106
Deficit		**(575,274)**		(225,560)
		790,370		1,113,456
Commitments (note 19)				
Subsequent event (note 21)				
	$	**1,225,065**	$	1,843,027

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, 2014**	Year ended December 31, 2013
Revenue		
Petroleum and natural gas sales	**$ 425,424**	$ 430,627
Royalties	**(82,621)**	(85,464)
Realized loss on derivative financial instruments (note 15)	**(23,262)**	(15,436)
Unrealized gain (loss) on derivative financial instruments (note 15)	**53,406**	(8,170)
	372,947	321,557
Expenses		
Operating	**95,128**	111,569
Transportation	**13,314**	12,572
General and administrative	**19,036**	18,629
Share-based compensation	**6,548**	4,453
Depletion and depreciation	**158,835**	190,176
	292,861	337,399
Income (loss) from operations	**80,086**	(15,842)
Financing (note 18)	**23,307**	17,226
Unrealized loss on marketable securities (note 7)	**948**	-
Impairment on property, plant and equipment (note 10)	**233,719**	71,206
Loss (gain) on divestiture of property, plant and equipment (note 9)	**287,836**	(1,269)
Loss before income taxes	**(465,724)**	(103,005)
Deferred tax recovery (note 16)	**(116,010)**	(23,694)
Net loss and comprehensive loss	**$ (349,714)**	$ (79,311)
Net loss per share (note 14)		
Basic	**$ (2.86)**	$ (0.65)
Diluted	**$ (2.86)**	$ (0.65)

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, 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

	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 2013	121,620	$1,275,777	$ 54,035	$ (146,249)	$ 1,183,563
Net loss	-	-	-	(79,311)	(79,311)
Share-based compensation expensed	-	-	4,453	-	4,453
Share-based compensation capitalized	-	-	4,660	-	4,660
Transfer of share-based compensation on exercises	-	42	(42)	-	-
Issued on exercise of options	15	91	-	-	91
Balance December 31, 2013	121,635	$1,275,910	$ 63,106	$ (225,560)	$ 1,113,456

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands)	**Year ended December 31, 2014**	Year ended December 31, 2013
Cash provided by (used in):		
Operating activities:		
Net loss	**$ (349,714)**	$ (79,311)
Adjustments:		
Share-based compensation	**6,548**	4,453
Financing expenses	**23,307**	17,226
Interest expense (note 18)	**(19,984)**	(14,358)
Unrealized loss on marketable securities	**948**	-
Unrealized loss (gain) on derivative financial instruments	**(53,406)**	8,170
Depletion and depreciation	**158,835**	190,176
Impairment of property, plant and equipment	**233,719**	71,206
Loss (gain) on divestiture of property, plant and equipment	**287,836**	(1,269)
Deferred tax recovery	**(116,010)**	(23,694)
Decommissioning obligations settled (note 13)	**(768)**	(4,333)
Change in non-cash working capital (note 17)	**(2,104)**	(6,317)
	169,207	161,949
Financing activities:		
Decrease in bank loan	**(147,784)**	(45,146)
Proceeds from exercise of options	**4,271**	91
Proceeds from issuance of flow-through shares	**11,901**	-
Issuance of senior unsecured notes, net of financing costs	**-**	145,462
Share issue costs	**(26)**	-
	(131,638)	100,407
Investing activities:		
Property, plant and equipment expenditures	**(306,775)**	(220,031)
Property acquisitions	**(138,868)**	(55,866)
Property dispositions	**388,346**	15,648
Change in non-cash working capital (note 17)	**19,728**	(2,107)
	(37,569)	(262,356)
Change in cash and cash equivalents	**-**	-
Cash and cash equivalents, beginning of year	**-**	-
Cash and cash equivalents, end of year	**$ -**	$ -

See accompanying notes to the consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2014 and 2013

(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 Alberta, British Columbia and Saskatchewan. 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 three partnerships, Crew Energy Partnership, Crew Heavy Oil Partnership and Crew Conventional Partnership. Subsequent to December 31, 2014, all of the remaining assets held within Crew Conventional Partnership were distributed to the partners and the partnership was dissolved. 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 6.

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 6, 2015.

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 comprise 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 plant	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. Leased assets 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) E&E 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 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. New accounting policies:

On January 1, 2014, the Company adopted International Financial Reporting Interpretations Committee ("IFRIC") Interpretation 21 – Levies, which addresses payments to government bodies. There was no impact on the Company's financial statements as a result of adopting the new standard.

5. Future accounting policies:

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

(a) 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, 2014 Crew is still determining the impact that the adoption of this standard will have on its financial statements.

(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, 2014 Crew is still determining the impact that the adoption of this standard will have on its financial statements.

(c) 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, 2014 Crew is still determining the impact that the adoption of this standard will have on its financial statements.

6. 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, 2014 and December 31, 2013, 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, 2014 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.

(iii) Derivatives:

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

(iv) 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).

(v) 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.

7. Marketable securities:

During 2014, the Company sold non-core undeveloped land located in northeast British Columbia, and received 1,415,094 common shares of a public company, trading on the TSX Venture exchange, as partial consideration. The shares received were initially valued at $2.12 per common share for a total value of $3.0 million. As at December 31, 2014 the fair market value of the marketable securities was $1.45 per common share and as a result an unrealized loss of $0.9 million was recorded in the Company's financial statements.

8. Exploration and evaluation assets:

Cost or deemed cost		Total
Balance, January 1, 2013	$	60,651
Transfer to property, plant and equipment		(45,095)
Balance, December 31, 2013	$	15,556
Divestitures		(15,556)
Balance, December 31, 2014	$	-

Exploration and evaluation (E&E) assets consisted of the Company's exploration projects which were pending the determination of proven and/or probable reserves. During 2014, the Company disposed of all its exploration and evaluation assets (Property, plant and equipment – note 9).

9. Property, plant and equipment:

Cost or deemed cost	Total
Balance, January 1, 2013	$ 2,397,442
Additions	220,031
Transfer from exploration and evaluation assets	45,095
Acquisitions	55,866
Divestitures	(21,971)
Change in decommissioning obligations	4,083
Capitalized share-based compensation	4,660
Balance, December 31, 2013	$ 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

Accumulated depletion and depreciation	Total
Balance, January 1, 2013	$ 670,696
Depletion and depreciation expense	190,176
Divestitures	(4,466)
Impairment (net)	71,206
Balance, December 31, 2013	$ 927,612
Depletion and depreciation expense	158,835
Divestitures	(615,726)
Impairment (net)	233,719
Balance, December 31, 2014	$ 704,440

Net book value	Total
Balance, December 31, 2013	$ 1,777,594
Balance, December 31, 2014	$ 1,146,596

The calculation of depletion for the three months ended December 31, 2014 included estimated future development costs of $1,295.7 million (December 31, 2013 - $995.3 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $67.1 million (December 31, 2013 - $93.4 million) and undeveloped land of $218.1 million (December 31, 2013 - $220.1 million) related to future development acreage.

The Company's 2014 acquisitions consisted mainly of undeveloped land and natural gas production in northeast British Columbia and heavy oil production in Lloydminster along with their associated decommissioning obligations.

During the second quarter of 2014, the Company closed the Alberta Gas Disposition comprised of assets which had a net book value of $263.1 million and associated decommissioning obligations of $29.2 million. Cash consideration received was $234 million, before closing adjustments. A loss of $8.1 million was recognized on the disposition's closing.

During the third quarter of 2014, the Company disposed of certain petroleum and natural gas properties in southern Alberta with a net book value of $463.1 million, including $15.6 million of exploration and evaluation assets, and associated decommissioning obligations of $26.7 million. Consideration consisted of cash of $150 million before closing adjustments. A loss of $288.4 million was recognized on the disposition's closing.

10. Impairment:

		Year ended December 31, 2014		Year ended December 31, 2013
Impairment losses:				
E&E Assets	**$**	**-**	$	-
PP&E		**80,180**		123,454
Assets held for sale		**153,539**		-
	$	**233,719**	$	123,454
Impairment reversals:				
E&E Assets	**$**	**-**	$	-
PP&E		**-**		(52,248)
	$	**-**	$	(52,248)
	$	**233,719**	$	71,206

(a) Assessment:

At December 31, 2014, and 2013, 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, were estimated as the fair value less costs to sell based on the net present value of the before tax cash flows from oil and gas proved plus probable reserves estimated by the Company's third party reserve evaluators discounted at a pre-tax rate of 10% (2013 – 10%) and the internally estimated fair value of undeveloped lands based on land sales and industry activity in the area.

Impairment reversals were 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. In determining the appropriate discount rate the Company considered the acquisition metrics of recent transactions completed on assets similar to those in the specific CGU.

(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 fair value less costs to sell of $260.1 million exceeded the carrying value of the assets 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.

(c) Results of 2013 assessment:

The following estimates were used in determining whether an impairment or reversal to the carrying value of the CGUs existed at December 31, 2013:

	WTI Oil (US$/bbl)	WCS ($Cdn/bbl)	AECO Gas ($Cdn/mmbtu)	$Cdn/$US
2014	94.65	77.81	4.00	0.94
2015	88.37	75.02	3.99	0.94
2016	84.25	75.29	4.00	0.94
2017	95.52	85.36	4.93	0.94
2018	96.96	86.64	5.01	0.94
2019	98.41	87.94	5.09	0.94
2020	99.89	89.26	5.18	0.94
2021	101.38	90.60	5.26	0.94
2022	102.91	91.96	5.35	0.94
2023	104.45	93.34	5.43	0.94
2024	106.02	94.74	5.52	0.94
Remainder	+1.5%/yr	+1.5%/yr	+1.5%/yr	0.94 thereafter

At December 31, 2013, it was determined that indicators of impairment existed and impairment tests were performed on the Company's CGUs. In the Alberta Gas CGU, reduced forward natural gas price forecasts resulted in the carrying value of the CGU exceeding its recoverable amount and Crew recognized a $16.3 million impairment charge. In the Company's Princess CGU, a lower estimated fair value in undeveloped land coupled with the extension in timing of cash-flows, from the deferral of planned waterflood projects, resulted in an impairment charge of $107.1 million. Offsetting these impairments was a reversal of prior period impairment charges of $52.2 million in the Company's Lloydminster heavy oil CGU. The reversal was determined appropriate as the 2013 drilling and recompletion program had resulted in improved well performance, adding additional reserves to the Company's pre-existing reserve base through extensions and infill drilling. In addition, operational results on certain pre-existing wells were better than historical results and, during 2013, a more favourable outlook on future Western Canadian Select heavy oil pricing was recognized by the Company's independent reserves evaluator.

11. Bank loan:

The Company's bank facility as at December 31, 2014 consisted of a revolving line of credit of $250 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 8, 2015. 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 are reviewed semi-annually and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. The credit agreement requires the Company to maintain a debt to EBITDA ratio of 4:1 and a secured debt to EBITDA ratio of 3:1 at the end of each fiscal quarter. Debt consists of the Company's bank debt and senior unsecured notes while secured debt consists of the Company's bank debt. At December 31, 2014, these ratios were 1.4:1 and 0.4:1, 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, 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 8, 2015. 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, 2014, 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, 2014, the Company had issued letters of credit totaling $2.4 million (December 31, 2013 - $12.1 million). The effective interest rate on the Company's borrowings under its bank facility for the year ended December 31, 2014 was 5.4% (2013 – 4.4%).

12. 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, 2014, the carrying value of the senior unsecured notes was net of deferred financing costs of $3.9 million (December 31, 2013 - $4.4 million).

13. Decommissioning obligations:

	As at December 31, 2014	As at December 31, 2013
Decommissioning obligations, beginning of year	**$ 108,118**	$ 108,787
Obligations incurred	**6,134**	10,975
Obligations acquired	**16,882**	997
Obligations settled	**(768)**	(4,333)
Obligations divested	**(56,408)**	(3,126)
Change in estimated future cash outflows	**6,042**	(7,889)
Accretion of decommissioning obligations	**2,836**	2,707
Decommissioning obligations, end of year	**$ 82,836**	$ 108,118

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 $82.8 million as at December 31, 2014 (December 31, 2013 - $108.1 million) based on an undiscounted total future liability of $84.8 million (December 31, 2013 - $117.1 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% (2013 – 2%). The discount factor, being the risk-free rate related to the liability, is 2.24% (December 31, 2013 – 3.13%). The $6.0 million (December 31, 2013 - $7.9 million) change in estimated future cash outflows is a result of the change in the estimated discount factor.

14. Share capital:

At December 31, 2014, the Company was authorized to issue an unlimited number of common shares with the holders of common shares entitled to one vote per share.

During 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 committing 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 will renounce the Canadian Exploration Expenses such that the full proceeds will be deductible against the subscribers' income for the fiscal year ended December 31, 2014. At December 31, 2014, the Company has incurred $2.2 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, 2013	6,420	$ 9.94
Granted	2,413	$ 7.00
Exercised	(15)	$ 5.65
Forfeited	(811)	$ 10.15
Expired	(29)	$ 9.16
Balance December 31, 2013	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

The weighted average trading price of the Company's common shares was $8.93 during the year ended December 31, 2014 (December 31, 2013 - $6.02).

The following table summarizes information about the stock options outstanding at December 31, 2014:

Range of exercise prices	Outstanding at Dec 31, 2014	Weighted average remaining life (years)	Weighted average exercise price	Exercisable at Dec 31, 2014	Weighted average exercise price
$ 5.16 to $ 7.01	2,353	1.5	$ 5.75	1,416	$ 5.71
$ 7.02 to $ 9.94	1,661	2.2	$ 7.19	521	$ 7.20
$ 9.95 to $14.63	912	0.9	$ 11.13	835	$ 11.04
$14.64 to $17.61	280	0.5	$ 14.98	280	$ 14.98
	5,206	1.6	$ 7.65	3,052	$ 8.27

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

Assumptions	**Year ended December 31, 2014**	Year ended, December 31, 2013
Risk free interest rate (%)	**1.3**	1.2
Expected life (years)	**4.0**	4.0
Expected volatility (%)	**43**	47
Forfeiture rate (%)	**15.6**	16.2
Weighted average fair value of options	**$ 2.57**	$ 2.63

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, 2014, the fair value of awards granted was calculated using an estimated forfeiture rate of 9% (December 31, 2013 – 6%). The weighted average fair value of awards granted for the year ended December 31, 2014 was $11.44 (December 31, 2013 - $7.01). In the case of PAs, the award value is adjusted for a payout multiplier which can range from 0.0 to 2.0 and is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. On the vesting dates, the Company has the option of settling the award value in cash or common shares of the Company.

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

	Number of restricted awards	Number of performance awards
Balance January 1, 2013	-	-
Granted	325	341
Forfeited	(29)	(21)
Balance December 31, 2013	296	320
Granted	732	901
Vested	(91)	(102)
Forfeited	(178)	(151)
Balance December 31, 2014	759	968

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, 2014 was 122,395,000 (December 31, 2013 – 121,629,000).

In computing diluted earnings per share for the year ended December 31, 2014, NIL (December 31, 2013 – 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 5,206,000 (December 31, 2013 – 7,978,000) stock options and 1,727,000 (December 31, 2013 – 616,000) restricted and performance awards that were not included in the diluted earnings per share calculation because they were anti-dilutive.

15. 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, 2014	December 31, 2013
Trade and other receivables	**$ 35,393**	$ 49,877
Marketable securities	**2,052**	-
Derivative financial assets	**41,024**	-
	$ 78,469	$ 49,877

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 2014, 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, 2014 the Company's receivables consisted of $21.4 million (December 31, 2013 - $38.4 million) of receivables from petroleum and natural gas marketers which has subsequently been collected, $5.8 million (December 31, 2013 - $6.4 million) from partners within jointly owned assets and operations of which $1.3 million has been subsequently collected, and $8.2 million (December 31, 2013 - $5.1 million) of deposits, prepaids and other accounts receivable. 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. Substantially all of the Company's petroleum and natural gas sales are conducted in Canada and are denominated in Canadian dollars. 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, 2014 was $135.2 million (December 31, 2013 - $275.4 million). For the year ended December 31, 2014, a 1.0 percent change to the effective interest rate would have a $1.6 million impact on net income (December 31, 2013 - $2.1 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, 2014, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Oil	750 bbl/day	January 1, 2015 – June 30, 2015	CDN$ WTI	$103.80	Swap	5,400
Oil	1,750 bbl/day	January 1, 2015 – December 31, 2015	CDN$ WTI	$102.62	Swap	23,092
Oil	2,000 bbl/day	January 1, 2015 – December 31, 2015	CDN$ WCS – WTI diff	($21.59)	Swap	(1,984)
Gas	30,000 gj/day	January 1, 2015 – December 31, 2015	AECO C Monthly Index	$3.75	Swap	11,590
Gas	7,500 gj/day	July 1, 2015 – December 31, 2015	AECO C Monthly Index	$3.41	Swap	942
Gas	2,500 gj/day	January 1, 2015 – March 31, 2015	US$ Chicago Citygate	$4.15	Swap(1)	(238)
Oil	500 bbl/day	January 1, 2016 – December 31, 2016	CDN$ WTI	$116.50	Call	(324)
Oil	250 bbl/day	January 1, 2016 – December 31, 2016	CDN$ WTI	$88.00 – $100.00	Call(2)	(412)
Total						38,066

(1) The referenced contract is associated with the cost of make-up gas resulting from processing a portion of the Company's natural gas liquids sales.
(2) The referenced contract is a structured call which is only triggered if the average CDN$ WTI trades above $100 per bbl for a given month during the term.

As at December 31, 2014, a 10% decrease to the price outlined in the contracts above would result in a $5.4 million increase in net income.

(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 11, that is subject to renewal annually by the lenders and has a contractual maturity in 2016. In addition, the Company issued $150 million in senior unsecured notes in 2013 that are scheduled to mature in 2020 as discussed in note 12.

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, 2014, the Company's ratio of net debt to annualized funds from operations was 1.92 to 1 (December 31, 2013 – 1.99 to 1). A substantial decline in both oil and natural gas prices in the fourth quarter of 2014 negatively impacted cash flow. With the low commodity price environment persisting into the early part of 2015, the Company has elected to increase its flexibility through the issuance of additional equity as discussed in note 21. In addition, the Company plans to continue its strategy of divesting of non-core properties, will adjust its annual capital expenditure program, if necessary, or may consider other forms of financing in order to maintain its financial flexibility.

		December 31, 2014		December 31, 2013
Net debt:				
Accounts receivable	**$**	**35,393**	$	49,877
Accounts payable and accrued liabilities		**(93,115)**		(89,975)
Working capital deficiency	**$**	**(57,722)**	$	(40,098)
Bank loan		**(49,904)**		(197,688)
Senior unsecured notes		**(146,110)**		(145,623)
Net debt	**$**	**(253,736)**	$	(383,409)
Fourth Quarter Annualized funds from operations:				
Cash provided by operating activities	**$**	**37,714**	$	48,850
Decommissioning obligations settled		**249**		379
Change in non-cash working capital		**(4,773)**		(940)
Accretion of deferred financing charges		**(155)**		(161)
Fourth Quarter Funds from operations	**$**	**33,035**	$	48,128
Annualized	**$**	**132,140**	$	192,512
Net debt to annualized funds from operations		**1.92**		1.99

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 11).

16. 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, 2014	Year ended December 31, 2013
Loss before income taxes	**$ (465,724)**	$ (103,005)
Combined federal and provincial income tax rate	**25.6%**	25.4%
Computed "expected" income tax recovery	**$ (119,039)**	$ (26,163)
Increase (decrease) in income taxes resulting from:		
Non-deductible share-based compensation	**1,733**	1,132
Change in income tax rates	**1,015**	656
Flow-through share renunciation	**574**	-
Other	**266**	681
	(115,451)	(23,694)
Premium on flow-through shares	**(559)**	-
Deferred income tax recovery	**$ (116,010)**	$ (23,694)

The income tax rate change is due to a change in the applied weighting of statutory provincial income tax rates.

(b) Deferred income tax liability:

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

	December 31, 2014	December 31, 2013
Deferred tax liabilities:		
Property, plant and equipment	**$ 74,756**	$ 210,387
Derivative financial instruments	**9,730**	-
Deferred tax assets:		
Derivative financial instruments	**-**	(3,898)
Decommissioning obligations	**$ (21,245)**	$ (27,472)
Non-capital losses	**(5,488)**	(5,464)
Other	**(383)**	(726)
Deferred income tax liability	**$ 57,370**	$ 172,827

The Company's assets have an approximate tax basis of $852 million at December 31, 2014 (December 31, 2013 - $967 million) available for deduction against future taxable income. The following table summarizes the tax pools:

	December 31, 2014	December 31, 2013
Cumulative Canadian Exploration Expense	**$ 200,700**	$ 179,200
Cumulative Canadian Development Expense	**453,500**	498,400
Cumulative Canadian Oil and Gas Property Expense	**-**	81,600
Undepreciated Capital Costs	**172,400**	184,000
Non-capital losses	**21,500**	21,500
Share issue costs	**3,900**	2,300
Estimated tax basis	**$ 852,000**	$ 967,000

Non-capital losses will begin expiring in 2028. The estimated income tax pools for 2014 have been reduced by the estimated deferred partnership income for 2014.

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

	January 1, 2013	Recognized in profit or loss	December 31, 2013
Property, plant and equipment	$ 227,019	$ (16,632)	$ 210,387
Decommissioning obligations	(27,545)	73	(27,472)
Derivative financial instruments	(1,815)	(2,083)	(3,898)
Non-capital losses	-	(5,464)	(5,464)
Other	(1,138)	412	(726)
	$ 196,521	$ (23,694)	$ 172,827

	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

17. Supplemental cash flow information:

Changes in non-cash working capital is comprised of:

	Year ended December 31, 2014	Year ended December 31, 2013
Changes in non-cash working capital:		
Accounts receivable	**$ 14,484**	$ (3,472)
Accounts payable and accrued liabilities	**3,140**	(4,952)
	$ 17,624	$ (8,424)
Operating activities	**$ (2,104)**	$ (6,317)
Investing activities	**19,728**	(2,107)
	$ 17,624	$ (8,424)
Interest paid	**$ (20,682)**	$ (11,479)

18. Financing:

	Year ended December 31, 2014	Year ended December 31, 2013
Interest expense	**$ 19,984**	$ 14,358
Accretion of deferred financing costs	**487**	161
Accretion of decommissioning obligations	**2,836**	2,707
	$ 23,307	$ 17,226

19. Commitments:

	Total	2015	2016	2017	2018	2019	Thereafter
Operating leases	$ 5,119	$ 2,494	$ 2,625	$ -	$ -	$ -	$ -
Firm transportation agreements	140,072	5,596	25,675	26,031	26,031	26,031	30,708
Firm processing agreement	55,125	12,029	10,556	9,114	8,509	8,228	6,689
Capital commitment	9,655	9,655	-	-	-	-	-
Total	$209,971	$ 29,774	$ 38,856	$ 35,145	$ 34,540	$34,259	$ 37,397

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

The 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 the Septimus area.

The capital commitment represents the Canadian Exploration Expenses to be incurred and renounced to subscribers of the shares (Share Capital – note 14).

20. Personnel expenses:

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

	Year ended December 31, 2014	Year ended December 31, 2013
Short-term benefits	**$ 4,766**	$ 4,438
Share-based compensation	**4,767**	3,474
	$ 9,533	$ 7,912

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.

21. Subsequent event:

On February 9, 2015, the Company entered into an agreement with a syndicate of underwriters who agreed to purchase 16,667,000 common shares of the Company, on a bought deal basis, at a price of $6.00 per common share for aggregate gross proceeds of approximately $100.0 million. The offering closed on March 3, 2015.

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

Gary P. Smith
Vice President, Exploration

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