interim report Q1 2015

first quarter ending March 31, 2015

crew energy inc.

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

FIRST QUARTER HIGHLIGHTS

- Updated our independent Montney Resource Evaluation, with the Best Estimate Economic Contingent Resource estimate increasing 48% year over year to 7.4 TCFE, which demonstrates the success of Crew's ongoing Montney-focused strategy;

- Realized production of 19,035 boe per day, which reflects higher Northeast British Columbia ("NE BC") volumes compared to the first quarter of 2014, the impact of over 11,200 boe per day production sold during 2014, and the curtailment of 800 boe per day of heavy oil production;

- Grew production from our NE BC areas to 14,260 boe per day or 75% of Crew's total production for the quarter, representing a 34% increase over the same period in 2014, primarily attributable to strong Montney drilling results. Production from Saskatchewan averaged 2,805 boe per day, representing 15% of the total, while Alberta averaged 1,970 boe per day, or 10% of total production;

- Generated funds from operations of $20.7 million ($0.16 per diluted share), impacted by significantly weakened commodity prices, and partially offset by a meaningful reduction in overall cash costs and hedging gains of $11.3 million;

- Achieved a 36% reduction in total cash costs per boe (including royalties, operating, transportation, general and administrative and interest) compared to the first quarter of 2014, and a 20% reduction relative to the previous quarter;

- Invested $91.4 million in capital expenditures, with $41.0 million (45%) directed to drilling and completions activities, and $41.8 million (46%) to facilities, equipment and pipelines. The majority of our infrastructure capital investment relates to continued construction of our new West Septimus facility, on schedule for commissioning in the third quarter, that will give us the processing capacity to double the production from our Montney assets;

- Drilled four (4.0 net) gas wells and two (2.0) net oil wells with 100% success, and focused on lower-cost, higher capital efficiency projects including completing nine (9.0 net) natural gas wells in Septimus / West Septimus, and one (1.0 net) heavy oil well in Lloydminster. Crew now has 25 Montney wells behind pipe either awaiting completion or tie-in;

- On restricted initial flow-back, five of our West Septimus wells yielded levels of sales condensate which are four times greater than our average historical Septimus wells and 3.7 times greater than the condensate ratios used in our year end 2014 independent reserve evaluation for West Septimus; and

- Successfully closed a $100 million bought deal equity financing in March 2015 which strengthened the balance sheet, and reduced Crew's net debt position to $230 million at the end of the quarter, on total current debt capacity of $410 million.

FINANCIAL & OPERATING HIGHLIGHTS

FINANCIAL ($ thousands, except per share amounts)	Three months ended March 31, 2015	Three months ended March 31, 2014
Petroleum and natural gas sales	**39,940**	130,368
Funds from operations[1]	**20,720**	51,810
Per share - basic	**0.16**	0.43
- diluted	**0.16**	0.42
Net income (loss)	**(15,770)**	(129,693)
Per share - basic	**(0.12)**	(1.07)
- diluted	**(0.12)**	(1.07)
Exploration and Development expenditures	**91,092**	66,140
Property acquisitions (net of dispositions)	**258**	102,532
Net capital expenditures	**91,350**	168,672

Capital Structure ($ thousands)	As at March 31, 2015	As at Dec. 31, 2014
Working capital deficiency[2]	**49,195**	57,722
Bank loan	**34,581**	49,904
	83,776	107,626
Senior Unsecured Notes	**146,279**	146,110
Total Net Debt	**230,055**	253,736
Current Debt Capacity[3]	**410,000**	430,000
Common Shares Outstanding (thousands)	**140,101**	123,429

Notes:
(1) Funds from operations is calculated as cash provided by operating activities, adding the change in non-cash working capital, decommissioning obligation expenditures and accretion of deferred financing costs. Funds from operations is used to analyze the Company's operating performance and leverage. Funds from operations does not have a standardized measure prescribed by International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures for other companies.
(2) Working capital deficiency includes cash and cash equivalents plus accounts receivable less accounts payable and accrued liabilities.
(3) Current Debt Capacity reflects the bank facility of $260 million as at May 7, 2015 plus $150 million in senior unsecured notes outstanding.

Operations	Three months ended March 31, 2015	Three months ended March 31, 2014
Daily production		
Light oil (bbl/d)	**657**	81
Heavy oil (bbl/d)	**4,735**	6,128
Natural gas liquids (bbl/d)	**2,060**	1,655
Natural gas (mcf/d)	**69,498**	53,715
Subtotal (boe/d @ 6:1)	**19,035**	16,817
Properties Sold (boe/d)	**-**	11,204[1]
Total (boe/d)	**19,035**	28,021
Average prices [2]		
Light oil ($/bbl)	**49.28**	90.78
Heavy oil ($/bbl)	**36.63**	69.50
Natural gas liquids ($/bbl)	**27.17**	63.78
Natural gas ($/mcf)	**2.62**	6.32
Oil equivalent ($/boe)	**23.31**	51.69

Notes:
(1) First quarter 2014 amounts are net of 11,204 boe/d of production volumes sold during Q2 and Q3 2014, including 3,217 bbl/d of oil, 1,780 bbl/d of natural gas liquids and 37,244 mcf/d of natural gas.
(2) Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments. Average prices for light oil, natural gas liquids and natural gas have been adjusted to reflect the impact of the production volumes sold as shown in Note 1.

	Three months ended March 31, 2015	Three months ended March 31, 2014
Netback ($/boe)[1]		
Revenue	**23.31**	51.69
Realized commodity hedging gain / (loss)	**6.61**	(3.47)
Royalties	**(2.00)**	(10.63)
Operating costs	**(9.28)**	(11.35)
Transportation costs	**(1.96)**	(1.22)
Operating netback [2]	**16.68**	25.02
G&A	**(2.18)**	(2.13)
Interest on long-term debt	**(2.40)**	(2.36)
Funds from operations	**12.10**	20.53
Drilling Activity		
Gross wells	**6**	21
Working interest wells	**6.0**	19.0
Success rate, net wells (%)	**100%**	100%

Notes:
(1) Netback figures for March 31, 2014 are as previously reported and have not been adjusted for Properties Sold.
(2) 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

Through the first quarter of 2015 Crew continued to advance our Montney focused strategy, while facing one of the weakest commodity price environments to impact the oil and gas industry in recent years. As prices have remained low in 2015, the importance of asset quality, balance sheet strength and prudent management has become increasingly apparent. Crew's world-class Montney assets, recently enhanced financial position and experienced management team puts Crew in a superior position to excel in this environment.

Over the past 18 months, we have directed our attention and our resources towards building and developing our Montney asset base, and our approach to development continues to be successfully demonstrated. As reflected in our updated resource evaluation completed by our independent resource engineers effective as at December 31, 2014, we have made strides in advancing Prospective Resource into the Contingent Resource category, while continuing the successful reclassification of Contingent Resource into probable reserves assigned at year end 2014. Crew is still in the early stages of development of this exciting resource with significant long term potential ahead of us. We have designed our development plan to optimize economics and strategically time drilling with the availability of infrastructure. In light of the broader environment, we have taken a responsive and prudent approach to our 2015 budget which provides flexibility and allows Crew to continue progressing through a variety of commodity price scenarios.

Our first quarter capital expenditures totaled $91.4 million, focused on projects that offer higher capital efficiencies and support the construction and commissioning of our new West Septimus facility. At 19,035 boe per day, our first quarter production volumes reflect minimal new production additions as planned and the curtailment of 800 boe per day of heavy oil production. Despite this, we grew our NE BC production by 34% compared to the first quarter of 2014, a demonstration of the strength and benefit of our focused strategy. With the completion of our West Septimus facility in the third quarter, we will have the processing capacity to double the production from our Montney assets.

With the closing of a $100 million bought deal equity financing in March 2015, our balance sheet was strengthened, positioning Crew to manage through uncertain and volatile periods in the commodity markets.

MONTNEY RESOURCE EVALUATION UPDATE

Crew is very pleased to report significant increases in our Economic Contingent Resource ("ECR") estimates following an updated independent Montney resource evaluation conducted by Sproule Associates Ltd. ("Sproule") on our NE BC acreage, effective December 31, 2014. Sproule performed detailed mapping across the areas which included section by section estimates of reservoir parameters, such as pressure, temperature, porosity, and water saturation, which make up the Total Petroleum Initially In Place ("TPIIP") determination. At 110 TCFE, Crew's TPIIP estimate provides the Company with significant opportunities to continue increasing the current ECR, plus add reserves with further drilling.

We have seen the magnitude and potential of the Montney continuously expand over time as ongoing drilling results by Crew and other Montney operators further delineate and de-risk this massive resource. Crew's best estimate ECR on natural gas increased 58% to 6.3 Tcf, natural gas liquids increased 4% to 166.6 million bbls, and oil increased 116% to 23.5 million bbls.

FINANCIAL

Crew's first quarter funds from operations of $20.7 million was lower than the previous quarter and the first quarter of 2014 by 37% and 60%, respectively, reflecting the significant decline in realized commodity prices and the sale of production volumes during 2014.

Our realized product pricing declined commensurate with decreases in benchmark prices, including a 46% decrease in realized light oil pricing that was consistent with the Cdn$ West Texas Intermediate ("WTI") benchmark price decrease of 45%. Although Crew typically realizes a heat premium on our natural gas price relative to the AECO benchmark, in the first quarter of 2015 this premium was impacted by weaker regional gas prices caused by temporarily constrained take-away capacity on the major pipelines servicing the greater Montney areas of NE BC and northwest Alberta. The primary pricing mechanism for Crew's Septimus natural gas production is the AECO 4A less CREC differential benchmark, which declined 64% in the quarter while Crew's realized natural gas price declined 59%. As a result of Crew's access to infrastructure, we have the ability to shift the majority of our NE BC natural gas production between the Alliance pipeline and the Spectra pipeline, which enables the Company to actively manage delivery points and obtain the best possible price in these markets on a daily basis. Due to this ability, we were able to mitigate some of the impact of regional natural gas price declines experienced in the first quarter.

Although the lower realized prices negatively impacted netbacks during the quarter, Crew successfully reduced our per boe cash costs by 36% compared to the first quarter of 2014, and 20% compared to the previous quarter. In addition, our per boe netback and funds from operations were supported by a realized gain on hedging of $11.3 million ($6.61 per boe) in the first quarter, compared to a loss of $3.47 per boe in the first quarter of 2014 and a gain of $1.83 per boe in the prior quarter. For the balance of 2015, we have protected a portion of our funds from operations and supported our ongoing financial stability with additional hedging contracts, outlined below under 'Transportation and Marketing'.

On March 3, 2015, Crew closed a $100 million bought deal financing that greatly enhanced our liquidity and financial flexibility, placing the Company in a position of relative strength to manage through a weakened commodity price environment. At the end of the first quarter, Crew had $230.1 million of net debt including working capital deficiency, comprised of $146.3 million in long-term senior unsecured notes (due for repayment in 2020), and $83.8 million in bank debt and working capital deficiency. Consistent with our ongoing efforts to maintain financial flexibility and balance sheet strength, the Company recently completed its annual bank facility review. The facility was successfully renewed with the same terms, conditions and fees as last year. Crew has elected to reduce the facility's maximum borrowing base by 7% to $260 million, facilitating lower overall borrowing costs while providing ample borrowing flexibility to execute our capital program. Further, since Crew is currently carrying the full cost of the West Septimus facility on our balance sheet, our quarter end debt levels are higher by approximately $26 million as it does not reflect the recovery of half of the facility cost (approximately $33 million) from our partner that will be recognized when the facility is complete.

In response to the weaker commodity price environment, Crew continues to work with all of our service providers to achieve cost reductions across many areas of our business and we have been pleased with the reductions in field costs secured to date. In addition, we have been active in reducing general & administrative ("G&A") costs, particularly around cash compensation, which is expected to contribute to a 22% (approximately $6.5 million) projected reduction in year-over-year G&A expenditures.

TRANSPORTATION AND MARKETING

During the latter part of 2014 and ongoing into 2015, natural gas pricing in NE BC and Northwest Alberta has been significantly impacted as a result of increased supply coupled with multiple, overlapping interruptible pipeline outages and transportation bottlenecks which have negatively affected realized pricing in the region. However, Crew is able to partially mitigate the impact of such market conditions by diverting natural gas production processed through our Septimus facility between the Alliance and the Spectra pipelines, which enables the Company to actively manage delivery points in order to achieve the optimal daily pricing available between these two markets. As such, we successfully reduced the impact of the price weakness in these two markets in the first quarter. In addition, in late 2014 Crew entered into forward physical contracts on 62% of our Septimus natural gas sales at fixed monthly CREC differentials which have been very favorable as compared to the actual settled monthly average differential. From the commencement of the contract in November 2014 through April 2015, Crew has realized a revenue gain of approximately $4.3 million. These contracts will remain in place through the end of November, 2015.

As part of our marketing strategy and planning, Crew has taken steps to enhance our market and operational diversification for our natural gas production. Effective December 1, 2015 Crew committed to 100 mmcf per day of firm receipt transportation service on the Alliance system. In conjunction with this we entered into natural gas sales contracts on 45 mmcf per day priced off of Chicago citygate indices, affording us improved market diversity and downstream takeaway capacity for a three year term. In addition, we have sold 28 mmcf per day priced directly off of the AECO index for a one year term. Longer term, Crew has committed to expansions of takeaway capacity on both the Spectra and TCPL systems. These efforts are critical in positioning Crew for future growth and to manage market price diversification.

As part of our marketing and transportation strategies, we also utilize financial risk management contracts to protect against price volatility. For the balance of 2015, we have currently hedged 33,800 gj per day of natural gas volumes 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 2,065 bbl per day of WCS differentials locked in at CDN$21.48 per bbl. Subsequent to the end of the quarter, we further added to our hedge position with 500 bbl/d of incremental contracts through mid-2016 that lock-in WCS differentials at US$14.95 per bbl.

Lastly, a critical component in the development plan for our Montney assets is managing infrastructure planning and implementation. During the first quarter we began designing the necessary surface equipment and pipeline tie-in to eliminate the trucking of condensate from our Septimus facility. This project will reduce condensate transportation costs by up to $4.00 per barrel in the area following its expected completion in the second quarter. Crew is also pursuing opportunities to more efficiently manage water sourcing and disposal at all three of our operating areas. The Company currently has two operating disposal wells and three tested wells awaiting regulatory approval.

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, with the ongoing construction of our new West Septimus facility and the drilling of inventory wells to supply both our new West Septimus facility as well as our existing Septimus facility.

At Septimus, the Company finished the drilling of a four well pad which is anticipated to be completed in the third quarter. At West Septimus, Crew completed nine of twelve natural gas wells that had been pre-drilled in 2014, which are expected to be brought on production in conjunction with the completion of the West Septimus facility. The drilling results we have observed to date in the West Septimus area are proving to be superior to our initial development in Septimus, due to improved completion techniques and hydrocarbon composition. Our West Septimus wells were assigned average proved plus probable reserves in our year end 2014 independent reserves report of 2.8 Bcf of natural gas and 83 mboe of natural gas liquids (59% condensate) based on historical well results at Septimus. Given the most recent well results at West Septimus, we believe there is significant upside potential as the area continues to be developed.

Crew's extensive infrastructure in the area has allowed five of the new wells to be flow tested through an existing six inch pipeline running 23 kilometers from West Septimus back to our Septimus plant. Over a five day test period the wells produced at condensate rates of 65 bbls/mmcf (sales) resulting in a restricted raw gas flow rate of 10 mmcf per day given the high liquids rates and flowing pressures. We are very encouraged by these condensate rates which are approximately four times the content of our average historical Septimus wells at 17 bbls/mmcf and are 3.7 times greater than ratios used in our year end 2014 independent reserve evaluation for West Septimus. Under normal operating conditions, we would expect a gas production profile that is equal to or greater than the booked production profile of wells at West Septimus. Using the assigned gas reserves of 2.8 bcf per well and the observed liquids rates, at constant AECO natural gas pricing of $2.50 per gj and a WTI price of US$60 per bbl, the West Septimus Montney generates an impressive IRR of approximately 39%.

We continue to reduce our cost structure through modified completion and flow back techniques as well as reduced pricing from our service providers. With the enhanced efficiencies and cost reductions we have achieved to date, Crew has elected to complete the drilling of a six well pad at West Septimus (three of which were drilled in 2014), which will bring the total inventory of wells in this area up to 15, with the remaining six wells to be completed in the second quarter. We remain on budget and on schedule to commission the new West Septimus facility during the third quarter of 2015, provided commodity prices are supportive. During the first quarter, we invested $34.7 million to further advance facility construction as per plan and upon commissioning, Crew will recover one-half of the overall cost of the facility from our partner, which is currently estimated at approximately $33 million.

Tower Oil – Montney, NE BC

During the first quarter of 2015, we completed the drilling of the last two wells of a four well pad at Tower which we plan to complete as commodity prices and project economics warrant. In addition, we continue to pursue more cost-effective water handling solutions at Tower targeting reduced capital and operating costs in the area. When the cost reductions can be implemented, and coupled with the continued evolution of drilling and completions practices at Tower, we are very well positioned to increase our exposure to light oil and condensate going forward.

Groundbirch / Attachie – Montney, NE BC

In 2014, we drilled and completed two wells at Groundbirch which are anticipated to be tied-in during the third quarter of 2015. At Attachie, we drilled and completed one exploration well and have plans to tie-in one well in 2015.

Lloydminster Oil - Alberta/Saskatchewan

Production at our Lloydminster heavy oil property averaged 4,775 boe per day in the first quarter of 2015, reflecting over 800 boe per day of production that was curtailed due to low commodity prices. New drilling will continue to be deferred until commodity prices recover sufficiently to provide more attractive rates of return. Recently, heavy oil differentials have narrowed significantly which may allow Crew to re-activate a small number of shut-in wells.

OUTLOOK

Crew continues to focus on the prudent and measured development of our Montney resource, an approach that is critical during periods where returns are muted by weak commodity prices. Our high-quality asset base with 110 TCFE of Total Petroleum Initially in Place ("TPIIP"), includes 487 net sections of Montney lands with exposure to all three hydrocarbon windows and is ideally situated near infrastructure to allow access to existing and new potential markets.

We now have 25 Montney wells drilled and behind pipe with 12 wells in various stages of completion and equipping. We plan to continue drilling at West Septimus in preparation for the start-up of our new West Septimus facility, which is currently on-schedule to be completed and commissioned in the third quarter as planned. Upon initial commissioning, the West Septimus facility is expected to be operating at approximately half of the full 60 mmcf per day capacity, allowing for a second phase of production growth once the facility reaches capacity, which would add an additional approximately 6,000 boe per day. Further, at our election, the Company can double the facility to 120 mmcf per day for a net cost to Crew of approximately $10 million, which would result in significant production additions.

We are maintaining annual production guidance of 20,000 to 22,000 boe per day, and our year-end exit forecast of 24,000 to 25,000 boe per day. Crew continues to monitor regional natural gas prices which have been impacted by temporary service restrictions on the major pipelines that service the Alberta and NE BC Montney areas. We believe that these restrictions may extend throughout the second quarter and potentially into the third quarter. If these conditions continue to impact regional transportation and prices, the Company may elect to delay start-up of the facility until these restrictions abate.

Building on the strength of our focused asset base and our continued operational success in the Montney, Crew has evolved to be a leading operator in the area. We have and will continue to deploy our capital responsibly as we convert Prospective Resource to Contingent Resource and move along the spectrum to reclassify Contingent Resource as reserves and ultimately production. Our priorities are focused on executing an effective capital spending program while sustaining a responsible debt level and further driving down our cost structure. With the significant cost savings realized in the first quarter, Crew's forecast cash flow using forward strip pricing combined with our budgeted net capital program of $185 million is currently expected to result in a year end net debt level below $255 million. Our strong balance sheet and ongoing hedging program have allowed Crew to secure financial flexibility through 2015 and into 2016.

We are excited about the near and longer term prospects inherent in our asset base and believe in the strength of our team to realize success. We would like to thank our employees and Board of Directors for their commitment to Crew, and our shareholders for their ongoing support through a challenging market environment.

NORTHEAST BRITISH COLUMBIA MONTNEY RESOURCE EVALUATION

The following discussion in "Northeast British Columbia Montney Resource Evaluation" is subject to a number of cautionary statements, assumptions and risks as set forth therein. See "Information Regarding Disclosure on Oil and Gas Reserves, Resources and Operational Information" at the end of this report for additional cautionary language, explanations and discussion and "Forward Looking Information and Statements" for a statement of principal assumptions and risks that may apply. See also "Definitions of Oil and Gas Resources and Reserves" in this report. The discussion includes reference to TPIIP, DPIIP, UPIIP and ECR per the Sproule Associates Ltd. ("Sproule") Resources Evaluation effective as at December 31, 2014, prepared in accordance with the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook"). Unless indicated otherwise in this report, all references to Contingent and Prospective Resource volumes are Best Estimate Contingent and Prospective Resource volumes.

Sproule was engaged to conduct an updated independent Montney resource evaluation of all of Crew's lands in the NE BC Montney region totaling 487 net sections, and including Septimus, West Septimus, Groundbirch/Monias, Attachie and Tower (the "Evaluated Areas") effective as of December 31, 2014, (the "Resource Evaluation"). The Resource Evaluation confirms the development and resource potential on the Company's land base providing us with significant opportunities to add reserves above the current booked reserves and to increase the current ECR. The commodity diversity of Crew's NE BC Montney assets allow us to navigate through commodity price cycles given the range of Crew's Montney landholdings with exposure to liquids rich gas, crude oil and dry natural gas (gas containing greater than 95% methane). The Resource Evaluation reaffirms Crew's belief in the considerable potential that exists to further increase our current reserve base, highlighting the world class potential of the NE BC Montney.

TPIIP in the Montney "gas window" increased to 64.3 TCF from 60.6 TCF due to additional acquisitions completed in 2014. The Resource Evaluation also included recognition of Crew's lands in the Montney "oil window", where TPIIP decreased slightly from 8.1 billion barrels of oil to 7.6 billion barrels of oil primarily due to divestitures completed in 2014. The tight Montney oil potential is in the early stages of development and requires additional data to realize the recoverable potential of these lands. The continued improvement of technology and the early results are very encouraging to the recovery of this vast resource.

The Resource Evaluation summarized below and the operational results to date within our Evaluated Areas highlight the quality of the lands that Crew has successfully acquired over the past seven years. With the improved economics of this play and the visibility of continued development of infrastructure in the Septimus corridor in particular we are committed to continue to pursue opportunities in this region and it is our intent to aggressively exploit the 64.3 TCF and 7.6 billion barrels of TPIIP on our acreage in order to grow production, reserves and cash flow into the future.

The following tables summarize the results of the Resource Evaluation along with comparatives to the prior year evaluation using the resource categories set out in the COGE Handbook:

	Dec. 31, 2014	April 30, 2014	
Natural Gas Resource Categories (1)(2)(3)(4)	**Tcf**	Tcf	**% Change**
Total Petroleum Initially In Place (TPIIP)	**64.3**	60.6	**6%**
Discovered Petroleum Initially In Place (DPIIP)	**30.5**	26.1	**17%**
Undiscovered Petroleum Initially In Place (UPIIP)	**33.8**	34.5	**(2%)**

(1) TPIIP, DPIIP and UPIIP have been estimated using a one percent and zero percent porosity cut-off in the December 2014 and April 2014 reports, respectively, which means that essentially all gas bearing rock has been incorporated into the calculations.
(2) All volumes in table are Company gross and raw gas volumes.
(3) Sproule's analysis identified four intervals in the Montney consisting of one interval in the Upper Montney and three intervals in the Lower Montney.
(4) Crew's acreage was divided into five (5) areas in the "gas window".

	Dec. 31, 2014	April 30, 2014	
Oil Resource Categories (1)(2)(3)(4)(5)	**Mmbbls**	Mmbbls	**% Change**
Total Petroleum Initially In Place (TPIIP)	**7,640**	8,052	**(5%)**
Discovered Petroleum Initially In Place (DPIIP)	**1,501**	1,363	**10%**
Undiscovered Petroleum Initially In Place (UPIIP)	**6,139**	6,689	**(8%)**

(1) TPIIP, DPIIP and UPIIP have been estimated using a one percent and zero percent porosity cut-off in the December 2014 and April 2014 reports, respectively, which means that essentially all gas bearing rock has been incorporated into the calculations.
(2) All volumes in table are Company gross.
(3) The oil volumes are quoted as Stock Tank Barrels ("STB").
(4) Sproule's analysis identified four intervals in the Montney consisting of one interval in the Upper Montney and three intervals in the Lower Montney.
(5) Crew's acreage was divided into five (5) areas in the "oil window".

	Dec. 31, 2014	April 30, 2014	
Reserves and Economic Contingent Resource (1)(2)(3)(6)(7)(8)	**Best Estimate**	Best Estimate	**% Change**
Natural gas (Tcf)			
Reserves (3)	**1.0**	0.5	**100%**
Economic Contingent Resource	**6.3**	4.0	**58%**
Natural gas liquids (Mmbbls) (4)(5)			
Reserves (3)	**33.1**	14.7	**125%**
Economic Contingent Resource	**166.6**	160.7	**4%**
Oil (Mmbbls)			
Reserves (3)	**5.9**	0.4	**1,375%**
Economic Contingent Resource	**23.5**	10.9	**116%**

(1) All DPIIP other than cumulative production, reserves, and ECR has been categorized as unrecoverable at this time. A portion of the Unrecoverable DPIIP may in the future be determined to be recoverable and reclassified as Contingent Resources or reserves as additional technical studies are performed, commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.
(2) All volumes in table are company gross and sales volumes.
(3) For reserves, the volume under the headings 'Best Estimate' are proved plus probable reserves as at December 31, 2014 and 2013, respectively.
(4) The liquid yields are based on average yield over the producing life of the property.
(5) Liquid yields are unique to each area. They are estimated based on gas composition of gas samples in the area and expected plant recoveries.
(6) There is no certainty that it will be commercially viable to produce any of the resources.
(7) ECR are risked for the chance of development.
(8) Approximately 90% of the ECR volumes assigned were categorized in the 'development pending' project maturity sub-class, with the balance as 'project on hold'; as such terms are defined in the COGE Handbook.

	Dec. 31, 2014	April 30, 2014	
Prospective Resources (1)(2)(5)(6)	**Best Estimate**	Best Estimate	**% Change**
Natural gas (Tcf)	**6.9**	6.3	**10%**
Natural gas liquids (Mmbbls) (3)(4)	**220.3**	254.4	**(13%)**
Oil (Mmbbls)(7)	**95.0**	14.4	**560%**

(1) All UPIIP other than Prospective Resources has been categorized as unrecoverable at this time.
(2) All volumes in table are company gross and sales volumes.
(3) The liquid yields are based on average yield over the producing life of the property.
(4) Liquid yields are unique to each area. They are estimated based on gas composition of gas samples in the area and expected plant recoveries.
(5) There is no certainty that it will be commercially viable to produce any of the resources.
(6) Prospective Resources are risked for the chance of discovery and the chance of development.
(7) Oil in the Lower Montney was classified as "unrecoverable" in the April 30, 2014 report. In the December 31, 2014 report, oil in the Lower Montney is classified as Prospective Resources.

Based upon the foregoing analysis and Crew's expertise in the Montney formation in NEBC, it is expected that significant additional reserves will be developed in the future with continued drilling success on currently undeveloped Montney acreage together with further development, completion refinements and improved economic conditions. Continuous development through multi-year exploration and development programs coupled with significant levels of future capital expenditures will be required in order for additional resources to be recovered in the future. Additional drilling, completion, and test results will be required before Crew can commit to development, which is needed for these Contingent Resources to be converted to reserves and a larger component of Prospective Resources to be converted to Contingent Resource.

Volumes of resources are estimated using volumetric calculations of the in-place quantities, combined with performance from analog reservoirs. The currently producing assets of Crew and other industry parties in the Montney area of NE B.C. are used as performance analogs for ECR within Crew's areas of operations. The evaluation of ECR is based on an independent third party evaluation that assumes that the all of Crew's ECR will be recovered using horizontal multi-stage hydraulic fracturing using multi-well pad drilling, which is an established technology.

Crew's ability to recover additional resources is subject to numerous principal risks, that include factors such as minimal well data from the Montney formation; access to capital that would enable us to continue development; low commodity prices which could impact economics; the future performance of wells; regulatory approvals; access to required services; overall industry cost structures; and the continued efficacy of fracture stimulation technologies. In order for ECR to be converted into reserves, Crew's management and technical teams must continue to assess commercial production rates, devise firm development plans that incorporate timing, infrastructure and capital commitments. With continued development and delineation, some resources currently classified as ECR are expected to be reclassified as Reserves.

A key contingency that prevents the classification of ECR as Reserves is the additional drilling, completions and testing required to confirm viable commercial rates. Sproule assigned ECR beyond those areas which were assigned Reserves but which were within three miles of existing wells. Further, a lack of infrastructure in the Evaluated Areas which is required to develop the Resources, such as gas gathering and processing, and natural gas liquids separation facilities, further impedes the reclassification of ECR to Reserves. In addition to these factors, and the general operational risks facing the oil and gas industry, there are several non-technical contingencies that need to be overcome in order to reclassify ECR to Reserves. These include lack of markets, legal, environmental and political concerns, which include but are not limited to the potential banning of hydraulic fracturing, a technique required to develop the ECR.

There is no certainty that any portion of the Prospective Resources will be discovered. There is no certainty that it will be commercially viable to produce any portion of the Prospective (if discovered) or Contingent Resources.

Definitions of Oil and Gas Resources and Reserves

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates as follows:

> **Proved Reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
>
> **Probable Reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.
>
> **Possible Reserves** are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Cumulative Production is the cumulative quantity of petroleum that has been recovered at a given date.

Resources encompasses all petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including Discovered and Undiscovered (recoverable and unrecoverable) plus quantities already produced. "Total resources" is equivalent to "Total Petroleum Initially-In-Place". Resources are classified in the following categories:

> **Total Petroleum Initially-In-Place ("TPIIP")** is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered.
>
> **Discovered Petroleum Initially-In-Place ("DPIIP")** is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially in place includes production, reserves, and contingent resources; the remainder is unrecoverable.
>
> **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to

classify as Contingent Resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage.

Economic Contingent Resources ("ECR") are those Contingent Resources which are currently economically recoverable.

Undiscovered Petroleum Initially-In-Place ("UPIIP") is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of undiscovered petroleum initially in place is referred to as "prospective resources" and the remainder as "unrecoverable."

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development.

Unrecoverable is that portion of DPIIP and UPIIP quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Uncertainty Ranges are described by the Canadian Oil and Gas Evaluation Handbook as low, best, and high estimates for reserves and resources. The **Best Estimate** is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

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

All amounts in this report are stated in Canadian dollars unless otherwise specified. Throughout this report, the terms Boe (barrels of oil equivalent), Mmboe (millions of barrels of oil equivalent), and Tcfe (trillion cubic feet of gas equivalent) are used. Such terms when used in isolation, may be misleading. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE and oil and liquids have been converted to natural gas equivalent on the basis of 1 bbl:6 mcfe. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip, and 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 the 6:1 conversion ratio, utilizing the 6:1 conversion ratio may be misleading as an indication of value. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. In accordance with Canadian practice, production volumes and revenues are reported on a company gross basis, before deduction of Crown and other royalties, unless otherwise stated. Unless otherwise specified, all reserves volumes in this report (and all information derived therefrom) are based on "company gross reserves" using forecast prices and costs. Our oil and gas reserves statement for the year-ended December 31, 2014 includes complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, and is contained within our Annual Information Form which is available on our SEDAR profile at www.sedar.com.

This report contains references to estimates of oil and gas classified as TPIIP, DPIIP, UPIIP and ECR in the Montney region in NE BC which are not, and should not be confused with, oil and gas reserves. See "Definitions of Oil and Gas Resources and Reserves". TPIIP, DPIIP and UPIIP have been estimated in 2015 using a one percent porosity cutoff.

Projects have not been defined to develop the resources in the Evaluated Areas as at the evaluation date. Such projects, in the case of the Montney resource development, have historically been developed sequentially over a number of drilling seasons and are subject to annual budget constraints, Crew's policy of orderly development on a staged basis, the timing of the growth of third party infrastructure, the short and long-term view of Crew on oil and gas prices, the results of exploration and development activities of Crew and others in the area and possible infrastructure capacity constraints. As with any resource estimates, the evaluation will change over time as new information becomes available.

Crew's belief that it will establish significant additional reserves over time with the conversion of Prospective Resource into Contingent Resource, Contingent Resource into probable reserves and probable reserves into proved reserves is a forward looking statement and is based on certain assumptions and is subject to certain risks, as discussed below under the heading "Forward Looking Information and Statements".

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 productions; estimates of 2015 year end bank debt; the recognition of significant resources under the heading "Northeast British Columbia Montney Resource Evaluation"; 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 G&A expenditures 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 and development 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 commissioning of the new West Septimus facility; 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 and the adequacy of cash flow to fund its planned expenditures; 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 and development of 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 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.

Test Results and Initial Production Rates

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

BOE equivalent

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

MANAGEMENT'S DISCUSSION AND ANALYSIS

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 unaudited condensed interim consolidated financial statements of the Company for the three month periods ended March 31, 2015 and 2014. The unaudited condensed interim consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). There have been no significant changes to the critical estimates disclosed in the Company's audited financial statements for the year ended December 31, 2014. All figures provided herein and in the March 31, 2015 unaudited condensed interim consolidated financial statements are reported in Canadian dollars. This MD&A is dated May 7, 2015.

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 March 31, 2015**	Three months ended March 31, 2014
Cash provided by operating activities	**17,221**	50,338
Decommissioning obligations settled	**270**	107
Change in operating non-cash working capital	**3,398**	1,527
Accretion of deferred financing costs	**(169)**	(162)
Funds from operations	**20,720**	51,810

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 the industry benchmark 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)	**March 31, 2015**	December 31, 2014
Current assets	**57,194**	78,469
Current liabilities	**(77,322)**	(95,337)
Marketable securities	**(1,401)**	(2,052)
Derivative financial instruments	**(27,666)**	(38,802)
Working capital deficit	**(49,195)**	(57,722)

($ thousands)	**March 31, 2015**	December 31, 2014
Bank loan	**(34,581)**	(49,904)
Senior unsecured notes	**(146,279)**	(146,110)
Working capital deficit	**(49,195)**	(57,722)
Net debt	**(230,055)**	(253,736)

RESULTS OF OPERATIONS

2014 Strategic Transactions

Acquisitions

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) to the Company's existing operations within northeast British Columbia.

Dispositions

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

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

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

Production

	Three months ended March 31, 2015				Three months ended March 31, 2014			
	Oil (bbl/d)	**Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
Northeast British Columbia	657	2,060	69,258	14,260	81	1,655	53,537	10,659
Lloydminster	4,735	-	240	4,775	6,128	-	178	6,158
Properties Sold	-	-	-	-	3,217	1,780	37,244	11,204
Total	5,392	2,060	69,498	19,035	9,426	3,435	90,959	28,021

Production for the three months ended March 31, 2015 decreased 32% over the same period in 2014 as a result of the Alberta Gas and Princess Dispositions. These dispositions were partially offset by the addition of production from the Septimus and Groundbirch acquisitions and the Company's successful drilling program at Septimus and the development of the light oil play at Tower. The Lloydminster heavy oil production decline has been accelerated by decreased capital spending and a reduced well reactivation program combined with over 800 boe/d of uneconomic heavy oil volumes being shut-in during the quarter.

Revenue

	Three months ended March 31, 2015	Three months ended March 31, 2014
Revenue ($ thousands)		
Light oil	**2,913**	662
Heavy oil	**15,612**	38,328
Natural gas liquids	**5,038**	9,500
Natural gas	**16,377**	30,532
Properties Sold	**-**	51,346
Total	**39,940**	130,368
Crew average prices		
Light oil ($/bbl)	**49.28**	90.78
Heavy oil ($/bbl)	**36.63**	69.50
Natural gas liquids ($/bbl)	**27.17**	63.78
Natural gas ($/mcf)	**2.62**	6.32
Oil equivalent ($/boe)	**23.31**	51.69
Benchmark pricing		
Light oil – Cdn$ WTI (Cdn $/bbl)	**60.38**	108.91
Heavy oil – WCS (Cdn $/bbl)	**42.11**	83.36
Natural gas liquids – Condensate @ Edmonton (Cdn $/bbl)	**54.18**	110.52
Natural Gas – AECO 2A daily index (Cdn $/mcf)	**2.77**	5.65
Alliance Natural Gas – AECO 4A less CREC differential (Cdn $/mcf)	**1.96**	5.44
Spectra Natural Gas – NGX Spectra Station #2 day ahead index (Cdn $/mcf)	**2.13**	5.21

Revenue for the three months ended March 31, 2015 decreased 69% as compared to the same quarter in 2014 as a result of the Alberta Gas and Princess Dispositions as well as lower 2015 production and realized commodity pricing. Light oil revenue increased as a result of new production from the Company's light oil play at Tower but was impacted negatively by the 46% decrease in realized light oil pricing. This price decline was consistent with the Company's Cdn$ West Texas Intermediate ("WTI") benchmark price decrease of 45%. Crew's realized natural gas price decreased 59% in the quarter from the same period in 2014, compared to the decrease in the AECO 2A benchmark of 51% and the decrease in the AECO 4A less CREC benchmark of 64% which reflects the primary market for Crew's Septimus natural gas production. Crew has the ability to shift its natural gas production processed through the Septimus gas plant between the Alliance and the Spectra pipelines allowing it the ability to actively manage delivery points to achieve the optimal daily pricing available between these two markets. As such, the Company was able to reduce the impact of the weakness in these two markets in the first quarter. In addition, the Company benefited from physically forward selling a portion of its natural gas at fixed monthly CREC differentials that were lower than the actual monthly average differential. Crew's first quarter heavy oil price decreased 47% which was comparable to the 49% decrease in the Company's Western Canadian Select ("WCS") benchmark. Crew's first quarter realized natural gas liquids ("ngl") price decreased 57% over the same period in 2014. The price received for Crew's condensate, which is included in ngl, decreased 50% over the same period in 2014 which was comparable to the 51% decrease in the Company's Condensate at Edmonton benchmark price. However, propane and butane are also included in the Company's natural gas liquids ("ngl") price and the price received for those products significantly declined in the first quarter as compared to the same period in 2014 which further negatively impacted Crew's total ngl price.

Royalties

($ thousands, except per boe)	**Three months ended March 31, 2015**	Three months ended March 31, 2014
Royalties	**3,434**	26,803
Per boe	**2.00**	10.63
Percentage of revenue	**8.6%**	20.6%

In the first quarter of 2015, royalties as a percentage of revenue decreased to 8.6% from 20.6% over the same period in 2014 predominantly due to significantly lower commodity prices. The Company's royalty rates are price sensitive and therefore a significant drop in commodity prices has reduced royalties and royalty rates in northeast British Columbia and in Lloydminster. The Company's royalties were also impacted by a one-time adjustment to actual mineral taxes paid during the quarter and the disposition of higher royalty rate production with the Alberta Gas and Princess Dispositions. Due to decreased commodity pricing, the Company now expects its royalties as a percentage of revenue to average between 11% and 13% 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.

As all of the Company's hedged production pertains to the current year, the 2015 unrealized loss on financial instruments is more representative of the unwinding of the Company's existing risk management contracts rather than fluctuations in forward market pricing.

These contracts had the following impact on the condensed interim consolidated statements of loss and comprehensive loss:

($ thousands)	**Three months ended March 31, 2015**	Three months ended March 31, 2014
Realized gain (loss) on derivative financial instruments	**11,327**	(8,745)
Per boe - Total	**6.61**	(3.47)
Unrealized loss on financial instruments	**(10,643)**	(19,029)

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

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Oil	750 bbl/day	April 1, 2015 – June 30, 2015	CDN$ WTI	$103.80	Swap	2,780
Oil	1,750 bbl/day	April 1, 2015 – December 31, 2015	CDN$ WTI	$102.62	Swap	17,210
Oil	2,000 bbl/day	April 1, 2015 – December 31, 2015	CDN$ WCS – WTI diff	($21.59)	Swap	(2,469)
Gas	30,000 gj/day	April 1, 2015 – December 31, 2015	AECO C Monthly Index	$3.75	Swap	9,224
Gas	7,500 gj/day	July 1, 2015 – December 31, 2015	AECO C Monthly Index	$3.41	Swap	1,001
Oil	500 bbl/day	January 1, 2016 – December 31, 2016	CDN$ WTI	$116.50	Call	(113)
Oil	250 bbl/day	January 1, 2016 – December 31, 2016	CDN$ WTI	$88.00 – $100.00	Call(1)	(210)
Total						27,423

(1) 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.

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

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Oil	250 bbl/day	October 1, 2015 – June 30, 2016	US$ WCS – WTI diff	($14.95)	Swap
Oil	250 bbl/day	January 1, 2016 – June 30, 2016	US$ WCS - WTI diff	($14.95)	Swap

Operating Costs

($ thousands, except per boe)	**Three months ended March 31, 2015**	Three months ended March 31, 2014
Operating costs from continued operations	**15,897**	28,622
Per boe	**9.28**	11.35

For the first quarter of 2015, the Company's operating costs per boe decreased 18% over the same period in 2014 as a result of the Princess Disposition as this property attracted higher operating costs per unit as compared to the Company's average operating costs per boe. In addition the Company has reduced well servicing costs and shut-in higher operating cost production in the Lloydminster heavy oil area. These decreases were partially offset by additional higher cost light oil production from Tower in British Columbia which came on production in the fourth quarter of 2014. With the decrease in higher operating cost production at Lloydminster combined with additional lower cost production expected to come onstream later in 2015, the Company now forecasts annual operating costs to average between $9.00 and $9.50 per boe for 2015.

Transportation Costs

($ thousands, except per boe)	**Three months ended March 31, 2015**	Three months ended March 31, 2014
Transportation costs from continued operations	**3,358**	3,088
Per boe	**1.96**	1.22

In the first quarter of 2015, the Company's transportation costs and transportation costs per boe increased as compared to the same period in 2014 as a result of the incremental production from the 2014 Groundbirch and Septimus acquisitions, which yields higher transportation costs per boe. In addition, new production at Tower currently has higher than historical corporate average clean oil trucking rates. Transportation costs per boe were also negatively impacted due to the disposition of lower transportation cost per unit production from the Princess and Alberta Gas Dispositions. The Company forecasts transportation costs per boe to range between $1.85 and $2.25 per boe in 2015.

Operating Netbacks

($/boe)	**Three months ended March 31, 2015**	Three months ended March 31, 2014
Revenue	**23.31**	51.69
Royalties	**(2.00)**	(10.63)
Realized commodity hedging gain/(loss)	**6.61**	(3.47)
Operating costs	**(9.28)**	(11.35)
Transportation costs	**(1.96)**	(1.22)
Operating netbacks	**16.68**	25.02

Operating netbacks for the first quarter of 2015 decreased 33% over the same period in 2014 as the Company's realized commodity prices materially decreased as compared to the same quarter in 2014. This was partially offset by significant realized hedging gains on Crew's risk management program combined with lower royalty expense due to the reduced commodity price environment and lower operating costs from the sale of higher operating cost production from the Princess Disposition and cost reduction strategies applied in Lloydminster.

General and Administrative Costs

($ thousands, except per boe)	**Three months ended March 31, 2015**	Three months ended March 31, 2014
Gross costs	**5,800**	7,892
Operator's recoveries	**(157)**	(82)
Capitalized costs	**(1,905)**	(2,450)
General and administrative expenses	**3,738**	5,360
Per boe	**2.18**	2.13

Gross and net post-recovery general and administrative costs decreased in the first quarter of 2015 compared to the same period in 2014 due to reduced staffing levels as a result of the Alberta Gas and Princess Dispositions and a reduction in the Company's compensation program prompted by the substantial decline in commodity prices over the past six months. As a result of these staff and compensation reductions the Company has reduced its general and administrative cost forecast to average between $2.00 and $2.25 per boe in 2015.

Share-Based Compensation

($ thousands)	**Three months ended March 31, 2015**	Three months ended March 31, 2014
Gross costs	**5,954**	2,234
Capitalized costs	**(2,959)**	(1,063)
Total share-based compensation	**2,995**	1,171

Share-based compensation expense for the first quarter of 2015 has increased compared to the same period in 2014 as a result of higher valued restricted and performance awards granted in the second quarter of 2014 combined with additional compensation expense recorded in the first quarter of 2015. The additional compensation expense was due to an increase in the performance multiplier applied to the performance awards recognizing the Company's positive 2014 performance.

Depletion and Depreciation

($ thousands, except per boe)	**Three months ended March 31, 2015**	Three months ended March 31, 2014
Depletion and depreciation	**26,005**	49,214
Per boe	**15.18**	19.51

Depletion and depreciation costs and costs per boe decreased in the first quarter of 2015, compared to the same period of 2014, as a result of increased proved plus probable reserve bookings from the Company's 2014 annual reserve evaluation combined with the removal of higher depletion rate assets from the Company's property, plant and equipment from the Alberta Gas and Princess Dispositions.

Finance Expenses

($ thousands, except per boe)	**Three months ended March 31, 2015**	Three months ended March 31, 2014
Interest on bank loan	**853**	2,680
Interest on senior notes	**3,098**	3,098
Accretion of deferred financing charges	**169**	162
Accretion of the decommissioning obligation	**471**	811
Total finance expense	**4,591**	6,751
Average debt level	**193,220**	348,352
Average drawings on bank loan	**43,220**	198,352
Effective interest rate on bank loan	**8.0%**	5.5%
Effective interest rate on senior notes	**8.4%**	8.4%
Effective interest rate on long-term debt	**8.3%**	6.7%
Interest on long-term debt per boe	**2.40**	2.36

For the first quarter of 2015, average debt levels decreased over the same period in 2014 due to receiving the proceeds from the Alberta Gas and Princess Dispositions in 2014 combined with the Common Share issuances discussed below in the *Share Capital* section. The effective interest rate on the Company's bank loan was higher in the first quarter of 2015, as compared to the same period in 2014, due to higher standby fees incurred on the Company's bank facility in 2015 resulting from decreased drawings on the facility. The Company expects its effective interest rate on long-term debt will average approximately 8.0% to 9.0%.

Deferred Income Taxes

In the first quarter of 2015, the provision for deferred taxes was a recovery of $4.3 million compared to a recovery of $43.7 million for the same period in 2014. The reduced recovery is a result of a reduced pre-tax loss experienced during the first quarter of 2015.

Cash, Funds from Operations and Net Income

($ thousands, except per share amounts)		**Three months ended March 31, 2015**	Three months ended March 31, 2014
Cash provided by operating activities		**17,221**	50,338
Funds from operations		**20,720**	51,810
Per share	- basic	**0.16**	0.43
	- diluted	**0.16**	0.42
Net loss		**(15,770)**	(129,693)
Per share	- basic	**(0.12)**	(1.07)
	- diluted	**(0.12)**	(1.07)

The decrease in cash provided by operating activities and funds from operations in the first quarter of 2015 was a result of reduced production due to the Alberta Gas and Princess Dispositions in 2014 and lower commodity prices in the first quarter of 2015. The decrease in net loss in the first quarter of 2015 was a result of impairment charges, net of tax, that impacted the first quarter of 2014.

Capital Expenditures, Property Acquisitions and Dispositions

During the first quarter of 2015, the Company drilled six (6.0 net) wells resulting in two (2.0 net) oil wells and four (4.0 net) natural gas wells. In addition, the Company completed nine (9.0 net) natural gas wells and one (1.0 net) heavy oil well and recompleted nine (8.3 net) heavy oil wells in the quarter. The Company spent $41.8 million directed to infrastructure predominantly on the Company's West Septimus facility currently planned for commissioning in the third quarter of 2015.

Total net capital expenditures are detailed below:

($ thousands)	**Three months ended March 31, 2015**	Three months ended March 31, 2014
Land	**811**	843
Seismic	**5,518**	2,254
Drilling and completions	**40,992**	51,836
Facilities, equipment and pipelines	**41,767**	8,129
Other	**2,004**	3,078
Total exploration and development	**91,092**	66,140
Property acquisitions (dispositions)	**258**	102,532
Total	**91,350**	168,672

LIQUIDITY AND CAPITAL RESOURCES

Capital Funding

The Company has a credit facility with a syndicate of lending banks (the "Syndicate") which includes a revolving line of credit and an operating line of credit (the "Facility"). Subsequent to March 31, 2015, the Facility was extended and the amount available on the revolving line was adjusted to $230 million while the operating line of credit remained at $30 million. The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 6, 2016. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 percent and all outstanding balances under the Facility will become repayable in one year from the extension date. The available lending limits of the Facility 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 March 31, 2015, these ratios were 1.4:1 and 0.3:1, 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 October 31, 2015. At March 31, 2015, the Company had drawings of $34.6 million on the Facility and had issued letters of credit totaling $2.9 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.

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

The Company will continue to fund its on-going operations from a combination of cash flow, debt, non-core asset dispositions and additional 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 March 31, 2015, the Company's working capital deficiency totaled $49.2 million which, when combined with the drawings on its bank loan, represented 32% of its current bank facility.

Share Capital

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

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 has renounced to the subscribers Canadian Exploration Expenses incurred by the Company after September 26, 2014 and prior to December 31, 2015 totaling $11.9 million. The Company has renounced the Canadian Exploration Expenses such that the full proceeds were deductible against the subscribers' income for the fiscal year ended December 31, 2014. At March 31, 2015, the Company has incurred $6.2 million in qualifying expenditures under this flow-through share offering.

Crew is authorized to issue an unlimited number of common shares. As at May 7, 2015, there were 140,983,966 common shares and options to acquire 4,883,303 common shares of the Company issued and outstanding. In addition, there were 1,236,221 restricted awards and 1,674,673 performance awards outstanding under the company's long-term incentive program.

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 endeavours to maintain it at or below 2.0 to 1.0. During periods of increased capital expenditures, acquisitions or low commodity prices, this ratio will increase. As shown below, as at March 31, 2015, the Company's ratio of net debt to annualized funds from operations was 2.78 to 1 (December 31, 2014 – 1.92 to 1). As a result of the recent significant decline in commodity prices, the Company increased its financial flexibility through the issuance of additional equity as discussed above in *Share Capital*. The Company plans to closely monitor commodity prices and, if necessary to maintain a strong financial position, will continue its strategy of divesting of non-core properties, will adjust its annual capital expenditure program or may consider other forms of financing.

($ thousands, except ratio)	March 31, 2015	December 31, 2014
Working capital deficit	**(49,195)**	(57,722)
Bank loan	**(34,581)**	(49,904)
Senior unsecured notes	**(146,279)**	(146,110)
Net debt	**(230,055)**	(253,736)
First quarter funds from operations	**20,720**	33,035
Annualized	**82,880**	132,140
Net debt to annualized funds from operations ratio	**2.78**	1.92

Contractual Obligations

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

($ thousands)	Total	2015	2016	2017	2018	2019	Thereafter
Bank Loan (note 1)	34,581	-	34,581	-	-	-	-
Senior unsecured notes (note 2)	150,000	-	-	-	-	-	150,000
Operating leases	4,495	1,870	2,625	-	-	-	-
Firm transportation agreements	139,520	4,936	25,683	26,041	26,041	26,041	30,778
Firm processing agreements	52,250	9,014	10,631	9,179	8,509	8,228	6,689
Capital commitment	5,694	5,694	-	-	-	-	-
Total	386,540	21,514	73,520	35,220	34,550	34,269	187,467

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

The firm processing agreements include commitments to process natural gas through third party owned gas processing facilities in 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 new West Septimus facility is currently on schedule to be completed and commissioned in the third quarter as planned. Crew is maintaining annual production guidance of 20,000 to 22,000 boe per day and our year-end exit forecast of 24,000 to 25,000 boe per day. The Company continues to monitor regional natural gas prices which have been impacted by temporary service restrictions on the three major pipelines that service the Alberta and northeast BC Montney areas and believe that these restrictions may extend throughout the second quarter and potentially into the third quarter. If these conditions continue to impact regional transportation, the Company may elect to defer start-up of the facility. With the cost savings realized in the first quarter and using forward strip pricing, Crew's forecasted funds from operations combined with our budgeted net capital expenditure program of $185 million is expected to result in a year-end net debt of approximately $255 million. The Company's strong balance sheet and ongoing hedging program have allowed us to secure financial flexibility through 2015 and into 2016.

ADDITIONAL DISCLOSURES

Quarterly Analysis

The following table summarizes Crew's key quarterly financial results for the past eight financial quarters:

($ thousands, except per share amounts)	Mar. 31 2015	Dec. 31 2014	Sept 30 2014	June 30 2014	Mar. 31 2014	Dec. 31 2013	Sept. 30 2013	June 30 2013
Total daily production (boe/d)	19,035	20,869	20,846	27,200	28,021	28,682	28,016	27,109
Exploration and development expenditures	91,092	81,447	106,405	52,783	66,140	55,996	68,435	30,348
Property acquisitions/(dispositions)	258	1,901	(141,796)	(215,115)	102,532	(1,931)	33,203	(5,717)
Average wellhead price ($/boe)	23.31	37.65	50.51	50.86	51.69	41.84	45.85	44.91
Petroleum and natural gas sales	39,940	72,295	96,879	125,882	130,368	110,394	118,173	110,793
Cash provided by operations	17,221	37,714	37,566	43,589	50,338	48,850	42,698	44,486
Funds from operations	20,720	33,035	39,023	47,724	51,810	48,128	42,035	48,087
Per share – basic	0.16	0.27	0.32	0.39	0.43	0.40	0.35	0.40
– diluted	0.16	0.27	0.31	0.38	0.42	0.40	0.35	0.40
Net income (loss)	(15,770)	(28,424)	(195,389)	3,792	(129,693)	(58,429)	(843)	2,008
Per share – basic	(0.12)	(0.23)	(1.60)	0.03	(1.07)	(0.48)	(0.01)	0.02
– diluted	(0.12)	(0.23)	(1.60)	0.03	(1.07)	(0.48)	(0.01)	0.02

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.

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.

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. 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 January 1, 2015 and ended on March 31, 2015 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

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

Dated as of May 7, 2015

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited) (thousands)		**March 31, 2015**		December 31, 2014
Assets				
Current Assets:				
Accounts receivable	**$**	**25,577**	$	35,393
Marketable securities (note 3)		**1,401**		2,052
Derivative financial instruments (note 9)		**30,216**		41,024
		57,194		78,469
Property, plant and equipment (note 4)		**1,217,989**		1,146,596
	$	**1,275,183**	$	1,225,065
Liabilities and Shareholders' Equity				
Current Liabilities:				
Accounts payable and accrued liabilities	**$**	**74,772**	$	93,115
Derivative financial instruments (note 9)		**2,550**		2,222
		77,322		95,337
Derivative financial instruments (note 9)		**243**		736
Bank loan (note 5)		**34,581**		49,904
Senior unsecured notes (note 6)		**146,279**		146,110
Decommissioning obligations (note 7)		**86,126**		82,836
Deferred premium on flow-through shares (note 8)		**1,417**		2,402
Deferred tax liability		**52,739**		57,370
Shareholders' Equity				
Share capital		**1,388,651**		1,292,693
Contributed surplus		**78,869**		72,951
Deficit		**(591,044)**		(575,274)
		876,476		790,370
Commitments (note 10)				
	$	**1,275,183**	$	1,225,065

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF LOSS AND COMPREHENSIVE LOSS

(unaudited) (thousands, except per share amounts)		**Three months ended March 31, 2015**		Three months ended March 31, 2014
Revenue				
Petroleum and natural gas sales	**$**	**39,940**	$	130,368
Royalties		**(3,434)**		(26,803)
Realized gain (loss) on derivative financial instruments (note 9)		**11,327**		(8,745)
Unrealized loss on derivative financial instruments (note 9)		**(10,643)**		(19,029)
		37,190		75,791
Expenses				
Operating		**15,897**		28,622
Transportation		**3,358**		3,088
General and administrative		**3,738**		5,360
Share-based compensation		**2,995**		1,171
Depletion and depreciation		**26,005**		49,214
		51,993		87,455
Loss from operations		**(14,803)**		(11,664)
Financing		**4,591**		6,751
Unrealized loss on marketable securities (note 3)		**651**		-
Loss on divestiture of property, plant and equipment		**-**		1,469
Impairment on property, plant and equipment		**-**		153,539
Loss before income taxes		**(20,045)**		(173,423)
Deferred tax recovery		**4,275**		43,730
Net loss and comprehensive loss	**$**	**(15,770)**	$	(129,693)
Net loss per share (note 8)				
Basic	**$**	**(0.12)**	$	(1.07)
Diluted	**$**	**(0.12)**	$	(1.07)

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(unaudited) (thousands)	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 2015	123,429	$ 1,292,693	$ 72,951	$ (575,274)	$ 790,370
Net loss for the period	-	-	-	(15,770)	(15,770)
Share-based compensation expensed	-	-	2,995	-	2,995
Share-based compensation capitalized	-	-	2,959	-	2,959
Issued on vesting of share awards	5	36	(36)	-	-
Issuance of common shares	16,667	100,002	-	-	100,002
Share issue costs, net of tax of $1,341	-	(4,080)	-	-	(4,080)
Balance March 31, 2015	**140,101**	**$ 1,388,651**	**$ 78,869**	**$ (591,044)**	**$ 876,476**

	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 for the period	-	-	-	(129,693)	(129,693)
Share-based compensation expensed	-	-	1,171	-	1,171
Share-based compensation capitalized	-	-	1,063	-	1,063
Transfer of share-based compensation on exercise of options	-	117	(117)	-	-
Issued on exercise of options	44	260	-	-	260
Balance March 31, 2014	121,679	$ 1,276,287	$ 65,223	$ (355,253)	$ 986,257

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited) (thousands)	**Three months ended March 31, 2015**	Three months ended March 31, 2014
Cash provided by (used in):		
Operating activities:		
Net loss	**$ (15,770)**	$ (129,693)
Adjustments:		
Share-based compensation	**2,995**	1,171
Financing expenses	**4,591**	6,751
Interest expense	**(3,951)**	(5,778)
Unrealized loss on marketable securities	**651**	-
Unrealized loss on derivative financial instruments	**10,643**	19,029
Depletion and depreciation	**26,005**	49,214
Impairment of property, plant and equipment	**-**	153,539
Loss on divestiture of property, plant and equipment	**-**	1,469
Deferred tax recovery	**(4,275)**	(43,730)
Decommissioning obligations settled	**(270)**	(107)
Change in non-cash working capital	**(3,398)**	(1,527)
	17,221	50,338
Financing activities:		
Increase (decrease) in bank loan	**(15,323)**	103,524
Proceeds from exercise of options	**-**	260
Proceeds from issuance of common shares	**100,002**	-
Share issue costs	**(5,421)**	-
	79,258	103,784
Investing activities:		
Property, plant and equipment expenditures	**(91,092)**	(66,140)
Property acquisitions	**(258)**	(104,490)
Property dispositions	**-**	1,958
Change in non-cash working capital	**(5,129)**	14,550
	(96,479)	(154,122)
Change in cash and cash equivalents	**-**	-
Cash and cash equivalents, beginning of period	**-**	-
Cash and cash equivalents, end of period	**$ -**	$ -

See accompanying notes to the condensed interim consolidated financial statements.

NOTES TO CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

For the three months ended March 31, 2015 and 2014

(Unaudited) (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 condensed interim consolidated financial statements (the "financial statements") of the Company are comprised of the accounts of Crew and its wholly owned subsidiary, Crew Oil and Gas Inc. which is incorporated in Canada, and two partnerships, Crew Energy Partnership and Crew Heavy Oil Partnership. Crew's principal place of business is located at Suite 800, 250 – 5th Street SW, Calgary, Alberta, Canada, T2P 0R4.

2. Basis of preparation:

These financial statements have been prepared in accordance with IAS 34 – Interim Financial Reporting of the International Financial Reporting Standards ("IFRS"). The financial statements use the accounting policies which the Company applied in its annual consolidated financial statements for the year ended December 31, 2014. The financial statements do not include certain disclosures that are normally required to be included in annual consolidated financial statements which have been condensed or omitted. These financial statements are presented in Canadian dollars, which is the functional currency of the Company, its subsidiary and partnerships.

The condensed interim consolidated financial statements were authorized for issue by the Board of Directors on May 7, 2015.

3. Marketable securities:

The Company holds 1,415,094 common shares of a public company trading on the TSX Venture exchange. The shares were valued at $1.45 per common share for a total value of $2.1 million at December 31, 2014. As at March 31, 2015, the fair market value of the marketable securities was $0.99 per common share and as a result an unrealized loss of $0.7 million (March 31, 2014 - NIL) was recorded in the Company's financial statements.

4. Property, plant and equipment:

Cost or deemed cost		Total
Balance, January 1, 2014	$	2,705,206
Additions		306,775
Acquisitions		155,750
Divestitures		(1,335,760)
Change in decommissioning obligations		12,176
Capitalized share-based compensation		6,889
Balance, December 31, 2014	$	1,851,036
Additions		91,092
Acquisitions		258
Change in decommissioning obligations		3,089
Capitalized share-based compensation		2,959
Balance, March 31, 2015	**$**	**1,948,434**

Accumulated depletion and depreciation		Total
Balance, January 1, 2014	$	927,612
Depletion and depreciation expense		158,835
Divestitures		(615,726)
Impairment (net)		233,719
Balance, December 31, 2014	$	704,440
Depletion and depreciation expense		26,005
Balance, March 31, 2015	**$**	**730,445**

Net book value		Total
Balance, December 31, 2014	$	1,146,596
Balance, March 31, 2015	$	1,217,989

The calculation of depletion for the three months ended March 31, 2015 included estimated future development costs of $1,258.4 million (December 31, 2014 - $1,295.7 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $65.7 million (December 31, 2014 - $67.1 million) and undeveloped land of $217.4 million (December 31, 2014 - $218.1 million) related to future development acreage.

5. Bank loan:

The Company's bank facility consists of a revolving line of credit and an operating line of credit (the "Facility"). Subsequent to March 31, 2015, the Facility was extended and the amount available on the revolving line was adjusted to $230 million while the operating line of credit remained at $30 million. The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 6, 2016. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 per cent and all outstanding advances thereunder will become repayable in one year from the extension date. The available lending limits of the Facility 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 March 31, 2015, these ratios were 1.4:1 and 0.3:1, respectively. EBITDA is a non-GAAP measure and is defined in the credit agreement as earnings before interest, taxes, depreciation and amortization, unrealized gains or losses on financial instruments, share-based compensation, all other non-cash items and EBITDA from disposed properties and acquisitions for the most recent twelve month period. Other non-cash items include impairment, gains or losses on divestitures, premium on flow-through shares and unrealized gains or losses on marketable securities for the most recent twelve month period. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled borrowing base review on or before October 31, 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 March 31, 2015, the Company's applicable pricing included a 1.0 percent margin on prime lending and a 2.0 percent stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.50 percent per annum standby fee on the portion of the facility that is not drawn. Borrowing margins and fees are reviewed annually as part of the bank syndicate's annual renewal. At March 31, 2015, the Company had issued letters of credit totaling $2.9 million (December 31, 2014 - $2.4 million). The effective interest rate on the Company's borrowings under its bank facility for the three months ended March 31, 2015 was 8.0% (December 31, 2014 – 5.4%).

6. 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. At March 31, 2015, the carrying value of the senior unsecured notes was net of deferred financing costs of $3.7 million (December 31, 2014 - $3.9 million).

7. Decommissioning obligations:

	Three months ended March 31, 2015	Year ended December 31, 2014
Decommissioning obligations, beginning of period	**$ 82,836**	$ 108,118
Obligations incurred	**719**	6,134
Obligations acquired	**-**	16,882
Obligations settled	**(270)**	(768)
Obligations divested	**-**	(56,408)
Change in estimated future cash outflows	**2,370**	6,042
Accretion of decommissioning obligations	**471**	2,836
Decommissioning obligations, end of period	**$ 86,126**	$ 82,836

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning obligations to be $86.1 million as at March 31, 2015 (December 31, 2014 - $82.8 million) based on an undiscounted total future liability of $88.2 million (December 31, 2014 - $84.8 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% (December 31, 2014 – 2%). The discount factor, being the risk-free rate related to the liability, is 2.24% (December 31, 2014 – 2.24%). The $2.4 million (December 31, 2014 - $6.0 million) change in estimated future cash outflows is a result of a change in estimated undiscounted abandonment costs.

8. Share capital:

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

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

During 2014, the Company closed a non-brokered private placement offering of 944,524 common shares at a price of $12.60 per share for gross proceeds of $11.9 million. The shares were issued on a flow-through basis, with an issuance premium to the common share trading value at the time of issuance of $3.0 million. Pursuant to the provisions of the Income Tax Act (Canada), the Company has renounced to the subscribers Canadian Exploration Expenses incurred by the Company after September 26, 2014 and prior to December 31, 2015 totaling $11.9 million. The Company renounced the Canadian Exploration Expenses such that the full proceeds were deductible against the subscribers' income for the fiscal year ended December 31, 2014. At March 31, 2015, the Company has incurred $6.2 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, 2015	5,206	$ 7.65
Forfeited	(2)	$ 8.75
Balance at March 31, 2015	**5,204**	**$ 7.65**

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

Range of exercise prices	Outstanding at Mar 31, 2015	Weighted average remaining life (years)	Weighted average exercise price	Exercisable at Mar 31, 2015	Weighted average exercise price
$ 5.16 to $ 7.01	2,353	1.2	$ 5.75	1,967	$ 5.70
$ 7.02 to $ 9.94	1,661	2.0	$ 7.19	525	$ 7.20
$ 9.95 to $14.63	910	0.6	$ 11.13	893	$ 11.11
$14.64 to $17.61	280	0.3	$ 14.98	280	$ 14.98
	5,204	1.3	$ 7.65	3,665	$ 7.94

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

Assumptions	**Three months ended March 31, 2015(1)**	Three months ended, March 31, 2014
Risk free interest rate (%)	**-**	1.3
Expected life (years)	**-**	4.0
Expected volatility (%)	**-**	43
Forfeiture rate (%)	**-**	16
Weighted average fair value of options	**$ -**	$ 2.57

(1) The Company is no longer eligible to issue options under the program and as a result, no new options have been granted for the three months ended March 31, 2015.

Restricted and Performance Award Incentive Plan:

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

Subject to terms and conditions of the RPAP, each RA and PA entitles the holder to an award value to be typically paid as to one-third on each of the first, second and third anniversaries of the date of grant. For the purpose of calculating share-based compensation, the fair value of each award is determined at the grant date using the closing price of the common shares. In the case of PAs, the award value is adjusted for a payout multiplier which can range from 0.0 to 2.0 and is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. On the vesting dates, the Company has the option of settling the award value in cash or common shares of the Company. No awards were granted for the three month period ended March 31, 2015.

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

	Number of RAs	Number of PAs
Balance January 1, 2015	759	968
Granted	-	-
Vested	(3)	(2)
Forfeited	(7)	(2)
Balance at March 31, 2015	**749**	**964**

Per share amounts:

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average shares outstanding for the period ended March 31, 2015 was 128,617,000 (March 31, 2014 – 121,647,000).

In computing diluted earnings per share for the period ended March 31, 2015, NIL (March 31, 2014 – NIL) shares were added to the weighted average Common Shares outstanding to account for the dilution of stock options and restricted and performance awards. There were 5,204,000 (March 31, 2014 – 6,298,000) stock options and 1,713,000 (March 31, 2014 – 609,000) restricted and performance awards that were not included in the diluted earnings per share calculation because they were anti-dilutive.

9. Financial risk management:

Derivative contracts:

It is the Company's policy to economically hedge a portion of its oil and natural gas revenues through the use of various financial derivative forward sales contracts and physical sales contracts. The Company does not apply hedge accounting for these contracts. The Company's production is usually sold using "spot" or near term contracts, with prices fixed at the time of transfer of custody or on the basis of a monthly average market price. The Company, however, may give consideration in certain circumstances to the appropriateness of entering into long term, fixed price marketing contracts. The Company does not enter into commodity contracts other than to meet the Company's expected sale requirements.

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. These instruments are considered level two under the fair value hierarchy. 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 date of the statement of financial position, using the remaining contracted oil and natural gas volumes and a risk-free interest rate (based on published government rates).

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

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Oil	750 bbl/day	April 1, 2015 – June 30, 2015	CDN$ WTI	$103.80	Swap	2,780
Oil	1,750 bbl/day	April 1, 2015 – December 31, 2015	CDN$ WTI	$102.62	Swap	17,210
Oil	2,000 bbl/day	April 1, 2015 – December 31, 2015	CDN$ WCS – WTI diff	($21.59)	Swap	(2,469)
Gas	30,000 gj/day	April 1, 2015 – December 31, 2015	AECO C Monthly Index	$3.75	Swap	9,224
Gas	7,500 gj/day	July 1, 2015 – December 31, 2015	AECO C Monthly Index	$3.41	Swap	1,001
Oil	500 bbl/day	January 1, 2016 – December 31, 2016	CDN$ WTI	$116.50	Call	(113)
Oil	250 bbl/day	January 1, 2016 – December 31, 2016	CDN$ WTI	$88.00 – $100.00	Call(1)	(210)
Total						27,423

(1) 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 March 31, 2015, a 10% decrease to the price outlined in the contracts above would result in a $4.2 million increase in net income.

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

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Oil	250 bbl/day	October 1, 2015 – June 30, 2016	US$ WCS – WTI diff	($14.95)	Swap
Oil	250 bbl/day	January 1, 2016 – June 30, 2016	US$ WCS - WTI diff	($14.95)	Swap

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 low commodity prices, this ratio will increase. As shown below, as at March 31, 2015, the Company's ratio of net debt to annualized funds from operations was 2.78 to 1 (December 31, 2014 – 1.92 to 1). As a result of the recent significant decline in commodity prices, the Company increased its financial flexibility through the issuance of additional equity (Share Capital – note 8). The Company plans to closely monitor commodity prices and, if necessary to maintain a strong financial position, will continue its strategy of divesting of non-core properties, will adjust its annual capital expenditure program or may consider other forms of financing.

		March 31, 2015		December 31, 2014
Net debt:				
Accounts receivable	**$**	**25,577**	$	35,393
Accounts payable and accrued liabilities		**(74,772)**		(93,115)
Working capital deficiency	**$**	**(49,195)**	$	(57,722)
Bank loan		**(34,581)**		(49,904)
Senior unsecured notes		**(146,279)**		(146,110)
Net debt	**$**	**(230,055)**	$	(253,736)
First Quarter Annualized funds from operations:				
Cash provided by operating activities	**$**	**17,221**	$	37,714
Decommissioning obligations settled		**270**		249
Change in non-cash working capital		**3,398**		(4,773)
Accretion of deferred financing charges		**(169)**		(155)
First Quarter Funds from operations	**$**	**20,720**	$	33,035
Annualized	**$**	**82,880**	$	132,140
Net debt to annualized funds from operations		**2.78**		1.92

Neither the Company nor any of its subsidiaries are subject to externally imposed capital requirements. The credit facilities are subject to a semi-annual review of the borrowing base which is directly impacted by the value of the oil and natural gas reserves (Bank loan – note 5).

10. Commitments:

	Total	2015	2016	2017	2018	2019	Thereafter
Operating leases	$ 4,495	$ 1,870	$ 2,625	$ -	$ -	$ -	$ -
Firm transportation agreements	139,520	4,936	25,683	26,041	26,041	26,041	30,778
Firm processing agreement	52,250	9,014	10,631	9,179	8,509	8,228	6,689
Capital commitment	5,694	5,694	-	-	-	-	-
Total	$ 201,959	$ 21,514	$ 38,939	$ 35,220	$ 34,550	$ 34,269	$ 37,467

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

The firm processing agreements include commitments to process natural gas through third party owned gas processing facilities in the Septimus area.

The capital commitment represents the Canadian Exploration Expenses to be incurred and renounced to subscribers of the shares (Share Capital – note 8).

DIRECTORS & OFFICERS

OFFICERS

Dale O. Shwed
President and Chief Executive Officer

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

Rob Morgan, P.Eng.
Senior Vice President and Chief Operating Officer

Ken Truscott
Senior Vice President, Business Development and Land

Jamie L. Bowman
Vice President, Marketing

Kurtis Fischer
Vice President, Business Development

Shawn A. Van Spankeren, CMA
Vice President, Finance and Administration

BOARD OF DIRECTORS

John A. Brussa,
Chairman Independent Director

Jeffery E. Errico,
Lead Director Independent Director

Dennis L. Nerland
Independent Director

Dale O. Shwed
President, Crew Energy Inc.

David G. Smith
Independent Director

Corporate Secretary

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

ABBREVIATIONS

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