FIRST QUARTER ENDING MARCH 31, 2014

# Q1 2014

crew energy inc.

➔ RESOURCE FOCUS ➔ OPPORTUNITY ➔ SUSTAINABILITY

Crew Energy Inc. ("Crew" or the "Company") (TSX-CR) of Calgary, Alberta is pleased to present its operating and financial results for the three month period ended March 31, 2014.

## HIGHLIGHTS

- Funds from operations in the first quarter increased 52% over the first quarter of 2013 and 8% over the prior quarter to $51.8 million while the funds from operations netback increased by 40%;
- Funds from operations per diluted share increased 50% over the first quarter of 2013 and increased 5% over the previous quarter to $0.42 per share;
- First quarter production was previously announced on April 9, 2014 and averaged 28,021 boe per day, an 8% increase over the same period in 2013 and a 2% decrease from the previous quarter;
- Operating netbacks improved 55% over the first quarter of 2013 to $28.49 per boe, before risk management losses, as a result of improved commodity prices and lower costs;
- Operating costs per boe decreased 6% over the same period in 2013 to $11.35 per boe;
- Crew completed and tied-in two wells at Septimus that are producing into the Company's gathering system averaging 1,200 boe per day and 1,180 boe per day (16% ngl);
- The Company updated its Montney Resource Evaluation which increased 20% to 109 TCFE of Total Petroleum Initially in Place ("TPIIP") and the Contingent Resource increased 44% to 5.0 TCFE;
- Crew added strategic production, reserves, land and infrastructure in northeast British Columbia acquiring 1,400 boe per day of production, 8.5 million boe of proved plus probable reserves, 75 net sections of Montney rights and over 130 kilometers of pipelines and 6,000 hp of field compression for $105 million;
- Subsequent to the quarter end, Crew announced the disposition of approximately 7,000 boe per day of production concentrated in the Deep Basin area of Alberta, 254,000 net acres of land and 60.4 million boe of proved plus probable reserves for $222 million in cash plus approximately 400 boe per day of heavy oil production.

| **Financial** *($ thousands, except per share amounts)* | **Three months ended March 31, 2014** | Three months ended March 31, 2013 |
|---|---|---|
| **Petroleum and natural gas sales** | **130,368** | 91,267 |
| **Funds from operations** (1) | **51,810** | 34,188 |
| Per share - basic | **0.43** | 0.28 |
| - diluted | **0.42** | 0.28 |
| **Net loss** | **(129,693)** | (22,047) |
| Per share - basic | **(1.07)** | (0.18) |
| - diluted | **(1.07)** | (0.18) |
| **Exploration and Development expenditures** | **66,140** | 65,252 |
| **Property acquisitions** (net of dispositions) | **102,532** | 14,663 |
| **Net capital expenditures** | **168,672** | 79,915 |
| **Capital Structure** *($ thousands)* | **As at March 31, 2014** | As at December 31, 2013 |
| Working capital deficiency (2) | **53,121** | 40,098 |
| Net assets held for sale (3) | **(231,677)** | – |
| Bank loan | **301,212** | 197,688 |
| | **122,656** | 237,786 |
| Senior unsecured notes | **145,785** | 145,623 |
| **Total net debt** | **268,441** | 383,409 |
| **Bank facility after closing of the Alberta Gas Disposition** | **350,000** | 420,000 |
| **Common Shares Outstanding** *(thousands)* | **121,679** | 121,635 |

(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 charges. 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 shown above includes accounts receivable less accounts payable and accrued liabilities..

(3) Net assets held for sale reflects the amounts reclassified from property, plant and equipment and decommissioning obligations for the assets less liabilities associated with the Alberta Gas Disposition as described on the following page.

| Operations | Three months ended March 31, 2014 | Three months ended March 31, 2013 |
|---|---|---|
| **Daily production** [1] | | |
| Princess and other oil (bbl/d) | **3,298** | 4,936 |
| Lloydminster oil (bbl/d) | **6,128** | 5,441 |
| Natural gas liquids (bbl/d) | **3,435** | 2,984 |
| Natural gas (mcf/d) | **90,959** | 75,597 |
| Oil equivalent (boe/d @ 6:1) | **28,021** | 25,961 |
| **Average prices** [1 & 2] | | |
| Princess and other oil ($/bbl) | **81.81** | 64.36 |
| Lloydminster oil ($/bbl) | **69.50** | 50.61 |
| Natural gas liquids ($/bbl) | **64.59** | 54.43 |
| Natural gas ($/mcf) | **5.84** | 3.42 |
| Oil equivalent ($/boe) | **51.69** | 39.06 |
| **Netback** ($/boe) | | |
| Revenue | **51.69** | 39.06 |
| Realized commodity hedging loss | **(3.47)** | (0.55) |
| Royalties | **(10.63)** | (7.41) |
| Operating costs | **(11.35)** | (12.03) |
| Transportation costs | **(1.22)** | (1.25) |
| Operating netback [3] | **25.02** | 17.82 |
| G&A | **(2.13)** | (1.99) |
| Interest on long-term debt | **(2.36)** | (1.19) |
| Funds from operations | **20.53** | 14.64 |
| **Drilling Activity** | | |
| Gross wells | **21** | 39 |
| Working interest wells | **19.0** | 36.8 |
| Success rate, net wells | **100%** | 100% |

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

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

(3) Operating netback equals petroleum and natural gas sales including realized hedging gains and losses on commodity based financial instruments 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

Crew continued to execute on its corporate strategy in the first quarter culminating in the closing of two separate transactions that resulted in the Company acquiring certain strategic Montney liquids rich natural gas properties in northeast British Columbia for approximately $105 million (the "Montney Acquisition"). The acquired assets include 75 net sections of land that are either contiguous with existing Crew land or increase Crew's working interest in joint interest lands. The acquired lands include production of 1,400 boe per day of predominantly natural gas production and 8.5 million boe of proved plus probable reserves. Subsequent to the end of the first quarter, Crew entered into an agreement to sell certain petroleum and natural gas assets including approximately 7,000 boe per day of 75% natural gas production and 60.4 mmboe of proved plus probable reserves focused primarily in the Deep Basin of Alberta (the "Alberta Gas Disposition"). Consideration for the Alberta Gas Disposition will include approximately $222 million in cash, before closing adjustments, plus approximately 400 bbls per day of heavy oil production. This disposition is scheduled to close on or about May 30, 2014, subject to satisfaction of customary industry closing conditions. In conjunction with the announcement of these transactions, the Company increased its 2014 capital budget to $285 million with the incremental $39 million directed exclusively to the Company's Montney resource development and an acceleration of Crew's Montney five year growth plan.

As previously announced, Crew's first quarter production averaged 28,021 boe per day as the severe winter weather along with an unusual number of wells temporarily shut-in due to third party drilling operations in the Lloydminster area impacted volumes by approximately 1,000 boe per day. Toward the end of March, the majority of the Company's 21 (19.0 net) wells drilled in the quarter came on production resulting in the Company achieving field estimated production rates of 30,400 boe per day in the month of April (inclusive of the 1,400 boe per day acquired at the end of March) consistent with budget expectations. During the first quarter, exploration and development capital expenditures were $66.1 million allocated $35.0 million to the northeast British Columbia Montney, $15.4 million to Princess Mannville development, $13.8 million to Lloydminster and $1.9 million to the Deep Basin and Other Alberta areas.

## FINANCIAL

Crew's first quarter funds from operations increased 8% over the prior quarter and 52% over the same period in 2013 to $51.8 million or $0.42 per diluted share. The Company's funds from operations benefited from stronger oil and natural gas pricing experienced during the quarter that were partially offset by a $8.7 million realized loss on the Company's risk management program. The Company's $130 million first quarter net loss was impacted by realized and unrealized losses of $27.8 million incurred on the Company's risk management program and a non-cash impairment charge of $153.5 million on assets related to the Alberta Gas Disposition that have been reclassified as held for sale.

An extended cold winter across North America has reduced natural gas storage levels to 52% below last year's level and 55% below the five year gas storage average level. Natural gas prices continue to reflect the reduced storage levels as the Company's realized natural gas price increased 53% over the previous quarter to average $5.84 per mcf for the first quarter of 2014. Oil prices strengthened during the quarter as the discount for Canadian heavy oil, measured as the Western Canadian Select ("WCS") price differential to West Texas Intermediate ("WTI"), narrowed to average CDN$25.55 per bbl as compared to CDN$33.89 for the previous quarter. A number of positive catalysts provided support for the increase in WCS oil prices including increased crude-by-rail exports and increased rail loading facilities and expansions scheduled for 2014.

The Company's hedging strategy is focused on protecting against significant declines in commodity prices that would negatively impact the funds from operations needed to fund the Company's on-going capital program. Strengthening commodity prices have significantly affected Crew's realized and unrealized losses from its risk management program in the first quarter of 2014. In the first quarter, the Company incurred a realized hedging loss of $8.7 million or $3.47 per boe as compared to $1.3 million or $0.55 per boe in the same period in 2013. During the first quarter of 2014, the Company also incurred unrealized losses on financial instruments of $19.0 million.

The Company had a successful first quarter exploration and development program which saw Crew spend $66.1 million focusing on development of liquids rich natural gas from the Montney formation at Septimus. Quarter-end net debt totaled $268 million which included a reclassification of the Alberta Gas Disposition assets from property, plant and equipment to current assets held for sale. Following the closing of the Alberta Gas Disposition, the Company's bank facility will be renewed at $350 million.

## OPERATIONS UPDATE

### Septimus/Tower, British Columbia

Crew achieved the fourth consecutive quarter of production growth at Septimus with average production of 10,140 boe per day and a March average of 10,650 boe per day as new wells in the quarter were brought on during the month and with the Septimus gas plant running at 95% to 102% of projected capacity. With sub-$5 per boe operating costs, an attractive and improving royalty structure and improved pricing, the operating netback at Septimus has increased 62% to $29.42 per boe compared to the first quarter of 2013 levels. The Company projects that an annual capital program of $40 to $50 million is required to maintain the Septimus gas plant at capacity and combined with the current pricing environment this would result in $40 to $50 million of annual free cash flow being generated from this first phase of Crew's Montney development. Future economics have been further enhanced with the announcement of a second tier to the British Columbia Deep Well Credit Program effective April 1, 2014. Based on this addition to the program the majority of Crew's Montney liquids rich natural gas drilling program will now qualify resulting in an increased NPV10 of approximately $0.8 million per well.

During the quarter, Crew conducted a second production test on the Montney oil exploration well drilled in the fourth quarter of 2013 located 11 kilometers northwest of the Company's existing Montney oil production. Following an 80 day shut in period, the well was brought back on production for an 11 day test during which it produced an average of 540 barrels of oil per day and 1.1 mmcf per day of natural gas for a total average rate of 723 boe per day. The well is expected to be tied into Crew's gathering system in the third quarter. The Company is planning to begin drilling its first well of a six well pad at Tower in June.

At Septimus, Crew drilled five (5.0 net) horizontal wells in the quarter with two of the wells on production at 6 to 8 mmcf per day as of the end of the quarter. With the evolution of the Company's development strategy to pad drilling to capture additional cost efficiencies, Crew is currently drilling the third well on a six well pad which is expected to be completed in the third quarter and will be brought on production following the planned turnaround at the Septimus gas plant in August. A second rig is operating in the Groundbirch area where the Company is drilling the second well on a two well pad. These wells are expected to be completed and tested in the third quarter along with one of the Attachie wells drilled in 2013. Crew also began ordering major equipment for the second Septimus facility anticipated to be on stream mid-2015 with a designed capacity of 60 mmcf per day of raw gas.

**Lloydminster, Alberta/Saskatchewan**

At Lloydminster, Crew drilled nine (7.6 net) oil wells and recompleted 16 (15.1 net) wells for $10.8 million. Production for the quarter averaged 6,150 boe per day and the Company is expecting to maintain production in the 6,000 boe per day range throughout the year with total capital expenditures of $35 million.

**Princess, Alberta**

During the first quarter, production at Princess averaged 3,950 boe per day as the majority of the wells in the Company's first quarter drilling program came on production early in the second quarter. Current production is approximately 4,500 boe per day based on field estimates with new wells still being optimized. Crew drilled six (6.0 net) wells with total capital expenditures of $14 million including well optimizations. The first quarter drilling program targeted new Mannville opportunities on the Company's Crown acreage and represents the first phase of delineation of a number of these lands. Crew is projecting to maintain production in the 4,000 to 4,500 boe per day range throughout the year as the Company continues to delineate its Mannville acreage.

**Deep Basin, Alberta**

Crew's Deep Basin and other minor Alberta properties produced an average of 7,220 boe per day during the quarter. Crew has announced an agreement to sell these assets pursuant to the Alberta Gas Disposition with an anticipated closing date of May 30, 2014.

## OUTLOOK

With the announced Alberta Gas Disposition, the Company revised forecasted 2014 average production to 25,500 to 26,500 boe per day and forecasts to exit the year at 26,000 to 27,000 boe per day, subject to closing the disposition on May 30, 2014. Exploration and development capital expenditures are now budgeted at $285 million, a $39 million increase over the previous budget. Net debt after closing of the transaction is forecasted to be approximately $280 million.

For the remainder of 2014, Crew plans to:

- Continue to develop and delineate our Montney resource which is now over 109 TCFE of TPIIP and 5.0 TCFE of Contingent Resource;
- Apply new and evolving drilling and completion technologies to improve Expected Ultimate Recoveries and initial production rates;
- Invest in Montney production infrastructure which is estimated at $35 million in 2014 in addition to pre-drilling the majority of the 18 wells planned to initially fill the new 60 mmcf per day facility;

- Evaluate the Montney potential at Crew's Attachie, Groundbirch and Tower, British Columbia properties;
- Continue to high-grade our asset base and consolidate acreage in the Montney in northeast British Columbia;
- Maintain aggregate production levels at Lloydminster and Princess with free funds from operations to be distributed to our Montney growth initiatives;

Our 2014 capital program has positioned the Company with an expanded resource and drilling inventory, important infrastructure as well as land that is strategic to our future growth plans. Crew's five year growth plan anticipates the construction of facilities to process 240 mmcf per day of natural gas and 10,000 bbls per day of light oil with targeted exit 2018 Montney production of approximately 45,000 boe per day.

We would like to thank our employees and Board of Directors for their steadfast commitment to Crew's success and our shareholders for their continued support. We are excited about our prospects and future and look forward to reporting our second quarter operating and financial results in August.

## 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" 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". The discussion includes reference to TPIIP, DPIIP, UPIIP and Contingent Resources per the Sproule Associates Ltd. ("Sproule") Resources Evaluation effective as at April 30, 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 Crew's 452 net Montney sections located in Northeast British Columbia ("NEBC") (the "Evaluated Areas") effective as of April 30, 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 Contingent Resource. The commodity diversity of Crew's NEBC 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 NEBC Montney.

TPIIP in the Montney "gas window" increased to 60.6 TCF from 44.6 TCF due to the Montney Acquisition completed in the first quarter. The Resource Evaluation also included recognition of Crew's lands in the Montney "oil window" where Crew has 138 net sections. On the oil bearing lands, TPIIP increased from 7.8 billion barrels of oil to 8.1 billion barrels of oil. 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 that is presented below and the results we have had at Septimus to date highlight the quality of the lands that Crew has successfully acquired over the past six years. With the improved economics of this play and the visibility of continued development of infrastructure in the Septimus corridor we are committed to continue to pursue opportunities in this region and it is our intent to aggressively exploit the 60.6 TCF and 8.1 billion barrels of TPIIP on our acreage in order to grow production, reserves and cashflow into the future.

The following tables summarize the results of the Resource Evaluation.

| Natural Gas Resource Categories [1][2][3] | Tcf |
|---|---|
| Total Petroleum Initially In Place (TPIIP) | 60.6 |
| Discovered Petroleum Initially In Place (DPIIP) | 26.1 |
| Undiscovered Petroleum Initially In Place (UPIIP) | 34.5 |

(1) All volumes in table are company gross and raw gas volumes.
(2) Sproule's analysis identified four intervals in the Montney consisting of one interval in the Upper Montney and three intervals in the Lower Montney.
(3) Crew's acreage was divided into six (6) areas in the "gas window". Crew owns 276 net sections in the gas window at April 30, 2014.

| Oil Resource Categories [1][2][3][4] | Mmbbls |
|---|---|
| Total Petroleum Initially In Place (TPIIP) | 8,052 |
| Discovered Petroleum Initially In Place (DPIIP) | 1,363 |
| Undiscovered Petroleum Initially In Place (UPIIP) | 6,689 |

(1) All volumes in table are company gross.
(2) The oil volumes are quoted as Stock Tank Barrels ("STB").
(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 "oil window". Crew owns 138 net sections in the oil window at April 30, 2014.

| Reserves and Contingent Resources [1][2][3][6][7] | Best Estimate |
|---|---|
| **Natural gas** (Tcf) | |
| Reserves [3] | 0.5 |
| Contingent Resources | 4.0 |
| **Natural gas liquids** (Mmbbls) [4][5] | |
| Reserves [3] | 14.7 |
| Contingent Resources | 160.7 |
| **Oil** (Mmbbls) | |
| Reserves [3] | 0.4 |
| Contingent Resources | 10.9 |

(1) All DPIIP other than cumulative production, reserves, and Contingent Resources has been categorized as unrecoverable at this time.
(2) All volumes in table are company gross and sales volumes.
(3) For reserves, the volume under the heading Best Estimate are proved plus probable reserves as at December 31, 2013.
(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) Contingent Resources includes an 85% development factor.

| Prospective Resources [1][2][5][6] | Best Estimate |
|---|---|
| Natural gas (Tcf) | 6.3 |
| Natural gas liquids (Mmbbls)[3][4] | 254.4 |
| Oil (Mmbbls) | 14.4 |

(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 includes an 85% development factor.

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. Additional drilling, completion, and test results are required before Crew can commit to development and these contingent resources can be converted to reserves and a larger component of Prospective Resources is converted to Contingent Resource.

The Prospective Resources have not been risked for chance of discovery. 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. The Contingent Resource contingencies are identified as economic or non-technical, there are no technical contingencies. Crew anticipates that a large portion of the Contingent Resources will be economically viable to develop. Significant positive factors are historic drilling success and production history on the more fully developed Montney acreage, abundant well log and production test data. Potential negative factors include lack of long term production history over the majority of Crew lands, lack of infrastructure, potential for variations in the quality of the Montney formation where minimal well data currently exists, access to the substantial amount of capital which would be required to develop the resources, low commodity prices that would curtail the economics of development and the future performance of wells, regulatory approvals, access to the required services at the appropriate cost and topographic or surface restrictions.

**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.

**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, 2013 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 proved plus probable reserves attributed to the assets acquired by the Company pursuant to the Montney Acquisition. Such reserves reflect Company internally estimated "gross" reserves prepared by a qualified reserves evaluator effective December 31, 2013 in accordance with the definitions and provisions contained in the COGE Handbook. Estimates of proved plus probable reserves contained herein attributed to the assets being disposed of pursuant to the Alberta Gas Disposition reflect "gross" reserves assigned by the Company's independent reserves evaluator, Sproule Associates Limited, effective December 31, 2013.*

*This report contains references to estimates of oil and gas classified as TPIIP, DPIIP, UPIIP and Contingent Resources in the Montney region in northeastern British Columbia 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 using a zero 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 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: completion of the Alberta Gas Disposition and the timing thereof and anticipated benefits to be derived therefrom; the effect of the Alberta Gas Disposition on continuing operations and plans to expand the 2014 capital program on a post-transaction basis; forecasted net debt after closing of the Alberta Gas Disposition; the volume and product mix of Crew's oil and gas production; production estimates including 2014 forecast average and exit productions; 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 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 new 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. In this report reference is made to the Company's five year growth plan including future processing capacity in Northeast British Columbia and a 2018 Montney production target of 45,000 boe per day which are not estimates or forecasts of rates that may actually be achieved. Such information reflects internal projections used by management for the purposes of making capital investment decisions and for internal long range planning and budget preparation. Accordingly, undue reliance should not be placed on same.*

*Forward-looking statements or information are based on a number of material factors, expectations or assumptions of Crew which have been used to develop such statements and information but which may prove to be incorrect. Although Crew believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because Crew can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified herein, assumptions have been made regarding, among other things: that all conditions to closing of the Alberta Gas Disposition are satisfied or waived; the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; the timely receipt of any required regulatory approvals; the ability of Crew to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects in which Crew has an interest in to operate the field in a safe, efficient and effective manner; the ability of Crew to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and cost of pipeline, storage and facility construction and expansion and the ability of Crew to secure adequate product transportation; future commodity prices; currency, exchange and interest rates; regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Crew operates; the ability of Crew to successfully market its oil and natural gas products. There are a number of assumptions associated with the potential of resource volumes assigned to the Evaluated areas including the quality of the Montney reservoir, future drilling programs and the funding thereof, continued performance from existing wells and performance of new wells, the growth of infrastructure, well density per section, and recovery factors and discovery and development necessarily involves known and unknown risks and uncertainties, including those identified in this report.*

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

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

### 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.*

*Crew is an oil and gas exploration and production company whose shares are traded on The Toronto Stock Exchange under the trading symbol "CR".*

## 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, 2014 and 2013 and the audited consolidated financial statements and Management Discussion and Analysis for the year ended December 31, 2013. The 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, 2013. All figures provided herein and in the condensed interim consolidated financial statements are reported in Canadian dollars.*

### Forward Looking Statements

*This MD&A contains forward looking statements. Management's assessment of future plans and operations, planned property transaction and the timing thereof, drilling plans and the timing thereof, plans for the tie-in and completion of wells and the timing thereof, capital expenditures, timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, completion of the Alberta Gas Disposition and the timing thereof and anticipated benefits to be derived therefrom, the effect of the Alberta Gas Disposition on continuing operations and plans to expand the 2014 capital program on a post-transaction basis, production estimates including 2014 average and 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, the Company's updated credit facility effective upon closing of the Alberta Gas Disposition, estimates regarding undeveloped land position and estimated future drilling, recompletion or reactivation locations and anticipated impact upon Crew's forecasts in respect of production 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: that all conditions to closing of the Alberta Gas Disposition are satisfied or waived; 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 that is commonly used in the oil and gas industry. It represents cash provided by operating activities before changes in non-cash working capital, decommissioning obligation expenditures 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, 2014** | Three months ended March 31, 2013 |
|---|---|---|
| Cash provided by operating activities | **50,338** | 25,917 |
| Decommissioning obligation expenditures | **107** | 1,780 |
| Change in non-cash working capital | **1,527** | 6,491 |
| Accretion of deferred financing charges | **(162)** | – |
| Funds from operations | **51,810** | 34,188 |

*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 under the bank facility is defined as earnings before interest, income taxes, depletion and depreciation, net impairment charges, exploration and evaluation expenditures and includes adjustments for any other non-cash items.*

*Operating Netback*

*Management uses certain industry benchmarks such as operating netback to analyze financial and operating performance. This benchmark as presented does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Operating netback equals total petroleum and natural gas sales including realized gains and losses on commodity derivative contracts 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 standardized meanings 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, including assets held for sale, and net debt:*

| *($ thousands)* | **March 31,2014** | December 31,2013 |
|---|---|---|
| Current assets | **320,419** | 49,877 |
| Current liabilities | **(174,271)** | (105,315) |
| Fair value of financial instruments | **32,408** | 15,340 |
| Working capital (deficit) | **178,556** | (40,098) |

| *($ thousands)* | **March 31, 2014** | December 31, 2013 |
|---|---|---|
| Bank loan | **(301,212)** | (197,688) |
| Senior unsecured notes | **(145,785)** | (145,623) |
| Working capital (deficit) | **178,556** | (40,098) |
| Net debt | **(268,441)** | (383,409) |

## RESULTS OF OPERATIONS

### Strategic Transactions

In March 2014, Crew arranged a series of transactions that resulted in the Company acquiring certain strategic Montney liquids rich natural gas properties in northeast British Columbia for approximately $105 million. The acquired assets include 75 net sections of land that are either contiguous with existing Crew land or increase Crew's working interest in joint interest lands. The acquired lands also include production of approximately 1,400 boe per day of predominantly natural gas production. These transactions closed prior to March 31, 2014.

In a separate transaction, Crew entered into an agreement to sell certain petroleum and natural gas assets including approximately 7,000 boe per day of 75% natural gas production focused primarily in the Deep Basin of Alberta (the "Alberta Gas Disposition"). Consideration for the Alberta Gas Disposition will include approximately $222 million in cash, before closing adjustments, plus 2,750 net acres of mineral rights in the Lloydminster area and approximately 400 bbls per day of heavy oil production. This disposition is scheduled to close on or about May 30, 2014. For further details see the Capital Expenditures, Acquisitions and Dispositions section. In order to reflect the effect of these transactions the forecasts, projections and estimates included in this management discussion and analysis have been prepared including the impact of the Alberta Gas Disposition assuming it closes on the date specified above.

### Production

| | **Three months ended March 31, 2014** | | | | Three months ended March 31, 2013 | | | |
|---|---|---|---|---|---|---|---|---|
| | **Oil (bbl/d)** | **Ngl (bbl/d)** | **Nat. gas (mcf/d)** | **Total (boe/d)** | Oil (bbl/d) | Ngl (bbl/d) | Nat. gas (mcf/d) | Total (boe/d) |
| Lloydminster | **6,128** | **–** | **178** | **6,158** | 5,441 | – | 539 | 5,531 |
| Princess | **2,882** | **96** | **5,892** | **3,960** | 4,386 | 117 | 6,836 | 5,642 |
| Northeast British Columbia | **81** | **1,655** | **53,537** | **10,659** | 177 | 1,132 | 36,053 | 7,318 |
| Deep Basin | **79** | **1,526** | **23,511** | **5,524** | 155 | 1,591 | 22,793 | 5,545 |
| Other | **256** | **158** | **7,841** | **1,720** | 218 | 144 | 9,376 | 1,925 |
| Total | **9,426** | **3,435** | **90,959** | **28,021** | 10,377 | 2,984 | 75,597 | 25,961 |

Production for the three months ended March 31, 2014 averaged 28,021 boe per day which represents an 8% increase as compared to the same quarter of 2013. The production growth is a result of the continued drilling success at Septimus, British Columbia and in the Lloydminster area in both Alberta and Saskatchewan. The Princess area production declines are the result of reduced capital spending in the area over the past two years. Corporate production was also negatively impacted due to extreme weather conditions experienced during the first quarter causing operational outages and a high number of wells being shut-in due to offsetting drilling operations in the Company's Lloydminster operations. In addition, Crew lost approximately 350 boe per day of natural gas production in northeastern British Columbia due to a fire at a compressor in the Sierra area in late 2013. The Company has elected to not spend capital on recommissioning the facility at this time.

### Revenue

| | **Three months ended March 31, 2014** | Three months ended March 31, 2013 |
|---|---|---|
| **Revenue** *($ thousands)* | | |
| Princess and other oil | **24,284** | 28,589 |
| Lloydminster oil | **38,328** | 24,782 |
| Natural gas liquids | **19,964** | 14,620 |
| Natural gas | **47,792** | 23,276 |
| Total | **130,368** | 91,267 |
| **Crew average prices** | | |
| Princess and other oil ($/bbl) | **81.81** | 64.36 |
| Lloydminster oil ($/bbl) | **69.50** | 50.61 |
| Natural gas liquids ($/bbl) | **64.59** | 54.43 |
| Natural gas ($/mcf) | **5.84** | 3.42 |
| Oil equivalent ($/boe) | **51.69** | 39.06 |
| **Benchmark pricing** | | |
| Conv. and heavy oil – WCS (Cdn $/bbl) | **83.36** | 62.96 |
| Oil and ngl – Cdn$ WTI (Cdn $/bbl) | **108.91** | 95.20 |
| Natural Gas – AECO C daily index (Cdn $/mcf) | **5.65** | 3.20 |

Revenue for the three months ended March 31, 2014 increased 43% compared to the same quarter in 2013. This is the result of the 8% increase in production coupled with the increase in all of the Company's realized commodity prices. Crew recognized a 27% increase in the price received for its Princess and other oil production for the quarter as compared to the prior year. This was slightly lower than the 32% increase in the Company's Western Canadian Select ("WCS") benchmark as a result of the decrease in higher valued oil production from the Deep Basin and Northeast British Columbia areas as compared to the same period last year. The 37% increase in Lloydminster oil pricing was greater than the increase in the WCS benchmark due to a lower relative cost of condensate purchased to blend the Lloydminster oil to pipeline specifications in the first quarter 2014 compared to the prior year. The Company also benefitted from physically forward selling its Lloydminster crude at fixed monthly average WCS differentials that were lower than the actual monthly average price reflected by the benchmark.

The Company's realized natural gas liquids ("ngl") price increased 19% compared to a 14% increase in the Company's Cdn$ West Texas Intermediate ("WTI") benchmark price as a result of an increase in ngl production in Northeast British Columbia where there was an increase in higher valued condensate production over the same period in 2013. The AECO C natural gas benchmark price increased 77% as compared to the 71% increase in the Company's realized natural gas price. This was the result of the Company entering into monthly index price contracts for a portion of its sales during the quarter, in a rapidly rising price environment, that were lower than the daily index prices recognized for the same period and which are the basis of our natural gas benchmark price.

### Royalties

| *($ thousands, except per boe)* | **Three months ended March 31, 2014** | Three months ended March 31, 2013 |
|---|---|---|
| Royalties | **26,803** | 17,325 |
| Per boe | **10.63** | 7.41 |
| Percentage of revenue | **20.6%** | 19.0% |

In the first quarter of 2014, the average corporate effective royalty rate increased to 20.6% from 19.0% in the same period of 2013 due to the increase in commodity pricing attracting a higher crown royalty rate. In addition, certain wells in the Deep Basin and Septimus areas came off royalty holidays in the latter half of 2013 increasing Crew's crown royalties in the first quarter of 2014. Crew forecasts royalty rates to average between 19% and 21% in 2014.

## Financial Instruments

*Commodities*

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

| *($ thousands)* | **Three months ended March 31, 2014** | Three months ended March 31, 2013 |
|---|---|---|
| Realized loss on financial instruments | **(8,745)** | (1,280) |
| Per boe | **(3.47)** | (0.55) |
| Unrealized loss on financial instruments | **(19,029)** | (14,719) |

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

| Subject of Contract | Notional Quantity | Remaining Term | Reference | Average Strike Price | Contract Traded | Fair Value ($000s) |
|---|---|---|---|---|---|---|
| Oil | 250 bbl/day | April 1, 2014 – June 30, 2014 | CDN$ WTI | $103.00 | Swap | (187) |
| Oil | 4,250 bbl/day | April 1, 2014 – December 31, 2014 | CDN$ WTI | $98.23 | Swap | (12,671) |
| Oil | 500 bbl/day | April 1, 2014 – December 31, 2014 | CDN$ WTI | $85.00 – $100.00 | Collar[(1)] | (1,382) |
| Oil | 250 bbl/day | April 1, 2014 – December 31, 2014 | CDN$ WTI | $85.00 – $103.25 | Collar[(2)] | (449) |
| Oil | 500 bbl/day | April 1, 2014 – December 31, 2014 | CDN$ WTI | $96.05 | Call | (1,830) |
| Oil | 500 bbl/day | April 1, 2014 – December 31, 2014 | US$ WTI | $86.75 | Call | (2,088) |
| Oil | 750 bbl/day | April 1, 2014 – June 30, 2014 | CDN$ WCS – WTI diff | $(24.33) | Swap | (180) |
| Oil | 2,750 bbl/day | April 1, 2014 – December 31, 2014 | CDN$ WCS – WTI diff | $(23.48) | Swap | (1,485) |
| Oil | 750 bbl/day | July 1, 2014 – December 31, 2014 | CDN$ WCS – WTI diff | $(23.75) | Swap | (346) |
| Gas | 15,000 gj/day | April 1, 2014 – October 31, 2014 | AECO C Monthly Index | $3.84 | Swap | (1,759) |
| Gas | 37,500 gj/day | April 1, 2014 – December 31, 2014 | AECO C Monthly Index | $3.57 | Swap | (9,431) |
| Oil | 250 bbl/day | January 1, 2015 – June 30, 2015 | CDN$ WTI | $102.50 | Swap | 17 |
| Oil | 250 bbl/day | January 1, 2015 – December 31, 2015 | CDN$ WTI | $86.00 | Call | (1,349) |
| Oil | 500 bbl/day | January 1, 2015 – December 31, 2015 | US$ WTI | $98.25 | Call | (610) |
| Oil | 500 bbl/day | April 1, 2014 – December 31, 2015 | CDN$ WCS – WTI diff | $(22.00) | Swap | 36 |
| Gas | 7,500 gj/day | January 1, 2015 – December 31, 2015 | AECO C Monthly Index | $3.74 | Swap | (655) |
| **Total** | | | | | | **(34,369)** |

(1) The referenced contract is a fade-in Collar whereby the price is fixed at $100/bbl unless the market price falls below $85/bbl in which case the price received will be $85/bbl.

(2) The referenced contract is a fade-in collar whereby the price is fixed at $103.25/bbl unless the market price falls below $85/bbl in which case the price received will be $85/bbl.

(3) This is a structured call which is only triggered if the average CDN$ WTI trades above $96 per bbl for a given month during the term.

Subsequent to March 31, 2014, the Company entered into the following derivative commodity contract:

| Subject of Contract | Volume | Term | Reference | Strike Price | Option Traded |
|---|---|---|---|---|---|
| Oil | 250 bbl/day | January 1, 2015 – June 30, 2015 | CDN$ WTI | $103.50 | Swap |

### Operating Costs

| *($ thousands, except per boe)* | **Three months ended March 31, 2014** | Three months ended March 31, 2013 |
|---|---|---|
| Operating costs | **28,622** | 28,110 |
| Per boe | **11.35** | 12.03 |

For the first quarter of 2014, total operating expenses per unit decreased 6% over the same period in 2013 as a result of the increase in production at Septimus which attracts lower operating costs per unit than the corporate average. This increase in lower cost production assisted in offsetting the effect of higher costs in the Princess area due to reduced production in this area which has a high fixed cost component. The Company forecasts annual operating costs to average $10.75 to $11.00 per boe as higher winter operating costs decline combined with increased lower cost production at Septimus, the benefits of which will be partially offset by the sale of lower operating cost Deep Basin assets in the second quarter.

### Transportation Costs

| *($ thousands, except per boe)* | **Three months ended March 31, 2014** | Three months ended March 31, 2013 |
|---|---|---|
| Transportation costs | **3,088** | 2,928 |
| Per boe | **1.22** | 1.25 |

Transportation costs per unit for the first quarter of 2014 were comparable to the same period of 2013 as increased production at Lloydminster and Septimus, which have higher per boe transportation costs, were offset by the elimination of higher transportation costs from the lost Sierra production. The Company forecasts transportation costs to range between $1.30 and $1.50 per boe in 2014 which is slightly higher than previously forecasted as a result of the Alberta Gas Disposition that has lower per unit transportation costs.

### Operating Netbacks

| *($/boe)* | **Three months ended March 31, 2014** | Three months ended March 31, 2013 |
|---|---|---|
| Revenue | **51.69** | 39.06 |
| Realized commodity hedging loss | **(3.47)** | (0.55) |
| Royalties | **(10.63)** | (7.41) |
| Operating costs | **(11.35)** | (12.03) |
| Transportation costs | **(1.22)** | (1.25) |
| Operating netbacks | **25.02** | 17.82 |

### General and Administrative Costs

| *($ thousands, except per boe)* | **Three months ended March 31, 2014** | Three months ended March 31, 2013 |
|---|---|---|
| Gross costs | **7,892** | 6,887 |
| Operator's recoveries | **(82)** | (119) |
| Capitalized costs | **(2,450)** | (2,124) |
| General and administrative expenses | **5,360** | 4,644 |
| Per boe | **2.13** | 1.99 |

Increased gross general and administrative costs were the result of higher staffing costs incurred due to an increase in activity levels during the latter half of 2013 and the first quarter of 2014. General and administrative costs per boe increased in the first quarter of 2014 as the increase in staffing costs outweighed the increase in production levels from the same period in 2013. The Company expects general and administrative costs per boe to average between $2.00 to $2.15 per boe for 2014 with lower production volumes resulting from the Alberta Gas Disposition.

### Share-Based Compensation

| ($ thousands) | Three months ended March 31, 2014 | Three months ended March 31,2013 |
|---|---|---|
| Gross costs | **2,234** | 1,086 |
| Capitalized costs | **(1,063)** | (556) |
| Total share-based compensation | **1,171** | 530 |

The Company's share-based compensation expense has increased in the first quarter of 2014 compared with the same period in 2013 due to the addition of the restricted and performance awards granted in the second quarter of 2013.

### Depletion and Depreciation

| ($ thousands, except per boe) | Three months ended March 31, 2014 | Three months ended March 31, 2013 |
|---|---|---|
| Depletion and depreciation | **49,214** | 48,379 |
| Per boe | **19.51** | 20.73 |

Total depletion and depreciation costs per boe have decreased in the first quarter of 2014 as compared with the same period in 2013 due to increased proved plus probable reserve bookings from the Company's annual reserve evaluation.

### Impairment

As described in the Strategic Transactions and Capital Expenditures, Acquisitions and Dispositions sections, subsequent to March 31, 2014, the Company has entered into the Alberta Gas Disposition agreement to dispose of approximately 7,000 boe per day of primarily natural gas production within Alberta. At March 31, 2014, these assets were reclassified as assets held for sale and recorded at fair value less costs to sell. As a result, an impairment charge of $153.5 million was recognized against these assets during the first quarter of 2014.

### Finance Expenses

| ($ thousands, except per boe) | Three months ended March 31, 2014 | Three months ended March 31, 2013 |
|---|---|---|
| Interest on bank loan | **2,680** | 2,792 |
| Interest on senior unsecured notes | **3,098** | – |
| Accretion of deferred financing charges | **162** | – |
| Accretion of the decommissioning obligation | **811** | 660 |
| Total finance expense | **6,751** | 3,452 |
| Average debt level | **348,352** | 259,783 |
| Effective interest rate on bank loan | **5.5%** | 4.3% |
| Effective interest rate on senior unsecured notes | **8.4%** | – |
| Effective interest rate on long-term debt | **6.7%** | 4.3% |
| Interest on long-term debt per boe | **2.36** | 1.19 |

In the first quarter of 2014, average debt levels increased over the same period 2013 due to incremental capital spending throughout the last three quarters of 2013. The effective interest rate on the Company's bank loan increased in the first quarter of 2014, as compared with the same period in 2013, due to higher standby fees on the Company's bank facility in the first quarter 2014 resulting from a large decrease in drawings on the facility due to the issuance of the senior unsecured notes in the fourth quarter of 2013. The Company expects its effective interest rate on long-term debt will average approximately 6.5% to 7.0% in 2014, a slight increase over previous estimates as a result of additional standby fees expected to be incurred on the undrawn facility.

**Deferred Income Taxes**

In the first quarter of 2014, the provision for deferred income taxes was a recovery of $43.7 million compared to a recovery of $7.3 million in the first quarter of 2013. The increased recovery was due to the Company having an increased pre-tax loss related to the realized and unrealized loss on financial instruments and the impairment charge incurred in the first quarter of 2014.

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

| *($ thousands, except per share amounts)* | **Three months ended March 31, 2014** | Three months ended March 31, 2013 |
|---|---|---|
| Cash provided by operating activities | **50,338** | 25,917 |
| Funds from operations | **51,810** | 34,188 |
| Per share – basic | **0.43** | 0.28 |
| – diluted | **0.42** | 0.28 |
| Net loss | **(129,693)** | (22,047) |
| Per share – basic | **(1.07)** | (0.18) |
| – diluted | **(1.07)** | (0.18) |

The increase in cash provided by operating activities and funds from operations in the first quarter 2014 was a result of higher realized commodity prices and increased production compared to the same period of 2013. The increase in net loss in the first quarter 2014 was a result of the realized and unrealized loss on financial instruments and an impairment charge on the Company's assets held for sale (see Impairment).

**Capital Expenditures, Acquisitions and Dispositions**

During the first quarter, the Company drilled a total of 21 (19.0 net) wells resulting in 16 (14.0 net) oil wells and 5 (5.0 net) natural gas wells. In addition, the Company completed 18 (18.0 net) wells and recompleted 17 (16.1 net) wells in the quarter. The Company added to its infrastructure spending $8.1 million on pipelines at Septimus and Princess and upgrading its batteries and facilities predominantly in the Lloydminster area.

In two transactions completed in late March 2014 Crew purchased approximately 75 sections of highly prospective Montney rights as well as 1,400 boe per day of natural gas production in the Septimus and Groundbirch areas of operation in northeast British Columbia for approximately $105 million. In addition, the Company closed the disposition of approximately 30 boe per day of non-core production in northwest Alberta for $2.0 million.

Subsequent to March 31, 2014, the Company entered into an agreement to dispose of certain petroleum and natural gas assets focused in the Deep Basin area of Alberta (the Alberta Gas Disposition). Consideration for the Alberta Gas Disposition will include approximately $222 million in cash, before closing adjustments, plus 2,750 net acres of mineral rights in the Lloydminster area and approximately 400 bbls per day of heavy oil production. The disposition is scheduled to close on May 30, 2014, subject to satisfaction of customary industry closing conditions. The assets to be sold consist of current production of approximately 7,000 boe per day and 254,000 net acres of land.

Total net capital expenditures for the quarter are detailed below:

| *($ thousands)* | **Three months ended March 31, 2014** | Three months ended March 31, 2013 |
|---|---|---|
| Land | **843** | 2,568 |
| Seismic | **2,254** | 3,204 |
| Drilling and completions | **51,836** | 48,867 |
| Facilities, equipment and pipelines | **8,129** | 8,281 |
| Other | **3,078** | 2,332 |
| Total exploration and development | **66,140** | 65,252 |
| Property acquisitions less dispositions | **102,532** | 14,663 |
| Total | **168,672** | 79,915 |

## LIQUIDITY AND CAPITAL RESOURCES

### Capital Funding

As at March 31, 2014, the Company has a credit facility with a syndicate of lending banks (the "Syndicate"). The credit facility includes a revolving line of credit of $390 million and an operating line of credit of $30 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 9, 2014. 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, 2014, these ratios were 2.2:1 and 1.5:1, respectively. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled borrowing base review on or before June 9, 2014. At March 31, 2014, the Company had drawings of $301.2 million on the Facility and had issued letters of credit totaling $1.1 million.

Subsequent to March 31, 2014, the Syndicate completed its annual review agreeing to extend and update the Facility to include the impact of the proposed Alberta Gas Disposition. Effective on the closing of the Alberta Gas Disposition, scheduled for May 30, 2014, the Facility will be extended on the current terms to June 8, 2015 and will be amended to include a revolving line of credit of $320 million and an operating line of credit of $30 million for a total Facility of $350 million. Proforma the closing of the disposition, the Company's March 31, 2014 drawings on the facility would have been $81.5 million.

On October 21, 2013, the Company issued $150 million of 8.375% senior notes due October 21, 2020. These notes are guaranteed, jointly and severally, on an unsecured basis, by each of the Company's current and future restricted subsidiaries. Interest on the notes accrues at the rate of 8.375% per year and is payable semi-annually.

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

### Working Capital

Working capital includes accounts receivable and net assets held for sale less accounts payable and accrued liabilities. At March 31, 2014, the Company's working capital totaled $178.6 million which, when combined with the drawings on its bank loan at March 31, 2014, represented approximately 35% of its pro-forma $350 million post Alberta Gas Disposition bank loan. The capital intensive nature of Crew's activities generally results in the Company carrying a working capital deficit. The Company maintains sufficient unused bank credit lines to satisfy any working capital deficiencies.

### Share Capital

Crew is authorized to issue an unlimited number of Common Shares. As at May 7, 2014, there were 122,167,443 Common Shares and options to acquire 5,962,437 Common Shares of the Company issued and outstanding. In addition, there were 906,559 restricted awards and 1,095,513 performance awards outstanding.

### Capital Structure

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

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

The Company monitors this ratio and strives to maintain it at or below 2.0 to 1.0. During periods of increase capital expenditures, acquisitions or during periods of low commodity prices, this ratio will increase over short-term periods. As shown below, as at March 31, 2014, the Company's ratio of net debt to annualized funds from operations was 1.30 to 1 (December 31, 2013 – 1.99 to 1). The Company plans to continue its strategy of divesting of non-core properties, will adjust its annual capital expenditure program if necessary or may consider other forms of financing in order to maintain its financial flexibility.

| *($ thousands, except ratio)* | **March 31, 2014** | December 31, 2013 |
|---|---|---|
| Working capital (deficit) (1) | **178,556** | (40,098) |
| Bank loan | **(301,212)** | (197,688) |
| Senior unsecured notes | **(145,785)** | (145,623) |
| Net debt | **(268,441)** | (383,409) |
| Funds from operations (2) | **51,810** | 48,128 |
| Annualized | **207,240** | 192,512 |
| Net debt to annualized funds from operations ratio | **1.30** | 1.99 |

(1) Includes net assets held for sale which reflect the amounts reclassified from property, plant and equipment and decommissioning obligations for the assets less liabilities associated with the Alberta Gas Disposition.

(2) Does not include any adjustments to cash-flows resulting from the anticipated disposal of assets held for sale.

### 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 | 2014 | 2015 | 2016 | 2017 | 2018 | Thereafter |
|---|---|---|---|---|---|---|---|
| Bank Loan (1) | 301,212 | – | – | 301,212 | – | – | – |
| Senior unsecured notes (2) | 150,000 | – | – | – | – | – | 150,000 |
| Operating leases | 6,891 | 1,772 | 2,494 | 2,625 | – | – | – |
| Firm transportation agreements | 20,873 | 2,994 | 4,245 | 4,085 | 2,559 | 2,507 | 4,483 |
| Firm processing agreements | 98,000 | 6,585 | 13,116 | 12,937 | 11,895 | 11,895 | 41,572 |
| Total | 576,976 | 11,351 | 19,855 | 320,859 | 14,454 | 14,402 | 196,055 |

(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.

(2) Matures on October 21, 2020.

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

The transportation agreements include a commitment to a third party to transport natural gas from a gas processing facility in the Septimus area to the Alliance pipeline system.

The firm processing agreements include a commitment to process natural gas through a third party owned gas processing facility in the Septimus area until 2021.

## GUIDANCE

After taking into effect the impact of the Alberta Gas Disposition, Crew is revising its forecasted average 2014 production to a range of 25,500 to 26,500 boe per day with plans to exit the year at 26,000 to 27,000 boe per day. Exploration and development capital expenditures are now budgeted at $285 million, a $39 million increase over the previous budget.

## 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 2014** | Dec. 31 2013 | Sept. 30 2013 | June 30 2013 | Mar. 31 2013 | Dec. 31 2012 | Sept. 30 2012 | June 30 2012 |
|---|---|---|---|---|---|---|---|---|
| Total daily production (boe/d) | **28,021** | 28,682 | 28,016 | 27,109 | 25,961 | 27,027 | 26,281 | 28,192 |
| Exploration and development expenditures | **66,140** | 55,996 | 68,435 | 30,348 | 65,252 | 55,173 | 44,443 | 30,432 |
| Property acquisitions/ (dispositions) | **102,532** | (1,931) | 33,203 | (5,717) | 14,663 | (86,395) | (5,872) | (4,290) |
| Average wellhead price ($/boe) | **51.69** | 41.84 | 45.85 | 44.91 | 39.06 | 41.21 | 38.16 | 38.96 |
| Petroleum and natural gas sales | **130,368** | 110,394 | 118,173 | 110,793 | 91,267 | 102,473 | 92,269 | 99,946 |
| Cash provided by operations | **50,338** | 48,850 | 42,698 | 44,486 | 25,917 | 50,873 | 46,935 | 49,557 |
| Funds from operations | **51,810** | 48,128 | 42,035 | 48,087 | 34,188 | 47,110 | 39,410 | 52,027 |
| Per share – basic | **0.43** | 0.40 | 0.35 | 0.40 | 0.28 | 0.39 | 0.33 | 0.43 |
| – diluted | **0.42** | 0.40 | 0.35 | 0.40 | 0.28 | 0.39 | 0.33 | 0.43 |
| Net income (loss) | **(129,693)** | (58,429) | (843) | 2,008 | (22,047) | 21,812 | (17,947) | 24,107 |
| Per share – basic | **(1.07)** | (0.48) | (0.01) | 0.02 | (0.18) | 0.18 | (0.15) | 0.20 |
| – diluted | **(1.07)** | (0.48) | (0.01) | 0.02 | (0.18) | 0.18 | (0.15) | 0.20 |

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 assets held for sale.

### Accounting Pronouncements

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

### 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, 2014 and ended on March 31, 2014 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

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

Dated as of May 7, 2014

# CONDENSED INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

| *(unaudited) (thousands)* | **March 31, 2014** | December 31, 2013 |
|---|---|---|
| **ASSETS** | | |
| Current Assets: | | |
| Accounts receivable | **$ 59,563** | $ 49,877 |
| Assets held for sale (note 3) | **260,856** | – |
| | **320,419** | 49,877 |
| Exploration and evaluation assets (note 4) | **15,556** | 15,556 |
| Property, plant and equipment (note 5) | **1,495,851** | 1,777,594 |
| | **$ 1,831,826** | $ 1,843,027 |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| Current Liabilities: | | |
| Accounts payable and accrued liabilities | **$ 112,684** | $ 89,975 |
| Fair value of financial instruments (note 10) | **32,408** | 15,340 |
| Liabilities associated with assets held for sale (note 3) | **29,179** | – |
| | **174,271** | 105,315 |
| Fair value of financial instruments (note 10) | **1,961** | – |
| Bank loan (note 6) | **301,212** | 197,688 |
| Senior unsecured notes (note 7) | **145,785** | 145,623 |
| Decommissioning obligations (note 8) | **93,243** | 108,118 |
| Deferred tax liability | **129,097** | 172,827 |
| Shareholders' Equity | | |
| Share capital | **1,276,287** | 1,275,910 |
| Contributed surplus | **65,223** | 63,106 |
| Deficit | **(355,253)** | (225,560) |
| | **986,257** | 1,113,456 |
| Commitments (note 11) | | |
| Subsequent event (notes 3 and 6) | | |
| | **$ 1,831,826** | $ 1,843,027 |

*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, 2014** | Three months ended March 31, 2013 |
|---|---|---|
| **Revenue** | | |
| Petroleum and natural gas sales | **$ 130,368** | $ 91,267 |
| Royalties | **(26,803)** | (17,325) |
| Realized loss on financial instruments (note 10) | **(8,745)** | (1,280) |
| Unrealized loss on financial instruments (note 10) | **(19,029)** | (14,719) |
| | **75,791** | 57,943 |
| **Expenses** | | |
| Operating | **28,622** | 28,110 |
| Transportation | **3,088** | 2,928 |
| General and administrative | **5,360** | 4,644 |
| Share-based compensation | **1,171** | 530 |
| Depletion and depreciation | **49,214** | 48,379 |
| | **87,455** | 84,591 |
| Loss from operations | **(11,664)** | (26,648) |
| Financing | **6,751** | 3,452 |
| Loss (gain) on divestitures | **1,469** | (775) |
| Impairment of assets held for sale (note 3) | **153,539** | – |
| Loss before income taxes | **(173,423)** | (29,325) |
| Deferred tax benefit | **43,730** | 7,278 |
| Net loss and comprehensive loss | **$ (129,693)** | $ (22,047) |
| Net loss per share (note 9) | | |
| Basic | **$ (1.07)** | $ (0.18) |
| Diluted | **$ (1.07)** | $ (0.18) |

*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, 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 exercises | – | 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** |

| | Number of shares | Share capital | Contributed surplus | Deficit | Total Shareholders' equity |
|---|---|---|---|---|---|
| Balance January 1, 2013 | 121,620 | $ 1,275,777 | $ 54,035 | $ (146,249) | $ 1,183,563 |
| Net loss for the period | – | – | – | (22,047) | (22,047) |
| Share-based compensation expensed | – | – | 530 | – | 530 |
| Share-based compensation capitalized | – | – | 556 | – | 556 |
| Balance March 31, 2013 | 121,620 | $ 1,275,777 | $ 55,121 | $ (168,296) | $ 1,162,602 |

*See accompanying notes to the condensed interim consolidated financial statements.*

# CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

| *(unaudited) (thousands)* | **Three months ended March 31, 2014** | Three months ended March 31, 2013 |
|---|---|---|
| **Cash provided by (used in):** | | |
| **Operating activities:** | | |
| Net loss | **$ (129,693)** | $ (22,047) |
| Adjustments: | | |
| Financing expenses | **6,751** | 3,452 |
| Interest expense | **(5,778)** | (2,792) |
| Share-based compensation | **1,171** | 530 |
| Unrealized loss on financial instruments | **19,029** | 14,719 |
| Depletion and depreciation | **49,214** | 48,379 |
| Impairment on assets held for sale | **153,539** | – |
| Loss (gain) on divestitures | **1,469** | (775) |
| Deferred tax benefit | **(43,730)** | (7,278) |
| Decommissioning obligations settled | **(107)** | (1,780) |
| Change in non-cash working capital | **(1,527)** | (6,491) |
| | **50,338** | 25,917 |
| **Financing activities:** | | |
| Increase in bank loan | **103,524** | 45,688 |
| Proceeds from exercise of options | **260** | – |
| | **103,784** | 45,688 |
| **Investing activities:** | | |
| Property, plant and equipment expenditures | **(66,140)** | (65,252) |
| Property acquisitions | **(104,490)** | (20,032) |
| Property dispositions | **1,958** | 5,369 |
| Change in non-cash working capital | **14,550** | 8,310 |
| | **(154,122)** | (71,605) |
| 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 THE CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

For the three months ended March 31, 2014 and 2013

*(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, in the provinces of Alberta, British Columbia and Saskatchewan. The condensed interim consolidated financial statements (the "financial statements") of the Company as at March 31, 2014 and for the three months ended March 31, 2014 and 2013 are comprised of the Company and its wholly owned subsidiary, Crew Oil and Gas Inc., which are incorporated in Canada and three partnerships, Crew Energy Partnership, Crew Conventional Partnership and Crew Heavy Oil Partnership which are registered in Canada. The Company conducts many of its activities jointly with others; these financial statements reflect only the Company's proportionate interest in such activities. 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, 2013, except as noted below. 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.

The condensed interim consolidated financial statements were authorized for issue by the Board of Directors on May 7, 2014.

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

## 3. ASSETS HELD FOR SALE:

| Assets held for sale | Total |
|---|---|
| Transfer from property, plant and equipment – cost | 659,735 |
| Transfer from property, plant and equipment – accumulated depletion and depreciation | (245,340) |
| Impairment | (153,539) |
| Balance | $ 260,856 |

| Liabilities associated with assets held for sale | Total |
|---|---|
| Transfer from decommissioning liabilities | 29,179 |
| Balance | $ 29,179 |
| Net assets held for sale | $ 231,677 |

Subsequent to March 31, 2014, the Company entered into an agreement to dispose of certain gas-weighted properties throughout Alberta (the "Alberta Gas Disposition") for total consideration of approximately $222 million in cash and heavy oil properties with an estimated fair value of $12 million, subject to certain closing adjustments and costs. As of March 31, 2014, the disposal was considered highly probable of occurring and the properties were available for immediate sale in their present condition. The transaction is expected to close on May 30, 2014. Given that the proceeds will consist of both cash and non-cash consideration, estimates and assumptions regarding discount rates were required to determine fair value less costs to sell at March 31, 2014. As the fair value less costs to sell was less than the carrying value of the assets, an impairment loss was recognized.

## 4. EXPLORATION AND EVALUATION ASSETS:

| Cost | Total |
|---|---|
| Balance, January 1, 2013 | $ 60,651 |
| Transfer to property, plant and equipment | (45,095) |
| Balance, December 31, 2013 | $ 15,556 |
| Transfer to property, plant and equipment | – |
| **Balance, March 31, 2014** | **$ 15,556** |

Exploration and evaluation (E&E) assets consist of the Company's exploration projects which are pending the determination of proven or probable reserves. Additions represent the Company's share of costs incurred on E&E assets during the period.

## 5. PROPERTY, PLANT AND EQUIPMENT:

| Cost | Total |
|---|---|
| Balance, January 1, 2013 | $ 2,397,442 |
| Additions | 220,031 |
| Transfer from exploration and evaluation assets | 45,095 |
| Acquisitions | 55,866 |
| Divestitures | (21,971) |
| Change in decommissioning obligations | 4,083 |
| Capitalized share-based compensation | 4,660 |
| Balance, December 31, 2013 | $ 2,705,206 |
| Additions | 66,140 |
| Transfer to assets held for sale (note 3) | (659,735) |
| Acquisitions | 117,218 |
| Divestitures | (3,755) |
| Change in decommissioning obligations | 914 |
| Capitalized share-based compensation | 1,063 |
| **Balance, March 31, 2014** | **$ 2,227,051** |

| Accumulated depletion and depreciation | Total |
|---|---|
| Balance, January 1, 2013 | $ 670,696 |
| Depletion and depreciation expense | 190,176 |
| Divestitures | (4,466) |
| Impairment (net) | 71,206 |
| Balance, December 31, 2013 | $ 927,612 |
| Depletion and depreciation expense | 49,214 |
| Transfer to assets held for sale (note 3) | (245,340) |
| Divestitures | (286) |
| **Balance, March 31, 2014** | **$ 731,200** |

| Net book value | Total |
|---|---|
| Balance, December 31, 2013 | $ 1,777,594 |
| **Balance, March 31, 2014** | **$ 1,495,851** |

The calculation of depletion for the three months ended March 31, 2014 included estimated future development costs of $957.1 million (December 31, 2013 – $995.3 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $91.8 million (December 31, 2013 – $93.4 million) and undeveloped land of $270.0 million (December 31, 2013 – $220.1 million).

## 6. BANK LOAN:

The Company's bank facility as at March 31, 2014 consisted of a revolving line of credit of $390 million and an operating line of credit of $30 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 9, 2014. 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. Secured debt consists of the Company's bank debt. At March 31, 2014, these ratios were 2.2:1 and 1.5:1, respectively. EBITDA, as defined by the credit agreement, is comprised of earnings before interest, taxes, depreciation and amortization and adjustments for other non-cash items. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled borrowing base review on or before June 9, 2014. 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, 2014, the Company's applicable pricing included a 2.0 percent margin on prime lending and a 3.0 percent stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.75 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, 2014, the Company had issued letters of credit totaling $1.1 million (December 31, 2013 – $12.1 million). The effective interest rate on the Company's borrowings under its bank facility for the period ended March 31, 2014 was 5.5% (2013 – 4.4%).

Subsequent to March 31, 2014, the Syndicate completed its annual review agreeing to extend and update the Facility to include the impact of the proposed Alberta Gas Disposition (note 3). Effective on the closing of the Alberta Gas Disposition, scheduled for May 30, 2014, the Facility will be extended on the current terms to June 8, 2015 and will be amended to include a revolving line of credit of $320 million and an operating line of credit of $30 million for a total Facility of $350 million.

## 7. SENIOR UNSECURED NOTES:

On October 21, 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, 2014, the carrying value of the senior unsecured notes was net of deferred financing costs of $4.2 million.

## 8. DECOMMISSIONING OBLIGATIONS:

| | **Three Months ended March 31, 2014** | Year ended December 31, 2013 |
|---|---|---|
| Decommissioning obligations, beginning of period | **$ 108,118** | $ 108,787 |
| Obligations incurred | **914** | 11,972 |
| Obligations acquired | **12,728** | – |
| Obligations settled | **(107)** | (4,333) |
| Obligations divested | **(42)** | (3,126) |
| Change in estimated future cash outflows | **–** | (7,889) |
| Accretion of decommissioning liabilities | **811** | 2,707 |
| Transferred to liabilities associated with assets held for sale (note 3) | **(29,179)** | – |
| Decommissioning obligations, end of period | **$ 93,243** | $ 108,118 |

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning obligations to be $93.2 million as at March 31, 2014 (December 31, 2013 – $108.1 million) based on an undiscounted total future liability of $100.9 million (December 31, 2013 – $117.1 million). These payments are expected to be made over the next 25 years with the majority of costs to be incurred between 2015 and 2036. The inflation rate applied to the liability is 2% (2013 – 2%). The discount factor, being the risk-free rate related to the liability, is 3.13% (December 31, 2013 – 3.13%).

## 9. SHARE CAPITAL:

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

**Share based payments:**

The Company has an option program that entitles officers, directors, employees and certain consultants to purchase shares in the Company. Options are granted at the market price of the shares at the date of grant, have a four year term and vest over three years. The Company has elected not to seek shareholder approval for the requisite three-year renewal of its option program. Subsequent to the Company's Annual Shareholder Meeting, scheduled for May 22, 2014, the Company will no longer be 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 share options are as follows:

| | Number of options | Weighted average exercise price |
|---|---|---|
| Balance January 1, 2014 | **7,978** | $ 9.03 |
| Granted | **5** | $ 7.25 |
| Exercised | **(44)** | $ 5.95 |
| Forfeited | **(142)** | $ 10.55 |
| Expired | **(1,499)** | $ 14.67 |
| **Balance at March 31, 2014** | **6,298** | **$ 7.68** |
| **Exercisable at March 31, 2014** | **2,368** | **$ 8.36** |

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

| Range of exercise prices | Outstanding at March 31, 2014 | Weighted average remaining life (years) | Weighted average exercise price | Exercisable at March 31, 2014 | Weighted average exercise price |
|---|---|---|---|---|---|
| $ 5.16 to $ 7.01 | 2,869 | 2.3 | $ 5.78 | 1,314 | $ 5.67 |
| $ 7.02 to $ 9.94 | 1,901 | 3.0 | $ 7.19 | 34 | $ 7.48 |
| $ 9.95 to $14.63 | 1,245 | 1.6 | $ 11.14 | 830 | $ 11.14 |
| $14.64 to $18.29 | 283 | 1.3 | $ 15.02 | 190 | $ 15.03 |
| | 6,298 | 2.3 | $ 7.68 | 2,368 | $ 8.36 |

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, 2014** | Three months ended March 31, 2013 |
|---|---|---|
| Risk free interest rate (%) | **1.3** | 1.3 |
| Expected life (years) | **4.0** | 4.0 |
| Expected volatility (%) | **43** | 50 |
| Forfeiture rate (%) | **16** | 16 |
| Weighted average fair value of options | **$ 2.57** | $ 2.56 |

**Restricted and Performance Award Incentive Plan:**

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

Subject to terms and conditions of the RPAP, each RA and PA entitles the holder to an award value to be typically paid as to one-third on each of the first, second and third anniversaries of the date of grant. For the purpose of calculating share-based compensation, the fair value of each award is determined at the grant date using the closing price of the common shares. For the period ended March 31, 2014, the fair value of awards granted were calculated using an estimated forfeiture rate of 9%. The weighted average fair value of awards granted for the period ended March 31, 2014 is $7.25. In the case of PAs, the award value is adjusted for a payout multiplier which can range from 0.0 to 2.0 and is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. On the vesting dates, the Company has the option of settling the award value in cash or common shares of the Company.

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

| | Number of restricted awards | Number of performance awards |
|---|---|---|
| Balance January 1, 2014 | **296** | 320 |
| Granted | **4** | 2 |
| Forfeited | **(8)** | (5) |
| **Balance at March 31, 2014** | **292** | **317** |

**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, 2014 was 121,647,000 (2013 – 121,620,000).

In computing the diluted loss per share for the period ended March 31, 2014, nil (2013 – nil) shares were added to the weighted average Common Shares outstanding to account for the dilution of stock options. There were 6,298,000 (2013 – 6,155,000) stock options and 609,000 (2013 – nil) restricted and performance awards that were not included in the diluted loss per share calculation because they were anti-dilutive.

## 10. FINANCIAL RISK MANAGEMENT:

**Derivative contracts:**

It is the Company's policy to economically hedge some oil and natural gas sales 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, 2014 the Company held derivative contracts as follows:

| Subject of Contract | Notional Quantity | Remaining Term | Reference | Average Strike Price | Contract Traded | Fair Value ($000s) |
|---|---|---|---|---|---|---|
| Oil | 250 bbl/day | April 1, 2014 – June 30, 2014 | CDN$ WTI | $103.00 | Swap | (187) |
| Oil | 4,250 bbl/day | April 1, 2014 – December 31, 2014 | CDN$ WTI | $98.23 | Swap | (12,671) |
| Oil | 500 bbl/day | April 1, 2014 – December 31, 2014 | CDN$ WTI | $85.00 – $100.00 | Collar(1) | (1,382) |
| Oil | 250 bbl/day | April 1, 2014 – December 31, 2014 | CDN$ WTI | $85.00 – $103.25 | Collar(2) | (449) |
| Oil | 500 bbl/day | April 1, 2014 – December 31, 2014 | CDN$ WTI | $96.05 | Call | (1,830) |
| Oil | 500 bbl/day | April 1, 2014 – December 31, 2014 | US$ WTI | $86.75 | Call | (2,088) |
| Oil | 750 bbl/day | April 1, 2014 – June 30, 2014 | CDN$ WCS – WTI diff | $(24.33) | Swap | (180) |
| Oil | 2,750 bbl/day | April 1, 2014 – December 31, 2014 | CDN$ WCS – WTI diff | $(23.48) | Swap | (1,485) |
| Oil | 750 bbl/day | July 1, 2014 – December 31, 2014 | CDN$ WCS – WTI diff | $(23.75) | Swap | (346) |
| Gas | 15,000 gj/day | April 1, 2014 – October 31, 2014 | AECO C Monthly Index | $3.84 | Swap | (1,759) |
| Gas | 37,500 gj/day | April 1, 2014 – December 31, 2014 | AECO C Monthly Index | $3.57 | Swap | (9,431) |
| Oil | 250 bbl/day | January 1, 2015 – June 30, 2015 | CDN$ WTI | $102.50 | Swap | 17 |
| Oil | 250 bbl/day | January 1, 2015 – December 31, 2015 | CDN$ WTI | $86.00 | Call | (1,349) |
| Oil | 500 bbl/day | January 1, 2015 – December 31, 2015 | US$ WTI | $98.25 | Call | (610) |
| Oil | 500 bbl/day | April 1, 2014 – December 31, 2015 | CDN$ WCS – WTI diff | $(22.00) | Swap | 36 |
| Gas | 7,500 gj/day | January 1, 2015 – December 31, 2015 | AECO C Monthly Index | $3.74 | Swap | (655) |
| Total | | | | | | (34,369) |

(1) The referenced contract is a fade-in collar whereby the price is fixed at $100/bbl unless the market price falls below $85/bbl in which case the price received will be $85/bbl.

(2) The referenced contract is a fade-in collar whereby the price is fixed at $103.25/bbl unless the market price falls below $85/bbl in which case the price received will be $85/bbl.

(3) This is a structured call which is only triggered if the average CDN$ WTI trades above $96 per bbl for a given month during the term.

As at March 31, 2014, a 10% decrease to the price outlined in the contracts above would result in a $21.2 million increase in income.

Subsequent to March 31, 2014, the Company entered into the following derivative commodity contract:

| Subject of Contract | Volume | Term | Reference | Strike Price | Option Traded |
|---|---|---|---|---|---|
| Oil | 250 bbl/day | January 1, 2015 – June 30, 2015 | CDN$ WTI | $103.50 | Swap |

**(b) 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 that 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 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 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, net working capital including assets held for sale (note 3), divided by annualized funds from operations for the most recent quarter.

The Company monitors this ratio and endeavours to maintain it at or below 2.0 to 1.0. During periods of increased capital expenditures, acquisitions or during periods of low commodity prices, this ratio will increase over short-term periods. As shown below, as at March 31, 2014 the Company's ratio of net debt to annualized funds from operations was 1.30 to 1, (December 31, 2013 – 1.99 to 1). The Company plans to continue its strategy of divesting of properties, will adjust its annual capital expenditure program if necessary or may consider other forms of financing in order to maintain its financial flexibility.

| | **March 31, 2014** | December 31, 2013 |
|---|---|---|
| Net debt: | | |
| Accounts receivable | **$ 59,563** | $ 49,877 |
| Assets held for sale (1) | **260,856** | – |
| Accounts payable and accrued liabilities | **(112,684)** | (89,975) |
| Liabilities associated with assets held for sale | **(29,179)** | – |
| Working capital (deficiency) | **$ 178,556** | $ (40,098) |
| Bank loan | **(301,212)** | (197,688) |
| Senior unsecured notes | **(145,785)** | (145,623) |
| Net debt | **$ (268,441)** | $ (383,409) |
| Annualized funds from operations: | | |
| Cash provided by operating activities (2) | **$ 50,338** | $ 48,850 |
| Decommissioning obligations settled | **107** | 379 |
| Change in non-cash working capital | **1,527** | (940) |
| Accretion of deferred financing charges | **(162)** | (161) |
| Funds from operations | **51,810** | 48,128 |
| Annualized | **$ 207,240** | $ 192,512 |
| Net debt to annualized funds from operations | **1.30** | 1.99 |

(1) Includes net assets held for sale as discussed in note 3.

(2) Does not include any adjustments to cash-flows resulting from the anticipated disposal of assets held for sale.

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 Company's oil and natural gas reserves (Bank Loan – note 6).

## 11. COMMITMENTS:

| *($ thousands)* | Total | 2014 | 2015 | 2016 | 2017 | 2018 | Thereafter |
|---|---|---|---|---|---|---|---|
| Operating leases | 6,891 | 1,772 | 2,494 | 2,625 | – | – | – |
| Firm transportation agreements | 20,873 | 2,994 | 4,245 | 4,085 | 2,559 | 2,507 | 4,483 |
| Firm processing agreement | 98,000 | 6,585 | 13,116 | 12,937 | 11,895 | 11,895 | 41,572 |
| Total | 125,764 | 11,351 | 19,855 | 19,647 | 14,454 | 14,402 | 46,055 |

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

The transportation agreements include a commitment to a third party to transport natural gas from a gas processing facility in the Septimus area to the Alliance pipeline system.

The firm processing agreements include a commitment to process natural gas through a third party owned gas processing facility in the Septimus area until 2021.

# CORPORATE INFORMATION

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Toronto-Dominion Bank

Canadian Imperial Bank of Commerce

Union Bank

Bank of Montreal

Bank of Nova Scotia

Alberta Treasury Branches

National Bank of Canada

JPMorgan Chase Bank

## LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

## RESERVE ENGINEERS

Sproule Associates Ltd.

## TRANSFER AGENT

Valiant Trust Company

## EXCHANGE LISTING

Toronto Stock Exchange
Stock Symbol: **CR**

## BOARD OF DIRECTORS

**John A. Brussa**, Chairman
Independent Director

**Jeffery E. Errico**
Independent Director

**Dennis L. Nerland**
Independent Director

**Dale O. Shwed**
President, Crew Energy Inc.

**David G. Smith**
Independent Director

## OFFICERS

**Dale O. Shwed**
President and Chief Executive Officer

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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**
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**Kurtis Fischer**
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**Gary P. Smith**
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