crew energy inc.

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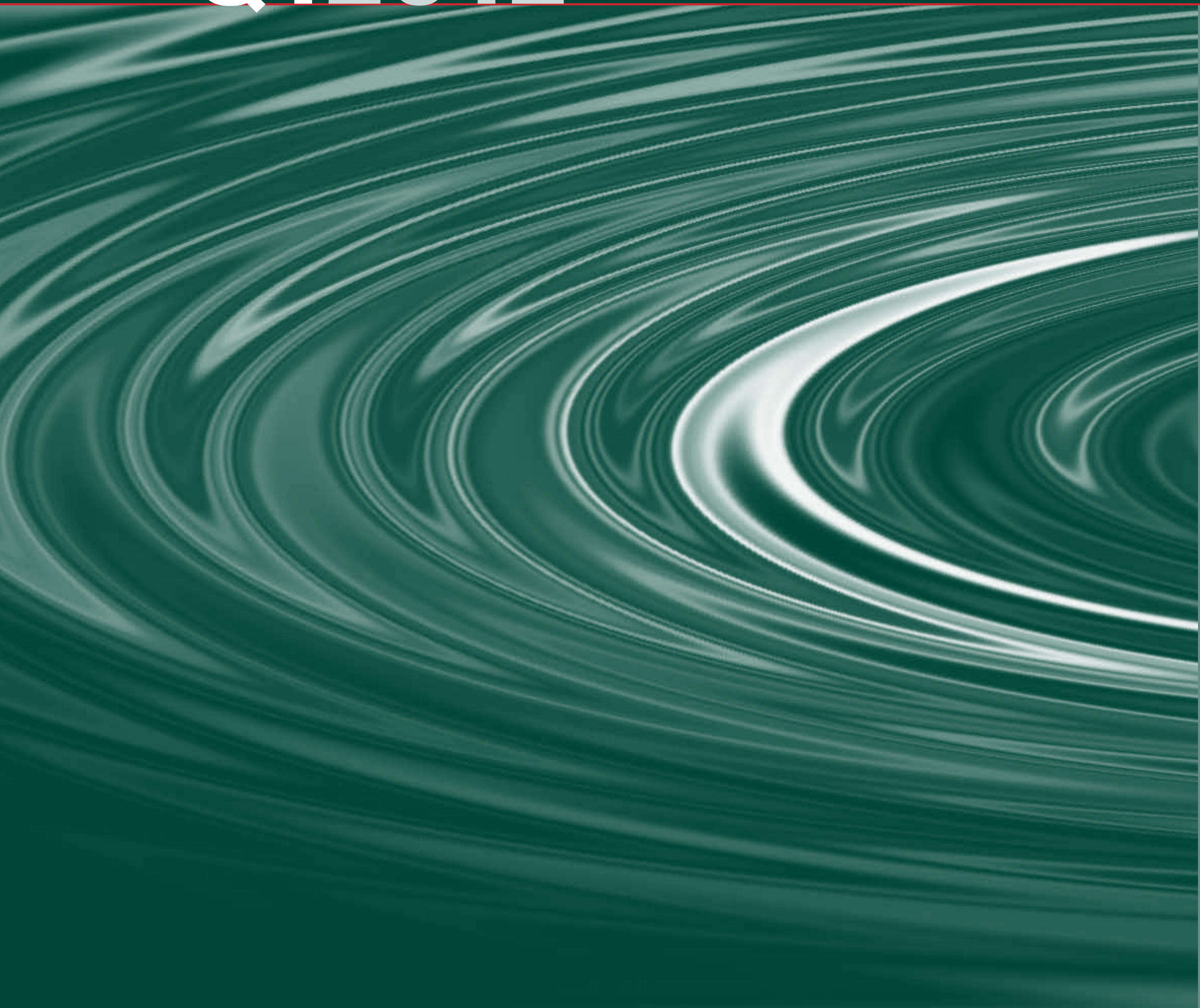
TSX: CR

Q1 2012



RESOURCE FOCUS > OPPORTUNITY > SUSTAINABILITY

Q1 2012

Crew Energy is pleased to present its financial and operating results for the three month period ended March 31, 2012.

HIGHLIGHTS

- Funds from operations increases 99% over the first quarter of 2011 to $48.1 million;
- Funds from operations per share increased 38% to $0.40 per share;
- Record first quarter production for the Company of 30,380 boe per day represents a 95% increase over the first quarter of 2011 and a slight increase over the fourth quarter of 2011;
- Production per share increased 35% over the first quarter of 2011;
- Oil and liquids production improved significantly to 16,037 bbls per day (53% of production), increasing from 6,923 bbls per day (44% of production) in the first quarter of 2011 representing a 132% increase and 57% increase on a per share basis;
- Since deploying its liquids focus strategy in 2007, Crew has increased its liquids production by 970% (315% per share);
- Crew drilled 60 wells in the quarter with a 97% success rate;
- Four first quarter wells were on production at the end of the quarter at Princess with two vertical wells on production at seven day test rates of 375 and 133 boe per day and two horizontal wells on production at 348 and 640 boe per day after seven days;
- Three Montney liquids rich gas wells were completed at Septimus and came on production at rates of 776, 693 and 588 boe per day;
- The latest Tower oil well flowed at an average gross rate of 500 boe per day (375 bbls per day oil and liquids and 0.75 mmcf per day of natural gas);
- Completed the annual renewal of the Company's credit facility receiving approval for a $430 million credit facility.

FINANCIAL *($ thousands, except per share amounts)*	**Three months ended March 31, 2012**	Three months ended March 31, 2011
Petroleum and natural gas sales	**123,075**	61,148
Funds from operations (1)	**48,057**	24,111
Per share – basic	**0.40**	0.29
– diluted	**0.40**	0.29
Net loss	**(6,430)**	(10,126)
Per share – basic	**(0.05)**	(0.12)
– diluted	**(0.05)**	(0.12)
Capital expenditures	**128,743**	75,165
Property acquisitions (net of dispositions)	**–**	361
Net capital expenditures	**128,743**	75,526

CAPITAL STRUCTURE *($ thousands)*	**As at March 31, 2012**	As at December 31, 2011
Working capital deficiency (2)	**78,424**	92,452
Bank loan	**320,153**	230,676
Net debt	**398,577**	323,128
Current bank facility	**430,000**	430,000
Common Shares Outstanding *(thousands)*	**120,760**	119,993

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

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

OPERATIONS	Three months ended March 31, 2012	Three months ended March 31, 2011
Daily production		
Conventional oil (bbl/d)	**6,770**	5,794
Heavy oil (bbl/d)	**6,162**	–
Natural gas liquids (bbl/d)	**3,105**	1,129
Natural gas (mcf/d)	**86,056**	52,109
Oil equivalent (boe/d @ 6:1)	**30,380**	15,608
Average prices (1)		
Conventional oil ($/bbl)	**81.10**	69.68
Heavy oil ($/bbl)	**71.04**	–
Natural gas liquids ($/bbl)	**53.05**	59.71
Natural gas ($/mcf)	**2.34**	4.00
Oil equivalent ($/boe)	**44.52**	43.53
Netback ($/boe)		
Operating netback (2)	**20.35**	20.20
Realized gain on financial instruments	**–**	(0.01)
G&A	**1.91**	1.98
Interest on bank debt	**1.06**	1.06
Funds from operations	**17.38**	17.17
Drilling Activity		
Gross wells	**60**	40
Working interest wells	**57.8**	39.3
Success rate, net wells	**97%**	100%

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

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

OVERVIEW

Operations for the first quarter of 2012 included the drilling of 60 (57.8 net) wells resulting in 46 (45.0 net) oil wells, 11 (9.8 net) natural gas wells, one (1.0 net) service well and two (2.0 net) dry and abandoned wells. Of the wells drilled, 24 were brought on production during the quarter. Drilling during the quarter was highlighted by 29 (29.0 net) wells at Princess, Alberta. The Company is currently completing and tying in these new wells and has been very pleased with the success of the vertical wells extending existing pool boundaries and identifying new pools at a cost of approximately $25,000 per producing boe. At Lloydminster, Saskatchewan, the Company drilled 18 (17.8 net) wells adding an estimated 760 boe per day of new production at a cost of $15,000 per producing boe. Due to the low natural gas price environment, gas well drilling was focused on providing production to meet processing commitments and to achieve land retention in Crew's main liquids rich gas areas at Septimus, British Columbia and in the Deep Basin of Alberta. During the quarter, the Company drilled five (5.0 net) wells at Septimus and currently plans to only complete three of these wells due to the low natural gas price environment. Additional gas drilling was conducted at Wapiti, in the Deep Basin, where the Company drilled five (4.6 net) wells and has since completed four wells resulting in successful gas wells adding average new production at a facility restricted rate of 494 boe per day per well, including 173 bbl per day per well of liquids.

Production during the quarter averaged 30,380 boe per day (53% liquids), slightly above the fourth quarter of 2011 and 95% greater than the first quarter of 2011. Production additions for the quarter were provided by the successful drilling programs at Princess, Lloydminster, Septimus and in the Deep Basin which helped to offset declines and 6.3 mmcf per day of Alberta dry natural gas production that was shut in during the quarter due to the poor natural gas pricing environment.

FINANCIAL

The first quarter saw a dramatic change in Crew's commodity pricing compared to the fourth quarter of 2011. During the quarter, prices received for the Company's natural gas production dropped 32% to average $2.34 per mcf for the quarter. Prices continued to fall throughout the quarter and sunk to a low of $1.60 per mcf early in the second quarter. This decrease has had a significant impact on the Company's funds from operations and has resulted in the shut-in of 6.3 mmcf per day of uneconomic dry sour gas production and the planned shut-in of an additional 4.5 mmcf per day in the second quarter which, when combined, represents approximately 12.5% of the Company's natural gas production. The shut-in of this gas is expected to add approximately $600,000 per month in funds from operations.

The Company's conventional and heavy oil prices were also volatile in the first quarter experiencing a 6% and 8% respective decline over the previous quarter. This decrease occurred unexpectedly in late February when the entire Canadian crude pricing complex declined by as much as $20 per barrel over a seven day period. This decline was attributed to a combined shortage of pipeline capacity and refinery demand out of the United States. The decrease in Canadian pricing continued throughout the remainder of February through to May. We are currently seeing improvement for the coming months but it is uncertain if the situation is completely resolved and there remains a possibility that we could see further weakening.

The Company's capital expenditures for 2012 were planned to be heavily weighted to the first quarter. During the quarter the Company spent $129 million on its capital program including $90 million on drilling and completions, as outlined above, and $22 million on facilities, equipment and tie-ins. The program was designed to provide production growth throughout the second quarter and into the early third quarter while the Company's operations were shut down during break-up. During the quarter, the Company acquired a strategic pipeline in the Septimus area for $8.1 million. This asset allows access to the Company's liquids rich natural gas production from the northwest portion of the Company's Septimus Montney gas field and also provides a short tie-in point for solution gas from the Company's emerging Tower oil play.

At quarter end, Crew's net debt increased to $399 million compared to the Company's newly approved $430 million bank facility. This debt level is projected to be the Company's peak reported debt level during the year as planned net capital spending for the remainder of the year is forecasted to bring year-end 2012 net debt back to approximately $350 million not including any dispositions.

The Company continues to actively protect its cash flow by hedging a portion of its future production against volatile commodity prices. Crew currently has hedged approximately 23.3 mmcf day of natural gas for the period of May through December 2012 at a price of approximately $2.00 per mcf. The Company also holds hedges against a significant decline in oil prices with an average of 6,600 barrels per day of West Texas Intermediate ("WTI") oil hedged at an average floor price of $94.25 per barrel for the period April through December 2012 and 2,000 barrels per day of WTI oil hedged at an average floor price of $102.25 per barrel for 2013. In addition, the Company currently holds hedges that fix the differential between WTI and Western Canadian Select ("WCS") pricing on an average of 2,000 barrels a day at a differential of $15.63 per barrel. During the first quarter, the Company successfully monetized certain 2012 WTI to WCS differential hedges resulting in realized hedging gains of $3.7 million.

OPERATIONS UPDATE

Pekisko Play, Princess, Alberta

Crew had a successful first quarter at Princess drilling 29 wells including 19 vertical wells and 10 horizontal wells. The Company's first quarter program focused on development of existing pools with the most appropriate technology and the drilling of two vertical wells that extended existing pool boundaries. One of the vertical wells tested at 296 boe per day and the second recently came on production with a seven day average rate of 375 boe per day. Four vertical wells were drilled beyond existing pool boundaries discovering new oil pools. One has come on production at an average seven day rate of 133 boe per day and the other three are in the process of being completed and brought on production. Two horizontal wells were brought on production subsequent to the end of the first quarter with seven day rates of 348 boe per day and 640 boe per day. First quarter production at Princess has been added at a cost of $25,000 per producing boe.

Princess Waterflood

Progress was made on infrastructure installation including Crew's 2012 waterflood implementation program where it is expected that all five approved waterfloods will be in operation by early in the third quarter. Two existing waterfloods (Pekisko "K" and "N" pools) continue to respond well with oil production rates increasing 50% and 35%, respectively, from pre-waterflood conditions with gas-oil ratios down 50% in both pools. Response on the "N" Pool has been very rapid with injection initiated less than ten months ago. Crew plans to implement six additional waterfloods in 2013.

History

Crew acquired the Princess asset in August 2008 which was producing approximately 2,000 boe per day at the time primarily from the West Tide Lake area. The Company recognized the significant hydrocarbon potential of the Pekisko formation on this large land base (300,000 net acres as at December 31, 2011 with only 13% classified as developed) and the potential to apply horizontal well technology to further enhance productivity. In September of 2008, Crew's first horizontal well was flowing at a rate of 633 bbls of oil per day and the impact of infill drilling with horizontal wells was confirmed. The first horizontal development program was at West Tide Lake which had previously been developed with 40 acre spacing using vertical wells. The vertical well control allowed Crew to map the distribution of the productive reservoir so that a horizontal depletion strategy could be undertaken. The Company then drilled 26 net wells (50% horizontal) in 2009 resulting in 22 net oil producing wells. This program yielded production growth to 5,238 boe per day in December 2009 which declined to 3,382 boe per day (35% decline) in April 2010 due to the initial decline rates typically experienced on horizontal wells (60% to 65% decline in the first year). In 2010, the Company drilled 62 net wells (54% horizontal) resulting in 54 oil wells. Production peaked at 8,000 boe per day during the month of December 2010 before declining to 4,948 boe per day (38% decline) in July 2011. At the time, Crew also recognized that secondary recovery would become critical to provide a growth platform for the future and started injection into the Pekisko "K" pool.

In 2011, Crew drilled 119 net wells (54% horizontal) resulting in 104 net oil wells (64 horizontal wells) and grew production to over 10,000 boe per day during the month of December 2011. The Company expanded transportation and processing infrastructure to handle increasing fluid production associated with the extensive drilling program and initiated the Company's second waterflood in the Pekisko "N" pool.

Consistent with the Princess production profile of the previous three years, production declined from 10,400 boe per day in December to current levels of 7,000 boe per day (33% decline). There is currently approximately 550 boe per day shut-in from single wells batteries due to spring breakup and only ten new wells from the first quarter drilling program are currently on production. Infrastructure expansion has been successful in allowing Crew to optimize production from a number of pools while some areas continue to encounter gathering system limitations particularly when a prolific well is introduced into the pipeline system. As the production from individual wells stabilizes within an area, the Company can better assess if any further facility enhancements are required.

Crew has historically used both vertical and horizontal wells to exploit and develop the Pekisko formation at Princess. The vertical wells are very effective tools to initially evaluate and delineate new pools providing significant data about the vertical distribution and quality of the reservoir. In cases where enhanced permeability is encountered as evidenced by high production rates (in excess of 100 boe per day per well), vertical wells are an economic means of developing these types of pools. If the permeability is more restricted resulting in lower production rates from the initial vertical wells (less than 40 boe per day per well), horizontal wells would be used to develop the pool. The economics of primary pool development are similar for the two methods described above as individual vertical or horizontal wells achieve an economic rate of return between 140% and 145% based on the average type wells currently booked by GLJ Petroleum Consultants ("GLJ") (135 mboe per horizontal well and 64 mboe per vertical well) and the April 1, 2012 GLJ price deck. In all cases, consideration of future secondary waterflood is also a factor in the selection and implementation of the most appropriate reservoir drainage architecture.

Heavy Oil, Lloydminster, Saskatchewan

At Lloydminster, Crew drilled 18 (17.8 net) wells and recompleted 20 (19.3 net) wells targeting oil in various Mannville group formations. The first quarter program added 760 boe per day of production for total capital expenditures of $11.5 million resulting in a capital efficiency of $15,000 per producing barrel of oil equivalent. This area continues to provide the Company with robust economics and will be a focus for drilling for the remainder of 2012. Crew was active at Crown land sales increasing its land position in the first quarter and expects to continue this level of activity through 2012. The Company has identified a number of reservoirs at Lloydminster that are excellent candidates for horizontal drilling with secondary recovery potential. With preferential access to the Manitou pipeline system and its wholly owned battery, water disposal and sand handling facility, Crew is in the position to expand its heavy oil program over the next 18 months.

Tower, British Columbia

Crew's second well at Tower was rig released and completed early in the second quarter with a horizontal section of 1,067 meters. The well was tested up 114 mm casing and after 12 days of testing was producing at a rate of 500 boe per day consisting of 375 bbls per day of 46 API oil and liquids and 0.75 mmcf per day of natural gas. The well is tied-in to the Septimus gas plant and will be able to be continuously produced following the initial test period. Crew's initial well at Tower with a horizontal section of 1,835 meters tested at 610 boe per day (342 bbls of oil and liquids and 1.7 mmcf per day of natural gas) and is awaiting surface land approval to be tied-in. Crew has a 33% working interest in both of these wells with the second well drilled adjacent to Crew's 100% working interest lands. Crew is preparing several multi-well pads to advance this project as dictated by production results. In addition to the significant oil test rates, the solution gas is richer than the gas stream at Septimus and is expected to yield approximately 63 bbls per mmcf which is 2.5 times greater than the liquids recovery at Septimus.

Crew has 30 net sections of Montney land at Tower including 27 sections with 100 percent working interest. The Company has modelled a depletion strategy that would require six to eight wells to be drilled per section. Crew is proceeding with necessary approvals to drill up to eight (6.0 net) additional wells at Tower and will assess timing based on well performance, capital availability and economic factors.

Septimus, British Columbia

At Septimus, Crew drilled four Montney horizontal wells and one vertical well. Three horizontal wells were completed in the quarter (one that was drilled in 2011) with two of the wells on production at initial rates of 776 boe per day and 693 boe per day (15% liquids) based on the initial ten days of production. The third well came on production at 588 boe per day (11% liquids) from a lower stratigraphic Montney interval that had not been previously tested. The test confirmed productivity from this lower unit and would indicate additional horizontal wells could be drilled to develop this interval of the Montney.

Crew successfully completed the acquisition of a 35.1 kilometer six inch pipeline extending through Crew's Septimus and Tower land base. Acquisition of this pipeline will allow Crew to ultimately develop lands on the far western edge of the Septimus area. In addition, Crew can immediately increase production from producing Septimus wells by providing additional pipeline capacity and reduced operating pressures into the Septimus gas plant. The pipeline provides a tie-in point for production from Tower wells directly to the Septimus gas plant.

Crew has two horizontal wells to complete and does not have any plans for any additional drilling at Septimus for the remainder of 2012 pending a recovery in natural gas prices.

Kobes, British Columbia

Crew continues to flow test its two horizontal wells at Kobes testing the long-term production characteristics of the Montney in this area. Liquids rates from the wells are averaging 88 bbls per mmcf per day (33% condensate). The Company has an inventory of over 200 drilling locations on this block and continues to work toward long-term processing and takeaway capacity in the area.

Deep Basin, Alberta

In the Deep Basin of Alberta, Crew drilled seven (5.9 net) liquids rich natural gas wells in the first quarter. The Company also expanded a facility adding compression in the Elmworth area. Four Cardium horizontal wells were drilled and completed with better than expected performance resulting in restricted rates of an average of 494 boe per day per well including 173 bbls per day per well of liquids (90 bbls/mmcf). One vertical well was drilled at Wanyandie and a horizontal well was drilled at Wapiti for lease retention as well as one horizontal Fahler well which is awaiting completion. Crew has an inventory of 185 Cardium drilling locations in the greater Wapiti area, the value of which will be preserved until the economics of this play compete with the Company's oil plays.

2012 GUIDANCE

Crew previously announced the 2012 capital expenditure program of $300 million on January 11, 2012 using the natural gas strip price at the time of $3.25 per mcf, $95 WTI and a 17% WTI to WCS differential for 2012. Realized commodity prices have declined precipitously with current natural gas prices now 25% lower than first quarter realized prices. Differentials between WTI pricing and WCS and Lloyd blend heavy oil widened significantly in the first quarter and continue to be volatile as a result of tightening pipeline and refining capacity in the United States. In light of reduced cash flow from these factors, Crew is reducing its 2012 capital expenditure budget by $75 million to $225 million. This will enable the Company to continue to grow its production year over year, increase its liquid weighting and maintain a strong balance sheet. The funding of this program will be from funds from operations, asset dispositions and the existing bank facility.

Crew has shut-in 6.3 mmcf per day of dry gas production and intends to shut-in an additional 4.5 mmcf per day (1,800 boe per day combined) of natural gas production in the second quarter which is expected to add approximately $600,000 per month in funds from operations. In addition, a third party facility at Elmworth, Alberta is going down for an unplanned turnaround which will result in approximately 2,000 boe per day being shut in for the month of May. With the $75 million (25%) reduction in capital expenditures, 2,500 boe per day of behind pipe of natural gas weighted production that has been deferred and 1,800 boe per day of shut-in production, Crew is forecasting to average approximately 28,000 to 29,000 boe per day in 2012 representing a 14% (5% without shut-in and deferred production) reduction in the Company's previous guidance. Despite the revised program, the Company is expected to deliver a 25% increase in production or 8% on a per share basis over 2011, positioning the Company to continue to grow its production into 2013.

OUTLOOK

When Crew was founded in 2003, the business strategy was to expose our shareholders to large oil and gas in place reservoirs and to grow per share production and reserves. The Company has established a sizeable land position of just under one million net acres focusing on four plays that offer our shareholders exposure to large accumulations of oil and liquids rich natural gas. Crew has a history of profitable growth with compounded annual growth per share in production and reserves of 13% and 28%, respectively. In 2007, Crew anticipated the growth of unconventional natural gas was going to have a profound impact on the supply-demand balance of natural gas. At that time, the Company committed to increase its liquids component of production which was 1,500 bbls per day or 17% of total production of 8,700 boe per day. The liquids component in the first quarter 2012 increased to 53% of total production and has grown to over 16,000 bbls per day increasing 970% (315% per share) over 2007. The strategy remains intact with the focus in the current commodity price environment to prioritize and invest in the highest return and the most capital efficient projects while retaining the upside for our shareholders on a significant resource of natural gas and natural gas liquids.

Crew will focus on oil development at Princess and Lloydminster and the testing of the emerging oil play at Tower. First quarter drilling results were strong with the Company discovering several new pools and successfully advancing secondary recovery programs at Princess as well as adding production at attractive flowing barrel metrics in all areas of operation. This program also addressed land retention at Septimus and the Deep Basin that will allow the Company to retain its resources in these areas. Crew will maintain its capital discipline by curtailing 2012 capital projects to preserve balance sheet strength while maintaining its long-term growth profile.

We would like to thank our shareholders for their patience and support in this environment. We are confident in the quality of our assets and the ability of our team to continue to build a top tier energy company. We look forward to updating our shareholders in the second quarter report.

NORMAL COURSE ISSUER BID

The Toronto Stock Exchange ("TSX") has accepted Crew's Notice of Intention to commence a normal course issuer bid (the "NCIB"). Under the NCIB, Crew may purchase for cancellation, from time to time, as Crew considers advisable, up to a maximum of 6,038,492 common shares of the Corporation ("Common Shares"), which represents 5% of the currently issued and outstanding Common Shares. Purchases of Common Shares will be made on the open market through the facilities of the TSX. The price which Crew will pay for any Common Shares purchased by it will be the prevailing market price of the Common Shares on the TSX at the time of such purchase. The actual number of Common Shares that may be purchased for cancellation and the timing of any such purchases will be determined by Crew, subject to a maximum daily purchase limitation of 261,920 Common Shares which equates to 25% of Crew's average daily trading volume for the six months ended April 30, 2012.

The NCIB will commence on May 14, 2012 and will terminate on May 13, 2013 or such earlier time as the NCIB is completed or terminated at the option of Crew. Macquarie Capital Markets Canada Ltd. will act on the Corporation's behalf to make purchases of Common Shares pursuant to the NCIB.

Management of Crew believes that, from time to time, the market price of its Common Shares may not fully reflect the underlying value of the Common Shares and that at such times the purchase of Common Shares would be in the best interests of Crew. Such purchases will increase the proportionate interest of, and may be advantageous to, all remaining shareholders.

On behalf of the Board,

Dale Shwed
President and C.E.O.

May 9, 2012

MANAGEMENT'S DISCUSSION AND ANALYSIS

ADVISORIES

Management's discussion and analysis ("MD&A") is the Company's explanation of its financial performance for the period covered by the financial statements along with an analysis of the Company's financial position. Comments relate to and should be read in conjunction with the unaudited interim consolidated financial statements of the Company for the three month periods ended March 31, 2012 and 2011 and the audited consolidated financial statements and Management Discussion and Analysis for the year ended December 31, 2011. The 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, 2011. All figures provided herein and in the 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, 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, production estimates, expected commodity mix and prices, future operating costs, future transportation costs, expected royalty rates, general and administrative expenses, interest rates, debt levels, funds from operations and the timing of and impact of implementing accounting policies, and Crew's forecasts in respect of production and cash flow for 2012 and resulting year-end net debt may constitute forward looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, the inability to fully realize the benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and inability to access sufficient capital from internal and external sources. As a consequence, the Company's actual results may differ materially from those expressed in, or implied by, the forward looking statements. Forward looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Crew believes that the expectations reflected in such forward looking statements or information are reasonable, undue reliance should not be placed on forward looking statements because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document and other documents filed by the Company, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Company has an interest in to operate the field in a safe, efficient and effective manner; Crew's ability to obtain financing on acceptable terms; 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, the transportation liability charge and acquisition 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, 2012**	Three months ended March 31, 2011
Cash provided by operating activities	**66,226**	26,469
Decommissioning obligation expenditures	**179**	(11)
Transportation liability charge	**–**	101
Change in non-cash working capital	**(18,348)**	(2,448)
Funds from operations	**48,057**	24,111

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 and net debt:

($ thousands)	**March 31, 2012**	December 31, 2011
Current assets	**73,068**	79,117
Current liabilities	**(160,812)**	(192,744)
Fair value of financial instruments	**9,320**	21,175
Working capital deficit	**(78,424)**	(92,452)

($ thousands)	**March 31, 2012**	December 31, 2011
Bank loan	**(320,153)**	(230,676)
Working capital deficit	**(78,424)**	(92,452)
Net debt	**(398,577)**	(323,128)

RESULTS OF OPERATIONS

Production

	Three months ended March 31, 2012					Three months ended March 31, 2011				
	Conv. Oil (bbl/d)	**Heavy Oil (bbl/d)**	**Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Conv. Oil (bbl/d)	Heavy Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
Alberta	**6,276**	**8**	**1,911**	**46,838**	**16,001**	5,677	–	361	22,471	9,783
British Columbia	**494**	**–**	**1,194**	**38,606**	**8,123**	117	–	768	29,638	5,825
Saskatchewan	**–**	**6,154**	**–**	**612**	**6,256**	–	–	–	–	–
Total	**6,770**	**6,162**	**3,105**	**86,056**	**30,380**	5,794	–	1,129	52,109	15,608

In the first quarter of 2012, production increased 95% over the same period in 2011 as a result of production additions from the Company's successful drilling program primarily in Princess, Alberta and Septimus, British Columbia combined with the acquisition of Caltex Energy Inc. ("Caltex") which added approximately 10,500 boe per day of heavy oil and liquids rich natural gas production effective July 1, 2011. Production was slightly below the Company's expectations as, during the quarter, the Company shut-in approximately 1,050 boe per day of uneconomic dry natural gas production due to low natural gas pricing. In addition, conventional oil production in Princess was lower than forecasted due to high gathering system back pressure lowering production from older wells.

Revenue

	Three months ended March 31, 2012	Three months ended March 31, 2011
Revenue *($ thousands)*		
Conventional oil	**49,964**	36,331
Heavy oil	**39,835**	–
Natural gas liquids	**14,989**	6,066
Natural gas	**18,287**	18,751
Total	**123,075**	61,148
Crew average prices		
Conventional oil ($/bbl)	**81.10**	69.68
Heavy oil ($/bbl)	**71.04**	–
Natural gas liquids ($/bbl)	**53.05**	59.71
Natural gas ($/mcf)	**2.34**	4.00
Oil equivalent ($/boe)	**44.52**	43.53
Benchmark pricing		
Conv. and heavy oil – WCS (Cdn $/bbl)	**81.60**	70.20
Oil and ngl – Cdn$ WTI (Cdn $/bbl)	**103.04**	92.74
Natural Gas – AECO C daily index (Cdn $/mcf)	**2.20**	3.82

The Company's first quarter 2012 revenue increased 101% compared to the same period in 2011. This was led by an increase of 38% in conventional oil revenue combined with the increased production described above, partially offset by a 42% decline in the Company's realized natural gas price. This decrease in realized natural gas pricing was consistent with the Company's AECO C benchmark price decline. The Company's realized natural gas liquids ("ngl") price declined 11% as compared to an 11% increase in the Company's Cdn$ West Texas Intermediate ("WTI") benchmark price due to the increased production of lower valued ethane and propane ngls from new production in northeast British Columbia and in Alberta from the Caltex acquisition. In addition, the price of ethane and propane have declined approximately 50% in the first quarter of 2012 compared to the same period in 2011 which is not factored into the Company's benchmark comparison. The Company's realized heavy oil price tracks the Company's Western Canadian Select ("WCS") benchmark less the cost of diluent used to blend the heavy oil production to meet pipeline specifications.

Royalties

($ thousands, except per boe)	Three months ended March 31, 2012	Three months ended March 31, 2011
Royalties	**30,825**	14,356
Per boe	**$ 11.15**	$ 10.22
Percentage of revenue	**25.0%**	23.5%

Royalties as a percentage of revenue increased to 25% in the first quarter of 2012 compared to 23.5% in the same period in 2011 as a result of the increased revenue from the Princess and Lloydminster areas which attract a higher effective royalty rate as compared to the corporate average royalty rate. Crew continues to forecast an annual 2012 royalty rate of between 24% and 26%.

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. In 2012, these contracts had the following impact on the consolidated statements of loss and comprehensive loss:

($ thousands)	Three months ended March 31, 2012	Three months ended March 31, 2011
Realized gain on financial instruments	**1,382**	1,016
Unrealized loss on financial instruments	**(2,737)**	(16,033)

As at March 31, 2012, the Company held derivative commodity contracts summarized as follows:

Subject of Contract	Notional Quantity	Remaining Term	Reference	Average Strike Price	Contract Traded	Fair Value ($000s)
Oil	1000 bbl/day	April 1, 2012 – April 30, 2012	CDN$ WTI	$106.30	Swap	100
Oil	1000 bbl/day	May 1, 2012 – December 31, 2012	US$ WTI	$106.30	Swaption(1)	(608)
Oil	3500 bbl/day	April 1, 2012 –December 31, 2012	CDN$ WTI	$100.361	Swap	(4,259)
Oil	3000 bbl/day	April 1, 2012 – December 31, 2012	CDN$ WTI	$86.667 – 96.242	Collar	(8,438)
Oil	2000 bbl/day	April 1, 2012 – December 31, 2012	CDN$ WCS – WTI diff	($15.625)	Swap	4,906
Oil	2000 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$102.218	Swap	(1,592)
Oil	750 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$92.60	Call	(4,716)
Oil	1000 bbl/day	January 1, 2013 – December 31, 2013	US$ WTI	$89.838	Call	(7,364)
Oil	1000 bbl/day	January 1, 2013 – December 31, 2013	US$ WTI	$107.225	Swaption(2)	(2,501)
US$ / CAD$ exchange	Sell US $2.0 mm per month	April 1, 2012 – December 31, 2012	CDN$/US$	1.050	Swap	885
US$ / CAD$ exchange	Buy US $1.0 mm per month	April 1, 2012 – December 31, 2012	CDN$/US$	1.037	Swap	(325)
Total						**(23,912)**

(1) The counter-party to this contract held a one-time option at April 30, 2012 to extend a swap at US$106.30 for the period indicated. The option was not exercised and the contract expired at no cost to the Company on April 30, 2012.

(2) The counter-party to these contracts holds a one-time option at December 31, 2012 to extend a swap on 1,000 bbl/d of oil at an average of WTI US$107.26.

Subsequent to March 31, 2012, the Company entered into the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Contract Traded
Natural Gas	25,000 gj/day	May 1, 2012 – December 31, 2012	AECO C Monthly Index	$ 1.869/gj	Swap

Operating Costs

($ thousands, except per boe)	**Three months ended March 31, 2012**	Three months ended March 31, 2011
Operating costs	**33,578**	16,418
Per boe	**$ 12.15**	$ 11.69

In the first quarter of 2012, the Company's operating costs per unit increased over the same period in 2011 as a result of the acquisition of the Caltex heavy oil production combined with increased production in the Princess area both of which have higher operating costs as compared to the Company's historical average costs per unit. The Company now forecasts operating costs to range from $11.50 to $12.00 per boe in 2012 which is slightly higher than previous guidance due to increased fuel and power costs and the reduction in the Company's forecasted natural gas production resulting from reduced spending on natural gas properties.

Transportation Costs

($ thousands, except per boe)	**Three months ended March 31, 2012**	Three months ended March 31, 2011
Transportation costs	**3,788**	2,996
Per boe	**$ 1.37**	$ 2.13

The Company realized lower first quarter 2012 transportation costs per unit as compared to the first quarter of 2011 due to a decrease in clean oil trucking in the Princess area as a new oil sales pipeline became operational during the quarter combined with the addition of lower transportation cost per unit production from the Caltex acquisition. The Company now forecasts transportation costs to range between $1.30 and $1.55 per boe for 2012 which is lower than the previously forecasted range due to a decrease in the cost of transporting Princess oil production and lower realized natural gas transportation costs.

Operating Netbacks

($/boe)	**Three months ended March 31, 2012**	Three months ended March 31, 2011
Revenue	**44.52**	43.53
Realized commodity hedging gain	**0.50**	0.72
Royalties	**(11.15)**	(10.22)
Operating costs	**(12.15)**	(11.69)
Transportation costs	**(1.37)**	(2.13)
Operating netbacks	**20.35**	20.21

General and Administrative Costs

($ thousands, except per boe)	**Three months ended March 31, 2012**	Three months ended March 31, 2011
Gross costs	**8,281**	4,197
Operator's recoveries	**(308)**	(113)
Capitalized costs	**(2,702)**	(1,296)
General and administrative expenses	**5,271**	2,788
Per boe	**1.91**	1.98

Increased gross general and administrative costs were the result of increased staff levels to accommodate the Company's increased activity level including increased office rental costs for additional office space. General and administrative costs per boe decreased in the first quarter of 2012 as compared with the same period in 2011 as increased production levels were partially offset by additional costs. The Company continues to expect general and administrative costs to average between $1.60 and $1.80 per boe for 2012 with higher amounts incurred in the first half of the year due to the payment of one time annual costs during this period.

Finance Expenses

($ thousands, except per boe)	**Three months ended March 31, 2012**	Three months ended March 31, 2011
Interest on bank debt	**2,938**	1,495
Accretion of the decommissioning obligation	**632**	477
Total finance expense	**3,570**	1,972
Average debt level	**267,656**	116,003
Effective interest rate on bank debt	**4.4%**	5.2%
Interest on bank debt per boe	**$ 1.06**	$ 1.06

In the first quarter of 2012, higher average debt levels from the acquisition of Caltex and increased capital spending increased the Company's interest on bank debt over the same period in 2011. The effective interest rate on the Company's bank debt decreased in the first quarter of 2012 as compared with the same period in 2011 due to a lower prime rate combined with lower stamping fees and decreased stand-by fees on the Company's bank facility. Accretion of the decommissioning obligation increased in the first quarter of 2012 compared with the same period in 2011 due to additional accretion on the Caltex decommissioning obligation which was acquired on July 1, 2011. The Company expects its effective interest rate on bank debt will average approximately 4.5% to 5.0% in 2012.

Share-Based Compensation

($ thousands)	**Three months ended March 31, 2012**	Three months ended March 31, 2011
Gross costs	**4,907**	1,544
Capitalized costs	**(2,473)**	(710)
Total share-based compensation	**2,434**	834

The Company's share-based compensation expense has increased in the first quarter of 2012 compared with the same period in 2011 due to an increase in the number of options outstanding with a higher weighted average exercise price.

Depletion and Depreciation

($ thousands, except per boe)	**Three months ended March 31, 2012**	Three months ended March 31, 2011
Depletion and depreciation	**50,515**	20,965
Per boe	**18.27**	14.92

Total depletion, depreciation and accretion costs per boe have increased in the first quarter of 2012 as compared with the same period in 2011 due to the addition of the fair market value of the Caltex assets at July 1, 2011 which was higher than the Company's pre-acquisition book value per boe for proved plus probable reserves.

Deferred Income Taxes

In the first quarter of 2012, the provision for deferred income taxes was a recovery of $1.8 million compared to a recovery of $4.1 million in the first quarter of 2011. The decreased recovery was due to the Company having a lower pre-tax loss in the first quarter of 2012.

Cash and Funds from Operations and Net Loss

($ thousands, except per share amounts)	**Three months ended March 31, 2012**	Three months ended March 31, 2011
Cash provided by operating activities	**66,226**	26,469
Funds from operations	**48,057**	24,111
Per share – basic	**0.40**	0.29
– diluted	**0.40**	0.29
Net loss	**(6,430)**	(10,126)
Per share – basic	**(0.05)**	(0.12)
– diluted	**(0.05)**	(0.12)

The first quarter 2012 increase in cash provided by operating activities and funds from operations was the result of increased production from the acquisition of Caltex in July 2011 and increased pricing received for the Company's oil production. The first quarter 2012 net loss was a result of decreased natural gas prices combined with higher depletion and depreciation costs due to the acquisition of Caltex while the net loss in the first quarter of 2011 was primarily due to an unrealized loss on the Company's risk management program.

Capital Expenditures, Acquisitions and Dispositions

During the first quarter, the Company drilled a total of 60 (57.8 net) wells resulting in 46 (45.0 net) oil wells, 11 (9.9 net) natural gas wells, one (1.0 net) service well and two (2.0 net) dry and abandoned wells. In addition, the Company completed 42 (41.4 net) wells and recompleted 20 (19.3 net) wells in the quarter. The Company continued to add to its infrastructure spending $21.9 million on pipelines and upgrading its batteries and facilities predominantly in the Princess, Lloydminster and Septimus areas. The Company also closed the acquisition of a strategic 35 kilometer six inch pipeline in northeastern British Columbia for consideration of $8.1 million. Crew continued to evaluate land in the Princess area completing a seismic shoot during the first quarter of 2012.

Total net capital expenditures for the quarter are detailed below:

($ thousands)	**Three months ended March 31, 2012**	Three months ended March 31, 2011
Land	**2,431**	411
Seismic	**2,984**	7,344
Drilling and completions	**89,846**	50,029
Facilities, equipment and pipelines	**30,044**	16,012
Other	**3,438**	1,369
Total exploration and development	**128,743**	75,165
Property acquisitions (dispositions)	**–**	361
Total	**128,743**	75,526

LIQUIDITY AND CAPITAL RESOURCES

Capital Funding

The Company has completed the annual review of its credit facility with its syndicate of lending banks (the "Syndicate"). The credit facility was renewed and includes a revolving line of credit of $400 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 10, 2013. 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. 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. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled borrowing base review on or before October 31, 2012. At March 31, 2012, the Company had drawings of $320.2 million on the Facility and had issued letters of credit totaling $11.8 million.

During the first quarter of 2012, the Company received proceeds of $5.4 million upon the exercise of 767,200 employee stock options.

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

Working Capital

The capital intensive nature of Crew's activities generally results in the Company carrying a working capital deficit. Working capital deficiency includes accounts receivable less accounts payable and accrued liabilities. The Company maintains sufficient unused bank credit lines to satisfy working capital deficiencies. At March 31, 2012, the Company's working capital deficiency totaled $78.4 million which, when combined with the drawings on its bank line, represented 93% of its bank facility at March 31, 2012.

Share Capital

As at May 9, 2012, Crew had 120,769,844 Common Shares and 7,787,100 options to acquire Common Shares of the Company issued and outstanding.

Capital Structure

The Company considers its capital structure to include working capital, bank debt, and shareholders' equity. Crew's primary capital management objective is to maintain a strong balance sheet 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 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 bank debt and net working capital, divided by annualized funds from operations for the most recent quarter.

The Company monitors this ratio and endeavours to maintain it at or below 2.0 to 1.0. This ratio may increase at certain times as a result of acquisitions or low commodity prices. As shown below, as at March 31, 2012, the Company's ratio of net debt to annualized funds from operations was 2.07 to 1 (December 31, 2011 – 1.25 to 1). This ratio has risen above the preferred range of the Company as a result of the substantial decrease in natural gas prices during the first quarter of 2012. In order to maintain the integrity of the Company's financial position, the Company plans to adjust its annual capital expenditure program to remain within funds from operations until natural gas prices recover or an alternative form of financing is consummated.

($ thousands, except ratio)	**March 31, 2012**	December 31, 2011
Working capital deficit	**(78,424)**	(92,452)
Bank loan	**(320,153)**	(230,676)
Net debt	**(398,577)**	(323,128)
Funds from operations	**48,057**	64,841
Annualized	**192,228**	259,364
Net debt to annualized funds from operations ratio	**2.07**	1.25

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	2012	2013	2014	2015	2016	Thereafter
Bank loan (1)	320,153	–	–	320,153	–	–	–
Operating leases	11,783	2,070	2,231	2,363	2,494	2,625	–
Firm transportation agreements	26,320	2,701	3,364	3,980	4,021	3,636	8,618
Firm processing agreement	73,114	6,766	8,031	8,926	8,961	8,783	31,647
Total	431,370	11,537	13,626	335,422	15,476	15,044	40,265

(1) Based on the existing terms of the Company's bank facility the first possible repayment date may come in 2014. However, it is expected that the revolving bank facility will be extended and no repayment will be required in the near term.

The operating leases include the Company's contractual obligation to a third party for its five year lease of additional 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 2019. Crew has retained the option to re-purchase a 50% interest in the facility at certain dates prior to January 1, 2014, at a cost of 50% of the total expanded facility's construction cost. If the Company re-purchases a 50% interest on January 1, 2014 for approximately $20 million, the remaining commitment would be reduced by approximately $27 million.

GUIDANCE

Realized commodity prices have declined precipitously leading to a first quarter natural gas price decline of 32% and a 6% and 8% decline in realized conventional and heavy oil prices, respectively, as compared with the fourth quarter of 2011. Current natural gas prices are now 25% lower than first quarter realized prices and have since hit ten year lows. Differentials between WTI pricing and WCS and Lloyd blend heavy oil have widened significantly as a result of tightening pipeline and refining capacity in the United States. The strength and flexibility of the Company's balance sheet is a priority, as such, Crew is reducing its 2012 capital expenditure budget by $75 million to $225 million to enable the Company to grow its production year over year, increase its liquid weighting and maintain a strong balance sheet. The funding of this program will be from funds from operations, asset dispositions and the existing bank facility.

Crew has shut-in 6.3 mmcf per day of uneconomic dry gas production and intends to shut-in an additional 4.5 mmcf per day of natural gas production in the second quarter. In addition, a third party facility at Elmworth, Alberta is going down for an unplanned turnaround which will result in approximately 2,000 boe per day being shut in for the month of May. With the $75 million (25%) reduction in capital expenditures, 2,500 boe per day of behind pipe of natural gas weighted production that has been deferred and 1,800 boe per day of shut-in production, Crew is forecasting to average approximately 28,000 to 29,000 boe per day in 2012 representing a 14% (5% without shut-in and deferred production) reduction in the Company's previous guidance.

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 2012**	Dec. 31 2011	Sept. 30 2011	June 30 2011	Mar. 31 2011	Dec. 31 2010	Sept. 30 2010	June 30 2010
Total daily production (boe/d)	**30,380**	30,034	27,510	16,443	15,607	14,654	13,061	12,048
Average wellhead price ($/boe)	**44.52**	51.41	45.33	46.94	43.53	42.00	37.39	39.25
Petroleum and natural gas sales	**123,075**	142,063	114,719	70,236	61,148	56,620	44,924	43,027
Cash provided by operations	**66,226**	39,969	54,095	32,896	26,469	20,225	18,956	23,422
Funds from operations	**48,057**	64,841	54,260	28,891	24,111	27,449	23,464	19,966
Per share – basic	**0.40**	0.54	0.45	0.34	0.29	0.34	0.29	0.25
– diluted	**0.40**	0.54	0.45	0.33	0.29	0.34	0.29	0.24
Net income (loss)	**(6,430)**	(148,529)	12,232	16,261	(10,126)	(14,214)	(17,281)	31,544
Per share – basic	**(0.05)**	(1.24)	0.10	0.19	(0.12)	(0.18)	(0.22)	0.39
– diluted	**(0.05)**	(1.24)	0.10	0.19	(0.12)	(0.18)	(0.22)	0.39

Significant factors and trends that have impacted the Company's results during the above periods include:

- Revenue is directly impacted by the Company's ability to replace existing declining production and add incremental production through its on-going capital expenditure program.
- Over the past few years, the price of natural gas has been negatively impacted by an increasing supply of natural gas coming from new technology tapping into abundant supplies of tight shale gas reservoirs in North America. With depressed natural gas prices, Crew has focused its capital expenditures towards oil development with higher netbacks. This has resulted in the commodity mix moving towards more oil and the Company's overall netbacks supplementing revenues and funds from operations.
- Production was negatively impacted by scheduled and unscheduled third party facility shutdowns in the second quarters of 2010 and 2011 and poor weather experienced in southern Alberta during the second quarters of 2010 and 2011 and third quarter of 2010.
- Revenue and royalties are significantly impacted by underlying commodity prices. The Company utilizes derivative contracts and forward sales contracts to reduce the exposure to commodity price fluctuations. These contracts can cause volatility in net income as a result of unrealized gains and losses on commodity derivative contracts held for risk management purposes.
- During 2010 and 2011, the Company sold assets with approximately 1,980 boe per day of production for $149.1 million. The major dispositions closed as follows:
  - Second quarter 2010 – 1,700 boe per day for $123.3 million
  - Second quarter 2011 – 140 boe per day for $12.3 million
  - Fourth quarter 2011 – 140 boe per day for $13.2 million
- These dispositions of assets in the Ferrier, Edson and Provost areas resulted in gains on sale of assets of $37.0 million, $4.7 million and $7.4 million in the second quarter of 2010 and the second and fourth quarters of 2011, respectively.
- The Company acquired Caltex Energy on July 1, 2011, adding approximately 10,500 boe per day of production.
- The Company incurred impairment charges of $18.7 million, $10.4 million and $181.9 million primarily on its natural gas weighted CGUs in the third and fourth quarters of 2010 and the fourth quarter of 2011, respectively.

Future Accounting Pronouncements

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

(a) IFRS-9 Financial Instruments:

As of January 1, 2013, the Company will be required to adopt IFRS-9 Financial Instruments, which is the result of the first phase of the IASB project to replace IAS-39 Financial Instruments: Recognition and Measurement. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has two classification categories: amortized cost and fair value. Portions of the standard remain in development and the full impact of the standard on the Company's financial statements will not be known until the project is complete.

(b) In May, 2011, the IASB released the following new standards which are effective for fiscal years beginning January 1, 2013 with earlier adoption permitted.

(i) IFRS-10 Consolidated Financial Statements, supercedes IAS-27 Consolidation and Separate Financial Statements and SIC-12 Consolidation – Special Purpose Entities. This standard provides a single model to be applied in control analysis for all investees including special purpose entities.

(ii) IFRS-11 Joint Arrangements, divides joint arrangements into two types, joint operations and joint ventures, each with their own accounting model. All joint arrangements are required to be reassessed on transition to IFRS 11 to determine their type to apply the appropriate accounting.

(iii) IFRS-12 Disclosures of Interests in Other Entities, combines in a single standard the disclosure requirements for subsidiaries, associates and joint arrangements as well as unconsolidated structured entities.

(iv) IFRS-13 Fair Value Measurement, defines fair value, establishes a framework for measuring fair value and sets out disclosure requirements for fair value measurements. This standard defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

Crew is currently assessing the expected impact, if any, that the adoption of these standards will have on its financial statements.

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, 2012 and ended on March 31, 2012 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 9, 2012

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited) (thousands)	**March 31, 2012**	December 31, 2011
ASSETS		
Current Assets:		
Accounts receivable	**$ 68,162**	$ 79,117
Fair value of financial instruments (note 8)	**4,906**	–
	73,068	79,117
Exploration and evaluation assets (note 3)	**57,285**	56,197
Property, plant and equipment (note 4)	**1,788,163**	1,707,405
	$ 1,918,516	$ 1,842,719
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 146,586**	$ 171,569
Fair value of financial instruments (note 8)	**14,226**	21,175
	160,812	192,744
Fair value of financial instruments (note 8)	**14,592**	–
Bank loan (note 5)	**320,153**	230,676
Decommissioning obligations (note 6)	**106,434**	104,836
Deferred tax liability	**182,450**	184,281
Shareholders' Equity		
Share capital (note 7)	**1,269,488**	1,261,884
Contributed surplus (note 7)	**38,808**	36,089
Deficit	**(174,221)**	(167,791)
	1,134,075	1,130,182
Commitments (note 9)		
	$ 1,918,516	$ 1,842,719

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, 2012**	Three months ended March 31, 2011
Revenue		
Petroleum and natural gas sales	**$ 123,075**	$ 61,148
Royalties	**(30,825)**	(14,356)
Realized gain on financial instruments (note 8)	**1,382**	1,016
Unrealized loss on financial instruments (note 8)	**(2,737)**	(16,033)
	90,895	31,775
Expenses		
Operating	**33,578**	16,418
Transportation	**3,788**	2,996
General and administrative	**5,271**	2,788
Share-based compensation	**2,434**	834
Depletion and depreciation	**50,515**	20,965
	95,586	44,001
Loss from operations	**(4,691)**	(12,226)
Financing	**3,570**	1,972
Loss before income taxes	**(8,261)**	(14,198)
Deferred tax recovery	**(1,831)**	(4,072)
Net loss and comprehensive loss	**$ (6,430)**	$ (10,126)
Net loss per share (note 7)		
Basic	**$ (0.05)**	$ (0.12)
Diluted	**$ (0.05)**	$ (0.12)

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, 2012	119,993	$ 1,261,884	$ 36,089	$ (167,791)	$ 1,130,182
Net loss for the period	–	–	–	(6,430)	(6,430)
Share-based compensation expensed	–	–	2,434	–	2,434
Share-based compensation capitalized	–	–	2,473	–	2,473
Transfer of share-based compensation on exercises	–	2,188	(2,188)	–	–
Issued on exercise of options	767	5,416	–	–	5,416
Balance March 31, 2012	**120,760**	**$ 1,269,488**	**$ 38,808**	**$ (174,221)**	**$ 1,134,075**

	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 2011	80,368	$ 649,768	$ 27,511	$ (37,629)	$ 639,650
Net loss for the period	–	–	–	(10,126)	(10,126)
Issue of shares	4,820	100,015	–	–	100,015
Share issue costs, net of tax of $1,326	–	(3,904)	–	–	(3,904)
Share-based compensation expensed	–	–	834	–	834
Share-based compensation capitalized	–	–	710	–	710
Transfer of share-based compensation on exercises	–	2,933	(2,933)	–	–
Issued on exercise of options	775	7,180	–	–	7,180
Balance March 31, 2011	85,963	$ 755,992	$ 26,122	$ (47,755)	$ 734,359

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited) (thousands)	**Three months ended March 31, 2012**	Three months ended March 31, 2011
Cash provided by (used in):		
Operating activities:		
Net loss	**$ (6,430)**	$ (10,126)
Adjustments:		
Depletion and depreciation	**50,515**	20,965
Financing expenses	**3,570**	1,972
Interest expense	**(2,938)**	(1,495)
Share-based compensation	**2,434**	834
Deferred tax reduction	**(1,831)**	(4,072)
Unrealized loss on financial instruments	**2,737**	16,033
Transportation liability charge	**–**	(101)
Decommissioning obligations settled	**(179)**	11
Change in non-cash working capital	**18,348**	2,448
	66,226	26,469
Financing activities:		
Increase (decrease) in bank loan	**89,477**	(50,238)
Issue of common shares	**–**	100,015
Proceeds from exercise of share options	**5,416**	7,180
Share issue costs	**–**	(5,218)
	94,893	51,739
Investing activities:		
Exploration and evaluation asset expenditures	**(2,477)**	(7,213)
Property, plant and equipment expenditures	**(126,266)**	(67,952)
Property acquisitions	**–**	(361)
Proceeds on sale of asset held for sale	**–**	15,116
Change in non-cash working capital	**(32,376)**	(17,798)
	(161,119)	(78,208)
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, 2012 and 2011

(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, 2012 and for the three months ended March 31, 2012 and 2011 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, 2011. 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 consolidated financial statements were authorized for issue by the Board of Directors on May 9, 2012.

3. EXPLORATION AND EVALUATION ASSETS:

Cost or deemed cost	Total
Balance, January 1, 2011	$ 72,281
Additions	9,864
Transfer to property, plant and equipment	(25,948)
Balance, December 31, 2011	$ 56,197
Additions	2,477
Transfer to property, plant and equipment	(1,389)
Balance, March 31, 2012	**$ 57,285**

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.

4. PROPERTY, PLANT AND EQUIPMENT:

Cost or deemed cost	Total
Balance, January 1, 2011	$ 1,018,265
Additions	366,010
Transfer from exploration and evaluation assets	25,948
Divestitures	(17,921)
Corporate acquisition	730,302
Change in decommissioning obligations	20,363
Capitalized share-based compensation	5,747
Balance, December 31, 2011	$ 2,148,714
Additions	126,266
Transfer from exploration and evaluation assets	1,389
Change in decommissioning obligations	1,145
Capitalized share-based compensation	2,473
Balance, March 31, 2012	**$ 2,279,987**

Accumulated depletion and depreciation	Total
Balance, January 1, 2011	$ 105,625
Depletion and depreciation expense	155,789
Divestitures	(2,046)
Impairment	181,941
Balance, December 31, 2011	$ 441,309
Depletion and depreciation expense	50,515
Balance, March 31, 2012	**$ 491,824**

Net book value	Total
Balance, December 31, 2011	$ 1,707,405
Balance, March 31, 2012	**$ 1,788,163**

The calculation of depletion for the three months ended March 31, 2012 included estimated future development costs of $648.4 million (December 31, 2011 – $681.4 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $89.6 million (December 31, 2011 – $87.0 million) and undeveloped land of $153.1 million (December 31, 2011 – $154.6 million) related to development acreage.

5. BANK LOAN:

The Company's bank facility consists of a revolving line of credit of $400 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 10, 2013. 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. 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. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled borrowing base review on or before October 31, 2012.

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, 2012, the Company's applicable pricing included a 1.25 percent margin on prime lending and a 2.25 percent stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.563 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, 2012, the Company had issued letters of credit totaling $11.8 million (December 31, 2011 – $10.2 million). The effective interest rate on the Company's borrowings under its bank facility for the period ended March 31, 2012 was 4.4% (2011 – 5.2%).

6. DECOMMISSIONING OBLIGATIONS:

	Three months ended March 31, 2012	Year ended December 31, 2011
Decommissioning obligations, beginning of period	**$ 104,836**	$ 54,828
Obligations incurred	**4,517**	7,781
Obligations settled	**(179)**	(1,144)
Obligations divested	**–**	(2,498)
Obligations acquired	**–**	30,887
Change in estimated future cash outflows	**(3,372)**	12,582
Accretion of decommissioning liabilities	**632**	2,400
Decommissioning obligations, end of period	**$ 106,434**	$ 104,836

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning obligations to be $106.4 million as at March 31, 2012 (December 31, 2011 – $104.8 million) based on an undiscounted total future liability of $112.2 million (December 31, 2011 – $107.2 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 discount factor, being the risk-free rate related to the liability, is 2.55% (December 31, 2011 – 2.40%).

7. SHARE CAPITAL:

At March 31, 2012, 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 number and weighted average exercise prices of share options are as follows:

	Number of options	Weighted average exercise price
Balance January 1, 2012	8,224	$ 12.93
Granted	469	$ 12.30
Exercised	(767)	$ 7.06
Forfeited	(89)	$ 13.87
Balance at March 31, 2012	**7,837**	**$ 13.45**
Exercisable at March 31, 2012	**2,306**	**$ 11.18**

The following table summarizes information about the stock options outstanding at March 31, 2012:

Range of exercise prices	Outstanding at March 31, 2012	Weighted average remaining life (years)	Weighted average exercise price	Exercisable at March 31, 2012	Weighted average exercise price
$ 3.43 to $ 7.01	865	0.8	$ 5.17	862	$ 5.17
$ 7.02 to $ 9.94	29	1.6	$ 9.16	15	$ 9.16
$ 9.95 to $14.63	2,180	3.4	$ 11.42	161	$ 12.85
$14.64 to $18.70	4,763	2.5	$ 15.92	1,268	$ 15.07
	7,837	2.6	$ 13.45	2,306	$ 11.18

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, 2012**	Three months ended March 31 2011
Risk free interest rate (%)	**1.2**	2.3
Expected life (years)	**4.0**	4.0
Expected volatility (%)	**60**	60
Forfeiture rate (%)	**17**	16
Weighted average fair value of options	**$ 5.78**	$ 9.28

Loss per share:

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, 2012 was 120,680,000 (2011 – 82,221,000).

In computing the diluted loss per share for the period ended March 31, 2012, nil (2011 – nil) shares were added to the weighted average Common Shares outstanding to account for the dilution of stock options. There were 7,837,000 (2011 – 4,797,000) stock options that were not included in the diluted loss per share calculation because they were anti-dilutive.

8. FINANCIAL RISK MANAGEMENT:

(a) 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, 2012 the Company held derivative contracts as follows:

Subject of Contract	Notional Quantity	Remaining Term	Reference	Average Strike Price	Contract Traded	Fair Value ($000s)
Oil	1000 bbl/day	April 1, 2012 – April 30, 2012	CDN$ WTI	$106.30	Swap	100
Oil	1000 bbl/day	May 1, 2012 – December 31, 2012	US$ WTI	$106.30	Swaption(1)	(608)
Oil	3500 bbl/day	April 1, 2012 – December 31, 2012	CDN$ WTI	$100.361	Swap	(4,259)
Oil	3000 bbl/day	April 1, 2012 – December 31, 2012	CDN$ WTI	$86.667 – 96.242	Collar	(8,438)
Oil	2000 bbl/day	April 1, 2012 – December 31, 2012	CDN$ WCS – WTI diff	($15.625)	Swap	4,906
Oil	2000 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$102.218	Swap	(1,592)
Oil	750 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$92.60	Call	(4,716)
Oil	1000 bbl/day	January 1, 2013 – December 31, 2013	US$ WTI	$89.838	Call	(7,364)
Oil	1000 bbl/day	January 1, 2013 – December 31, 2013	US$ WTI	$107.225	Swaption(2)	(2,501)
US$ / CAD$ exchange	Sell US $2.0 mm per month	April 1, 2012 – December 31, 2012	CDN$/US$	1.050	Swap	885
US$ / CAD$ exchange	Buy US $1.0 mm per month	April 1, 2012 – December 31, 2012	CDN$/US$	1.037	Swap	(325)
Total						(23,912)

(1) The counter-party to this contract held a one-time option at April 30, 2012 to extend a swap at US$106.30 for the period indicated. The option was not exercised and the contract expired at no cost to the Company on April 30, 2012.

(2) The counter-party to these contracts holds a one-time option at December 31, 2012 to extend a swap on 1,000 bbl/d of oil at an average of WTI US$107.26.

As at March 31, 2012, a 10% decrease to the price outlined in the contracts above would result in a $10.4 million increase in income.

Subsequent to March 31, 2012, the Company entered into the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Average Strike Price	Contract Traded
Natural Gas	25,000 gj/day	May 1, 2012 – December 31, 2012	AECO C Monthly Index	$1.869	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 which may or may not be successful. Therefore, the Company monitors the level of risk incurred in its capital expenditures to balance the proportion of debt and equity in its capital structure.

The Company considers its capital structure to include working capital, the bank loan, 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 bank debt and net working capital, divided by annualized funds from operations for the most recent quarter.

The Company monitors this ratio and endeavours to maintain it at or below 2.0 to 1.0 in a normalized commodity price environment. This ratio may increase at certain times as a result of acquisitions or low commodity prices. As shown below, as at March 31, 2012 the Company's ratio of net debt to annualized cash flow was 2.07 to 1, (December 31, 2011 – 1.25 to 1). The ratio has risen above the preferred range of the Company as a result of the substantial decrease in natural gas prices during the first quarter of 2012. In order to maintain the integrity of the Company's financial position, the Company plans to adjust its annual capital expenditure program to remain within funds from operations until natural gas prices recover or an alternative form of financing is consummated. There were no changes in the Company's approach to capital management during the period.

	March 31, 2012	December 31, 2011
Net debt:		
Accounts receivable	**$ 68,162**	$ 79,117
Accounts payable and accrued liabilities	**(146,586)**	(171,569)
Working capital deficiency	**$ (78,424)**	$ (92,452)
Bank loan	**(320,153)**	(230,676)
Net debt	**$ (398,577)**	$ (323,128)
Annualized funds from operations:		
Cash provided by operating activities	**$ 66,226**	$ 39,969
Decommissioning obligations settled	**179**	483
Transportation liability charge	**–**	35
Change in non-cash working capital	**(18,348)**	24,354
Funds from operations	**48,057**	64,841
Annualized	**$ 192,228**	$ 259,364
Net debt to annualized funds from operations	**2.07**	1.25

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

9. COMMITMENTS:

($ thousands)	Total	2012	2013	2014	2015	2016	Thereafter
Operating leases	11,783	2,070	2,231	2,363	2,494	2,625	–
Firm transportation agreements	26,320	2,701	3,364	3,980	4,021	3,636	8,618
Firm processing agreement	73,114	6,766	8,031	8,926	8,961	8,783	31,647
Total	111,217	11,537	13,626	15,269	15,476	15,044	40,265

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 2019. Crew has retained the option to re-purchase a 50% interest in the facility at certain dates prior to January 1, 2014, at a cost of 50% of the total expanded facility's construction cost. If the Company re-purchases a 50% interest on January 1, 2014 for approximately $20 million, the remaining commitment would be reduced by approximately $27 million.

CAUTIONARY STATEMENTS

Forward-looking information and statements

This report contains certain forward–looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "project", "should", "believe", "plans", "intends" "forecast" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this report contains forward-looking information and statements pertaining to the following: the volume and product mix of Crew's oil and gas production; production estimates including 2012 forecast average production; plans to shut-in production; future oil and natural gas prices and Crew's commodity risk management programs; future liquidity and financial capacity; projected debt levels; future results from operations and operating metrics; management's expectations in regards to waterfloods at Princess; anticipated reductions in operating costs; 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 number of potential drilling locations; the amount and timing of capital projects; operating costs; the total future capital associated with development of reserves and resources; and methods of funding our capital program.

Forward-looking statements or information are based on a number of material factors, expectations or assumptions of Crew which have been used to develop such statements and information but which may prove to be incorrect. Although Crew believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because Crew can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified herein, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; the timely receipt of any required regulatory approvals; the ability of Crew to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects in which Crew has an interest in to operate the field in a safe, efficient and effective manner; the ability of Crew to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and cost of pipeline, storage and facility construction and expansion and the ability of Crew to secure adequate product transportation; future commodity prices; currency, exchange and interest rates; regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Crew operates; the ability of Crew to successfully market its oil and natural gas products. Included herein is an estimate of Crew's year-end net debt based on assumptions as to cash flow, capital spending in 2012 and the other assumptions utilized in arriving at Crew's 2012 capital budget. To the extent such estimate constitutes a financial outlook, it is included herein to provide readers with an understanding of estimated capital expenditures and the effect thereof on debt levels and readers are cautioned that the information may not be appropriate for other purposes.

The forward-looking information and statements included in this report are not guarantees of future performance and should not be unduly relied upon. Such information and statements, including the assumptions made in respect thereof, involve known and unknown risks, uncertainties and other factors that may cause actual results or events to defer materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; changes in the demand for or supply of Crew's products; 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.

BOE equivalent

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

Test Results and Initial Production Rates

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

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

CORPORATE INFORMATION

HEAD OFFICE

Suite 800, 250 - 5th Street S.W.
Calgary, Alberta T2P 0R4
Phone: (403) 266-2088
Fax: (403) 266-6259
www.crewenergy.com

AUDITORS

KPMG LLP

BANKERS

Toronto-Dominion Bank

Canadian Imperial Bank of Commerce

Union Bank

Bank of Montreal

Bank of Nova Scotia

Alberta Treasury Branches

National Bank of Canada

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVE ENGINEERS

GLJ Petroleum Consultants

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
Stock Symbol: **CR**

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Independent Director

Jeffery E. Errico
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Dennis L. Nerland
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Dale O. Shwed
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Michael D. Sandrelli
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ABBREVIATIONS

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

crew
energy inc.

printed in Canada