crew energy inc.

TSX: CR

Q2 2012

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Q2 2012

Crew Energy Inc. (TSX-CR) of Calgary, Alberta is pleased to present its operating and financial results for the three and six month periods ended June 30, 2012.

HIGHLIGHTS

- Funds from operations increased 80% over the second quarter of 2011 to $52.0 million while increasing 8% over the first quarter of 2012;
- Funds from operations per share increased 30% to $0.43 per share over the second quarter of 2011 and increased 8% over the first quarter of 2012;
- Second quarter production increased 72% over the same period of 2011 and was 7% lower than the first quarter as the Company shut-in uneconomic natural gas production;
- Production per share increased 22% over the second quarter of 2011;
- The Company's two Princess Pekisko waterfloods have continued to show positive results with production now increasing 110% from the "N" pool and increasing 80% from the "K" pool;
- Drilled and completed the Company's first operated Montney oil well at Tower, British Columbia with first month production of 318 boe per day of which 200 bbls were oil and liquids;
- Operating costs of $11.32 per boe were 7% lower than the first quarter;
- A $25.8 million reduction in net debt during the second quarter led to a decrease of 14% in second quarter debt to annualized funds from operations to 1.8 times.

	Three months ended		Six months ended	
FINANCIAL *($ thousands, except per share amounts)*	**June 30, 2012**	June 30, 2011	**June 30, 2012**	June 30, 2011
Petroleum and natural gas sales	**99,946**	70,236	**223,021**	131,384
Funds from operations (1)	**52,027**	28,891	**100,084**	53,002
Per share – basic	**0.43**	0.34	**0.83**	0.63
– diluted	**0.43**	0.33	**0.83**	0.62
Net loss	**24,107**	16,261	**17,677**	6,135
Per share – basic	**0.20**	0.19	**0.15**	0.07
– diluted	**0.20**	0.19	**0.15**	0.07
Capital expenditures	**30,432**	53,185	**159,175**	128,350
Property acquisitions (net of dispositions)	**(4,290)**	(12,650)	**(4,290)**	(12,289)
Net capital expenditures	**26,142**	40,535	**154,885**	116,061
CAPITAL STRUCTURE *($ thousands)*			**As at June 30, 2012**	As at Dec. 31, 2011
Working capital deficiency (2)			**12,094**	92,452
Bank loan			**360,710**	230,676
Net debt			**372,804**	323,128
Current bank facility			**430,000**	430,000
Common Shares Outstanding *(thousands)*			**120,830**	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 June 30, 2012	Three months ended June 30, 2011	Six months ended June 30, 2012	Six months ended June 30, 2011
Daily production				
Conventional oil (bbl/d)	**5,940**	5,458	**6,355**	5,625
Heavy oil (bbl/d)	**6,040**	–	**6,101**	–
Natural gas liquids (bbl/d)	**2,809**	1,369	**2,957**	1,250
Natural gas (mcf/d)	**80,419**	57,698	**83,237**	54,919
Oil equivalent (boe/d @ 6:1)	**28,192**	16,443	**29,286**	16,028
Average prices (1)				
Conventional oil ($/bbl)	**70.41**	82.50	**76.11**	75.93
Heavy oil ($/bbl)	**58.95**	–	**65.05**	–
Natural gas liquids ($/bbl)	**56.27**	63.74	**54.58**	61.93
Natural gas ($/mcf)	**2.06**	4.06	**2.20**	4.03
Oil equivalent ($/boe)	**38.96**	46.94	**41.84**	45.29
Netback ($/boe)				
Operating netback (2)	**23.33**	22.03	**21.78**	21.15
G&A	**1.68**	1.89	**1.80**	1.94
Interest on bank debt	**1.37**	0.82	**1.21**	0.94
Funds from operations	**20.28**	19.32	**18.77**	18.27
Drilling Activity				
Gross wells	**3**	15	**63**	55
Working interest wells	**1.6**	15.0	**59.4**	54.3
Success rate, net wells	**100%**	100%	**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

Second quarter operations and drilling activity levels were reduced due to spring break-up. Operations for the second quarter of 2012 included the drilling of three (1.6 net) wells resulting in one oil well at Lloydminster, one (0.3 net) natural gas well in Kakwa, Alberta and one (0.3 net) oil well at Tower, British Columbia.

Production during the quarter averaged 28,192 boe per day (52% liquids) which was 7% below the first quarter of 2012 due to the shut-in of 1,200 boe per day of uneconomic natural gas production, the inability to truck clean oil from single well batteries in Alberta and Saskatchewan and an eight week outage at a third party facility resulting in the curtailment of 700 boe per day of natural gas and associated liquids throughout the quarter.

FINANCIAL

Crew's second quarter financial results were highlighted by a strengthening of the Company's financial position as a result of stronger cash flow and lower capital spending. Quarterly cash flow was bolstered by realized risk management gains which offset lower commodity prices. The Company's second quarter commodity pricing continued to weaken as compared to the first quarter of 2012. During the quarter, prices received for the Company's natural gas production dropped 12% to $2.06 per mcf compared to the average price received in the first quarter of $2.34 per mcf.

The Company's conventional and heavy oil prices also experienced decreases tracking world oil prices as they declined through the second quarter as concerns over Asian growth and the European debt crisis weighed on the market. The average West Texas Intermediate ("WTI") price decreased 8% during the quarter to average $94 per bbl compared to $103 per bbl in the first quarter of 2012. Crew's crude pricing was also impacted by the widening of the differential between WTI pricing and Canadian crude pricing during the quarter. The differential between WTI and the Company's benchmark

Western Canadian Select ("WCS") widened from 21% in the first quarter to 24% in the second quarter. During the quarter, Crew's average price received for conventional oil decreased 13% to average $70.41 per bbl and the price received for the Company's heavy oil decreased 17% to $58.95 per bbl as a result of the widening differentials.

Crew significantly curtailed its capital expenditures during the second quarter as activity levels were reduced during spring break-up. The Company spent $30.4 million primarily on completions, well optimization, tie-ins and recompletions of existing wells. Crew also completed certain non-core asset dispositions of primarily undeveloped land in central Alberta for net proceeds of approximately $4.2 million. During the quarter, Crew's net debt decreased to $372.8 million on a $430 million bank facility as the Company's funds from operations exceeded net capital expenditures by approximately $26 million.

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 per day of natural gas for the period of July through December 2012 at a price of approximately $2.00 per mcf and has an additional 21.0 mmcf per day of natural gas hedged for 2013 with an average floor price of $3.18 per mcf. The Company also holds hedges against a significant decline in oil prices with an average of 6,500 barrels per day of WTI oil hedged at an average floor price of $94.04 per barrel for the period July through December 2012 and 3,500 barrels per day of WTI oil hedged at an average floor price of $91.11 per barrel for 2013. In addition, the Company currently holds hedges that fix the differential between WTI and WCS pricing on an average of 2,000 barrels a day at a differential of $15.63 per barrel. During the second quarter, the Company monetized certain 2013 WTI oil hedges resulting in realized hedging gains of $12.1 million.

OPERATIONS UPDATE

Pekisko Play, Princess, Alberta

Activity at Princess focused on the completion and tie-in of our Q1 drilling program. By the end of the second quarter, a total of 15 wells had been brought on production with the remainder to be completed and tested in the third and fourth quarter. Four vertical wells drilled in the first quarter outside existing pool boundaries confirmed the extension of the Pekisko oil trends and further supports our long term inventory of drilling locations. Production averaged 6,850 boe per day for the quarter with production impacted by spring breakup as well as a turnaround at our West Tide Lake facility.

Our Tilley waterfloods continue to show positive response with the Pekisko "N" pool production rate 110% above and the Pekisko "K" pool production rate 80% above pre-waterflood conditions. Crew has initiated injection into three new Alderson waterfloods, and expects to have two West Tide Lake waterfloods on injection in the third quarter and one additional Alderson waterflood in the fourth quarter for a total of six new waterfloods in 2012. Crew plans to drill an additional eight (7.5 net) wells at Princess for the remainder of 2012 to further delineate our large undeveloped land base (86% of 460 net sections are undeveloped).

Heavy Oil, Lloydminster, Saskatchewan

At the end of the second quarter, Crew started the second phase of the Company's 2012 drilling program and drilled one (1.0 net) oil well in the second quarter. The Company plans to drill an additional 10 to 15 wells and continue with the successful recompletion program targeting secondary hydrocarbon zones within existing wellbores. These workovers have very strong economics as capital costs range from $50,000 to $100,000 with results comparable to the drilling, completion and equipping of a new well at a cost of approximately $500,000.

Tower, British Columbia

Crew drilled one (0.33 net) Montney oil well at Tower in the second quarter. Given this well's proximity to the Company's existing infrastructure in the area, Crew was able to bring the well on production immediately following the initial completion. Gross field estimated production for the initial 30 days averaged 318 boe per day comprised of 161 bbls per day 46 API oil, 39 bbls per day of natural gas liquids and 710 mcf per day of natural gas. Crew's first non-operated well at Tower has received the necessary surface land approvals and is expected to be on production in the third quarter. Crew is proceeding with necessary approvals to drill up to eight (6.0 net) additional wells, the timing of which will be determined based on the performance of the first two wells and capital availability.

Septimus/Kobes, British Columbia

At Septimus, Crew diverted a total of 14 wells from the western edge of the Septimus field into the newly acquired six inch Septimus/Tower pipeline which is now connected to the Septimus gas plant. Gathering system pressures were reduced by approximately 1,400 kPa resulting in a three mmcf per day increase in production (27 bbls/mmcf liquids). Crew also has two (2.0 net) Montney horizontal wells drilled in the first quarter for which completions were deferred given the weakness in natural gas prices. The Company is expected to proceed with the completion and tie-in of these wells in the third or fourth quarter. At Kobes, the Company is planning to drill one well late in the year to continue our entire 23 net section land block for an additional ten years.

2012 GUIDANCE

Crew is maintaining its guidance to average production of 28,000 to 29,000 boe per day for 2012. Priority has been given to debt reduction, oil investments and retention of the Company's liquids rich natural gas resource assets. By managing capital expenditures and certain monetization programs, Crew expects to exit the year with approximately $350 to $360 million of net debt while maintaining net capital spending at approximately $225 million. This program is expected to increase average annual production by approximately 6,000 boe per day (25%) year over year and position Crew to continue its growth through 2013 and beyond. With improving natural gas prices, the Company's 3,500 boe per day of shut-in and deferred production is expected to be placed on production assisting in achieving this goal in 2013. Crew has been actively hedging oil and gas production volumes for 2013 which has historically been used to underpin funds from operations in order to maintain a base capital program.

OUTLOOK

Since the Company was founded in 2003, Crew's strategy has been to explore for and develop large oil and gas in place reservoirs where technology can be applied to improve recoveries with a goal to grow the Company's production, funds from operations and reserves on a per share basis. Crew's staff has successfully managed through many commodity cycles and is well prepared and confident in our ability to continue to do the same in the current environment. Capital preservation and balance sheet strength become paramount in a low or volatile commodity price cycle and the $25.8 million of debt reduction in the second quarter is a testament to our resolve to accomplish these goals. As in past commodity price cycles, the current volatile environment has created both challenges and opportunities. Crew will continue to invest in the highest return and most capital efficient projects while retaining the upside for our shareholders on a significant resource of oil, natural gas and natural gas liquids. We look forward to reporting our progress on the 2012 business plan in the third quarter report.

On behalf of the Board,

Dale Shwed
President and C.E.O.

August 10, 2012

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the Six Months and Quarter ended June 30, 2012 and 2011

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 and six month periods ended June 30, 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:

	Three months ended		Six months ended	
($ thousands)	**June 30, 2012**	June 30, 2011	**June 30, 2012**	June 30, 2011
Cash provided by operating activities	**49,557**	32,896	**115,783**	59,365
Decommissioning obligation expenditures	**371**	132	**550**	121
Transportation liability charge	–	103	–	204
Acquisition costs [1]	–	2,150	–	2,150
Change in non-cash working capital	**2,099**	(6,390)	**(16,249)**	(8,838)
Funds from operations	**52,027**	28,891	**100,084**	53,002

(1) This amount relates to costs incurred for the Caltex acquisition that closed on July 1, 2011.

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 balance sheet in order to fund the future growth of the Company. Crew monitors working capital and net debt as part of its capital structure. Working capital and net debt do not have a standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. The following tables outline Crew's calculation of working capital and net debt:

($ thousands)	**June 30, 2012**	December 31, 2011
Current assets	**78,689**	79,117
Current liabilities	**(78,833)**	(192,744)
Fair value of financial instruments	**(11,950)**	21,175
Working capital deficit	**(12,094)**	(92,452)

($ thousands)	**June 30, 2012**	December 31, 2011
Bank loan	**(360,710)**	(230,676)
Working capital deficit	**(12,094)**	(92,452)
Net debt	**(372,804)**	(323,128)

RESULTS OF OPERATIONS

Production

	Three months ended June 30, 2012					Three months ended June 30, 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	**5,726**	**9**	**1,345**	**39,391**	**13,645**	5,348	–	434	21,772	9,411
British Columbia	**214**	**–**	**1,464**	**39,841**	**8,318**	110	–	935	35,926	7,032
Saskatchewan	**–**	**6,031**	**–**	**1,187**	**6,229**	–	–	–	–	–
Total	**5,940**	**6,040**	**2,809**	**80,419**	**28,192**	5,458	–	1,369	57,698	16,443

In the second quarter of 2012, production increased 71% compared to the same period in 2011 as a result of production additions from the successful drilling program in late 2011 and the first quarter of 2012 in the Princess, Alberta and Septimus and Kobes, British Columbia areas combined with the acquisition of Caltex Energy Inc. ("Caltex") effective July 1, 2011. These production increases were partially offset by approximately 1,200 boe per day of uneconomic natural gas being shut-in during the quarter.

	Six months ended June 30, 2012					Six months ended June 30, 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	**6,000**	**8**	**1,628**	**43,114**	**14,822**	5,511	–	398	22,120	9,595
British Columbia	**355**	**–**	**1,329**	**39,223**	**8,221**	114	–	852	32,799	6,433
Saskatchewan	**–**	**6,093**	**–**	**900**	**6,243**	–	–	–	–	–
Total	**6,355**	**6,101**	**2,957**	**83,237**	**29,286**	5,625	–	1,250	54,919	16,028

Production for the first six months of 2012 increased due to the previously mentioned successful drilling programs in the Princess, Septimus and Kobes areas combined with the acquisition of Caltex.

Revenue

	Three months ended		Six months ended	
	June 30, 2012	June 30, 2011	**June 30, 2012**	June 30, 2011
Revenue *($ thousands)*				
Conventional oil	**38,063**	40,975	**88,027**	77,306
Heavy oil	**32,402**	–	**72,237**	–
Natural gas liquids	**14,386**	7,944	**29,375**	14,010
Natural gas	**15,095**	21,317	**33,382**	40,068
Total	**99,946**	70,236	**223,021**	131,384
Crew average prices				
Conventional oil ($/bbl)	**70.41**	82.50	**76.11**	75.93
Heavy oil ($/bbl)	**58.95**	–	**65.05**	–
Natural gas liquids ($/bbl)	**56.27**	63.74	**54.58**	61.93
Natural gas ($/mcf)	**2.06**	4.06	**2.20**	4.03
Oil equivalent ($/boe)	**38.96**	46.94	**41.84**	45.29
Benchmark pricing				
Conv. and heavy oil – WCS (Cdn $/bbl)	**71.29**	82.09	**76.44**	76.31
Oil and ngl – Cdn$ WTI (Cdn $/bbl)	**94.32**	99.20	**98.68**	95.97
Natural Gas – AECO C daily index (Cdn $/mcf)	**1.93**	3.94	**2.06**	3.88

Crew's second quarter 2012 revenue increased 42% over the second quarter of 2011 as a result of the production additions from the Company's successful drilling program and the Caltex acquisition. This was partially offset by a decrease in oil, natural gas liquids ("ngl") and natural gas pricing. Crew's conventional oil price decreased 15% which was in line with the Western Canadian Select ("WCS") benchmark price decrease. The Company's ngl price decreased 12% as compared with a 5% decrease in the Cdn$ West Texas Intermediate ("WTI") benchmark price due to increased production of lower valued ethane and a decrease in the price of ethane and propane which is not factored into the Company's benchmark comparison. During the second quarter, the Company's natural gas price decreased 49% over the same period in 2011 which was comparable with the decrease in the AECO benchmark price decrease.

For the first six months of 2012, the Company's realized conventional oil price slightly increased over the same period in 2011 which was comparable with the WCS benchmark increase. The Company's ngl price decreased 12% over the same period in 2011 compared to an increase in the Cdn$ WTI benchmark due to the previously mentioned additional ethane volumes and a decrease in the price of ethane and propane which is not factored into the Company's benchmark pricing. For the first six months of 2012, the Company's natural gas price decreased 45% which was comparable with a 47% decrease in the AECO benchmark price.

Royalties

	Three months ended		Six months ended	
($ thousands, except per boe)	**June 30, 2012**	June 30, 2011	**June 30, 2012**	June 30, 2011
Royalties	**22,729**	16,574	**53,554**	30,930
Per boe	**8.86**	11.08	**10.05**	10.66
Percentage of revenue	**22.7%**	23.6%	**24.0%**	23.5%

Royalties increased for the three and six month periods ended June 30, 2012 compared to the same periods in 2011 as a result of the increased production and revenues added by the Company's drilling program and the acquisition of Caltex. Royalties as a percentage of revenue decreased in the second quarter of 2012 as the Company received prior period gas cost allowance credits from its properties in Wapiti and Edson, Alberta. For the first six months of 2012, the Company's corporate royalty rate increased over the same period in 2011 due to increased heavy oil revenue from the Caltex acquisition which attracts a higher effective royalty rate as compared to the corporate average royalty rate. Crew forecasts royalty rates to average approximately 24% for 2012.

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 income and comprehensive income:

	Three months ended		Six months ended	
($ thousands)	**June 30, 2012**	June 30, 2011	**June 30, 2012**	June 30, 2011
Realized gain/(loss) on financial instruments	**15,239**	(1,001)	**16,621**	15
Unrealized gain/(loss) on financial instruments	**29,140**	15,770	**26,403**	(263)

During the second quarter, the Company monetized the value inherent in derivative contracts that the Company held on certain 2013 WTI oil swaps. The Company realized a gain of $12.1 million on these transactions.

As at June 30, 2012, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Remaining Term	Reference	Average Strike Price	Contract Traded	Fair Value ($000s)
Oil	3,500 bbl/day	July 1, 2012 –December 31, 2012	CDN$ WTI	$100.36	Swap	8,250
Oil	3,000 bbl/day	July 1, 2012 – December 31, 2012	CDN$ WTI	$86.67 – 96.24	Collar	1,462
Oil	2,000 bbl/day	July 1, 2012 – December 31, 2012	CDN$ WCS – WTI diff	($15.625)	Swap	4,558
Oil	2,000 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$90.00	Swap	(480)
Oil	750 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$92.60	Call	(2,171)
Oil	1,000 bbl/day	January 1, 2013 – December 31, 2013	US$ WTI	$89.84	Call	(3,568)
Oil	1,000 bbl/day	January 1, 2013 – December 31, 2013	US$ WTI	$107.23	Swaption(1)	(489)
Natural Gas	25,000 gj/day	July 1, 2012 –December 31, 2012	AECO C monthly Index	$1.87	Swap	(2,409)
Natural Gas	10,000 gj/day	January 1, 2013 –December 31, 2013	AECO C Monthly Index	$3.04	Swap	(107)
Natural Gas	5,000 gj/day	January 1, 2013 –December 31, 2013	AECO C Monthly Index	$2.65 – 3.50	Collar	(72)
US$ / CAD$ exchange	Sell US $2.0 mm per month	July 1, 2012 – December 31, 2012	CDN$/US$	1.05	Swap	354
US$ / CAD$ exchange	Buy US $1.0 mm per month	July 1, 2012 – December 31, 2012	CDN$/US$	1.04	Swap	(100)
Total						**5,228**

(1) 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$107.23.

Subsequent to June 30, 2012, the Company entered into the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Average Strike Price	Contract Traded
Oil	1,500 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$92.60	Swap
Natural Gas	7,500 gj/day	January 1, 2013 – December 31, 2013	AECO C Monthly Index	$3.10	Swap

Operating Costs

	Three months ended		Six months ended	
($ thousands, except per boe)	**June 30, 2012**	June 30, 2011	**June 30, 2012**	June 30, 2011
Operating costs	**29,044**	17,033	**62,622**	33,451
Per boe	**11.32**	11.38	**11.75**	11.53

For the first six months of 2012, operating costs and operating costs per boe have increased as compared with the same periods in 2011 due to the addition of higher cost heavy oil production from the acquisition of Caltex. In the second quarter of 2012, despite the additional higher cost heavy oil production, the Company's corporate operating costs per unit decreased over the same period in 2011. This was due to lower costs in the Princess area as the Company significantly reduced its fluid handling costs with additional water handling and water injection capabilities. In addition, the electrification of wells has significantly reduced rental and fuel costs in the Princess area. The Company continues to forecast operating costs to average between $11.50 and $12.00 for 2012.

Transportation Costs

	Three months ended		Six months ended	
($ thousands, except per boe)	**June 30, 2012**	June 30, 2011	**June 30, 2012**	June 30, 2011
Transportation costs	**3,569**	2,671	**7,357**	5,667
Per boe	**1.39**	1.78	**1.38**	1.95

In the second quarter and first six months of 2012, the Company's transportation costs per boe decreased compared to the same periods in 2011 due to a new Princess oil sales pipeline becoming operational in the first quarter of 2012 combined with the addition of lower transportation cost per unit production from the Caltex acquisition. The Company continues to forecast transportation costs per unit to range between $1.30 and $1.55 per boe for 2012.

Operating Netbacks

	Three months ended		Six months ended	
($/boe)	**June 30, 2012**	June 30, 2011	**June 30, 2012**	June 30, 2011
Revenue	**38.96**	46.94	**41.84**	45.29
Realized commodity hedging gain/(loss)	**5.94**	(0.67)	**3.12**	–
Royalties	**(8.86)**	(11.08)	**(10.05)**	(10.66)
Operating costs	**(11.32)**	(11.38)	**(11.75)**	(11.53)
Transportation costs	**(1.39)**	(1.78)	**(1.38)**	(1.95)
Operating netbacks	**23.33**	22.03	**21.78**	21.15

General and Administrative Costs

	Three months ended		Six months ended	
($ thousands, except per boe)	**June 30, 2012**	June 30, 2011	**June 30, 2012**	June 30, 2011
Gross costs	**7,576**	4,398	**15,856**	8,595
Operator's recoveries	**(633)**	(107)	**(941)**	(220)
Capitalized costs	**(2,635)**	(1,456)	**(5,336)**	(2,752)
General and administrative expenses	**4,308**	2,835	**9,579**	5,623
Per boe	**1.68**	1.89	**1.80**	1.94

In the second quarter and first six months of 2012, increased general and administrative costs after recoveries and capitalization were the result of increased staff levels and office space to manage the additional core areas and production acquired in the Caltex acquisition. General and administrative costs per boe decreased in the second quarter and first six months of 2012 as compared to the same periods in 2011 as increased production more than offset the increase in net costs. The Company expects general and administrative expenses to average between $1.60 and $1.80 per boe for 2012.

Finance Expenses

	Three months ended		Six months ended	
($ thousands, except per boe)	**June 30, 2012**	June 30, 2011	**June 30, 2012**	June 30, 2011
Interest on bank debt	**3,508**	1,231	**6,446**	2,726
Accretion of the decommissioning obligation	**678**	529	**1,310**	1,006
Acquisition costs	**–**	2,150	**–**	2,150
Total finance expense	**4,186**	3,910	**7,756**	5,882
Average debt level	**348,816**	83,501	**308,236**	99,662
Effective interest rate on bank debt	**4.0%**	5.9%	**4.2%**	5.5%
Interest on bank debt per boe	**1.37**	0.82	**1.21**	0.94

In the second quarter of 2012 and first six months of 2012, higher average debt levels from the acquisition of Caltex and increased capital spending over the past twelve months have increased the Company's interest expense. The effective interest rate on the Company's interest decreased due to a lower prime rate combined with lower stamping fees and decreased standby fees on the Company's bank facility. Accretion of the decommissioning obligation increased in the second quarter and first six months of 2012 over the same periods in 2011 due to additional accretion on the Caltex decommissioning obligation which was acquired on July 1, 2011. With the decrease in the standby fees, the Company expects its effective interest rate on bank debt will average 4.0% to 4.5% in 2012.

Share-Based Compensation

	Three months ended		Six months ended	
($ thousands)	**June 30, 2012**	June 30, 2011	**June 30, 2012**	June 30, 2011
Gross costs	**4,638**	3,169	**9,545**	4,712
Capitalized costs	**(2,356)**	(1,459)	**(4,829)**	(2,168)
Total share-based compensation	**2,282**	1,710	**4,716**	2,544

In the second quarter and first six months of 2012, the Company's stock-based compensation expense has increased compared with the same periods in 2011 due to an increase in the number of stock options outstanding with a higher weighted average expense per award. The increase in stock options outstanding was due to the additional staff added in conjunction with the Caltex acquisition.

Depletion and Depreciation

	Three months ended		Six months ended	
($ thousands, except per boe)	**June 30, 2012**	June 30, 2011	**June 30, 2012**	June 30, 2011
Depletion and depreciation	**48,624**	23,129	**99,139**	44,094
Per boe	**18.95**	15.46	**18.60**	15.20

Total depletion and depreciation costs per boe have increased in the second quarter and first six months of 2012 compared to the same periods 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 second quarter and first six months of 2012, the provision for deferred income taxes was $9.0 million and $7.2 million, respectively, compared to $5.6 million and $1.5 million for the same periods in 2011 due to higher pre-tax earnings in 2012.

Cash and Funds from Operations and Net Income

	Three months ended		Six months ended	
($ thousands, except per share amounts)	**June 30, 2012**	June 30, 2011	**June 30, 2012**	June 30, 2011
Cash provided by operating activities	**49,557**	32,896	**115,783**	59,365
Funds from operations	**52,027**	28,891	**100,084**	53,002
Per share – basic	**0.43**	0.34	**0.83**	0.63
– diluted	**0.43**	0.33	**0.83**	0.62
Net Income	**24,107**	16,261	**17,677**	6,135
Per share – basic	**0.20**	0.19	**0.15**	0.07
– diluted	**0.20**	0.19	**0.15**	0.07

The second quarter and first six months of 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 combined with increased realized hedging gains from the Company's successful hedging program partially offset by decreased commodity pricing. The second quarter and first six months of 2012 increase in net income was the result of an increase in the unrealized gain on the Company's risk management program.

Capital Expenditures, Acquisitions and Dispositions

During the second quarter of 2012, the Company drilled a total of three (1.6 net) wells resulting in two (1.3 net) oil wells and one (0.3 net) natural gas well. In addition during the quarter, the Company completed 12 (11.3 net) wells and recompleted 20 (19.1 net) wells within the Princess, Lloydminster and Tower, British Columbia oil focused areas. The Company continued to add to its infrastructure spending $11.7 million on pipelines and upgrading its batteries and facilities predominantly in the Princess and Septimus areas. The Company also closed minor dispositions of non-core undeveloped lands in central Alberta for $4.3 million. Total net capital expenditures are detailed below:

	Three months ended		Six months ended	
($ thousands)	**June 30, 2012**	June 30, 2011	**June 30, 2012**	June 30, 2011
Land	**1,270**	2,005	**3,701**	2,416
Seismic	**992**	832	**3,976**	8,176
Drilling, completions and recompletions	**13,757**	36,488	**103,603**	86,516
Facilities, equipment and pipelines	**11,691**	12,116	**41,735**	28,128
Other	**2,722**	1,744	**6,160**	3,114
Total exploration and development	**30,432**	53,185	**159,175**	128,350
Property acquisitions (dispositions)	**(4,290)**	(12,650)	**(4,290)**	(12,289)
Total	**26,142**	40,535	**154,885**	116,061

LIQUIDITY AND CAPITAL RESOURCES

Capital Funding

The Company has a credit facility with a syndicate of lending banks (the "Syndicate"). The credit facility includes a revolving line of credit of $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 June 30, 2012, the Company had drawings of $360.7 million on the Facility and had issued letters of credit totaling $10.0 million.

During the first six months of 2012, the Company received proceeds of $5.7 million upon the exercise of 837,200 employee stock options.

On May 7, 2012, the Company filed notice with the Toronto Stock Exchange ("TSX") to make a normal course issuer bid to purchase and cancel up to a maximum of 6,038,492 of the outstanding Common Shares of the Company. The bid commenced on May 14, 2012 and will terminate on May 13, 2013. Purchases will be made on the open market through the facilities of the TSX in accordance with its policies and the price which the Company will pay for any Common Shares purchased will be the prevailing market price of the common shares on the TSX at the time of such purchase. As of June 30, 2012, no share re-purchases have been made.

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 June 30, 2012, the Company's working capital deficiency totaled $12.1 million which, when combined with the drawings on its bank line, represented 87% of its bank facility at June 30, 2012.

Share Capital

As at August 10, 2012, Crew had 120,829,844 Common Shares and options to acquire 9,527,750 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 June 30, 2012, the Company's ratio of net debt to annualized funds from operations was 1.79 to 1 (December 31, 2011 – 1.25 to 1). 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)	**June 30, 2012**	December 31, 2011
Working capital deficit	**(12,094)**	(92,452)
Bank loan	**(360,710)**	(230,676)
Net debt	**(372,804)**	(323,128)
Funds from operations	**52,027**	64,841
Annualized	**208,108**	259,364
Net debt to annualized funds from operations ratio	**1.79**	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)	360,710	–	–	360,710	–	–	–
Operating leases	10,916	1,203	2,231	2,363	2,494	2,625	–
Firm transportation agreements	25,358	1,739	3,364	3,980	4,021	3,636	8,618
Firm processing agreement	70,851	4,503	8,031	8,926	8,961	8,783	31,647
Total	467,835	7,445	13,626	375,979	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

Crew is maintaining its guidance to average production of 28,000 to 29,000 boe per day for 2012. Priority has been given to debt reduction, oil investments and retention of the Company's liquids rich natural gas resource assets. By managing capital expenditures and certain monetization programs, Crew expects to exit the year with approximately $350 to $360 million of net debt while maintaining net capital spending at approximately $225 million.

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)	**June 30 2012**	Mar. 31 2012	Dec. 31 2011	Sept. 30 2011	June 30 2011	Mar. 31 2011	Dec. 31 2010	Sept. 30 2010
Total daily production (boe/d)	**28,192**	30,380	30,034	27,510	16,443	15,607	14,654	13,061
Average wellhead price ($/boe)	**38.96**	44.52	51.41	45.33	46.94	43.53	42.00	37.39
Petroleum and natural gas sales	**99,946**	123,075	142,063	114,719	70,236	61,148	56,620	44,924
Cash provided by operations	**49,557**	66,226	39,969	54,095	32,896	26,469	20,225	18,956
Funds from operations	**52,027**	48,057	64,841	54,260	28,891	24,111	27,449	23,464
Per share – basic	**0.43**	0.40	0.54	0.45	0.34	0.29	0.34	0.29
– diluted	**0.43**	0.40	0.54	0.45	0.33	0.29	0.34	0.29
Net income (loss)	**24,107**	(6,430)	(148,529)	12,232	16,261	(10,126)	(14,214)	(17,281)
Per share – basic	**0.20**	(0.05)	(1.24)	0.10	0.19	(0.12)	(0.18)	(0.22)
– diluted	**0.20**	(0.05)	(1.24)	0.10	0.19	(0.12)	(0.18)	(0.22)

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 2011 and 2012 and poor weather experienced in southern Alberta during the second quarter of 2011. The Company also shut–in approximately 1,200 boe of uneconomic natural gas production in the second quarter of 2012.
- 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. The Company also monetized certain 2012 WTI to WCS differential hedges in the first quarter of 2012 and certain 2013 WTI hedges in the second quarter of 2012 resulting in realized gains of $3.7 million and $12.1 million, respectively.
- The Company acquired Caltex Energy on July 1, 2011 adding approximately 10,500 boe per day of production.
- During 2011 and 2012, the Company sold non–core assets for proceeds of approximately $30 million. These dispositions in the Gilby, Provost and Kakwa, Alberta areas resulted in gains on sale of assets of $4.7 million, $7.4 million and $3.5 million in the second and fourth quarters of 2011 and the second quarter of 2012, respectively.
- 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, supersedes 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 April 1, 2012 and ended on June 30, 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 August 10, 2012

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited) (thousands)	**June 30, 2012**	December 31, 2011
ASSETS		
Current Assets:		
Accounts receivable	**$ 66,739**	$ 79,117
Fair value of financial instruments (note 8)	**11,950**	–
	78,689	79,117
Exploration and evaluation assets (note 3)	**57,285**	56,197
Property, plant and equipment (note 4)	**1,771,681**	1,707,405
	$ 1,907,655	$ 1,842,719
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 78,833**	$ 171,569
Fair value of financial instruments (note 8)	**–**	21,175
	78,833	192,744
Fair value of financial instruments (note 8)	**6,722**	–
Bank loan (note 5)	**360,710**	230,676
Decommissioning obligations (note 6)	**106,855**	104,836
Deferred tax liability	**191,456**	184,281
Shareholders' Equity		
Share capital (note 7)	**1,269,856**	1,261,884
Contributed surplus (note 7)	**43,337**	36,089
Deficit	**(150,114)**	(167,791)
	1,163,079	1,130,182
Commitments (note 9)		
	$ 1,907,655	$ 1,842,719

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

	Three months ended		Six months ended	
(unaudited) (thousands, except per share amounts)	**June 30, 2012**	June 30, 2011	**June 30, 2012**	June 30, 2011
Revenue				
Petroleum and natural gas sales	**$ 99,946**	$ 70,236	**$ 223,021**	$ 131,384
Royalties	**(22,729)**	(16,574)	**(53,554)**	(30,930)
Realized gain (loss) on financial instruments (note 8)	**15,239**	(1,001)	**16,621**	15
Unrealized gain (loss) on financial instruments (note 8)	**29,140**	15,770	**26,403**	(263)
	121,596	68,431	**212,491**	100,206
Expenses				
Operating	**29,044**	17,033	**62,622**	33,451
Transportation	**3,569**	2,671	**7,357**	5,667
General and administrative	**4,308**	2,835	**9,579**	5,623
Share-based compensation	**2,282**	1,710	**4,716**	2,544
Depletion and depreciation	**48,624**	23,129	**99,139**	44,094
	87,827	47,378	**183,413**	91,379
Income from operations	**33,769**	21,053	**29,078**	8,827
Financing	**(4,186)**	(3,910)	**(7,756)**	(5,882)
Gain on divestitures	**3,530**	4,697	**3,530**	4,697
Income before income taxes	**33,113**	21,840	**24,852**	7,642
Deferred tax expense	**9,006**	5,579	**7,175**	1,507
Net income and comprehensive income	**$ 24,107**	$ 16,261	**$ 17,677**	$ 6,135
Net income per share (note 7)				
Basic	**$ 0.20**	$ 0.19	**$ 0.15**	$ 0.07
Diluted	**$ 0.20**	$ 0.19	**$ 0.15**	$ 0.07

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(unaudited) (thousands)	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 2012	119,993	$ 1,261,884	$ 36,089	$ (167,791)	$ 1,130,182
Net income for the period	–	–	–	17,677	17,677
Share-based compensation expensed	–	–	4,716	–	4,716
Share-based compensation capitalized	–	–	4,829	–	4,829
Transfer of share-based compensation on exercises	–	2,297	(2,297)	–	–
Issued on exercise of options	837	5,675	–	–	5,675
Balance June 30, 2012	**120,830**	**$1,269,856**	**$ 43,337**	**$ (150,114)**	**$ 1,163,079**

	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 income for the period	–	–	–	6,135	6,135
Issue of shares	4,820	96,092	–	–	96,092
Share-based compensation expensed	–	–	2,544	–	2,544
Share-based compensation capitalized	–	–	2,168	–	2,168
Transfer of share-based compensation on exercises	–	3,024	(3,024)	–	–
Issued on exercise of options	799	7,402	–	–	7,402
Balance June 30, 2011	85,987	$ 756,286	$ 29,199	$ (31,494)	$ 753,991

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended		Six months ended	
(unaudited) (thousands)	**June 30, 2012**	June 30, 2011	**June 30, 2012**	June 30, 2011
Cash provided by (used in):				
Operating activities:				
Net income	**$ 24,107**	$ 16,261	**$ 17,677**	$ 6,135
Adjustments:				
Depletion and depreciation	**48,624**	23,129	**99,139**	44,094
Financing expenses	**4,186**	3,910	**7,756**	5,882
Interest expense	**(3,508)**	(1,231)	**(6,446)**	(2,726)
Acquisition costs	**–**	(2,150)	**–**	(2,150)
Share-based compensation	**2,282**	1,710	**4,716**	2,544
Deferred tax expense	**9,006**	5,579	**7,175**	1,507
Unrealized (gain) loss on financial instruments	**(29,140)**	(15,770)	**(26,403)**	263
Gain on divestitures	**(3,530)**	(4,697)	**(3,530)**	(4,697)
Transportation liability charge	**–**	(103)	**–**	(204)
Decommissioning obligations settled	**(371)**	(132)	**(550)**	(121)
Change in non-cash working capital	**(2,099)**	6,390	**16,249**	8,838
	49,557	32,896	**115,783**	59,365
Financing activities:				
Increase (decrease) in bank loan	**40,557**	14,129	**130,034**	(36,109)
Issue of common shares	**–**	–	**–**	100,015
Proceeds from exercise of share options	**259**	222	**5,675**	7,402
Share issue costs	**–**	(26)	**–**	(5,244)
	40,816	14,325	**135,709**	66,064
Investing activities:				
Exploration and evaluation asset expenditures	**–**	(1,606)	**(2,477)**	(8,819)
Property, plant and equipment expenditures	**(30,432)**	(51,579)	**(156,698)**	(119,531)
Property divestitures	**4,290**	12,650	**4,290**	12,289
Proceeds on sale of asset held for sale	**–**	–	**–**	15,116
Change in non-cash working capital	**(64,231)**	(6,686)	**(96,607)**	(24,484)
	(90,373)	(47,221)	**(251,492)**	(125,429)
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 and six months ended June 30, 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 June 30, 2012 and for the three and six months ended June 30, 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 August 10, 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, June 30, 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	156,698
Transfer from exploration and evaluation assets	1,389
Divestitures	(760)
Change in decommissioning obligations	1,259
Capitalized share-based compensation	4,829
Balance, June 30, 2012	**$ 2,312,129**

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	99,139
Balance, June 30, 2012	**$ 540,448**

Net book value	Total
Balance, December 31, 2011	$ 1,707,405
Balance, June 30, 2012	**$ 1,771,681**

The calculation of depletion for the period ended June 30, 2012 included estimated future development costs of $648.1 million (December 31, 2011 - $681.4 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $89.7 million (December 31, 2011 - $87.0 million) and undeveloped land of $150.3 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 June 30, 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 June 30, 2012, the Company had issued letters of credit totaling $10.0 million (December 31, 2011 - $10.2 million). The effective interest rate on the Company's borrowings under its bank facility for the period ended June 30, 2012 was 4.0% (2011 – 5.9%).

6. DECOMMISSIONING OBLIGATIONS:

	Six months ended June 30, 2012	Year ended December 31, 2011
Decommissioning obligations, beginning of period	**$ 104,836**	$ 54,828
Obligations incurred	**4,631**	7,781
Obligations settled	**(550)**	(1,144)
Obligations divested	**–**	(2,498)
Obligations acquired	**–**	30,887
Change in estimated future cash outflows	**(3,372)**	12,582
Accretion of decommissioning liabilities	**1,310**	2,400
Decommissioning obligations, end of period	**$ 106,855**	$ 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 $106.9 million as at June 30, 2012 (December 31, 2011 - $104.8 million) based on an undiscounted total future liability of $114.3 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 June 30, 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.

The Company has received approval for the commencement of a Normal Course Issuer Bid from the Toronto Stock Exchange ("TSX"). Under the bid, the Company may purchase for cancellation up to 6,038,492 of its Common Shares, representing approximately 5% of the public float of issued and outstanding shares. Purchases under the bid can be made between May 14, 2012 and May 13, 2013. Purchases will be made on the open market through the facilities of the TSX in accordance with its policies and the price which the Company will pay for any common shares purchased will be the prevailing market price of the common shares on the TSX at the time of such purchase. As of June 30, 2012, no share re-purchases have been made.

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	2,996	$ 6.69
Exercised	(837)	$ 6.78
Forfeited	(125)	$ 14.05
Expired	(151)	$ 15.69
Balance at June 30, 2012	**10,107**	**$ 11.53**
Exercisable at June 30, 2012	**2,679**	**$ 12.52**

The following table summarizes information about the stock options outstanding at June 30, 2012:

Range of exercise prices	Outstanding at June 30, 2012	Weighted average remaining life (years)	Weighted average exercise price	Exercisable at June 30, 2012	Weighted average exercise price
$5.16 to $7.01	3,317	3.1	$ 5.56	792	$ 5.30
$7.02 to $9.94	35	1.7	$ 9.22	15	$ 9.16
$9.95 to $14.63	2,119	3.2	$ 11.36	130	$ 12.56
$14.64 to $18.47	4,636	2.3	$ 15.90	1,742	$ 15.83
	10,107	2.8	$ 11.53	2,679	$ 12.52

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

	Three months ended		Six months ended	
Assumptions	**June 30, 2012**	June 30, 2011	**June 30, 2012**	June 30, 2011
Risk free interest rate (%)	**1.4**	2.5	**1.4**	2.4
Expected life (years)	**4.0**	4.0	**4.0**	4.0
Expected volatility (%)	**61**	60	**61**	60
Forfeiture rate (%)	**16.4**	16.1	**16.6**	16.2
Weighted average fair value of options	**$ 2.67**	$ 8.31	**$ 3.15**	$ 8.45

Income per share:

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average shares outstanding for the three month period ended June 30, 2012 was 120,811,000 (2011 – 85,981,000) and for the six month period ended June 30, 2012, the weighted average number of shares outstanding was 120,737,000 (2011 – 84,111,000).

In computing the diluted income per share for the three month period ended June 30, 2012, 148,000 (2011 – 1,249,000) were added to the weighted average common shares outstanding to account for the dilution of stock options and for the six month period ended June 30, 2012, 407,000 (2011 – 1,521,000) shares were added to the weighted average common shares for the dilution. There were 6,793,000 (2011 – 1,783,000) stock options that were not included in the diluted income 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 June 30, 2012 the Company held derivative contracts as follows:

Subject of Contract	Notional Quantity	Remaining Term	Reference	Average Strike Price	Contract Traded	Fair Value ($000s)
Oil	3,500 bbl/day	July 1, 2012 – December 31, 2012	CDN$ WTI	$100.36	Swap	8,250
Oil	3,000 bbl/day	July 1, 2012 – December 31, 2012	CDN$ WTI	$86.67 – 96.24	Collar	1,462
Oil	2,000 bbl/day	July 1, 2012 – December 31, 2012	CDN$ WCS – WTI diff	($15.63)	Swap	4,558
Oil	2,000 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$90.00	Swap	(480)
Oil	750 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$92.60	Call	(2,171)
Oil	1,000 bbl/day	January 1, 2013 – December 31, 2013	US$ WTI	$89.84	Call	(3,568)
Oil	1,000 bbl/day	January 1, 2013 – December 31, 2013	US$ WTI	$107.23	Swaption[(1)]	(489)
Natural Gas	25,000 gj/day	July 1, 2012 – December 31, 2012	AECO C monthly Index	$1.87	Swap	(2,409)
Natural Gas	10,000 gj/day	January 1, 2013 – December 31, 2013	AECO C Monthly Index	$3.04	Swap	(107)
Natural Gas	5,000 gj/day	January 1, 2013 – December 31, 2013	AECO C Monthly Index	$2.65 – 3.50	Collar	(72)
US$ / CAD$ exchange	Sell US $2.0 mm per month	July 1, 2012 – December 31, 2012	CDN$/US$	1.05	Swap	354
US$ / CAD$ exchange	Buy US $1.0 mm per month	July 1, 2012 – December 31, 2012	CDN$/US$	1.04	Swap	(100)
Total						5,228

(1) 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$107.23.

As at June 30, 2012, a 10% decrease in the price outlined in the contracts above would result in a $12.8 million increase in income.

During the second quarter, the Company monetized the value inherent in derivative contracts that the Company held on certain 2013 WTI oil swaps. The Company realized a gain of $12.1 million on these transactions.

Subsequent to June 30, 2012, the Company entered into the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Average Strike Price	Contract Traded
Oil	1,500 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$92.60	Swap
Natural Gas	7,500 gj/day	January 1, 2013 – December 31, 2013	AECO C Monthly Index	$3.10	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 June 30, 2012 the Company's ratio of net debt to annualized cash flow was 1.79 to 1, (December 31, 2011 – 1.25 to 1). 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.

	June 30, 2012	December 31, 2011
Net debt:		
Accounts receivable	**$ 66,739**	$ 79,117
Accounts payable and accrued liabilities	**(78,833)**	(171,569)
Working capital deficiency	**$ (12,094)**	$ (92,452)
Bank loan	**(360,710)**	(230,676)
Net debt	**$ (372,804)**	$ (323,128)
Annualized funds from operations:		
Cash provided by operating activities	**$ 49,557**	$ 39,969
Decommissioning obligations settled	**371**	483
Transportation liability charge	**–**	35
Change in non-cash working capital	**2,099**	24,354
Funds from operations	**52,027**	64,841
Annualized	**$ 208,108**	$ 259,364
Net debt to annualized funds from operations	**1.79**	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	10,916	1,203	2,231	2,363	2,494	2,625	–
Firm transportation agreements	25,358	1,739	3,364	3,980	4,021	3,636	8,618
Firm processing agreement	70,851	4,503	8,031	8,926	8,961	8,783	31,647
Total	107,125	7,445	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

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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
Independent Director

Dennis L. Nerland
Independent Director

Dale O. Shwed
President, Crew Energy Inc.

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Independent Director

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

ABBREVIATIONS

bbl	barrels
bbl/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent(6 mcf: 1 bbl)
bopd	barrels of oil per day
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

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