TSX: CR

crew energy inc.

Crew Energy Inc. of Calgary, Alberta is pleased to present its financial and operating results for the three and nine month periods ended September 30, 2010.

2010 Q3

HIGHLIGHTS

- Third quarter funds from operations of $24.1 million was 23% higher than the third quarter of 2009;
- Production of 13,061 boe per day was 8.4% higher than the second quarter of 2010;
- During the quarter, Crew had three vertical exploration oil discoveries at Princess that tested at rates of 1,330, 1,170 and 345 bbls of oil per day which has led to an expanded resource and drilling inventory significantly expanding the play;
- Operating costs per boe have decreased 12% over the third quarter of 2009;
- Crew finalized a restructured agreement with Aux Sable Canada ("ASC") that will result in ASC funding the expansion of the Septimus gas plant scheduled to be completed in late 2010.

FINANCIAL	Three months ended		Nine months ended	
($ thousands, except per share amounts)	**Sept. 30, 2010**	Sept. 30, 2009	**Sept. 30, 2010**	Sept. 30, 2009
Petroleum and natural gas sales	**44,924**	38,510	**149,723**	124,183
Funds from operations (1)	**24,104**	19,640	**73,014**	56,197
Per share – basic	**0.30**	0.25	**0.92**	0.76
– diluted	**0.29**	0.25	**0.90**	0.76
Net income (loss)	**(7,387)**	(7,376)	**(7,636)**	(28,661)
Per share – basic	**(0.09)**	(0.09)	**(0.10)**	(0.39)
– diluted	**(0.09)**	(0.09)	**(0.10)**	(0.39)
Exploration and development investment	**65,138**	35,390	**187,522**	73,255
Property acquisitions (net of dispositions)	**–**	–	**(132,640)**	(34,378)
Net capital expenditures	**65,138**	35,390	**54,882**	38,877
CAPITAL STRUCTURE *($ thousands)*			**As at Sept. 30, 2010**	As at Dec. 31, 2009
Working capital deficiency (2)			**36,132**	46,654
Bank loan			**110,770**	135,601
Net debt			**146,902**	182,255
Bank facility			**210,000**	250,000
Common Shares Outstanding *(thousands)*			**80,206**	78,152

(1) Funds from operations is calculated as cash provided by operating activities, adding the change in non-cash working capital, asset retirement 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 Canadian Generally Accepted Accounting Principles 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		Nine months ended	
	Sept. 30, 2010	Sept. 30, 2009	**Sept. 30, 2010**	Sept. 30, 2009
Daily production				
Natural gas (mcf/d)	**48,188**	49,478	**49,863**	54,314
Oil (bbl/d)	**3,803**	3,376	**3,788**	3,447
Natural gas liquids (bbl/d)	**1,227**	1,443	**1,265**	1,345
Oil equivalent (boe/d @ 6:1)	**13,061**	13,065	**13,364**	13,844
Average prices (1)				
Natural gas ($/mcf)	**4.07**	3.23	**4.63**	4.04
Oil ($/bbl)	**62.86**	63.91	**67.16**	55.61
Natural gas liquids ($/bbl)	**43.21**	29.94	**50.13**	32.16
Oil equivalent ($/boe)	**37.39**	32.04	**41.04**	32.86
Netback ($/boe)				
Operating netback (2)	**21.87**	17.77	**22.32**	16.67
Realized gain on financial instruments (3)	**(0.24)**	(1.20)	**(0.15)**	(0.52)
G&A	**1.05**	1.10	**1.25**	1.13
Interest and other	**0.99**	1.54	**1.20**	1.19
Funds from operations	**20.07**	16.33	**20.02**	14.87
Drilling Activity				
Gross wells	**26**	12	**59**	20
Working interest wells	**24.9**	12.0	**55.4**	14.8
Success rate, net wells	**100%**	100%	**100%**	99%

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

(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 Canadian Generally Accepted Accounting Principles and therefore may not be comparable with the calculations of similar measures for other companies.

(3) Amount includes realized gains and losses on non-commodity financial instruments.

OVERVIEW

Operations during the third quarter of 2010 were highlighted by the drilling of a record 26 (24.9 net) horizontal wells with 100% success. At Princess, Alberta, the Company drilled sixteen (16.0 net) oil wells and four (4.0 net) salt water disposal wells. In northeast British Columbia, three (3.0 net) liquids rich natural gas wells were drilled at Septimus, and two (1.5 net) exploration wells were drilled at the Company's Portage and Goose properties. In addition, a third party drilled one (0.4 net) horizontal farmout well at Pine Creek, Alberta, targeting the Spirit River formation.

Production in the third quarter was 13,061 boe per day, up 8.4% from the second quarter. Wet weather in the Princess area continued to hamper all operations, particularly completion and tie-in of previously drilled wells. By the end of the third quarter, fourteen wells were waiting to be placed on production at Princess and three liquids rich gas wells at Septimus.

Crew continued to add to its land base in the third quarter, purchasing 7.4 net sections of land for $1.65 million. These lands expanded our presence in resource plays at Pine Creek (Cardium) and Boudreau, British Columbia (Montney) and a new exploration area.

FINANCIAL SUMMARY

Cash flow for the third quarter increased 16.5% over the second quarter of 2010 as a result of the 8.4% increase in production and a 12% reduction in costs combined with a $5.1 million third quarter gain on the Company's hedging program. Year to date the Company's hedging program has added $9.7 million of cash flow to help fund the 2010 capital program. For the fourth quarter of 2010, the Company has an average of 17.5 mmcf per day of natural gas hedged at an average fixed price of $6.25 per mcf and 3,400 bbl per day of oil hedged at a minimum floor price of Canadian dollar WTI $81.70 per bbl.

The Company has also established commodity hedges to help secure cash flow for 2011. Crew has entered into Canadian dollar WTI oil price swaps and floors on an average of 3,000 bbl per day for 2011. These transactions averaged a minimum floor price of approximately CDN $85.80 per bbl for WTI oil. The Company has also entered into a number of cross commodity transactions to enhance natural gas prices for 2011. These transactions have included the sale of financial calls against the price on 1,000 bbls per day of 2012 WTI oil at an average call price of US$87.50 per bbl. The proceeds from the sale of these calls were used to financially fix the price on 9.4 mmcf per day of natural gas at an average AECO NIT price of approximately $5.30 per mcf. A detailed list of the Company's hedge positions is included in the attached management's discussion and analysis.

The Company's capital program during the third quarter resulted in total expenditures for the quarter of $65.1 million. These expenditures were financed primarily through a combination of funds flow from operations and an increase in the Company's net debt. Total net debt at the end of the quarter was $147 million. Subsequent to the quarter end, Crew's banking syndicate re-confirmed the Company's banking facility at total borrowing capacity of $210 million.

OPERATIONS UPDATE

Pekisko Play, Princess, Alberta

Crew plans to drill a total of 50 oil wells in 2010 at Princess out of a current inventory of over 700 locations with a targeted 2010 exit rate of 7,000 to 8,000 boe per day. Drilling results have exceeded expectations as the Company expands its activities at Princess.

Crew now has 30 horizontal oil wells on production and an expected 22 additional wells to be placed on production before year end. Confidence in the play continues to build with additional production history and positive recent test rates. Initial production rates for the thirty wells on production averaged 210 boe per day. After six months of production, wells are averaging 150 boe per day and after one year of production, wells are producing on average 145 boe per day. Two wells have two years of production history and are currently producing an average of 110 boe per day which is 95% oil.

Crew's vertical exploration well program has been very successful and continues to expand the size of the prospective lands under Crew's control. Crew tested three vertical exploration wells which, on initial test, produced marginal volumes of oil however, after acid stimulation, these wells exhibited extremely prolific test results. The first exploration test flowed at 1,330 bbls of oil per day and gas at 500 mcf per day after three days. The second exploration test flowed at 345 bbls of oil per day and gas at 350 mcf per day after three days and the third exploration well swabbed oil at 1,170 bbls of oil per day after a three day test. These results are representative of the growing geographic expanse of the Pekisko play and its excellent reservoir quality.

The Pekisko play is in its infancy and Crew continues to learn and experiment with a variety of drilling, completion and production practices in an effort to optimize production and capital efficiency. The Company has fracture stimulated older vertical wells with sand or acid and has seen oil production increased by an average of five times their previous production rates. Crew plans to continue with its optimization and stimulation program in the fourth quarter and into 2011, expanding the scope to include horizontal wells.

Fluid handling and operating pressures are important variables in the operations at Princess. In 2010 and 2011, Crew plans to dedicate capital for a significant infrastructure build out to accommodate several years of future growth. This is expected to reduce operating costs and reduce pipeline pressures enabling wells to produce at higher rates for longer periods of time. An illustration of the effect of flowing pressures is Crew's 8-8 well (one of Crew's first horizontal wells) which exhibited a 65% increase in production from 90 boe per day to 150 boe per day once a new pipeline had been installed reducing area operating pressures.

Montney Play, Septimus, Northeast British Columbia

Crew drilled three (3.0 net) liquids rich gas wells in the Montney formation at Septimus in the third quarter of 2010. These wells are scheduled to be completed in the fourth quarter and are forecasted to add 1,900 boe per day of production. Three wells were brought on production in the third quarter, highlighted by one well which had an average first full month of production rate of 7.7 mmcf per day.

Expansion of the Septimus gas processing facility, which will double its capacity from its current capability of 25 mmcf per day, is proceeding as planned, with expected commissioning in mid December. Aux Sable Canada ("ASC"), the current owner of the facility, completed the installation of a 20 inch pipeline from the Septimus gas facility to the Alliance pipeline in the third quarter. This pipeline is capable of transporting over 350 mmcf per day of gas and associated liquids.

Crew is pleased to announce that it has completed a restructuring of its agreement with ASC whereby Crew will be reimbursed for the expansion cost of the facility expected to be approximately $16.9 million. Crew will continue to operate the expanded facility on ASC's behalf and process the majority of its Septimus production through the facility in exchange for a processing and operating fee. This transaction is expected to close by year end. Crew has also retained an option to acquire a 50% interest in the facility prior to January 1, 2014 at a cost of 50% of the expanded facility construction cost. Reduced operating costs at Septimus are primarily responsible for the 12% reduction in corporate operating costs as compared with the same quarter in 2009. Septimus operating costs are expected to be in the $6.00 per boe range in 2011.

In addition to Crew's activity at Septimus, the Company also drilled two (1.5 net) horizontal Montney exploration wells in the third quarter. At Portage, the Company drilled one (0.5 net) well following up on its gas discovery at the property in the second quarter. Positive results were experienced while drilling and the well will be completed in the fourth quarter. In addition, one (1.0 net) well was drilled at the Company's Goose property, with completion expected in 2011. Two (2.0 net) sections of land were purchased in the third quarter to add to the Company's large 100% W.I. land base in this area.

During the third quarter, Crew also undertook the recompletion of a standing vertical well at Tower. The Lower Montney was fracture stimulated in the well and flowed at a test rate of 125 barrels of 42o API oil per day and 70 mcf per day of natural gas. This is further verification of the oil prone nature of the Company's lands at Tower which was initially identified by a partner operated well drilled in the area in 2009 and completed in the Upper Montney. A number of horizontal wells are planned to be drilled on this property in 2011 targeting Lower and Upper Montney oil.

Cardium Play, West Central Alberta

Crew owns 60 net sections of oil prone Cardium rights in the Edson–Pine Creek, Alberta area. At Pine Creek, Crew has identified 80 net Cardium oil drilling locations. Licensing of three Cardium horizontal wells at Pine Creek is expected prior to year end, with drilling to commence in 2011.

In the third quarter, the first (0.33 net) of two Cardium horizontal farmout wells at Edson was put on production at an initial rate of 272 boe per day (44% oil). The second farmout well (0.5 net) was drilled recently and is currently being completed.

Kobes, British Columbia

This 23 section 100% Crew controlled block is situated in the Kobes/Townsend Montney rich fairway which has been de-risked by offsetting industry activity and Crew's vertical completion in the heart of the Company's land base testing at 2.5 mmcf per day of gas and 125 bbls per day of condensate. This acreage was amassed at an average price of $609 per hectare prior to the recent run up in area prices. The first expiries associated with this property occur in 2013. Crew plans to drill two strategically situated horizontal wells which are expected to continue the land beyond 2013 until 2018.

Portage, British Columbia

This 66 section contiguous block (50% Crew) has been continued for a further five year term as a result of the Montney wells drilled by Crew under the previously announced farm-in agreement. With the lands proven productive by Crew's drilling activity, the earliest land expiries will not occur until 2015.

Horn River/Cordova Embayment, British Columbia

Crew's land base has been offset by industry activity that has yielded production test rates of up to 11 mmcf per day. The Company's land base has been continued indefinitely due to offsetting Devonian production which allows the Company to monitor the infrastructure build out in the area and realize the value of this resource at the appropriate time.

OUTLOOK

Business Environment

In a repeated theme, oil prices have remained relatively strong as the world's economies continue their recovery. Natural gas prices, however, remain weak as North American supplies continue to grow due to the aggressive development of unconventional natural gas plays. As a result of this commodity price imbalance, Crew has been focusing its capital and technical resources towards the pursuit of growth of its oil and liquids production. The Company is in the enviable position to quickly adapt to commodity price cycles in order to focus on oil or liquids rich natural gas directed drilling. This was demonstrated in the third quarter of 2010 with the Company drilling 20 net wells at Princess.

Despite the depressed natural gas price environment the Company's liquids rich Septimus Montney production continues to show good economic returns. However, the continued prospect of low natural gas prices combined with the inflating cost of high pressure fracturing services has resulted in the economics of our oil plays overwhelming the economics of our liquids rich natural gas plays. As such, capital deployment for the fourth quarter of 2010 and 2011 is expected to be largely dedicated toward oil directed drilling.

Active Fourth Quarter

Crew continues to catch up from the wet spring and summer with 22 wells at Princess expected to be placed on production before year end. With current production of approximately 5,500 boe per day and much improved weather conditions at Princess, the Company expects to be producing 7,000 to 8,000 boe per day at year end. In addition to the active drilling, completions and infrastructure program, Crew is now actively engaged in an acid stimulation program that has to date produced very encouraging results with three horizontal well stimulations planned for the fourth quarter. Crew's three exploration discoveries have converted land previously believed to be less prospective to land that is now highly prospective with significant development potential.

Crew's net exploration and development expenditures are forecasted to be approximately $225 million for 2010 with the majority spent at Princess. As a result of the aforementioned persistent weather delays, Crew is forecasting average 2010 production of 13,600 to 14,000 boe per day. Exit production is now forecast to be 17,000 to 18,000 boe per day.

Crew's outlook continues to improve as the Company has significantly de-risked the technical aspects and geographic scope of the Princess oil play. The Company currently plans to dedicate the majority of its capital to this oil play affording our shareholders exposure to, we believe, one of the most economically attractive oil plays in North America. With the ability to switch to either commodity, Crew is in an enviable position that offers our shareholders material upside in oil and natural gas plays with scale and repeatability. We are very excited about our drilling results as the success of the drilling program continues to expand our production, hydrocarbon resource and drilling inventory. We look forward to reporting our fourth quarter and year end results in 2011.

On behalf of the Board,

Dale Shwed
President and C.E.O.

November 8, 2010

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 consolidated financial statements of the Company for the three and nine month periods ended September 30, 2010 and 2009 and the audited consolidated financial statements and Management Discussion and Analysis for the year ended December 31, 2009. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in Canada and all figures provided herein and in the December 31, 2009 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 and the impact on Crew, 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 adoption of IFRS and other accounting policies 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 and partner approvals and ability 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, regulatory and partner approvals, 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.

Non-GAAP Measures

One of the benchmarks Crew uses to evaluate its performance is funds from operations. Funds from operations is a measure not defined in GAAP that is commonly used in the oil and gas industry. It represents cash provided by operating activities before changes in non-cash working capital, asset retirement expenditures and the transportation liability charge. The Company considers it a key measure as it demonstrates the ability of the business 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 GAAP 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		Nine months ended	
($ thousands)	**Sept. 30, 2010**	Sept. 30, 2009	**Sept. 30, 2010**	Sept. 30, 2009
Cash provided by operating activities	**19,596**	24,902	**75,958**	65,925
Asset retirement expenditures	**201**	196	**906**	478
Transportation liability charge (1)	**156**	328	**638**	985
Change in non-cash working capital	**4,151**	(5,786)	**(4,488)**	(11,191)
Funds from operations	**24,104**	19,640	**73,014**	56,197

(1) The amount for the nine months ended September 30, 2010 does not include the transportation liability write-down of $344,000 as described in the Transportation Costs section.

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 Canadian GAAP 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 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.

RESULTS OF OPERATIONS

Production

	Three months ended							
	September 30, 2010				September 30, 2009			
	Oil (bbl/d)	**Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
Alberta	**3,670**	**388**	**22,243**	**7,765**	3,194	880	33,606	9,675
British Columbia	**133**	**839**	**25,945**	**5,296**	182	563	15,872	3,390
Total	**3,803**	**1,227**	**48,188**	**13,061**	3,376	1,443	49,478	13,065

Production for the third quarter of 2010 was consistent with the same period in 2009. Natural gas and associated liquids production decreased in the third quarter compared with the third quarter of 2009 due to the disposition of approximately 2,300 boe per day of primarily natural gas production from two separate dispositions in Ferrier and Edson, Alberta which closed in late 2009 and at the end of the first quarter of 2010, respectively. These dispositions were offset by production additions from a successful drilling program which added liquids rich natural gas production in the Septimus, British Columbia area and oil production in the Princess, Alberta area. The weather related delays that hampered activity in the second quarter of 2010 in southern Alberta continued through the third quarter of 2010. This has created delays in bringing on new oil production in the quarter and, consequently, the Company's oil production was below its original expectations.

	Nine months ended							
	September 30, 2010				September 30, 2009			
	Oil (bbl/d)	**Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
Alberta	**3,663**	**537**	**24,887**	**8,348**	3,241	915	36,899	10,305
British Columbia	**125**	**728**	**24,976**	**5,016**	206	430	17,415	3,539
Total	**3,788**	**1,265**	**49,863**	**13,364**	3,447	1,345	54,314	13,844

Production for the first nine months of 2010 decreased over the same period in 2009 due to the previously mentioned asset dispositions but was partially offset by production additions from a successful drilling program as described above.

Revenue

	Three months ended		Nine months ended	
	Sept. 30, 2010	Sept. 30, 2009	**Sept. 30, 2010**	Sept. 30, 2009
Revenue *($ thousands)*				
Natural gas	**18,052**	14,685	**62,965**	59,953
Oil	**21,994**	19,850	**69,451**	52,323
Natural gas liquids	**4,878**	3,975	**17,307**	11,809
Sulphur	**–**	–	**–**	98
Total	**44,924**	38,510	**149,723**	124,183
Crew average prices				
Natural gas ($/mcf)	**4.07**	3.23	**4.63**	4.04
Oil ($/bbl)	**62.86**	63.91	**67.16**	55.61
Natural gas liquids ($/bbl)	**43.21**	29.94	**50.13**	32.16
Oil equivalent ($/boe)	**37.39**	32.04	**41.04**	32.86
Benchmark pricing				
Natural Gas – AECO C daily index (Cdn $/mcf)	**3.59**	3.02	**4.19**	3.83
Oil – Bow River Crude Oil (Cdn $/bbl)	**73.15**	73.20	**76.88**	65.79
Oil and ngl – Cdn$ West Texas Int. (Cdn $/bbl)	**79.18**	74.91	**80.40**	65.96

Crew's third quarter 2010 revenue increased 17% over the same period in 2009 due to a 26% increase in its natural gas price and a 44% increase in its natural gas liquids price partially offset by a 2% decrease in the Company's oil price. Decreased production of lower valued natural gas production in the Sierra, British Columbia area replaced by increased production of higher valued natural gas from the Septimus area accounts for Crew's increased natural gas pricing as compared to the benchmark. The Company's benchmark Bow River Crude oil price remained consistent in the third quarter compared with the same period in 2009 which was in line with the Company's minor oil price decrease. The price received for the Company's natural gas liquids (ngl) production increased 44% while the Company's Cdn$ West Texas Intermediate benchmark increased 6% due to the sale of the Company's assets in the Ferrier area in 2009 which included lower valued ethane production. In addition, the Company increased production of higher valued condensate from the Septimus area in the third quarter of 2010.

For the nine months ended September 30, 2010, Crew's natural gas price increased 15% compared with a 9% increase in the Company's benchmark. The aforementioned replacement of lower valued Sierra natural gas production with higher valued Septimus natural gas production accounts for the disproportionate increase in pricing. Crew's oil price increased proportionately with the Bow River Crude Oil benchmark for the nine month period ended September 30, 2010. The Company's ngl price increased disproportionately due to the previously mentioned sale of lower valued ethane production in the Ferrier area and increased higher valued condensate production in the Septimus area.

Royalties

	Three months ended		Nine months ended	
($ thousands, except per boe)	**Sept. 30, 2010**	Sept. 30, 2009	**Sept. 30, 2010**	Sept. 30, 2009
Royalties	**8,920**	6,668	**30,488**	22,860
Per boe	**7.42**	5.55	**8.36**	6.05
Percentage of revenue	**19.9%**	17.3%	**20.4%**	18.4%

Royalties as a percentage of revenue increased in the third quarter and first nine months of 2010 compared to the same periods of 2009 due to new oil and natural gas production from the Princess area which, in the current pricing environment, attracts a higher royalty rate than the Company's older production. Corporately, with an increase in forecasted sales from Princess area production, Crew forecasts annual royalties as a percentage of revenue to average 20% to 22% for 2010.

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 reduce 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 2010, these contracts had the following impact on the consolidated statement of operations:

	Three months ended		Nine months ended	
($ thousands)	**Sept. 30, 2010**	Sept. 30, 2009	**Sept. 30, 2010**	Sept. 30, 2009
Realized gain on financial instruments	**5,114**	7,794	**9,798**	13,990
Unrealized gain (loss) on financial instruments	**(5,326)**	3,082	**5,206**	4,136

As at September 30, 2010, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Natural Gas	2,500 gj/day	November 1, 2009 – December 31, 2010	AECO C Monthly Index	$6.00/gj	Swap	581
Natural Gas	5,000 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$8.00/gj	Call	–
Natural Gas	10,000 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$7.75/gj	Call	–
Natural Gas	2,500 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$6.20/gj	Swap	626
Natural Gas	5,000 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$6.08/gj	Swap	1,591
Natural Gas	2,500 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$5.25/gj	Swap	409
Natural Gas	2,500 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$5.55/gj	Swap	477
Natural Gas	2,500 gj/day	April 1, 2010 – October 31, 2010	AECO C Monthly Index	$5.30/gj	Swap	150
Natural Gas	5,000 mmbtu/day	January 1, 2010 – December 31, 2010	AECO/NYMEX Basis diff	US$($0.55)	Swap	(73)
Oil	250 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$78.50/bbl	Swap	(118)
Oil	500 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$72.00 – $88.00/bbl	Collar	(47)
Oil	250 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$82.50/bbl	Swap	(25)
Oil	500 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$80.50/bbl	Swap	(125)
Oil	500 bbl/day	January 1, 2010 – December 31, 2010	US$ WTI	US$81.00/bbl	Swap	(9)
Oil	250 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$80.00 – $95.02/bbl	Collar	23
Oil	250 bbl/day	March 1, 2010 – December 31, 2010	CDN$ WTI	$84.00/bbl	Swap	53
Oil	250 bbl/day	July 1, 2010 – December 31, 2010	CDN$ WTI	$88.10/bbl	Swap	102
Oil	250 bbl/day	July 1, 2010 – December 31, 2010	CDN$ WTI	$91.50/bbl	Swap	281
Oil	250 bbl/day	August 9, 2010 – December 31, 2010	CDN$ WTI	$85.00/bbl	Swap	31
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	US$ WTI	US$80.15/bbl	Swap	(880)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$86.00/bbl	Swap	(170)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$82.00 – $94.62/bbl	Collar	49
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$90.20/bbl	Swap	410
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$80.00 – $95.45/bbl	Collar	(4)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$90.00/bbl	Swap	193
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$88.50/bbl	Swap	53
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$85.00 – $100.50/bbl	Collar	352
Total						3,930

Foreign currency

Although all of the Company's petroleum and natural gas sales are conducted in Canada and are denominated in Canadian dollars, Canadian commodity prices are influenced by fluctuations in the Canadian to U.S. dollar exchange rate.

At September 30, 2010, the Company held the following derivative foreign currency contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
USD / CAD $ exchange	US $2M / Month	January 1, 2010 – December 31, 2010	CAD/USD	1.094	Swap	382
Total						382

Interest rate

The Company is exposed to interest rate fluctuations on its bank loan which bears a floating rate of interest. As shown below, at September 30, 2010, Crew had contracts in place fixing the interest rate on $100 million of bankers' acceptances at a rate of 1.10%. The Company pays additional stamping fees and margins on bankers' acceptances as outlined in note 3 of the financial statements.

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
BA Rate	$50M / year	February 10, 2009 – February 10, 2011	BA – CDOR	1.10%	Swap	22
BA Rate	$50M / year	February 12, 2009 – February 12, 2011	BA – CDOR	1.10%	Swap	38
Total						60

Subsequent to September 30, 2010, the Company entered into the following financial instrument contracts:

Subject of Contract	Volume	Term	Reference	Strike Price (per bbl)	Option Traded
Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.85	Swap (1)
Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.90	Swap (1)
Gas	5,000 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$5.00	Swap (1)
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$88.00	Swap
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	US$ WTI	US$85.00	Call (1)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	US$ WTI	US$90.00	Call (1)

(1) Derivative contracts are part of a paired transaction in which the proceeds from the sale of 2012 oil calls were used to fund the 2011 natural gas swaps at the prices indicated.

Operating Costs

	Three months ended		Nine months ended	
($ thousands, except per boe)	**Sept. 30, 2010**	Sept. 30, 2009	**Sept. 30, 2010**	Sept. 30, 2009
Operating costs	**12,318**	14,000	**39,967**	42,258
Per boe	**10.25**	11.65	**10.95**	11.18

In the third quarter and first nine months of 2010, the Company's operating costs and costs per unit decreased over the same periods in 2009 due to the addition of lower cost natural gas and associated liquids production in the Septimus area. This was partially offset by the addition of higher cost production from the Princess area and the disposition of lower cost production in the Ferrier and Edson areas in late 2009 and early 2010. With additional forecasted production to offset fixed costs in the Princess and Septimus areas and cost cutting measures associated with water handling at Princess, the Company continues to expect costs to average between $10.00 and $10.75 per boe for 2010.

Transportation Costs

	Three months ended		Nine months ended	
($ thousands, except per boe)	**Sept. 30, 2010**	Sept. 30, 2009	**Sept. 30, 2010**	Sept. 30, 2009
Transportation costs	**2,243**	2,830	**6,763**	8,095
Transportation liability write-down	**–**	–	**344**	–
Transportation costs excluding liability write down	**2,243**	2,830	**7,107**	8,095
Per boe	**1.87**	2.35	**1.95**	2.14

In the third quarter and first nine months of 2010, the Company's transportation costs and transportation costs per unit decreased over the same period in 2009 due to the Company permanently assigning its unutilized firm transportation commitment in northeastern British Columbia in March 2010. The Company forecasts transportation costs to range between $1.75 and $2.00 per boe for 2010.

Operating Netbacks

	Three months ended							
	September 30, 2010				September 30, 2009			
	Oil ($/bbl)	**Ngl ($/bbl)**	**Nat. gas ($/mcf)**	**Total ($/boe)**	Oil ($/bbl)	Ngl ($/bbl)	Nat. gas ($/mcf)	Total ($/boe)
Revenue	**62.86**	**43.21**	**4.07**	**37.39**	63.91	29.94	3.23	32.04
Realized commodity hedging gain	**3.03**	**–**	**0.85**	**4.02**	0.70	–	1.33	5.28
Royalties	**(18.73)**	**(7.05)**	**(0.35)**	**(7.42)**	(17.61)	(8.22)	(0.02)	(5.55)
Operating costs	**(14.03)**	**(6.42)**	**(1.51)**	**(10.25)**	(11.23)	(9.58)	(2.03)	(11.65)
Transportation costs	**(1.50)**	**(1.25)**	**(0.36)**	**(1.87)**	(2.11)	(0.20)	(0.47)	(2.35)
Operating netbacks	**31.63**	**28.49**	**2.70**	**21.87**	33.66	11.94	2.04	17.77

	Nine months ended							
	September 30, 2010				September 30, 2009			
	Oil ($/bbl)	**Ngl ($/bbl)**	**Nat. gas ($/mcf)**	**Total ($/boe)**	Oil ($/bbl)	Ngl ($/bbl)	Nat. gas ($/mcf)	Total ($/boe)
Revenue	**67.16**	**50.13**	**4.63**	**41.04**	55.61	32.16	4.04	32.86
Realized commodity hedging gain	**1.31**	**–**	**0.58**	**2.54**	0.24	–	0.79	3.18
Royalties	**(19.46)**	**(10.57)**	**(0.50)**	**(8.36)**	(14.75)	(9.94)	(0.36)	(6.05)
Operating costs	**(14.11)**	**(8.45)**	**(1.65)**	**(10.95)**	(11.73)	(9.32)	(1.87)	(11.18)
Transportation costs	**(1.42)**	**(1.26)**	**(0.38)**	**(1.95)**	(1.65)	(0.07)	(0.44)	(2.14)
Operating netbacks	**33.48**	**29.85**	**2.68**	**22.32**	27.72	12.83	2.16	16.67

General and Administrative Costs

	Three months ended		Nine months ended	
($ thousands, except per boe)	**Sept. 30, 2010**	Sept. 30, 2009	**Sept. 30, 2010**	Sept. 30, 2009
Gross costs	**3,675**	3,436	**11,722**	10,134
Operator's recoveries	**(1,146)**	(797)	**(2,573)**	(1,609)
Capitalized costs	**(1,264)**	(1,319)	**(4,574)**	(4,262)
General and administrative expenses	**1,265**	1,320	**4,575**	4,263
Per boe	**1.05**	1.10	**1.25**	1.13

Increased third quarter 2010 general and administrative costs before recoveries and capitalization were mainly due to the cost of additional office space added in late 2009 in order to accommodate the Company's future growth plans. In the third quarter of 2010, net general and administrative costs and costs per boe have decreased due to additional operator's recoveries from the Company's increased capital expenditures as compared with the same period in 2009. For the first nine months of 2010, gross costs before recoveries and capitalization as well as net general and administrative costs have increased as a result of increased staff levels and increased office rent costs to accommodate the Company's larger operations in Princess and Septimus. The Company expects general and administrative expenses to average between $1.10 and $1.25 per boe for the year.

Interest

	Three months ended		Nine months ended	
($ thousands, except per boe)	**Sept. 30, 2010**	Sept. 30, 2009	**Sept. 30, 2010**	Sept. 30, 2009
Interest expense	**1,188**	1,846	**4,370**	4,500
Average debt level	**79,623**	169,837	**88,431**	206,910
Effective interest rate	**5.9%**	4.4%	**6.6%**	2.9%
Per boe	**0.99**	1.54	**1.20**	1.19

Crew's third quarter and first nine months of 2010 interest expense has decreased over the same periods in 2009 due to a significant decrease in outstanding average debt levels. During the third quarter, the margin charged on the Company's borrowings under its prime loans and the stamping fees charged on its outstanding bankers' acceptances have decreased but this has been partially offset by increased prime interest rates and interest rates charged on bankers' acceptances. Effective interest rates increased for the three and nine months ended September 30, 2010 due to increased standby fees charged on the unutilized facility and the amortization of annual renewal fees against the significantly decreased drawn facility as the denominator.

Stock-Based Compensation

	Three months ended		Nine months ended	
($ thousands)	**Sept. 30, 2010**	Sept. 30, 2009	**Sept. 30, 2010**	Sept. 30, 2009
Gross costs	**2,069**	1,635	**6,848**	5,056
Capitalized costs	**(1,035)**	(817)	**(3,424)**	(2,528)
Total stock-based compensation	**1,034**	818	**3,424**	2,528

The Company's stock-based compensation expense has increased in the third quarter and first nine months of 2010 as compared with the same periods in 2009 due to an increase in the fair value of stock options that were issued to Crew employees and service providers, resulting from the Company's increased share price.

Depletion, Depreciation and Accretion

	Three months ended		Nine months ended	
($ thousands, except per boe)	**Sept. 30, 2010**	Sept. 30, 2009	**Sept. 30, 2010**	Sept. 30, 2009
Depletion, depreciation and accretion	**27,711**	32,142	**85,478**	99,936
Per boe	**23.06**	26.74	**23.43**	26.44

Depletion, depreciation and accretion costs and per unit costs have decreased in the third quarter and first nine months of 2010 due to low cost reserve additions from a successful drilling program in the Company's Septimus and Princess areas as well as the sale of the Edson assets which received a greater price per unit than the Company's corporate depletion rate.

Future Income Taxes

The provision for future income taxes was a recovery of $2.6 million in the third quarter of 2010 and a recovery of $2.7 million for the first nine months of 2010 compared to recoveries of $2.9 million and $13.5 million, respectively for the same periods of 2009. The decreased recoveries were the result of greater pre-tax losses in 2009 as compared to the same periods in 2010.

Cash and Funds from Operations and Net Loss

($ thousands, except per share amounts)	Three months ended Sept. 30, 2010	Three months ended Sept. 30, 2009	Nine months ended Sept. 30, 2010	Nine months ended Sept. 30, 2009
Cash provided by operating activities	**19,596**	24,902	**75,598**	65,925
Funds from operations	**24,104**	19,640	**73,014**	56,197
Per share – basic	**0.30**	0.25	**0.92**	0.76
– diluted	**0.29**	0.25	**0.90**	0.76
Net loss	**(7,387)**	(7,376)	**(7,636)**	(28,661)
Per share – basic	**(0.09)**	(0.09)	**(0.10)**	(0.39)
– diluted	**(0.09)**	(0.09)	**(0.10)**	(0.39)

For the third quarter and first nine months of 2010, an increase in funds from operations was the result of increased commodity pricing and lower operating and transportation costs for the periods. For the third quarter of 2010, the net loss was consistent with the same period in 2009 as reduced depletion costs were offset by a net unrealized loss on financial instruments. The net loss for the first nine months of 2010 decreased compared to the same period in 2009 primarily due to increased revenue from increased commodity pricing and decreased depletion, depreciation and accretion costs from the sale of assets in late 2009 and early 2010.

Capital Expenditures, Acquisitions and Dispositions

During the third quarter of 2010, the Company drilled 26 (24.9 net) wells resulting in 16 (16.0 net) oil wells, six (4.9 net) gas wells and four (4.0 net) water disposal wells. In addition, the Company also completed 33 (33.0 net) wells at Septimus, Princess and Pine Creek, Alberta and recompleted four (4.0 net) well in the Septimus, Plain Lake and Provost, Alberta areas. Continued wet weather hampered tying in many of these wells as only 15 of the 33 completed wells were brought on production in the third quarter. The Company also added to its infrastructure at Princess by expanding and upgrading fluid handling capacity and pipelines to its oil batteries in the area. In the third quarter of 2010, Crew began the expansion of the Septimus facility by procuring equipment for the scheduled fourth quarter construction of the expansion. The Company has an agreement in place to sell the Septimus gas plant expansion for its as built cost of approximately $16.9 million. The sale is scheduled to close after completion of the expansion, expected to be in the fourth quarter of 2010. Details can be found in the Contractual Obligations section.

During the third quarter, the Company was notified that it was granted a $7.6 million infrastructure credit from the British Columbia government. This credit was issued as a result of the Company's work with a third party processor in the Septimus area to expand and increase the natural gas takeaway capacity associated with the Company's Montney gas development in the area. The third quarter capital expenditures are reported net of the $7.6 million of government incentives confirmed during the quarter.

Exploration and development capital expenditures for the third quarter and first nine months of 2010 were $65.1 and $187.5 million, respectively, compared to $35.4 and $73.3 million for the same periods in 2009. The expenditures are detailed below:

($ thousands)	Three months ended Sept. 30, 2010	Three months ended Sept. 30, 2009	Nine months ended Sept. 30, 2010	Nine months ended Sept. 30, 2009
Land	**2,866**	1,013	**37,738**	4,881
Seismic	**182**	81	**5,277**	2,176
Drilling and completions	**49,681**	17,767	**116,573**	28,167
Facilities, equipment and pipelines	**11,304**	15,040	**23,074**	33,384
Other	**1,105**	1,489	**4,860**	4,647
Exploration and development	**65,138**	35,390	**187,522**	73,255
Property dispositions	**–**	–	**(132,640)**	(34,378)
Total net	**65,138**	35,390	**54,882**	38,877

As at September 30, 2010, budgeted net expenditures for 2010 are estimated at approximately $95 million.

LIQUIDITY AND CAPITAL RESOURCES

Capital Funding

The Company has a credit facility with a syndicate of banks (the "Syndicate") that includes a revolving line of credit of $190 million and an operating line of credit of $20 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 13, 2011. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 percent and all outstanding balances under the Facility will become repayable in one year from the renew date. The available lending limits of the Facility are reviewed semi-annually and are based on the Syndicate's interpretation of the Company's reserves and future commodity prices. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled review on or before June 13, 2011. At September 30, 2010, the Company had committed drawings of $110.8 million on the Facility and had issued letters of credit totaling $3.6 million.

During the first nine months of 2010, the Company has received proceeds of $18.8 million due to the exercise of 2,053,366 employee stock options.

The Company will continue to fund its on-going operations from a combination of cash flow, debt, the proceeds from future 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. However, the Company maintains sufficient unused bank credit lines to satisfy such working capital deficiencies. At September 30, 2010, the Company's working capital deficiency (including accounts receivable, accounts payable and accrued liabilities) totaled $36.1 million which, when combined with the drawings on its bank line, represented 70% of its current bank facility.

Share Capital

As at November 8, 2010, Crew had issued and outstanding 80,283,534 Common Shares and had options to acquire 5,416,400 Common Shares 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 some 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. This ratio may increase at certain times as a result of acquisitions or low commodity prices. As shown below, as at September 30, 2010, the Company's ratio of net debt to annualized funds from operations was 1.52 to 1 (December 31, 2009 – 1.67 to 1).

($ thousands, except ratio)	**Sept. 30, 2010**	Dec. 31, 2009
Accounts receivable	**43,182**	37,574
Accounts payable and accrued liabilities	**(79,314)**	(84,228)
Working capital deficiency	**(36,132)**	(46,654)
Bank loan	**(110,770)**	(135,601)
Net debt	**(146,902)**	(182,255)
Funds from operations	**24,104**	27,256
Annualized	**96,416**	109,024
Net debt to annualized funds from operations ratio	**1.52**	1.67

Contractual Obligations

Throughout the course of its ongoing business, the Company enters into various contractual obligations such as credit agreements, purchases 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 the 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	2010	2011	2012	2013	2014	Thereafter
Bank Loan (1)	110,770	–	–	110,770	–	–	–
Operating Leases	3,490	432	1,743	1,315	–	–	–
Capital commitments	5,000	3,000	2,000	–	–	–	–
Transportation agreements	12,802	1,157	4,018	955	953	953	4,766
Processing agreement	28,204	762	3,049	3,049	3,049	3,049	15,246
Total	160,266	5,351	10,810	116,089	4,002	4,002	20,012

(1) Based on the existing terms of the Company's bank facility the first possible repayment date may come in 2012; however, it is expected that the revolving bank facility will be extended and no repayment will be required in the near term.

The transportation agreements include an $8.8 million commitment to a third party to transport natural gas from the gas processing facility in the Septimus, British Columbia area to the Alliance pipeline system. The remaining commitment relates to firm transportation commitments that were acquired as part of the Company's May 2007 private company acquisition, of which, in 2010, the Company permanently assigned approximately $6.2 million of its firm commitments to third parties.

During 2009, Crew entered into the firm processing agreement to process natural gas through a third party owned gas processing facility in the Septimus area. Under the terms of the agreement Crew has committed to process a minimum monthly volume of gas through the facility commencing on December 1, 2009 and continuing through November 30, 2019. The commitment is included in the above table.

Subsequent to the quarter end, the Company amended the agreement with the owner of this facility. Under the terms of the amended agreement, Crew has begun expansion of the existing facility. On completion of the expansion, Crew will be reimbursed for the full cost of the facility in return for an expanded processing commitment that will extend to December 2020. Crew has also 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.

Guidance

In a repeated theme, oil prices have remained relatively strong as the world's economies continue their recovery. Natural gas prices, however, remain weak as North American supplies continue to grow due to the aggressive development of unconventional natural gas plays. As a result of this commodity price imbalance, Crew has been focusing its capital and technical resources towards the pursuit of growth of its oil and liquids production. The Company is in the enviable position to quickly adapt to commodity price cycles in order to focus on oil or liquids rich natural gas directed drilling. This was demonstrated in the third quarter of 2010 with the Company drilling 20 net wells at Princess.

Despite the depressed natural gas price environment, the Company's liquids rich Septimus Montney production continues to show good economic returns. However, the continued prospect of low natural gas prices combined with the inflating cost of high pressure fracturing services has resulted in the economics of our oil plays overwhelming the economics of our liquids rich natural gas plays. As such, capital deployment for the fourth quarter of 2010 and 2011 is expected to be largely dedicated toward oil directed drilling.

Crew's net exploration and development expenditures are forecasted to be approximately $225 million for 2010 with the majority being spent at Princess. As a result of the aforementioned persistent weather delays, Crew is forecasting average 2010 production of 13,600 to 14,000 boe per day. Exit production is now forecast to be 17,000 to 18,000 boe per day.

ADDITIONAL DISCLOSURES

Quarterly Analysis

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

($ thousands, except per share amounts)	**Sept. 30 2010**	June 30 2010	Mar. 31 2010	Dec. 31 2009	Sept. 30 2009	June 30 2009	Mar. 31 2009	Dec. 31 2008
Total daily production (boe/d)	**13,061**	12,048	15,001	14,470	13,065	13,466	15,022	14,869
Average wellhead price ($/boe)	**37.39**	39.25	45.75	43.30	32.04	32.10	34.28	42.99
Petroleum and natural gas sales	**44,924**	43,027	61,772	57,646	38,510	39,331	46,342	58,806
Cash provided by operations	**19,596**	24,149	32,213	16,734	24,902	21,517	19,506	25,700
Funds from operations	**24,104**	20,693	28,217	27,256	19,640	20,036	16,521	29,646
Per share – basic	**0.30**	0.26	0.36	0.35	0.25	0.27	0.23	0.42
– diluted	**0.29**	0.25	0.35	0.35	0.25	0.27	0.23	0.42
Net income (loss)	**(7,387)**	(2,691)	2,442	(9,154)	(7,376)	(12,267)	(9,018)	(74,853)
Per share – basic	**(0.09)**	(0.03)	0.03	(0.12)	(0.10)	(0.17)	(0.13)	(1.05)
– diluted	**(0.09)**	(0.03)	0.03	(0.12)	(0.10)	(0.17)	(0.13)	(1.05)

Crew's petroleum and natural gas sales, cash and funds from operations and net income are all impacted by production levels and volatile commodity pricing. From 2008 to 2010, these performance measures have fluctuated as a result of volatile oil and natural gas prices.

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.
- Production in the second quarter of 2009 and 2010 was negatively impacted by scheduled and unscheduled third party facility shutdowns and poor weather experienced in southern Alberta in 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 on a portion of its production. 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.
- In the fourth quarter of 2008, Crew performed an impairment test on its goodwill and determined that its carrying value exceeded its fair value and therefore an impairment charge of $69.1 million was required.
- In 2009 and 2010, the Company sold assets with approximately 2,970 boe per day of production for $182.9 million. The major dispositions closed as follows:
  - First quarter 2009 – 130 boe per day for $10.7 million
  - Second quarter 2009 – 540 boe per day for $22.5 million
  - Fourth quarter 2009 – 600 boe per day for $25.3 million
  - Second quarter 2010 – 1,700 boe per day for $123.3 million

New Accounting Pronouncements

International Financial Reporting Standards

Effective January 1, 2011, Canadian public companies are required to adopt International Financial Reporting Standards ("IFRS") which will include comparatives for 2010. Crew's financial statements up to and including the December 31, 2010 financial statements will continue to be reported in accordance with Canadian GAAP as it exists on each reporting date. Financial statements for the quarter ended March 31, 2011, including comparative amounts, will be prepared on an IFRS basis.

In order to transition to IFRS, management has established a project team and formed an executive steering committee. A transition plan has been developed to convert the financial statements to IFRS. External advisors have been retained and will continue to assist management with the project on an as needed basis. Training has been provided to key employees and staff training programs will continue throughout 2010. The Company continues to assess the effect of the transition on information systems, internal controls over financial reporting and disclosure controls and procedures. Systems and controls are being updated as IFRS accounting processes are implemented. Significant system and control changes are not anticipated. The project team and steering committee continue to provide updates to senior management and the Audit Committee. The Company's auditors are involved throughout the process to ensure the Company's policies are in accordance with the new standards.

Analysis of differences between IFRS and Canadian GAAP is continuing. There are significant accounting policy changes anticipated on adoption of IFRS which are described in more detail below. Management is continuing to finalize its accounting policies and as such is unable to quantify the impact on the financial statements at this time. In addition, anticipated changes to IFRS and International Accounting Standards prior to adoption could cause changes to certain items based on new facts and circumstances.

Many of the differences between IFRS and Canadian GAAP are being quantified; however, Crew has not yet prepared a full set of annual financial statements under IFRS. The impacts of the identified differences are still being determined. Most adjustments required on transition to IFRS will be made retrospectively against opening retained earnings as of the date of the first comparative balance sheet. In July 2009, the International Accounting Standards Board ("IASB") issued amendments to IFRS 1 "First time adoption of IFRS" allowing additional exemptions for first-time adopters. Under these amendments, full cost oil and gas companies can elect to use the recorded amount under a previous GAAP as the deemed cost for oil and gas assets on the transition date to IFRS. Crew is currently planning to adopt this exemption. Management has analyzed the various other accounting policy choices available under IFRS 1 and has determined the following to be most appropriate for Crew:

- Depletion and depreciation of Property, Plant and Equipment ("PP&E") will be based on significant components. Under IFRS 1, the net book value of the PP&E can be allocated to the new cost centres on the basis of Crew's reserve volumes or values as per the deemed cost election. Depletion of resource properties will generally continue to be calculated using the unit-of-production method but Crew has the option to base the calculation on proved reserves or proved plus probable reserves. Crew has concluded that it will allocate the PP&E balance using Crew's reserve values and expects to use proved plus probable reserves to calculate the depletion of resource properties.

- Oil and gas properties will be classified as either PP&E or Exploration and Evaluation assets (E&E). Upon transition to IFRS, Crew will reclassify all E&E expenditures that are currently included in the PP&E balance on the Consolidated Balance Sheet. These assets will be measured at cost and will not be depleted but will be assessed for impairment when indicators suggest the possibility of impairment. Crew is currently finalizing its policy on E&E assets, which will primarily consist of undeveloped exploration lands.

- IFRS 1 allows Crew to use the IFRS rules for business combinations on a prospective basis rather than restating all business combinations. Crew will elect to use this exemption; therefore, Crew will not be recording any adjustments to retrospectively restate any of its business combinations that have occurred prior to January 1, 2010.

- Currently Crew expenses stock-based compensation on a straight-line basis. Under IFRS, share-based payments are expensed based on a graded vesting schedule. Crew will also be required to incorporate a forfeiture multiplier rather than account for forfeitures as they occur as currently practiced under Canadian GAAP.

- Under Canadian GAAP, impairment testing on oil and gas properties is performed at a cost centre level. Under IFRS, impairment testing will be performed at a lower level, referred to as a cash generating unit. This will result in a greater number of impairment tests. At January 1, 2010, Crew does not expect any impairment on its PP&E.

- Under Canadian GAAP, Crew's Asset Retirement Obligation calculation is based on a credit adjusted risk free rate. Under IFRS, Crew is required to revalue its entire liability for asset retirement costs at each balance sheet date using a current liability-specific discount rate. It is expected that the asset retirement obligation will increase upon transition to IFRS if the liability is revalued to reflect the estimated risk-free rate of interest.

In accordance with its transition plan, Crew has analyzed accounting policy alternatives and drafted its IFRS position papers. Crew is in the process of finalizing its January 1, 2010 IFRS opening balance sheet and having its external auditors review the Company's draft IFRS balance sheet impacts. In the fourth quarter, the Company also plans to begin drafting its 2010 IFRS comparative quarterly financial statements and will assess and review the impact of the IFRS changes on disclosure controls and internal controls, including identification of instances where controls may require amendments or additions in order to address the accounting policy changes required under IFRS. No material changes in control procedures are presently expected. The Company expects to be in a position to provide quantitative information about the impact of IFRS on its financial statements following the fourth quarter of 2010.

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.

Crew'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 Canadian generally accepted accounting principles. 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 July 1, 2010 and ended on September 30, 2010 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 November 8, 2010

CONSOLIDATED BALANCE SHEETS

(unaudited) (thousands)	**September 30, 2010**	December 31, 2009
ASSETS		
Current Assets:		
Accounts receivable	**$ 43,182**	$ 37,574
Fair value of financial instruments (note 7)	**4,372**	–
Future income taxes	**–**	542
	47,554	38,116
Property, plant and equipment (note 2)	**898,413**	925,132
	$ 945,967	$ 963,248
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 79,314**	$ 84,228
Fair value of financial instruments (note 7)	**–**	834
Future income taxes	**991**	–
Current portion of other long-term obligations (note 4)	**463**	1,313
	80,768	86,375
Bank loan (note 3)	**110,770**	135,601
Other long-term obligations (note 4)	**–**	132
Asset retirement obligations (note 5)	**33,735**	35,341
Future income taxes	**98,425**	101,519
SHAREHOLDERS' EQUITY		
Share capital (note 6)	**643,917**	617,605
Contributed surplus (note 6 (c))	**22,082**	22,769
Deficit	**(43,730)**	(36,094)
	622,269	604,280
Commitments (note 10)		
Subsequent events (notes 7 and 10)		
	$ 945,967	$ 963,248

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF OPERATIONS, COMPREHENSIVE INCOME (LOSS) AND RETAINED EARNINGS (DEFICIT)

	Three months ended		Nine months ended	
(unaudited) (thousands, except per share amounts)	**Sept. 30, 2010**	Sept. 30, 2009	**Sept. 30, 2010**	Sept. 30, 2009
Revenue				
Petroleum and natural gas sales	**$ 44,924**	$ 38,510	**$ 149,723**	$ 124,183
Royalties	**(8,920)**	(6,668)	**(30,488)**	(22,860)
Realized gain on financial instruments (note 7)	**5,114**	7,794	**9,798**	13,990
Unrealized gain (loss) on financial instruments (note 7)	**(5,326)**	3,082	**5,206**	4,136
	35,792	42,718	**134,239**	119,449
Expenses				
Operating	**12,318**	14,000	**39,967**	42,258
Transportation (note 4)	**2,243**	2,830	**6,763**	8,095
General and administrative	**1,265**	1,320	**4,575**	4,263
Interest	**1,188**	1,846	**4,370**	4,500
Stock-based compensation (note 6(d))	**1,034**	818	**3,424**	2,528
Depletion, depreciation and accretion	**27,711**	32,142	**85,478**	99,936
	45,759	52,956	**144,577**	161,580
Loss before income taxes	**(9,967)**	(10,238)	**(10,338)**	(42,131)
Future income tax reduction	**(2,580)**	(2,862)	**(2,702)**	(13,470)
Loss and comprehensive loss	**(7,387)**	(7,376)	**(7,636)**	(28,661)
Retained earnings (deficit), beginning of period	**(36,343)**	(19,564)	**(36,094)**	1,721
Deficit, end of period	**$ (43,730)**	$ (26,940)	**$ (43,730)**	$ (26,940)
Loss per share (note 6(e))				
Basic	**$ (0.09)**	$ (0.09)	**$ (0.10)**	$ (0.39)
Diluted	**$ (0.09)**	$ (0.09)	**$ (0.10)**	$ (0.39)

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended		Nine months ended	
(unaudited) (thousands)	**Sept. 30, 2010**	Sept. 30, 2009	**Sept. 30, 2010**	Sept. 30, 2009
Cash provided by (used in):				
Operating activities:				
Net loss	**$ (7,387)**	$ (7,376)	**$ (7,636)**	$ (28,661)
Items not involving cash:				
Depletion, depreciation and accretion	**27,711**	32,142	**85,478**	99,936
Stock-based compensation	**1,034**	818	**3,424**	2,528
Future income tax reduction	**(2,580)**	(2,862)	**(2,702)**	(13,470)
Unrealized (gain) loss on financial instruments	**5,326**	(3,082)	**(5,206)**	(4,136)
Transportation liability charge (note 4)	**(156)**	(328)	**(982)**	(985)
Asset retirement expenditures	**(201)**	(196)	**(906)**	(478)
Change in non-cash working capital (note 9)	**(4,151)**	5,786	**4,488**	11,191
	19,596	24,902	**75,958**	65,925
Financing activities:				
Increase (decrease) in bank loan	**38,925**	(8,160)	**(24,831)**	(56,860)
Issue of common shares	**1,220**	22	**18,813**	43,422
Share issue costs	**–**	(3)	**(48)**	(2,442)
	40,145	(8,141)	**(6,066)**	(15,880)
Investing activities:				
Exploration and development	**(65,138)**	(35,390)	**(187,522)**	(73,255)
Property dispositions	**–**	–	**132,640**	34,378
Change in non-cash working capital (note 9)	**5,397**	18,629	**(15,010)**	(11,168)
	(59,741)	(16,761)	**(69,892)**	(50,045)
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 consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the three and nine months ended September 30, 2010 and 2009

(Unaudited) (Tabular amounts in thousands)

1. SIGNIFICANT ACCOUNTING POLICIES:

The interim consolidated financial statements of Crew Energy Inc. ("Crew" or the "Company") have been prepared by management in accordance with accounting principles generally accepted in Canada. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the year ended December 31, 2009. The disclosure which follows is incremental to the disclosure included with the December 31, 2009 consolidated financial statements. These interim consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto for the year ended December 31, 2009.

Certain comparative amounts have been reclassified to conform to current period presentation.

2. PROPERTY, PLANT AND EQUIPMENT:

September 30, 2010	**Cost**	**Accumulated depletion & depreciation**	**Net book value**
Petroleum and natural gas properties and equipment	**$ 1,359,156**	**$ 460,743**	**$ 898,413**

December 31, 2009	Cost	Accumulated depletion & depreciation	Net book value
Petroleum and natural gas properties and equipment	$ 1,302,399	$ 377,267	$ 925,132

The cost of unproved properties at September 30, 2010 of $173,711,000 (2009 - $159,751,000) was excluded from the depletion calculation. Estimated future development costs associated with the development of the Company's proved reserves of $136,955,000 (2009 - $93,818,000) have been included in the depletion calculation and estimated salvage values of $35,234,000 (2009 - $38,851,000) have been excluded from the depletion calculation.

In April 2010, the Company closed the disposition of oil and gas assets in the Edson, Alberta area for gross proceeds of $126 million, before closing adjustments.

The following directly attributable general and administrative and stock-based compensation expenses related to exploration and development activities were capitalized.

	Nine months ended September 30, 2010	Year ended December 31, 2009
General and administrative expense	**$ 4,463**	$ 5,736
Stock-based compensation expense, including future income taxes	**4,577**	4,442
	$ 9,040	$ 10,178

RESOURCE FOCUS ● OPPORTUNITY ● SUSTAINABILITY

3. BANK LOAN:

The Company's bank facility consists of a revolving line of credit of $190 million and an operating line of credit of $20 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 13, 2011. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 percent 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 June 13, 2011.

Advances under the Facility are available by way of prime rate loans with interest rates of between 1.25 percent and 2.75 percent over the bank's prime lending rate and bankers' acceptances and LIBOR loans, which are subject to stamping fees and margins ranging from 2.25 percent to 3.75 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 0.56 percent to 0.94 percent depending upon the same debt to EBITDA ratio.

As at September 30, 2010, the Company's applicable pricing included a 1.75 percent margin on prime lending and a 2.75 percent stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.69 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 September 30, 2010, the Company had issued letters of credit totaling $3.6 million. The effective interest rate on the Company's borrowings under its bank Facility for the three months ended September 30, 2010 was 5.9% (2009 – 2.4%).

4. OTHER LONG-TERM OBLIGATIONS:

As part of the May, 2007 private company acquisition, the Company acquired several firm transportation agreements. These agreements had a fair value at the time of the acquisition of a $4.9 million liability. This amount was accounted for as part of the acquisition cost and will be charged as a reduction to transportation expenses over the life of the contracts as they are incurred. The charge for the three and nine months ended September 30, 2010 was $0.2 million and $0.7 million, respectively (2009 - $0.3 million and $1.0 million).

In March 2010, the Company permanently assigned a portion of the firm transportation agreements to third parties at no cost to Crew. As a result, the remaining liability associated with the assigned contracts was written-off during the first quarter of 2010 as a $0.3 million reduction of transportation expense.

5. ASSET RETIREMENT OBLIGATIONS:

Total future asset retirement obligations were determined by management and were based on Crew's net ownership interest, the estimated future costs to reclaim and abandon the wells and facilities and the estimated timing of when the costs will be incurred. Crew estimated the net present value of its total asset retirement obligation as at September 30, 2010 to be $33,735,000 (December 31, 2009 - $35,341,000) based on a total future liability of $61,180,000 (December 31, 2009 - $64,030,000). These payments are expected to be made over the next 30 years. An 8% to 10% (2009 – 8% to 10%) credit adjusted risk free discount rate and 2% (2009 – 2%) inflation rate were used to calculate the present value of the asset retirement obligation.

The following table reconciles Crew's asset retirement obligations:

	Nine months ended September 30, 2010	Year ended December 31, 2009
Carrying amount, beginning of period	$ 35,341	$ 34,941
Liabilities incurred	729	385
Liabilities disposed	(3,431)	(2,161)
Accretion expense	2,002	2,765
Liabilities settled	(906)	(589)
Carrying amount, end of period	$ 33,735	$ 35,341

6. SHARE CAPITAL:

(a) Authorized:

Unlimited number of Common Shares

(b) Common Shares issued:

	Number of shares	Amount
Common shares, December 31, 2009	78,152	$ 617,605
Exercise of stock options	2,054	18,813
Stock-based compensation	–	7,535
Share issue costs, net of income taxes of $12	–	(36)
Common shares, September 30, 2010	**80,206**	**$ 643,917**

(c) Contributed Surplus:

	Amount
Contributed surplus, December 31, 2009	$ 22,769
Exercise of options	(7,535)
Stock-based compensation	6,848
Contributed surplus, September 30, 2010	**$ 22,082**

(d) Stock-based compensation:

The Company measures compensation costs associated with stock-based compensation using the fair market value method under which the cost is recognized over the vesting period of the underlying security. The fair value of each stock option is determined at each grant date using the Black-Scholes model with the following weighted average assumptions used for options granted during the three month period ended September 30, 2010: risk free interest rate 1.89% (2009 – 2.16%), expected life 4 years (2009 – 4 years), volatility 61% (2009 – 60%), and an expected dividend of nil (2009 – nil). The Company has not incorporated an estimated forfeiture rate for stock options that will not vest, rather the Company accounts for actual forfeitures as they occur.

During the first nine months of 2010, the Company recorded $6,848,000, (2009 - $5,056,000) of stock-based compensation expense related to the stock options, of which $3,424,000 (2009 - $2,528,000) was capitalized in accordance with the Company's full cost accounting policy. As stock-based compensation is non-deductible for income tax purposes, a future income tax liability of $1,153,000 (2009 - $854,000) associated with the current year's capitalized stock-based compensation has been recorded.

The average fair value of the stock options granted during the nine months ended September 30, 2010, as calculated by the Black-Scholes method, was $8.03 per option (2009 - $2.04).

	Number of Options	Price Range	Weighted average exercise price
Balance December 31, 2009	5,751	$2.78 to $18.70	$ 8.33
Granted	2,235	$13.36 to $18.36	$ 15.17
Exercised	(2,054)	$2.78 to $16.60	$ 9.16
Forfeited	(440)	$2.78 to $16.60	$ 8.49
Balance September 30, 2010	5,492	$3.43 to $18.70	$ 10.79
Exercisable	1,687	$3.43 to $18.70	$ 9.00

(e) Per share amounts:

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 September 30, 2010 was 80,129,000 (2009 – 78,084,000) and for the nine month period ended September 30, 2010 the weighted average number of shares outstanding was 79,561,000 (2009 – 74,289,000).

In computing diluted per share amounts for the three month period ended September 30, 2010, no shares (2009 – nil) were added to the weighted average number of Common Shares outstanding for the dilution added by the stock options and for the nine month period ended September 30, 2010, no shares (2009 – nil) were added to the weighted average number of common shares for the dilution. There were 5,492,000 (2009 – 5,770,000) stock options that were not included in the diluted earnings per share calculation because they were anti-dilutive.

7. FINANCIAL INSTRUMENTS:

Overview

The Company has exposure to credit, liquidity and market risks from its use of financial instruments. This note provides information about the Company's exposure to each of these risks, the Company's objectives, policies and processes for measuring and managing risk. Further quantitative disclosures are included throughout these financial statements.

The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework. The Board has implemented and monitors compliance with risk management policies. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

(a) Credit risk:

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from petroleum and natural gas marketers and joint venture partners and the fair value of derivative instruments.

The carrying amount of accounts receivable and derivative assets, when outstanding, represents the maximum credit exposure. As at September 30, 2010 the Company's receivables consisted of $17.0 (2009 - $17.2) million of receivables from petroleum and natural gas marketers which has subsequently been collected, $10.2 (2009 - $9.2) million from joint venture partners of which $0.8 million has been subsequently collected, and $16.0 (2009 - $11.2) million of government deposits and incentives, prepaids and other accounts receivable. The Company does not consider any receivables to be past due.

(b) Liquidity risk:

Accounts payable and financial instruments have contractual maturities of less than one year. The Company maintains a revolving credit facility, as outlined in note 3, that is subject to renewal annually by the lenders and has a contractual maturity in 2012. The Company also maintains and monitors a certain level of cash flow which is used to finance operating and capital expenditures as the Company does not pay dividends. See Capital Management note 8.

(c) Market risk:

Market risk is the risk that changes in market conditions, such as commodity prices, interest rates, and foreign exchange rates will affect the Company's net income or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing the Company's returns.

The Company utilizes both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted in accordance with the Company's risk management policy that has been approved by the Board of Directors.

(i) Commodity price risk

The Company has attempted to mitigate a portion of the commodity price risk through the use of various financial derivative and physical delivery sales contracts as outlined below. The Company's Board of Directors approved policy is to enter into commodity price contracts when considered appropriate to a maximum of 50% of forecasted production volumes for a period of not more than two years. Any contracts extending beyond two years requires Board approval.

Derivatives are recorded on the balance sheet at fair value at each reporting period with the change in fair value being recognized as an unrealized gain or loss on the consolidated statement of operations.

(ii) Foreign currency exchange rate risk

The Company has attempted to mitigate a portion of its foreign exchange fluctuation risk through the use of financial derivatives as outlined below.

(iii) Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its bank loan which bears a floating rate of interest. For the three and nine months ended September 30, 2010, a 1.0 percent change to the effective interest rate would have a $0.1 million and $0.5 million impact on net income (2009 - $0.3 and $1.1 million).

The Company has attempted to mitigate the impact of future fluctuations in interest rates on its outstanding debt by entering into contracts fixing the base interest rate on $100 million of banker's acceptance borrowings as outlined below. These rates are, under the Company's bank Facility, subject to an additional stamping fee of 2.75 percent as of September 30, 2010.

The Company's derivative contracts in place as of September 30, 2010 are as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Natural Gas	2,500 gj/day	November 1, 2009 – December 31, 2010	AECO C Monthly Index	$6.00	Swap	581
Natural Gas	5,000 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index less $0.09	$8.00	Call	–
Natural Gas	10,000 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$7.75	Call	–
Natural Gas	2,500 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$6.20	Swap	626
Natural Gas	5,000 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$6.08	Swap	1,591
Natural Gas	2,500 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$5.25	Swap	409
Natural Gas	2,500 gj/day	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$5.55	Swap	477
Natural Gas	2,500 gj/day	April 1, 2010 – October 31, 2010	AECO C Monthly Index	$5.30	Swap	150
Natural Gas	5,000 mmbtu/ day	January 1, 2010 – December 31, 2010	AECO/NYMEX Basis diff	US$(0.55)	Swap	(73)
Oil	250 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$78.50	Swap	(118)
Oil	500 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$72.00 – $88.00	Collar	(47)
Oil	250 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$82.50	Swap	(25)
Oil	500 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$80.50	Swap	(125)
Oil	500 bbl/day	January 1, 2010 – December 31, 2010	US$ WTI	US$81.00	Swap	(9)
Oil	250 bbl/day	January 1, 2010 – December 31, 2010	CDN$ WTI	$80.00 – $95.02	Collar	23
Oil	250 bbl/day	March 1, 2010 – December 31, 2010	CDN$ WTI	$84.00	Swap	53
Oil	250 bbl/day	July 1, 2010 – December 31, 2010	CDN$ WTI	$88.10	Swap	102
Oil	250 bbl/day	July 1, 2010 – December 31, 2010	CDN$ WTI	$91.50	Swap	281
Oil	250 bbl/day	August 9, 2010 – December 31, 2010	CDN$ WTI	$85.00	Swap	31
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	US$ WTI	US$80.15	Swap	(880)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$86.00	Swap	(170)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$82.00 – $94.62	Collar	49
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$90.20	Swap	410
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$80.00 – $95.45	Collar	(4)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$90.00	Swap	193
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$88.50	Swap	53
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$85.00 – $100.50	Collar	352
Total commodity contracts						3,930

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
USD / CAD $ exchange	US $2M / Month	January 1, 2010 – December 31, 2010	CAD/USD	1.094	Swap	382
Total foreign exchange contract						382

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
BA Rate	$50M / year	February 10, 2009 – February 10, 2011	BA – CDOR	1.10%	Swap	22
BA Rate	$50M / year	February 12, 2009 – February 12, 2011	BA – CDOR	1.10%	Swap	38
Total interest rate contracts						60
Total financial instruments						4,372

As at September 30, 2010, a $0.10 change to the price per thousand cubic feet of natural gas on the contracts outlined above would have a $0.1 million impact on net income.

As at September 30, 2010, a $1.00 per barrel change to the price of oil on the contracts outlined above would have a $0.9 million impact on net income.

As at September 30, 2010, a $0.01 change to the exchange rate on the foreign exchange contracts outlined above would have less than a $0.1 million impact on net income.

As at September 30, 2010, a 0.1% change to the interest rate on the interest rate contracts outlined above would have less than a $0.1 million impact on net income.

Subsequent to September 30, 2010, the Company entered into the following financial derivative contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.85	Swap (1)
Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.90	Swap (1)
Gas	5,000 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$5.00	Swap (1)
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$88.00	Swap
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	US$ WTI	US$85.00	Call (1)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	US$ WTI	US$90.00	Call (1)

(1) Derivative contracts are part of a paired transaction in which the proceeds from the sale of 2012 oil calls were used to fund the 2011 natural gas swaps at the prices indicated.

Fair value of financial instruments

The Company's financial instruments as at September 30, 2010 and 2009 include accounts receivable, derivative contracts, accounts payable and accrued liabilities, and bank debt. The fair values of accounts receivable and accounts payable and accrued liabilities approximate their carrying amounts due to their short-terms to maturity.

The fair value of derivative contracts is determined by discounting the difference between the contracted price and published forward price curves as at the balance sheet date, using the remaining contracted notional volumes.

Bank debt bears interest at a floating market rate and accordingly the fair market value approximates the carrying value.

8. CAPITAL MANAGEMENT:

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 some 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 September 30, 2010, the Company's ratio of net debt to annualized funds from operations was 1.52 to 1 (December 31, 2009 – 1.67 to 1).

	September 30, 2010	December 31, 2009
Net debt:		
Accounts receivable	**$ 43,182**	$ 37,574
Accounts payable and accrued liabilities	**(79,314)**	(84,228)
Working capital deficiency	**$ (36,132)**	$ (46,654)
Bank loan	**(110,770)**	(135,601)
Net debt	**$ (146,902)**	$ (182,255)
Annualized funds from operations:		
Cash provided by operating activities	**$ 19,596**	$ 16,734
Asset retirement expenditures	**201**	111
Transportation liability charge	**156**	329
Change in non-cash working capital	**4,151**	10,082
Funds from operations	**24,104**	27,256
Annualized	**$ 96,416**	$ 109,024
Net debt to annualized funds from operations	**1.52**	1.67

The Company has commodity, interest rate and foreign exchange hedging for 2010 and 2011 to provide support for its funds from operations and assist in funding its capital expenditure program.

There has been no change in the Company's approach to capital management during the period ended September 30, 2010.

9. SUPPLEMENTAL CASH FLOW INFORMATION:

	Three months ended		Nine months ended	
	Sept. 30, 2010	Sept. 30, 2009	**Sept. 30, 2010**	Sept. 30, 2009
Changes in non-cash working capital:				
Accounts receivable	**$ (13,548)**	$ 762	**$ (5,608)**	$ 15,044
Accounts payable and accrued liabilities	**14,794**	23,653	**(4,914)**	(15,021)
	$ 1,246	$ 24,415	**$ (10,522)**	$ 23
Operating activities	**$ (4,151)**	$ 5,786	**$ 4,488**	$ 11,191
Investing activities	**5,397**	18,629	**(15,010)**	(11,168)
	$ 1,246	$ 24,415	**$ (10,522)**	$ 23

The Company made the following cash outlays in respect of interest expense:

	Three months ended		Nine months ended	
	Sept. 30, 2010	Sept. 30, 2009	**Sept. 30, 2010**	Sept. 30, 2009
Interest	**$ 1,325**	$ 1,662	**$ 3,887**	$ 5,850

10. COMMITMENTS:

The Company has the following fixed term commitments related to its on-going business:

	Total	2010	2011	2012	2013	2014	Thereafter
Operating Leases	$ 3,490	$ 432	$ 1,743	$ 1,315	$ –	$ –	$ –
Capital commitments	5,000	3,000	2,000	–	–	–	–
Transportation agreements	12,802	1,157	4,018	955	953	953	4,766
Processing agreement	28,204	762	3,049	3,049	3,049	3,049	15,246
Total	$ 49,496	$ 5,351	$ 10,810	$ 5,319	$ 4,002	$ 4,002	$ 20,012

The transportation agreements include an $8.8 million commitment to a third party to transport natural gas from the gas processing facility in the Septimus, British Columbia area to the Alliance pipeline system. The remaining commitment relates to firm transportation commitments that were acquired as part of the Company's May 2007 private company acquisition, of which, in 2010, the Company permanently assigned approximately $6.2 million of its firm commitments to third parties.

During 2009, Crew entered into an agreement to process natural gas through a third party owned gas processing facility in the Septimus area of northeast British Columbia. Under the terms of the agreement, Crew has committed to process a minimum monthly volume of gas through the facility commencing on December 1, 2009 and continuing through November 30, 2019. The commitment is included in the above table.

Subsequent to the quarter end, the Company amended the agreement with the owner of this facility. Under the terms of the amended agreement, Crew has begun expansion of the existing facility. On completion of the facility, Crew will be reimbursed for the full cost of the facility in return for an expanded processing commitment that will extend to December 2020. Crew has also 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.

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", "forecasts" 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 forecast 2010 exit rates; anticipated disposal rates on water disposal wells; future oil and natural gas prices and Crew's commodity risk management programs; future liquidity and financial capacity; future results from operations and operating metrics; anticipated reductions in operating costs; future costs, expenses and royalty rates; future interest costs; the exchange rate between the $US and $Cdn; future development, exploration, acquisition and development activities and related capital expenditures and the timing thereof; the number of wells to be drilled, completed and tied-in and the timing thereof; the amount and timing of capital projects; planned expansion of the Septimus gas processing facility and Crew's reimbursement of costs thereunder; operating costs; the total future capital associated with development of reserves and resources; forecasts in operating expenses.

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 and partner approvals; the ability of Crew to obtain qualified staff, regulatory and partner approvals, 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; and the ability of Crew to successfully market its oil and natural gas products.

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 partners; 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.

CORPORATE INFORMATION

HEAD OFFICE

Suite 1400, 425 - 1st Street S.W.
Calgary, Alberta T2P 3L8
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

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVE ENGINEERS

GLJ Petroleum Consultants

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
Stock Symbol: **CR**

BOARD OF DIRECTORS

John A. Brussa, Chairman
Independent Director

Jeffery E. Errico
Independent Director

Dennis L. Nerland
Independent Director

Dale O. Shwed
President, Crew Energy Inc.

David G. Smith
Independent Director

OFFICERS

Dale O. Shwed
President and
Chief Executive Officer

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

Ken Truscott
Senior Vice President, Business
Development and Land

Noel Cronin, P.Eng
Vice President, Operations
and Production

Kurtis Fischer
Vice President, Acquisitions
and Divestitures

Gary P. Smith
Vice President, Exploration

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

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

crew energy inc.

RESOURCE FOCUS • OPPORTUNITY • SUSTAINABILITY

crew
energy inc.

Suite 1400, 425 - 1st Street S.W.
Calgary, Alberta T2P 3L8
Phone: (403) 266-2088
Fax: (403) 266-6259
www.crewenergy.com