CREW ENERGY ISSUES 2011 SECOND QUARTER FINANCIAL AND OPERATING RESULTS
CALGARY, ALBERTA – AUGUST 10, 2011

Crew Energy Inc. (TSX-CR) of Calgary, Alberta is pleased to present its operating and financial results for the three and six month periods ended June 30, 2011.

Highlights

- Second quarter production of 16,443 boe per day represents a 37% (27% per share) increase over the same period in 2010 and a 5% (1% per share) increase over the first quarter of 2011;
- Second quarter liquids production increased to 6,827 bbls per day, a 54% increase over the second quarter of 2010;
- Funds from operations in the second quarter increased by 45% (38% per share) over the same period in 2010 and by 20% (17% per share) over the first quarter of 2011;
- Crew closed the acquisition of Caltex Energy Inc. on July 1, 2011 adding over 10,500 boe per day of production;
- Crew's active drilling program at Princess has resulted in exceptional test results in a previously undrilled area of the play with three wells testing 528, 707 and 2,030 bbls of oil per day as final test rates;
- Crew's success at Septimus, British Columbia continued with two (2.0 net) liquids rich wells testing, after seven days, 9.0 mmcf per day and 7.4 mmcf per day at flowing casing pressures of 1,740 psi and 1,530 psi, respectively.

Financial ($ thousands, except per share amounts)	**Three months ended June 30, 2011**	Three months ended June 30, 2010	**Six months ended June 30, 2011**	Six months ended June 30, 2010
Petroleum and natural gas sales	**70,236**	43,027	**131,384**	104,799
Funds from operations (note 1)	**28,891**	19,966	**53,002**	47,293
Per share - basic	**0.34**	0.25	**0.63**	0.60
- diluted	**0.33**	0.24	**0.62**	0.58
Net income (loss)	**16,261**	31,544	**6,135**	49,314
Per share - basic	**0.19**	0.39	**0.07**	0.62
- diluted	**0.19**	0.39	**0.07**	0.61
Capital expenditures	**53,185**	62,582	**128,350**	120,767
Property acquisitions (net of dispositions)	**(12,650)**	(121,724)	**(12,289)**	(132,640)
Net capital expenditures	**40,535**	(59,142)	**116,061**	(11,873)

Capital Structure ($ thousands)	**As at June 30, 2011**	As at Dec. 31, 2010
Working capital deficiency (note 2)	**40,177**	40,707
Bank loan	**102,591**	138,700
Net debt	**142,768**	179,407
Bank facility	**275,000**	240,000
Common Shares Outstanding (thousands)	**85,987**	80,368

Notes:
(1) Funds from operations is calculated as cash provided by operating activities, adding the change in non-cash working capital, decommissioning obligation expenditures, the transportation liability charge and acquisition costs. Funds from operations is used to analyze the Company's operating performance and leverage. Funds from operations does not have a standardized measure prescribed by International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures for other companies.
(2) Working capital deficiency includes only accounts receivable and assets held for sale less accounts payable and accrued liabilities.

Operations	**Three months ended June 30, 2011**	Three months ended June 30, 2010	**Six months ended June 30, 2011**	Six months ended June 30, 2010
Daily production				
Natural gas (mcf/d)	**57,698**	45,753	**54,919**	50,715
Oil (bbl/d)	**5,458**	3,305	**5,625**	3,780
Natural gas liquids (bbl/d)	**1,369**	1,117	**1,250**	1,284
Oil equivalent (boe/d @ 6:1)	**16,443**	12,048	**16,028**	13,517
Average prices (note 1)				
Natural gas ($/mcf)	**4.06**	4.31	**4.03**	4.89
Oil ($/bbl)	**82.50**	65.86	**75.93**	69.36
Natural gas liquids ($/bbl)	**63.74**	52.01	**61.93**	53.50
Oil equivalent ($/boe)	**46.94**	39.25	**45.29**	42.83
Netback				
Operating netback ($/boe) (note 2)	**22.03**	21.33	**21.15**	22.55
Realized loss (gain) on financial instruments ($/boe)	**-**	(0.17)	**-**	(0.09)
G&A ($/boe)	**1.89**	2.16	**1.94**	2.01
Interest on bank debt ($/boe)	**0.82**	1.12	**0.94**	1.30
Funds from operations ($/boe)	**19.32**	18.22	**18.27**	19.33
Drilling Activity				
Gross wells	**15**	11	**55**	33
Working interest wells	**15.0**	10.3	**54.3**	30.5
Success rate, net wells	**100%**	100%	**100%**	100%

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

Overview

Operations during the second quarter of 2011 were highlighted by the drilling of 15 (15.0 net) wells with 100% success. At Princess, Alberta, Crew drilled four (4.0 net) horizontal wells targeting oil and four (4.0 net) water disposal wells. The Company drilled four (4.0 net) wells at Septimus, British Columbia targeting liquids rich Montney gas. In addition, two (2.0 net) horizontal wells were drilled for Lloydminster oil at Killam, Alberta and one (1.0 net) well was drilled at Provost, Alberta targeting Viking oil. Due to an early and prolonged spring breakup and extreme rainfall, only one of the wells drilled in the second quarter at Princess is currently on production. All four wells drilled at Septimus were completed and are on production due to their proximity to pre-existing pad sites. One of the wells at Killam is producing and the Provost well is currently testing. As a result of weather related delays, net capital expenditures in the second quarter were $40.5 million or 30% lower than budgeted.

Average production for the second quarter was 16,443 boe per day which is a 5% increase over the first quarter of 2011. This increase occurred despite extreme wet weather in all of Crew's core areas during the second quarter which severely curtailed operations. In addition, the Spectra McMahon gas facility in Fort St. John, British Columbia was shut down for a turnaround for two weeks in June which reduced Crew's average June production by approximately 700 boe per day. Crew also closed the sale of approximately 140 boe per day of non-core natural gas production in the Gilby, Alberta area for $12.6 million on April 1, 2011.

On May 2, 2011, Crew announced the acquisition of Caltex Energy Inc. This transaction closed on July 1, 2011 and added approximately 10,500 boe per day of estimated production (68% oil and liquids), 42.7 million boe of proved plus probable reserves (independently evaluated effective December 31, 2010) and 137,000 net undeveloped acres of land. Crew has identified over 900 future drilling and recompletion opportunities on Caltex lands. This acquisition is consistent with Crew's strategy to focus on large hydrocarbon in place reservoirs, oil production growth and less capital intensive drilling and completion projects.

OPERATIONS UPDATE

Pekisko Play - Princess, Alberta

During the second quarter, Crew drilled four (4.0 net) horizontal wells targeting oil and four (4.0 net) water disposal wells in the West Tide Lake area. Wet conditions during the quarter allowed for only one well to be placed on production. Subsequent to quarter end, Crew has had exceptional success in a previously undrilled area at Tide Lake with one well production testing at an area record of 2,311 boe per day (88% oil) and two additional wells testing at 732 boe per day (97% oil) and 610 boe per day (87% oil) . The Company currently has six completion rigs active at Princess to expedite the production from wells drilled in the first and second quarters.

Crew drilled four (4.0 net) water disposal wells in the quarter with all being drilled horizontally in the Leduc formation. These wells will be completed in the third quarter and are expected to be in service in the fourth quarter.

The Company's Tilley waterflood is on schedule for start-up in mid-August with all pipelines and well conversions currently in place. Five additional wells are slated for injection with waterflood modelling suggesting oil recovery potential to increase to approximately 20% to 30% from the current estimated primary recovery of 10% to 13%. Crew believes widespread application of secondary recovery schemes could be applied to other Pekisko reservoirs in the Princess area. Besides materially improving oil recovery, waterflood applications are expected to result in reduced operating costs as produced water is re-injected into the reservoir and decline rates are reduced through reservoir pressure maintenance.

In the third quarter of 2011, the Alderson and West Tide Lake batteries are scheduled for turnarounds which are expected to enhance throughput by reducing area inlet and pipeline pressures. Crew is constructing a fourth oil facility in the greater Princess area at Alderson which will be capable of processing 52,000 bbls per day of emulsion and over 7,000 bbls per day of oil and is expected to begin construction in October. The Company has plans to construct a new facility at Tide Lake in the first quarter of 2012 capable of processing 26,200 bbls per day of emulsion and 3,100 bbls of oil per day. This aggressive infrastructure build-out is expected to continue as the Company continues to drill the southern and eastern areas of its land base at Princess.

Drilling success at Princess continues to support significant capital investment. Crew currently has six drilling rigs active in the Princess area. For the remainder of 2011, Crew plans to drill 47 horizontal, 20 vertical and 11 water disposal wells and has a backlog of 16 horizontal and 11 vertical wells to place on production at Princess. The targeted exit production rate for the area remains at 12,000 boe per day.

Montney Play - Northeast British Columbia

Crew drilled four (4.0 net) wells in the Montney formation at Septimus in the second quarter of 2011 with all being successful liquids rich gas wells. One well drilled in the first quarter was brought on production at a rate of 11.5 mmcf per day at a flowing casing pressure of 1,436 psi. Two of the second quarter wells each had average seven day test rates of 3.5 mmcf per day at a flowing casing pressure of 1,175 psi. The other two second quarter wells were brought on production in early July and have current rates of 9.1 mmcf per day at 1,740 psi flowing casing pressure and 7.4 mmcf per day at 1,530 psi flowing casing pressure. Current production at Septimus exceeds 6,400 boe per day based on field estimates. One (0.33 net) non-operated well drilled at Tower targeting Montney oil is currently being completed. Crew plans to drill three to five (3.0 to 5.0 net) more wells at Septimus in the remainder of 2011.

In addition to this activity, Crew is also active in the Montney play at Kobes, British Columbia. During the second quarter, the Company completed its analysis of a large three dimensional seismic survey over Crew's contiguous 23 net section land block and plans to drill its first two horizontal wells into this play in September or October. This play may require up to twelve wells per section to adequately drain the estimated 1,000 feet thick gas saturated rock at Kobes.

Other Exploration Plays – Central Alberta

At Killam, Alberta, the Company drilled two (2.0 net) dual leg horizontal wells targeting oil in the Mannville Group offsetting Crew production and recent industry activity. The first well is currently on production at a stable rate of 120 boe per day (49% oil) and the second well is awaiting pressure build-up.

At Provost, Alberta, Crew drilled one (1.0 net) horizontal well targeting oil in the Viking formation. This well is currently undergoing testing. At Pine Creek, Alberta, the Company recently completed the drilling of two (2.0 net) horizontal wells with one well targeting Cardium oil and the other targeting Mannville liquids rich gas. Both wells are awaiting completion. Crew plans to drill an additional two (2.0 net) Mannville wells and one (1.0 net) Cardium horizontal well in the third quarter.

Acquisition of Caltex Energy Inc.

On July 1, 2011, Crew closed the acquisition of Caltex Energy Inc. This transaction adds production of approximately 10,500 boe per day, reserves of 42.7 million boe of proved plus probable reserves and undeveloped land of 137,000 net acres. Current produced and booked recovery factors on oil of 4% and liquids rich gas of 27% is anticipated to be improved through a large infill drilling and recompletion inventory of over 900 identified locations.

In the second half of 2011, Crew plans to drill up to 26 wells in the Lloydminster area of Saskatchewan targeting Mannville oil and up to five wells in the Wapiti area of Alberta targeting liquids rich gas in the Cardium. To date, one (1.0 net) horizontal well and three (2.56 net) vertical wells have been drilled at Lloydminster with all wells awaiting completion.

Outlook

Crew is planning to be very active over the next six months with nine drilling rigs, seven service rigs and six pipeline crews currently active. Through the first six months of 2011, the Company has only completed 35% of its planned $330 million capital budget. Average production for the month of July based on field estimates was 27,500 boe per day and the Company has 37 wells to place on production and 119 wells planned to be drilled for the remainder of 2011.

With the closing of the Caltex acquisition on July 1, Crew is forecasting average 2011 production of 23,000 to 24,000 boe per day. The $330 million capital program is expected to result in exit 2011 production of 32,500 to 34,500 boe per day. Net debt at the end of the second quarter was $142.8 million and Crew currently has a $400 million borrowing base with a syndicate of seven banks. Crew will proactively manage its business to maintain its strong balance sheet and financial flexibility.

Our immediate focus continues to be the successful integration of the Caltex staff and properties and the efficient execution of our capital program. With the Caltex acquisition, Crew has been transformed into an intermediate producer with four highly focused areas of operation. The Company has an inventory of over 13 years of opportunities based on our current pace of development and has assembled a resource rich suite of assets over our eight year history. Crew is concentrating on the development of oil in two of the most economically attractive plays in North America as well as the de-risking of its vast liquids rich natural gas resource in northeastern British Columbia and Alberta. We are excited about our future and look forward to reporting our progress in our business plan in our third quarter report.

Management's Discussion and Analysis

ADVISORIES

Management's discussion and analysis ("MD&A") is the Company's explanation of its financial performance for the period covered by the financial statements along with an analysis of the Company's financial position. Comments relate to and should be read in conjunction with the unaudited interim consolidated financial statements of the Company for the three and six month periods ended June 30, 2011 and 2010 and the audited consolidated financial statements and Management's Discussion and Analysis for the year ended December 31, 2010. In 2010, the CICA Handbook was revised to incorporate International Financial Reporting Standards ("IFRS"), and require publicly accountable enterprises to apply such standards effective for years beginning on or after January 1, 2011. Previously, the Company prepared its interim and annual consolidated financial statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). The interim consolidated financial statements have been prepared in accordance with IFRS and all figures provided herein and in the December 31, 2010 consolidated financial statements are reported in Canadian dollars.

Forward Looking Statements

This MD&A contains forward looking statements. Management's assessment of future plans and operations, drilling plans and the timing thereof, plans for the tie-in and completion of wells and the timing thereof, capital expenditures, timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, production estimates, expected commodity mix and prices, future operating costs, future transportation costs, expected royalty rates, general and administrative expenses, interest rates, debt levels, funds from operations and the timing of and impact of implementing accounting policies, estimated production associated with the properties of Caltex, estimates regarding undeveloped land position and estimated future drilling, recompletion or reactivation locations associated with the Caltex properties and anticipated impact upon Crew's forecasts in respect of production and cash flow for 2011 and resulting year-end net debt may constitute forward looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, the inability to fully realize the benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and inability to access sufficient capital from internal and external sources. As a consequence, the Company's actual results may differ materially from those expressed in, or implied by, the forward looking statements. Included herein is an estimate of Crew's year-end net debt based on assumptions as to cash flow, capital spending in 2011 and other assumptions utilized in arriving at Crew's 2011 capital budget including without limitation assumptions about the impact of the Caltex properties on Crew. Forward looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Crew believes that the expectations reflected in such forward looking statements or information are reasonable, undue reliance should not be placed on forward looking statements because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document and other documents filed by the Company, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Company has an interest in to operate the field in a safe, efficient and effective manner; Crew's ability to obtain financing on acceptable terms; field production rates and decline rates; the ability to reduce operating costs; the ability to replace and expand oil and natural gas reserves through acquisition, development or exploration; the timing and costs of pipeline, storage and facility construction and expansion; the ability of the Company to secure adequate product transportation; future petroleum and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company operates; and Crew's ability to successfully market its petroleum and natural gas products. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) or at the Company's website (www.crewenergy.com). Furthermore, the forward looking statements contained in this document are made as at the date of this document and the Company does not undertake any obligation to update publicly or to revise any of the included forward looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Conversions

The oil and gas industry commonly expresses production volumes and reserves on a "barrel of oil equivalent" basis ("boe") whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved analysis of results and comparisons with other industry participants.

Throughout this MD&A, Crew has used the 6:1 boe measure which is the approximate energy equivalency of the two commodities at the burner tip. Boe does not represent a value equivalency at the wellhead nor at the plant gate which is where Crew sells its production volumes and therefore may be a misleading measure, particularly if used in isolation.

Non-IFRS Measures

Funds from operations

One of the benchmarks Crew uses to evaluate its performance is funds from operations. Funds from operations is a measure not defined in IFRS that is commonly used in the oil and gas industry. It represents cash provided by operating activities before changes in non-cash working capital, decommissioning obligation expenditures, the transportation liability charge and acquisition costs. The Company considers it a key measure as it demonstrates the ability of the Company's continuing operations to generate the cash flow necessary to fund future growth through capital investment and to repay debt. Funds from operations should not be considered as an alternative to or more meaningful than cash provided by operating activities as determined in accordance with IFRS as an indicator of the Company's performance. Crew's determination of funds from operations may not be comparable to that reported by other companies. Crew also presents funds from operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of income per share. The following table reconciles Crew's cash provided by operating activities to funds from operations:

($ thousands)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Cash provided by operating activities	32,896	23,422	59,365	54,745
Decommissioning obligation expenditures	132	129	121	705
Transportation liability charge (note 1)	103	154	204	482
Acquisition costs (note 2)	2,150	-	2,150	-
Change in non-cash working capital	(6,390)	(3,739)	(8,838)	(8,639)
Funds from operations	28,891	19,966	53,002	47,293

Notes:
(1) The amount for the six months ended June 30, 2010 does not include the transportation liability write-down of $344,000 as shown in the transportation costs section.
(2) This amount relates to costs incurred for the Caltex acquisition that closed on July 1, 2011. See Finance Expenses section for further details.

Operating Netback

Management uses certain industry benchmarks such as operating netback to analyze financial and operating performance. This benchmark as presented does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Operating netback equals total petroleum and natural gas sales including realized gains and losses on commodity derivative contracts less royalties, operating costs and transportation costs calculated on a boe basis. Management considers operating netback an important measure to evaluate its operational performance as it demonstrates its field level profitability relative to current commodity prices. The calculation of Crew's netbacks can be seen below in the Operating Netbacks section.

Working Capital and Net Debt

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

($ thousands)	June 30, 2011	December 31, 2010
Current assets	42,252	61,020
Current liabilities	(91,045)	(101,088)
Fair value of financial instruments	8,477	(982)
Current portion of other long-term obligations	139	343
Working capital deficit	(40,177)	(40,707)

($ thousands)	June 30, 2011	December 31, 2010
Bank loan	(102,591)	(138,700)
Working capital deficit	(40,177)	(40,707)
Net debt	(142,768)	(179,407)

RESULTS OF OPERATIONS

Acquisition of Caltex

On July 1, 2011, Crew closed the previously announced acquisition whereby the Company acquired all of the issued and outstanding shares of Caltex Energy Inc. ("Caltex"), a Canadian private oil and gas company with operations in Saskatchewan and Alberta (the "Transaction"). Caltex shareholders received 0.38 of a Crew common share for each Caltex share held or an aggregate of approximately 33.6 million Crew shares.

Upon closing of the Transaction, Caltex became a wholly owned subsidiary of Crew and immediately following closing, former Caltex shareholders owned approximately 28% of the combined entity.

Crew believes the Transaction represents the successful continuation of our strategy of exploiting high netback assets with significant resource potential. The Company has increased its 2011 production guidance to 23,000 to 24,000 boe per day with an anticipated exit rate of 32,500 to 34,500 boe per day.

Production

	Three months ended June 30, 2011				Three months ended June 30, 2010			
	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	5,348	434	21,772	9,411	3,184	420	21,633	7,210
British Columbia	110	935	35,926	7,032	121	697	24,120	4,838
Total	5,458	1,369	57,698	16,443	3,305	1,117	45,753	12,048

In the second quarter of 2011, oil production increased 65% compared to the same period in 2010 as a result of production additions from the successful drilling program in late 2010 and the first quarter of 2011 in the Princess, Alberta area. Natural gas and natural gas liquids ("ngl") production increased in the second quarter of 2011 compared with the second quarter of 2010 resulting from the successful drilling program in 2011 in the Septimus, British Columbia area.

	Six months ended June 30, 2011				Six months ended June 30, 2010			
	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	5,511	398	22,120	9,595	3,659	612	26,232	8,643
British Columbia	114	852	32,799	6,433	121	672	24,483	4,874
Total	5,625	1,250	54,919	16,028	3,780	1,284	50,715	13,517

Production for the first six months of 2011 increased due to the previously mentioned successful drilling programs in the Septimus and Princess areas which more than offset the disposition of approximately 1,700 boe per day of natural gas and associated liquids production in the Edson, Alberta area in the second quarter of 2010.

Revenue

	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Revenue ($ thousands)				
Natural gas	21,317	17,929	40,068	44,913
Oil	40,975	19,809	77,306	47,457
Natural gas liquids	7,944	5,289	14,010	12,429
Total	70,236	43,027	131,384	104,799
Crew average prices				
Natural gas ($/mcf)	4.06	4.31	4.03	4.89
Oil ($/bbl)	82.50	65.86	75.93	69.36
Natural gas liquids ($/bbl)	63.74	52.01	61.93	53.50
Oil equivalent ($/boe)	46.94	39.25	45.29	42.83
Benchmark pricing				
Natural Gas – AECO C daily index (Cdn $/mcf)	3.94	3.94	3.88	4.49
Oil – Bow River Crude Oil (Cdn $/bbl)	92.86	75.24	86.78	77.75
Oil and ngl – Cdn$ West Texas Int. (Cdn $/bbl)	99.20	80.12	95.97	81.01

Crew's second quarter 2011 revenue was significantly higher as compared to the second quarter of 2010 as a result of the increased production of natural gas and associated natural gas liquids in the Septimus area and increased oil production from the Princess area. This increased production was enhanced by the increase in oil and natural gas liquids pricing partially offset by a decrease in the Company's natural gas pricing.

In the second quarter of 2011, the Company's natural gas benchmark price was consistent with the same period in 2010 while the Company's realized average natural gas price decreased 6% over the same period in 2010. This is a result of increased production of lower valued residual natural gas from oil wells in the Princess area. The Company's realized oil price increased 25% which was comparable with the increase in the Bow River Crude benchmark of 23% for the same period in 2010. In the second quarter of 2011, the Company's ngl price increased proportionately with the increase in the Company's benchmark Cdn$ West Texas Intermediate price compared to the same period in 2010.

For the first six months of 2011 the Company's realized natural gas price decreased 18% compared to the benchmark that decreased 14% for the same period in 2010 as a result of the increased production of residual natural gas from oil wells in the Princess area as well as the disposition of higher heat content natural gas production from the Edson area in the second quarter of 2010. The Company's realized oil and ngl price both increased similar to the increases in the Company's benchmark pricing for the first six months of 2011 as compared to the same period in 2010.

Royalties

($ thousands, except per boe)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Royalties	16,574	8,419	30,930	21,568
Per boe	11.08	7.68	10.66	8.82
Percentage of revenue	23.6%	19.6%	23.5%	20.6%

Royalties as a percentage of revenue increased in the second quarter and for the first six months of 2011 compared to the same periods in 2010 due to increased production in the Princess area which, in the current pricing environment, attracts a higher royalty rate than Crew's other producing areas. Crew continues to forecast royalty rates to average between 23% and 25% for 2011.

Financial Instruments

Commodities

The Company enters into derivative and physical risk management contracts in order to reduce volatility in financial results, to protect acquisition economics and to ensure a certain level of cash flow to fund planned capital projects. Crew's strategy focuses on the use of puts, costless collars, swaps and fixed price contracts to limit exposure to fluctuations in commodity prices, interest rates and foreign exchange rates while allowing for participation in commodity price increases. The Company's financial derivative trading activities are conducted pursuant to the Company's Risk Management Policy approved by the Board of Directors. In 2011, these contracts had the following impact on the consolidated statement of income:

($ thousands)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Realized gain/(loss) on financial instruments	(1,001)	3,756	15	4,684
Unrealized gain/(loss) on financial instruments	15,770	2,334	(263)	10,532

As at June 30, 2011, 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	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.85	Swap(1)	534
Natural Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.90	Swap(1)	556
Natural Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.95	Swap(1)	578
Natural Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.965	Swap(1)	671
Natural Gas	7,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$5.00	Swap(1)	1,901
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	US$ WTI	US$80.15	Swap	(1,485)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$86.00	Swap	(411)
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$88.00	Swap	(564)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$88.50	Swap	(279)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$90.00	Swap	(167)
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$90.20	Swap	(320)
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$93.00	Swap	(16)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$80.00 - $95.45	Collar	(123)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$82.00 - $94.62	Collar	(132)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$85.00 - $100.50	Collar	(19)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$85.00	Call(1)	(3,614)
Oil	750 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$90.00	Call(1)	(3,768)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	US$ WTI	US$90.00	Call(1)	(2,993)
Oil	250 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$100.45	Swap	268
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$101.00	Swap	630
Oil	250 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$100.50	Swap	276
Total						(8,477)

(1) These 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

($ thousands, except per boe)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Operating costs	17,033	12,663	33,451	27,649
Per boe	11.38	11.55	11.53	11.30

In the second quarter of 2011, the Company's operating costs per unit decreased over the same period in 2010 due to increased production which lowered fixed costs per boe. The Company also significantly increased production in the Septimus area which has a lower cost per unit than the Company's operating cost per boe. This was partially offset by increased production in the Princess area which has a higher cost per boe than the Company's average operating cost per boe. For the first six months of 2011, the Company's operating costs per unit increased as compared to the same period in 2010 due to the second quarter 2010 sale of the Edson properties which had a lower cost per boe. With the addition of the Caltex properties, the Company forecasts operating costs to average $11.00 to $12.00 per boe for 2011.

Transportation Costs

($ thousands, except per boe)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Transportation costs including liability write-down	2,671	2,143	5,667	4,520
Transportation liability write-down	-	-	-	344
Transportation costs	2,671	2,143	5,667	4,864
Per boe	1.78	1.95	1.95	1.99

In the second quarter and first six months of 2011, the Company's transportation costs per boe decreased compared to the same periods in 2010 due to increased production at Princess and Septimus which both attract a lower transportation cost per unit than the Company's average transportation cost per unit. With the addition of the Caltex properties, the Company expects transportation costs per boe to range between $1.70 and $1.90 per boe for 2011.

Operating Netbacks

	Three months ended June 30, 2011				Three months ended June 30, 2010			
	Oil ($/bbl)	Ngl ($/bbl)	Natural gas ($/mcf)	Total ($/boe)	Oil ($/bbl)	Ngl ($/bbl)	Natural gas ($/mcf)	Total ($/boe)
Revenue	82.50	63.74	4.06	46.94	65.86	52.01	4.31	39.25
Realized commodity hedging gain (loss)	(6.47)	-	0.42	(0.67)	1.02	-	0.07	3.26
Royalties	(27.49)	(11.24)	(0.29)	(11.08)	(18.30)	(10.69)	(0.44)	(7.68)
Operating costs	(15.73)	(8.48)	(1.55)	(11.38)	(15.69)	(9.89)	(1.69)	(11.55)
Transportation costs	(1.62)	(1.65)	(0.32)	(1.78)	(1.94)	(1.08)	(0.35)	(1.95)
Operating netbacks	31.19	42.37	2.32	22.03	30.95	30.35	1.90	21.33

	Six months ended June 30, 2011				Six months ended June 30, 2010			
	Oil ($/bbl)	Ngl ($/bbl)	Natural gas ($/mcf)	Total ($/boe)	Oil ($/bbl)	Ngl ($/bbl)	Natural gas ($/mcf)	Total ($/boe)
Revenue	75.93	61.93	4.03	45.29	69.36	53.50	4.89	42.83
Realized commodity hedging gain (loss)	(4.30)	-	0.44	-	0.42	-	0.03	1.83
Royalties	(24.86)	(11.19)	(0.31)	(10.66)	(19.84)	(12.28)	(0.56)	(8.82)
Operating costs	(15.23)	(8.43)	(1.61)	(11.53)	(14.15)	(9.44)	(1.72)	(11.30)
Transportation costs	(1.66)	(1.76)	(0.36)	(1.95)	(1.38)	(1.26)	(0.36)	(1.99)
Operating netbacks	29.88	40.55	1.31	21.15	34.41	30.52	2.28	22.55

General and Administrative Costs

($ thousands, except per boe)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Gross costs	4,398	3,926	8,595	8,099
Operator's recoveries	(107)	(191)	(220)	(368)
Capitalized costs	(1,456)	(1,368)	(2,752)	(2,804)
General and administrative expenses	2,835	2,367	5,623	4,927
Per boe	1.89	2.16	1.94	2.01

Increased general and administrative costs after recoveries and capitalization for the second quarter and first six months of 2011 were mainly the result of increased staff levels to accommodate the Company's increased production levels. The Company's general and administrative costs per boe have decreased in the second quarter and first six months of 2011 due to the increased production levels over the same periods in 2010. The introduction of IFRS has resulted in the Company altering the recoveries and the capitalization of some general and administrative costs. As such, net general and administrative expenses for the three and six months ended June 30, 2010, increased to $2.4 million and $4.9 million from $1.6 million and $3.3 million as reported under previous GAAP. With the addition of production from the Caltex properties, the Company expects general and administrative expenses to average between $1.30 and $1.80 per boe for 2011.

Stock-Based Compensation

($ thousands)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Gross costs	3,169	2,309	4,712	4,789
Capitalized costs	(1,459)	(1,061)	(2,168)	(2,202)
Total stock-based compensation	1,710	1,248	2,544	2,587

In the second quarter of 2011, the Company's stock-based compensation expense has increased compared with the same period in 2010 due to an increase in the number of stock options outstanding combined with the Company incurring higher stock-based compensation costs in the first year of the option grants due to a graded vesting schedule under IFRS.

Depletion and Depreciation

($ thousands, except per boe)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Depletion and depreciation	23,129	17,506	44,094	37,587
Per boe	15.46	15.97	15.20	15.36

Total depletion and depreciation costs per boe have decreased in the second quarter and first six months of 2011 compared to the same periods in 2010 due to successful lower cost reserve additions from the Company's drilling program over the past year. Under IFRS, Crew depletes its assets on a component basis utilizing total proved plus probable reserves as opposed to depleting using total proved reserves under previous GAAP.

Finance Expenses

($ thousands, except per boe)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Interest on bank debt	1,231	1,225	2,726	3,182
Accretion of the decommissioning obligation	529	477	1,006	1,009
Acquisition costs	2,150	-	2,150	-
Total finance expense	3,910	1,702	5,882	4,191
Average debt level	83,501	50,446	99,662	92,908
Effective interest rate on bank debt	5.9%	9.7%	5.5%	6.9%
Interest on bank debt per boe	0.82	1.12	0.94	1.30

In the second quarter of 2011, interest on bank debt was similar to the same period in 2010 as lower margins on the Company's bank facility were offset by higher average debt levels. For the first six months of 2011, the Company's effective interest rate on bank debt was lower than the same period in 2010 due to lower margins on the Company's bank facility combined with reduced deferred financing costs. The Company projects its effective interest rate on bank debt will average approximately 5.0% to 5.5% in 2011.

Acquisition costs are those expenditures incurred by Crew during the three months ended June 30, 2011 related to the acquisition of Caltex which closed on July 1, 2011. Under IFRS, costs such as legal, accounting and regulatory fees associated with the acquisition of a business are expensed in the period in which they are incurred.

Deferred Income Taxes

In the second quarter and first six months of 2011, the provision for deferred income taxes was $5.6 million and $1.5 million, respectively, compared to $9.9 million and $15.9 million for the same period in 2010 due to higher pre-tax earnings in 2010.

Cash and Funds from Operations and Net Income

($ thousands, except per share amounts)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Cash provided by operating activities	32,896	23,422	59,365	54,745
Funds from operations	28,891	19,966	53,002	47,293
Per share - basic	0.34	0.25	0.63	0.60
- diluted	0.33	0.24	0.62	0.60
Net income	16,261	31,544	6,135	49,314
Per share - basic	0.19	0.39	0.07	0.62
- diluted	0.19	0.39	0.07	0.62

The second quarter and first six months of 2011 increase in cash provided by operating activities and funds from operations was the result of increased oil and ngl pricing combined with higher production levels. The second quarter and first six months of 2011 decreased net income was due to a significant gain on sale recorded on the disposition of the Edson properties in the second quarter of 2010.

Capital Expenditures, Acquisitions and Dispositions

During the second quarter, the Company drilled a total of 15 (15.0 net) wells resulting in seven (7.0 net) oil wells, four (4.0 net) natural gas wells and four (4.0 net) service wells. In addition, the Company completed ten (10.0 net) wells and recompleted six (6.0 net) wells in the quarter. The Company continued to add to its infrastructure spending $12.1 million on pipelines and upgrading its batteries and facilities predominantly in the Princess and Septimus areas. The Company also closed a disposition of non-core production in central Alberta for $12.6 million. Total net capital expenditures for the quarter are detailed below:

($ thousands)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Land	2,005	27,155	2,416	34,872
Seismic	832	164	8,176	5,095
Drilling and completions	36,488	26,561	86,516	66,891
Facilities, equipment and pipelines	12,116	7,490	28,128	11,770
Other	1,744	1,212	3,114	2,139
Total exploration and development	53,185	62,582	128,350	120,767
Property acquisitions (dispositions)	(12,650)	(121,724)	(12,289)	(132,640)
Total	40,535	(59,142)	116,061	(11,873)

Liquidity and Capital Resources

Capital Funding

Upon closing of the Caltex acquisition on July 1, 2011, the Company completed an update to its bank facility with a syndicate of banks (the “Syndicate”). The Company’s lenders have increased the Company’s total bank facility to $400 million. The credit Facility includes a revolving line of credit of $370 million and an operating line of credit of $30 million (the “Facility”). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 11, 2012. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 percent and all outstanding balances under the Facility will become repayable in one year. The available lending limits of the Facility are reviewed semi-annually and are based on the Syndicate’s interpretation of the Company’s reserves and future commodity prices. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled borrowing base review on or before October 15, 2011. At June 30, 2011, the Company had drawings of $102.6 million on the Facility and had issued letters of credit totaling $10.6 million.

On March 2, 2011, the Company closed a bought deal sale of 4,820,000 Common Shares of the Company at a price of $20.75 per share for aggregate gross proceeds of $100 million.

During the first six months of 2011, the Company received proceeds of $7.4 million upon the exercise of 799,000 employee stock options.

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

Working Capital

The capital intensive nature of Crew’s activities generally results in the Company carrying a working capital deficit. Working capital deficit includes accounts receivable less accounts payable and accrued liabilities. The Company maintains sufficient unused bank credit lines to satisfy working capital deficits. At June 30, 2011, the Company‘s working capital deficiency totaled $40.2 million which, when combined with the drawings on its bank line and the estimated net debt of approximately $65 million assumed from the Caltex acquisition, represented approximately 52% of its updated bank facility at July 1, 2011.

Share Capital

As at August 9, 2011, Crew had 119,594,738 Common Shares and options to acquire 7,707,800 Common Shares of the Company issued and outstanding.

Capital Structure

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

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

The Company monitors this ratio and endeavours to maintain it at or below 2.0 to 1.0. This ratio may increase at certain times as a result of acquisitions or low commodity prices. As shown below, as at June 30, 2011, the Company's ratio of net debt to annualized funds from operations was 1.24 to 1 (December 31, 2010 – 1.63 to 1).

($ thousands, except ratio)	June 30, 2011	Dec. 31, 2010
Working capital deficit	(40,177)	(40,707)
Bank loan	(102,591)	(138,700)
Net debt	(142,768)	(179,407)
Funds from operations	28,891	27,449
Annualized	115,564	109,796
Net debt to annualized funds from operations ratio	1.24	1.63

Contractual Obligations

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

($ thousands)	Total	2011	2012	2013	2014	2015	Thereafter
Bank Loan (note 1)	102,591	-	-	102,591	-	-	-
Operating Leases	2,188	879	1,309	-	-	-	-
Capital commitments	1,000	1,000	-	-	-	-	-
Firm transportation agreements	20,018	2,000	1,535	1,535	2,110	2,110	10,728
Firm processing agreement	74,700	3,290	6,526	6,526	8,239	8,239	41,880
Total	200,497	7,169	9,370	110,652	10,349	10,349	52,608

Note 1 – Based on the existing terms of the Company's bank facility the first possible repayment date may come in 2013. 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 $18.8 million commitment to a third party to transport natural gas from a gas processing facility in the Septimus 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. 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 committed to process a minimum monthly volume of gas through the facility commencing on December 1, 2009 and continuing through November 30, 2019.

In the fourth quarter of 2010, the Company amended the agreement with the owner of this facility. Under the terms of the amended agreement, Crew constructed a facility expansion during the fourth quarter of 2010 and subsequently closed the sale of the Septimus facility expansion in the first quarter of 2011. Upon completion of the expansion, Crew was reimbursed for the cost of the facility expansion of $16.9 million in return for an expanded processing commitment that will extend to December 2020. As part of the amended agreement, 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. If the Company re-purchases a 50% interest on January 1, 2014 for approximately $18.0 million, the remaining commitment would be reduced by approximately $29.0 million.

Guidance

Crew is planning to be very active over the next six months with nine drilling rigs, seven service rigs and six pipeline crews currently active. Through the first six months of 2011, the Company has only completed 35% of its planned $330 million capital budget. Average production for the month of July based on field estimates was 27,500 boe per day and the Company has 37 wells to place on production and 119 wells planned to be drilled for the remainder of 2011.

With the closing of the Caltex acquisition on July 1, Crew is forecasting average 2011 production of 23,000 to 24,000 boe per day. The $330 million capital program is expected to result in exit 2011 production of 32,500 to 34,500 boe per day. Net debt at the end of the second quarter was $142.8 million and Crew currently has a $400 million borrowing base with a syndicate of seven banks. Crew will proactively manage its business to maintain its strong balance sheet and financial flexibility.

Additional Disclosures

Quarterly Analysis

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

($ thousands, except per share amounts)	June 30 2011	Mar. 31 2011	Dec. 31 2010	Sept. 30 2010	June 30 2010	Mar. 31 2010	Dec. 31 2009	Sept. 30 2009
Total daily production (boe/d)	16,443	15,607	14,654	13,061	12,048	15,001	14,470	13,065
Average wellhead price ($/boe)	46.94	43.53	42.00	37.39	39.25	45.75	43.30	32.04
Petroleum and natural gas sales	70,236	61,148	56,620	44,924	43,027	61,772	57,646	38,510
Cash provided by operations	32,896	26,469	20,225	18,956	23,422	31,323	16,734	24,902
Funds from operations	28,891	24,111	27,449	23,464	19,966	27,327	27,256	19,640
Per share – basic	0.34	0.29	0.34	0.29	0.25	0.35	0.35	0.25
– diluted	0.33	0.29	0.34	0.29	0.24	0.34	0.35	0.25
Net income (loss)	16,261	(10,126)	(14,214)	(17,280)	31,544	17,770	(9,154)	(7,376)
Per share – basic	0.19	(0.12)	(0.18)	(0.22)	0.39	0.23	(0.12)	(0.10)
– diluted	0.19	(0.12)	(0.18)	(0.22)	0.39	0.22	(0.12)	(0.10)

(1) The 2010 and 2011 quarterly results have been adjusted to conform to IFRS. The quarterly results for 2009 have not been adjusted and reflect the results in accordance with previous GAAP.

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

- Revenue is directly impacted by the Company's ability to replace existing declining production and add incremental production through its on-going capital expenditure program.
- Over the past two years, the price of natural gas has been negatively impacted by an increasing supply of natural gas coming from new technology tapping into abundant supplies of tight shale gas reservoirs in North America. With depressed natural gas prices, Crew has focused its capital expenditures towards oil development with higher netbacks. This has resulted in the commodity mix moving towards more oil and the Company's overall netbacks improving revenues and funds from operations.
- Production in the second quarters of 2010 and 2011 was negatively impacted by scheduled and unscheduled third party facility shutdowns and poor weather experienced in southern Alberta during the second quarters of 2010 and 2011 and third quarter of 2010.
- Revenue and royalties are significantly impacted by underlying commodity prices. The Company utilizes derivative contracts and forward sales contracts to reduce the exposure to commodity price fluctuations.

These contracts can cause volatility in net income as a result of unrealized gains and losses on commodity derivative contracts held for risk management purposes.

- From 2009 to 2011, the Company sold assets with approximately 2,440 boe per day of production for $182.9 million. The major dispositions closed as follows:
    - Fourth quarter 2009 – 600 boe per day for $25.3 million
    - Second quarter 2010 – 1,700 boe per day for $123.3 million
    - Second quarter 2011 – 140 boe per day for $12.6 million
- Three dispositions of assets in the Ferrier and Edson areas resulted in gains on sale of assets of $9.9 million, $37.0 million and $4.7 million in the first and second quarters of 2010 and the second quarter of 2011, respectively.
- The Company incurred impairment charges of $18.7 million and $10.4 million on two of its natural gas weighted CGUs in the third and fourth quarters of 2010, respectively.

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. Note 15 to the interim consolidated financial statements provides reconciliations between the Company's 2010 previous GAAP results and its 2010 results under IFRS. The reconciliations include the consolidated statement of financial position as at June 30, 2010, and consolidated statements of income and comprehensive income for the three and six months ended June 30, 2010.

The following provides summary reconciliations of Crew's January 1, 2010 previous GAAP to IFRS transitional Summary Statement of Financial Position reconciliations along with a discussion of the significant IFRS accounting policy changes:

Summary Statement of Financial Position Reconciliations

As at Date of IFRS Transition – January 1, 2010

($ thousands)	Previous GAAP	Note	Effect of Transition to IFRS	IFRS
Current assets	38,116		(542)	37,574
Exploration and evaluation	-	(1)	35,591	35,591
Property, plant and equipment	925,132	(1)	(35,591)	889,541
	963,248		(542)	962,706
Current liabilities	86,375		-	86,375
Bank loan	135,601		-	135,601
Other long-term obligations	132		-	132
Decommissioning obligations	35,341	(6)	17,722	53,063
Deferred tax liability	101,519	(6)	(5,031)	96,488
Share capital	617,605	(8)	3,383	620,988
Contributed surplus	22,769	(7)	2,737	25,506
Deficit	(36,094)	(6,7,8)	(19,353)	(55,447)
	963,248		(542)	962,706

On transition to IFRS, on January 1, 2010, Crew used certain exemptions allowed under IFRS 1 First Time Adoption of International Financial Reporting Standards. The exemptions used were as follows:

1. Oil and gas properties are classified as Property, Plant and Equipment ("PP&E") or Exploration and Evaluation assets ("E&E"). Crew reclassified all E&E expenditures included in the PP&E balance under previous GAAP, as a separate item under IFRS. These assets are measured at cost and are not depleted but will be assessed for impairment when indicators suggest the possibility of impairment. Once these E&E assets have reached technical feasibility and commercial viability, they are transferred to PP&E. At the time of transfer, they were subjected to an impairment test. Crew's E&E assets primarily consist of undeveloped exploration lands and at January 1, 2010 were valued at $35.6 million.

2. Under IFRS, PP&E assets are grouped into areas designated as cash generating units ("CGU") for the purposes of impairment testing and further broken down into components within the CGU for purposes of depletion and depreciation. IFRS 1 provides for the allocation of the previous GAAP net book value of PP&E assets, excluding E&E assets, to CGUs and components on a pro rata basis using the reserve volumes or values as at December 31, 2009. Crew has elected to allocate the PP&E balance using reserve values and at January 1, 2010, the value allocated to the PP&E assets is $889.5 million.

3. Under previous GAAP, impairment testing of oil and gas properties is performed at a cost centre level. Under IFRS, impairment testing is performed at the CGU level. This will result in a greater number of impairment tests. At January 1, 2010, Crew did not have any impairment of its PP&E under IFRS.

4. Depletion and depreciation of PP&E is calculated at a component level. Depletion of resource properties within PP&E is calculated using the unit-of-production method under IFRS using proved plus probable reserves. Depreciation of office equipment will continue to be calculated using a declining balance method.

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

6. Under previous GAAP, Crew's decommissioning obligation was discounted over its life based on a credit adjusted risk free rate which was 8% to 10% at December 31, 2009. Under IFRS, Crew is required to revalue its liability for decommissioning costs at each balance sheet date using a current liability-specific discount rate. As a result, the Company's decommissioning obligation increased upon transition to IFRS as the liability was re-valued using a discount rate of 4% to reflect the Company's estimated risk-free rate of interest. The re-valued decommissioning obligation at the transition date was $53.1 million with the offsetting $17.7 million (net of $4.5 million of the deferred tax liability) increase in the liability being charged to retained earnings as also provided for under the deemed cost election for full cost oil and gas companies.

7. Under previous GAAP, Crew expensed stock-based compensation on a straight-line basis. Under IFRS, share-based payments are expensed based on a graded vesting schedule. Crew also incorporated a forfeiture multiplier rather than account for forfeitures as they occur as was practiced under previous GAAP. The adjustment to contributed surplus to account for the graded vesting and forfeitures was an increase of $2.7 million with the offset being charged to retained earnings.

8. Under previous GAAP, the deferred tax liability associated with the renouncement of tax deductions from the issuance of flow through shares was recorded as a reduction in share capital at the time of renouncement. Under IFRS, the difference between the deferred tax liability associated with the renouncement of the tax deductions and the premium price received on the issuance of flow through shares over the market value of the Company's common shares at the time of issue is recorded as a deferred tax expense at the time of the renouncement. This deferred tax expense effectively represents the net loss on the distribution of the tax deductions to investors. The transitional adjustment resulted in an increase of $3.4 million to share capital with a resulting offset being charged to retained earnings.

Use of estimates and judgments:

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Reserve estimates including production profiles, future development costs, and discount rates are a critical part of many of the estimated amounts and calculations contained in the financial statements. These estimates are verified by third party professional engineers, who work with information provided by the Company to establish reserve determinations. These determinations are updated at least on an annual basis, and more frequently as significant business combinations take place.

Significant areas of estimation, uncertainty and critical judgments in applying accounting policies that impact the amounts recognized in the interim consolidated financial statements include:

- Impairment testing – estimates of reserves, future commodity prices, future costs, production profiles, discount rates, market value of land.
- Depletion and depreciation - oil and natural gas reserves, including future prices, costs and reserve base to use on calculation of depletion.
- Decommissioning obligations – estimates relating to amounts, likelihood, timing, inflation and discount rates.
- Stock-based compensation – forfeiture rates and volatility.
- Derivatives – expected future oil and natural gas prices and expected volatility in these prices; expected interest rates; expected future foreign exchange rates.
- Deferred tax – estimates of reversal of temporary differences, tax rates substantively enacted, and likelihood of assets being realized.
- Provisions and contingencies – estimates relating to onerous contracts, including discount rates associated with long term contracts.

The following provides summary reconciliations of Crew's 2010 previous GAAP to IFRS results:

Summary Statement of Financial Position Reconciliations

As at December 31, 2010

($ thousands)	Previous GAAP	Note	Effect of Transition to IFRS	IFRS
Current assets	61,020		-	61,020
Exploration and evaluation	-	(1)	72,281	72,281
Property, plant and equipment	937,050	(1)	(24,410)	912,640
	998,070		47,871	1,045,941
Current liabilities	101,088		-	101,088
Bank loan	138,700		-	138,700
Fair value of financial instruments	9,196		-	9,196
Decommissioning obligations	36,073	(2)	18,755	54,828
Deferred tax liability	96,330	(1,2)	6,149	102,479
Share capital	646,385		3,383	649,768
Contributed surplus	23,553	(3)	3,958	27,511
Deficit	(53,255)	(1,2,3)	15,626	(37,629)
	998,070		47,871	1,045,941

1. The PP&E adjustment includes the impact of the reclassification of E&E assets ($72.3 million decrease in PP&E), lower depletion as a result of using proved plus probable reserves to calculate depletion ($31.6 million increase in PP&E), gains on sale of assets and gains on farmout of assets ($48.2 million increase in PP&E), impairment on the Company's gas focused CGUs ($29.1 million decrease in PP&E), reduction of capitalized G&A, capital recoveries and associated deferred tax impact ($2.8 million decrease in PP&E).
2. Includes the adjustment to revalue the liability to a risk free interest rate of 3.50% at December 31, 2010 and the related deferred tax impact.
3. Includes recalculation of stock based compensation incorporating graded vesting and a forfeiture multiplier.

Summary Net Earnings Reconciliations

	2010				
($ thousands)	Annual	Q4	Q3	Q2	Q1
Net earnings/(loss) – previous GAAP	(17,161)	(9,525)	(7,387)	(2,691)	2,442
Addition/(deduction):					
General and administrative	(3,244)	(987)	(640)	(727)	(890)
Stock-based compensation	(1,020)	(501)	(322)	(178)	(19)
Depletion and depreciation	31,559	6,001	6,740	7,489	11,329
Decommissioning obligation accretion	674	161	161	175	178
Gain on divestitures and farmouts	48,242	-	-	38,360	9,882
Property, plant and equipment impairment	(29,072)	(10,336)	(18,736)	-	-
Deferred income tax	(12,159)	973	2,904	(10,884)	(5,152)
	34,980	(4,689)	(9,893)	34,235	15,328
Net earnings/(loss) - IFRS	17,819	(14,214)	(17,280)	31,544	17,770

Impact of Transition to IFRS on 2010 Results:

- Exploration and Evaluation (“E&E”) – In 2010, Crew incurred $36.7 million of E&E expenditures acquiring undeveloped land and evaluating its undeveloped land with seismic acquisitions. This amount was reclassified from PP&E, under previous GAAP, to E&E under IFRS.
- Divestitures and farmouts – Under previous GAAP, proceeds from divestitures were deducted from the full cost pool without recognition of a gain or loss unless the divestiture resulted in a change in the depletion rate of 20% or greater in which case a gain or loss was recorded. Under IFRS, gains and losses are recorded on divestitures and farmouts and are calculated as the difference between the proceeds and the net book value of the asset disposed of. For the year ended December 31, 2010, the Company recorded a $46.9 million gain on disposition of oil and gas properties and an additional $1.3 million gain on farmouts for IFRS as compared to nil under previous GAAP.
- Impairment of PP&E – Under IFRS, impairment tests of PP&E are performed at a CGU level as opposed to the entire Company’s PP&E balance with a full cost ceiling test under previous GAAP. Impairment is recognized if the carrying value exceeds the recoverable amount for a CGU. The recoverable amount is determined using fair value less costs to sell based on discounted future cash flows of proved plus probable reserves using forecast prices and costs. In the third quarter of 2010, as a result of decreased natural gas prices and a subsequent decrease in the Company’s future natural gas prices used in the Company’s reserves, Crew incurred an $18.7 million impairment charge in certain CGUs. Further deterioration in future natural gas pricing in the fourth quarter of 2010 resulted in the Company incurring an additional $10.4 million impairment charge on the same natural gas weighted CGUs. PP&E impairments can be reversed in the future if the recoverable amount increases.
- Depletion and depreciation expense – Under IFRS, Crew has chosen to calculate the depletion expense utilizing proved plus probable reserves as opposed to proved reserves under previous GAAP. This has resulted in a reduction of depletion and depreciation expense of approximately $31.6 million in 2010.

Future Accounting Changes

The following pronouncements may have an impact on the Company’s financial statements and will become effective for financial reporting periods beginning on or after January 1, 2013 and have not yet been adopted by the Company.

- In November 2009, the IASB published IFRS 9, “Financial Instruments,” which covers the classification and measurement of financial assets as part of its project to replace IAS 39, “Financial Instruments; Recognition and Measurement.” In October 2010, the requirements for classifying and measuring financial liabilities were added to IFRS 9. Under this guidance, entities have the option to recognize financial liabilities at fair value through earnings. If this option is elected, entities would be required to reverse the portion of the fair value change due to a company’s own credit risk out of earnings and recognize the change in other comprehensive income. IFRS 9 is effective for the Company on January 1, 2013. Early adoption is permitted and the standard is required to be applied retrospectively. The Company is currently evaluating the impact of adopting IFRS 9.
- IFRS 10 – Consolidated Financial Statements builds on existing principles and standards and identifies the concept of control as the determining factor in whether an entity should be included in the consolidated financial statements of the parent company.
- IFRS 11 – Joint Arrangements establishes the principles for financial reporting by entities when they have an interest in jointly controlled operations.
- IFRS 12 – Fair Value Measurement defines fair value and requires disclosure about fair value measurements.
- IAS 27 – Separate Financial Statements revised the existing standard which addresses the presentation of parent company financial statements that are not consolidated financial statements.
- IAS 28 – Investments in Associates and Joint Ventures revised the existing standard and prescribes the accounting for investments and set out the requirements for the application of the equity method when accounting for investments in associates and joint ventures.

The Company has not completed its evaluation of the effect of adopting these standards on its financial statements.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

The Company's Chief Executive Officer (“CEO”) and Chief Financial Officer (“CFO”) have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The Company’s CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on April 1, 2011 and ended on June 30, 2011 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. There were no changes to internal controls over financial reporting as a result of the transition to IFRS.

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

Dated as of August 9, 2011

Cautionary Statements

Forward-looking information and statements

This news release 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" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this news release contains forward-looking information and statements pertaining to the following: the volume and product mix of Crew's oil and gas production; production estimates; year-end production and net debt forecasts; 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 anticipated number of future drilling and recompletion opportunities on Caltex properties; the amount and timing of capital projects including new infrastructure at Princess; operating costs; the total future capital associated with development of reserves and resources; anticipated increases in recovery factors related to the Company's Tilley waterflood and forecast reductions 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 approvals; the ability of Crew to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects in which Crew has an interest in to operate the field in a safe, efficient and effective manner; the ability of Crew to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and cost of pipeline, storage and facility construction and expansion and the ability of Crew to secure adequate product transportation; future commodity prices; currency, exchange and interest rates; regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Crew operates; the ability of Crew to successfully market its oil and natural gas products; ability to improve upon historical recovery factors, anticipated benefits from the Caltex acquisition and anticipated impact upon Crew's forecasts in respect of production and cash flow for 2011 and resulting year-end net debt. Included herein is an estimate of Crew's year-end net debt based on assumptions as to the Caltex acquisition, cash flow, capital spending in 2011 and the other assumptions utilized in arriving at Crew's 2011 capital budget. To the extent such estimate constitutes a financial outlook, it was approved by management of Crew on May 18, 2011 and such financial outlook is included herein to provide readers with an understanding of estimated capital expenditures and the effect thereof on debt levels and readers are cautioned that the information may not be appropriate for other purposes.

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

The forward-looking information and statements contained in this news release speak only as of the date of this news release, 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.

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

Financial statements for the three and six month periods ended June 30, 2011 and 2010 are attached.

FOR DETAILED INFORMATION, PLEASE CONTACT:

Dale Shwed, President and C.E.O.
Telephone: (403) 231-8850
Email: dale.shwed@crewenergy.com

John Leach, Senior Vice President and C.F.O.
Telephone: (403) 231-8859
Email: john.leach@crewenergy.com

Website: www.crewenergy.com

CREW ENERGY INC.
Consolidated Statements of Financial Position
(unaudited)
(thousands)

	June 30, 2011	December 31, 2010
Assets		
Current Assets:		
Accounts receivable	**$ 42,252**	$ 44,922
Fair value of financial instruments (note 10)	**-**	982
Assets held for sale	**-**	15,116
	42,252	61,020
Exploration and evaluation assets (note 4)	**79,888**	72,281
Property, plant and equipment (note 5)	**985,319**	912,640
	$ 1,107,459	$ 1,045,941
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 82,429**	$ 100,745
Fair value of financial instruments (note 10)	**8,477**	-
Current portion of other long-term obligations (note 7)	**139**	343
	91,045	101,088
Fair value of financial instruments (note 10)	**-**	9,196
Bank loan (note 6)	**102,591**	138,700
Decommissioning obligations (note 8)	**57,167**	54,828
Deferred tax liability	**102,665**	102,479
Shareholders' Equity		
Share capital (note 9)	**756,286**	649,768
Contributed surplus	**29,199**	27,511
Deficit	**(31,494)**	(37,629)
	753,991	639,650
Commitments (note 13)		
Subsequent event (note 14)		
	$ 1,107,459	$ 1,045,941

See accompanying notes to the consolidated financial statements.

CREW ENERGY INC.
Consolidated Statements of Income and Comprehensive Income
(unaudited)
(thousands, except per share amounts)

	Three months ended June 30, 2011	Three months ended June 30, 2010	**Six months ended June 30, 2011**	Six months ended June 30, 2010
		(note 15)		(note 15)
Revenue				
Petroleum and natural gas sales	**$ 70,236**	$ 43,027	**$ 131,384**	$ 104,799
Royalties	**(16,574)**	(8,419)	**(30,930)**	(21,568)
Realized gain (loss) on financial instruments (note 10)	**(1,001)**	3,756	**15**	4,684
Unrealized gain (loss) on financial instruments (note 10)	**15,770**	2,334	**(263)**	10,532
	68,431	40,698	**100,206**	98,447
Expenses				
Operating	**17,033**	12,663	**33,451**	27,649
Transportation (note 7)	**2,671**	2,143	**5,667**	4,520
General and administrative	**2,835**	2,367	**5,623**	4,927
Stock-based compensation	**1,710**	1,248	**2,544**	2,587
Depletion and depreciation	**23,129**	17,506	**44,094**	37,587
	47,378	35,927	**91,379**	77,270
Income from operations	**21,053**	4,771	**8,827**	21,177
Financing (note 12)	**(3,910)**	(1,702)	**(5,882)**	(4,191)
Gain on divestitures	**4,697**	38,360	**4,697**	48,242
Income before income taxes	**21,840**	41,429	**7,642**	65,228
Deferred tax expense	**5,579**	9,885	**1,507**	15,914
Net income and comprehensive income	**$ 16,261**	$ 31,544	**$ 6,135**	$ 49,314
Net income per share (note 9)				
Basic	**$ 0.19**	$ 0.39	**$ 0.07**	$ 0.62
Diluted	**$ 0.19**	$ 0.39	**$ 0.07**	$ 0.61

See accompanying notes to the consolidated financial statements.

CREW ENERGY INC.
Consolidated Statements of Changes in Shareholders' Equity
(unaudited)
(thousands)

	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 2011	80,368	$ 649,768	$ 27,511	$ (37,629)	$ 639,650
Net income for the period	-	-	-	6,135	6,135
Issue of shares (net of issue costs)	4,820	96,092	-	-	96,092
Stock-based compensation expensed	-	-	2,544	-	2,544
Stock-based compensation capitalized	-	-	2,168	-	2,168
Transfer of stock-based compensation on exercises	-	3,024	(3,024)	-	-
Issued on exercise of options	799	7,402	-	-	7,402
Balance June 30, 2011	85,987	$ 756,286	$ 29,199	$ (31,494)	$ 753,991

	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 2010	78,152	$ 620,988	$ 25,506	$ (55,447)	$ 591,047
Net income for the period	-	-	-	49,314	49,314
Issue of shares (net of share issue costs)	-	(36)	-	-	(36)
Stock-based compensation expensed	-	-	2,587	-	2,587
Stock-based compensation capitalized	-	-	2,202	-	2,202
Transfer of stock-based compensation on exercises	-	7,046	(7,046)	-	-
Issued on exercise of options	1,944	17,593	-	-	17,593
Balance June 30, 2010	80,096	$ 645,591	$ 23,249	$ (6,133)	$ 662,707

See accompanying notes to the consolidated financial statements.

CREW ENERGY INC.
Consolidated Statements of Cash Flows
(unaudited)
(thousands)

	Three months ended June 30, 2011	Three months ended June 30, 2010	**Six months ended June 30, 2011**	Six months ended June 30, 2010
Cash provided by (used in):				
Operating activities:				
Net income	**$ 16,261**	$ 31,544	**$ 6,135**	$ 49,314
Adjustments:				
Depletion and depreciation	**23,129**	17,506	**44,094**	37,587
Financing expenses (note 12)	**3,910**	1,702	**5,882**	4,191
Interest expense (note 12)	**(1,231)**	(1,225)	**(2,726)**	(3,182)
Acquisition costs (note 12)	**(2,150)**	-	**(2,150)**	-
Stock-based compensation	**1,710**	1,248	**2,544**	2,587
Deferred tax expense	**5,579**	9,885	**1,507**	15,914
Unrealized (gain) loss on financial instruments	**(15,770)**	(2,334)	**263**	(10,532)
Gain on divestitures	**(4,697)**	(38,360)	**(4,697)**	(48,242)
Transportation liability charge (note 7)	**(103)**	(154)	**(204)**	(826)
Decommissioning obligations settled	**(132)**	(129)	**(121)**	(705)
Change in non-cash working capital (note 11)	**6,390**	3,739	**8,838**	8,639
	32,896	23,422	**59,365**	54,745
Financing activities:				
Increase (decrease) in bank loan	**14,129**	(81,756)	**(36,109)**	(63,756)
Issue of common shares	**-**	-	**100,015**	-
Proceeds from exercise of share options	**222**	6,356	**7,402**	17,593
Share issue costs	**(26)**	(48)	**(5,244)**	(48)
	14,325	(75,448)	**66,064**	(46,211)
Investing activities:				
Exploration and evaluation asset expenditures	**(1,606)**	(24,048)	**(8,819)**	(35,519)
Property, plant and equipment expenditures	**(51,579)**	(38,534)	**(119,531)**	(85,248)
Property divestitures	**12,650**	121,724	**12,289**	132,640
Proceeds on sale of asset held for sale	**-**	-	**15,116**	-
Change in non-cash working capital (note 11)	**(6,686)**	(7,116)	**(24,484)**	(20,407)
	(47,221)	52,026	**(125,429)**	(8,534)
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.

CREW ENERGY INC.
Notes to Consolidated Financial Statements
For the three and six months ended June 30, 2011 and 2010
(Unaudited)
(Tabular amounts in thousands)

1. Reporting entity:

Crew Energy Inc. ("Crew" or the "Company") is an oil and gas exploration, development and production Company based in Calgary, Alberta, Canada. Crew conducts its operations in the Western Canadian Sedimentary basin, primarily in the provinces of Alberta and British Columbia. The consolidated financial statements of the Company as at and for the three and six months ended June 30, 2011 and 2010 comprise the Company and its wholly owned subsidiary, Crew Resources Inc. which are incorporated in Canada, and a partnership, Crew Energy Partnership. The Company conducts many of its activities jointly with others; these financial statements reflect only the Company's proportionate interest in such activities.

2. Basis of preparation:

(a) Statement of compliance:

The interim consolidated financial statements have been prepared in accordance with IAS 34 – Interim Financial Reporting of the International Financial Reporting Standards ("IFRS"). IFRS 1 – First-time adoption of International Financial Reporting Standards ("IFRS 1") has been applied to these interim consolidated financial statements.

An explanation of how the transition to IFRS has affected the reported financial position, financial performance and cash flows of the Company is provided in note 15. The note includes reconciliations of equity and net loss for comparative periods from former Canadian GAAP ("previous GAAP") to IFRS.

These interim consolidated financial statements follow the same accounting policies and method of computation as shown in note 3 of the Company's interim consolidated financial statements for the three months ended March 31, 2011. These are the accounting policies the Company expects to adopt in its annual consolidated financial statements for the year ended December 31, 2011, with the exception of certain disclosures that are normally required to be included in annual consolidated financial statements which have been condensed or omitted.

The consolidated financial statements were authorized for issue by the Board of Directors on August 9, 2011.

(b) Basis of measurement:

The consolidated financial statements have been prepared on the historical cost basis except for the derivative financial instruments that are measured at fair value.

The methods used to measure fair values are discussed in note 3.

(c) Functional and presentation currency:

These consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency.

2. Basis of preparation (continued):

(d) Use of estimates and judgments:

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Reserve estimates including production profiles, future development costs, and discount rates are a critical part of many of the estimated amounts and calculations contained in the financial statements. These estimates are verified by third party professional engineers, who work with information provided by the Company to establish reserve determinations. These determinations are updated at least on an annual basis.

Significant areas of estimation, uncertainty and critical judgments in applying accounting policies that impact the amounts recognized in the interim consolidated financial statements include:

- Impairment testing – estimates of reserves, future commodity prices, future costs, production profiles, discount rates, market value of land.
- Depletion and depreciation - oil and natural gas reserves, including future prices, costs and reserve base to use on calculation of depletion.
- Decommissioning obligations – estimates relating to amounts, likelihood, timing, inflation and discount rates.
- Stock-based compensation – forfeiture rates and volatility.
- Derivatives – expected future oil and natural gas prices and expected volatility in these prices; expected interest rates; expected future foreign exchange rates.
- Deferred tax – estimates of reversal of temporary differences, tax rates substantively enacted, and likelihood of assets being realized.
- Provisions and contingencies – estimates relating to onerous contracts, including discount rates associated with long term contracts.

3. Determination of fair values:

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

(i) Property, plant and equipment and intangible exploration assets:

The fair value of property, plant and equipment recognized in an acquisition is based on market values. The market value of property, plant and equipment is the estimated amount for which property, plant and equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of oil and natural gas interests (included in property, plant and equipment) and intangible exploration assets is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions.

3. Determination of fair values (continued):

(i) Property, plant and equipment and intangible exploration assets (continued):

The market value of other items of property, plant and equipment is based on the quoted market prices for similar items.

(ii) Cash and cash equivalents, accounts receivable, bank loans and accounts payable:

The fair value of cash and cash equivalents, accounts receivable, bank loans and accounts payable are estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At June 30, 2011 and December 31, 2010, the fair value of these balances approximated their carrying value due to their short term to maturity. Bank loans bear a floating rate of interest and therefore carrying value approximates fair value.

(iii) Derivatives:

The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and published forward price curves as at the balance sheet date, using the remaining contracted oil and natural gas volumes and a risk-free interest rate (based on published government rates). The fair value of options and costless collars is based on option models that use published information with respect to volatility, prices and interest rates.

(iv) Stock options:

The fair value of employee stock options is measured using a Black Scholes option pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility (based on weighted average historic volatility adjusted for changes expected due to publicly available information), weighted average expected life of the instruments (based on historical experience and general option holder behaviour), expected dividends, and the risk-free interest rate (based on government bonds).

4. Exploration and evaluation assets:

Cost or deemed cost		Total
Balance, January 1, 2010	$	35,591
Additions		37,234
Transfer to property, plant and equipment		(544)
Balance, December 31, 2010	$	72,281
Additions		8,819
Transfer to property, plant and equipment		(1,212)
Balance, June 30, 2011	$	79,888

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

(a) Impairment charge*:*

The impairment of exploration and evaluation assets, and any eventual reversal thereof, is recognized as additional depletion and depreciation expense in the statement of income.

4. Exploration and evaluation assets (continued):

(b) Recoverability of exploration and evaluation assets:

The Company assesses the recoverability of exploration and evaluation assets, before and at the moment of reclassification to property, plant and equipment, using Cash Generating Units ("CGUs"). The CGU includes both the exploration and evaluation CGU and CGUs related to oil and natural gas interests for that area, but not larger than a segment.

5. Property, plant and equipment:

Cost or deemed cost	Total
Balance, January 1, 2010	$ 889,541
Additions	223,508
Property acquisition	2,522
Transfer from exploration and evaluation assets	544
Divestitures	(93,975)
Asset held for sale	(15,116)
Change in decommissioning obligations	6,524
Capitalized stock-based compensation	4,717
Balance, December 31, 2010	$ 1,018,265
Additions	119,892
Transfer from exploration and evaluation assets	1,212
Divestitures	(9,221)
Change in decommissioning obligations	2,457
Capitalized stock-based compensation	2,168
Balance, June 30, 2011	$ 1,134,773

Accumulated depletion and depreciation	Total
Balance, January 1, 2010	$ -
Depletion and depreciation expense	79,016
Divestitures	(2,463)
Impairment	29,072
Balance, December 31, 2010	$ 105,625
Divestitures	(265)
Depletion and depreciation expense	44,094
Balance, June 30, 2011	$ 149,454

Net book value	Total
Balance, January 1, 2010	$ 889,541
Balance, December 31, 2010	$ 912,640
Balance, June 30, 2011	$ 985,319

The calculation of depletion for the period ended June 30, 2011 included estimated future development costs of $263.0 million (December 31, 2010 - $297.4 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $52.7 million (December 31, 2010 - $51.1 million) and undeveloped land of $97.7 million (December 31, 2010 - $110.6 million) related to development acreage.

(a) Impairment charge*:*

The impairment of property, plant and equipment, and any eventual reversal thereof, are recognized in depletion and depreciation in the statement of income.

(b) Contingencies:

Although the Company believes that it has title to its oil and natural gas properties, it cannot control or completely protect itself against the risk of title disputes or challenges.

6. Bank loan:

The Company's bank facility as at June 30, 2011 consists of a revolving line of credit of $255 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 11, 2012. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 per cent and all outstanding advances thereunder will become repayable in one year. The available lending limits of the Facility are reviewed semi-annually and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled borrowing base review on or before October 15, 2011.

Advances under the Facility are available by way of prime rate loans with interest rates between 1.00 percent and 2.50 percent over the bank's prime lending rate and bankers' acceptances and LIBOR loans, which are subject to stamping fees and margins ranging from 2.00 percent to 3.50 percent depending upon the debt to EBITDA ratio of the Company calculated at the Company's previous quarter end. Standby fees are charged on the undrawn facility at rates ranging from 0.50 percent to 0.875 percent depending upon the debt to EBITDA ratio.

As at June 30, 2011, 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 June 30, 2011, the Company had issued letters of credit totaling $10.6 million (December 31, 2010 - $1.1 million). The effective interest rate on the Company's borrowings under its bank facility for the three months ended June 30, 2011 was 5.9% (2010 – 9.7%).

7. Other long-term obligations:

As part of a May 3, 2007 private company acquisition, the Company acquired several firm transportation agreements. These agreements had a fair value at the time of acquisition of $4.9 million liability. This amount was accounted for as part of the acquisition cost and is charged as a reduction to transportation expenses over the life of the contracts as they are incurred. The charge for the three months and six months ended June 30, 2011 was $0.1 million and $0.2 million respectively (2010 - $0.2 million and $0.5 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.

8. Decommissioning obligations:

	As at June 30, 2011	As at December 31, 2010
Decommissioning obligations, beginning of period	**$ 54,828**	$ 53,063
Obligations incurred	**2,171**	3,383
Obligations settled	**(121)**	(1,512)
Obligations divested	**(1,003)**	(5,212)
Change in estimated future cash outflows	**286**	3,141
Accretion of decommissioning liabilities	**1,006**	1,965
Decommissioning obligations, end of period	**$ 57,167**	$ 54,828

8. Decommissioning obligations (continued):

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and gathering systems. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning obligations to be $57.2 million as at June 30, 2011 (December 31, 2010 - $54.8 million) based on an undiscounted total future liability of $64.7 million (December 31, 2010 - $63.4 million). These payments are expected to be made over the next 25 years with the majority of costs to be incurred between 2012 and 2036. The discount factor, being the risk-free rate related to the liability, is 3.50% (December 31, 2010 – 3.50%).

9. Share capital:

At June 30, 2011, the Company was authorized to issue an unlimited number of common shares with the holders of common shares entitled to one vote per share.

Share based payments:

The Company has an option program that entitles officers, directors, employees and certain consultants to purchase shares in the Company. Options are granted at the market price of the shares at the date of grant, have a four year term and vest over three years.

The number and weighted average exercise prices of share options are as follows:

	Number of options	Weighted average exercise price
Balance January 1, 2010	5,751	$ 8.33
Granted	2,237	$ 15.18
Exercised	(2,216)	$ 9.28
Forfeited	(442)	$ 9.50
Balance December 31, 2010	5,330	$ 10.79
Granted	2,345	$ 17.77
Exercised	(799)	$ 9.26
Forfeited	(359)	$ 17.21
Balance at June 30, 2011	6,517	$ 13.14

The following table summarizes information about the stock options outstanding at June 30, 2011:

Range of exercise prices	Outstanding at June 30, 2011	Weighted average remaining life (years)	Weighted average exercise price	Exercisable at June 30, 2011	Weighted average exercise price
$ 3.43 to $ 7.01	1,041	1.5	$ 5.16	589	$ 5.17
$ 7.02 to $ 9.94	1,055	0.6	$ 7.48	999	$ 7.38
$ 9.95 to $14.63	229	1.7	$ 13.22	126	$ 13.06
$14.64 to $18.70	3,910	3.1	$ 16.30	714	$ 15.27
$18.71 to $21.19	282	3.6	$ 19.75	-	$ -
	6,517	2.4	$ 13.14	2,428	$ 9.46

9. Share capital (continued):

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

Assumptions	**Three months ended June 30, 2011**	Three months ended, June 30, 2010	**Six months ended June 30, 2011**	Six months ended, June 30, 2010
Risk free interest rate (%)	**2.5**	2.3	**2.4**	2.3
Expected life (years)	**4.0**	4.0	**4.0**	4.0
Expected volatility (%)	**60**	61	**60**	61
Forfeiture rate (%)	**16.1**	17.3	**16.2**	17.3
Weighted average fair value of options	**$ 8.31**	$ 7.07	**$ 8.45**	$ 7.07

Net income per share:

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average shares outstanding for the three month period ended June 30, 2011 was 85,981,000 (2010 – 79,888,000) and for the six month period ended June 30, 2011, the weighted average number of shares outstanding was 84,111,000 (2010 – 79,272,000).

In computing diluted earnings per share for the three month period ended June 30, 2011, 1,249,000 (2010 – 1,930,000) were added to the weighted average Common Shares outstanding to account for the dilution of stock options and for the six month period ended June 30, 2011, 1,521,000 (2010 – 2,099,000) were added to the weighted average number of common shares for the dilution. There were 1,783,000 (2010 – 2,559,000) stock options that were not included in the diluted earnings per share calculation because they were anti-dilutive.

10. Derivative contracts and capital management:

(a) Derivative contracts:

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

10. Derivative contracts and capital management (continued):

(a) Derivative contracts (continued):

At June 30, 2011, 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	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.85	Swap(1)	534
Natural Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.90	Swap(1)	556
Natural Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.95	Swap(1)	578
Natural Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.965	Swap(1)	671
Natural Gas	7,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$5.00	Swap(1)	1,901
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	US$ WTI	US$80.15	Swap	(1,485)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$86.00	Swap	(411)
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$88.00	Swap	(564)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$88.50	Swap	(279)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$90.00	Swap	(167)
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$90.20	Swap	(320)
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$93.00	Swap	(16)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$80.00 - $95.45	Collar	(123)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$82.00 - $94.62	Collar	(132)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$85.00 - $100.50	Collar	(19)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$85.00	Call(1)	(3,614)
Oil	750 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$90.00	Call(1)	(3,768)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	US$ WTI	US$90.00	Call(1)	(2,993)
Oil	250 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$100.45	Swap	268
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$101.00	Swap	630
Oil	250 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$100.50	Swap	276
Total						(8,477)

(1) These 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.

10. Derivative contracts and capital management (continued):

(b) Capital management (continued):

The Company's policy is to maintain a strong capital base so as to maintain investor, creditor and market confidence and to sustain future development of the business. The Company manages its capital structure and makes adjustments to it in the light of changes in economic conditions and the risk characteristics of the underlying oil and natural gas assets. The Company considers its capital structure to include shareholders' equity, bank loans and working capital. In order to maintain or adjust the capital structure, the Company may issue shares and adjust its capital spending to manage current and projected debt levels.

The Company monitors capital based on the ratio of net debt to annualized cash flow. This ratio is calculated as net debt, defined as outstanding bank loans plus or minus working capital, divided by cash flow from operations before changes in non-cash working capital for the most recent calendar quarter and then annualized. The Company's strategy is to maintain a ratio of no more than 2 to 1. This ratio may increase at certain times as a result of acquisitions. In order to facilitate the management of this ratio, the Company prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors.

As at June 30, 2011, the Company's ratio of net debt to annualized cash flow was 1.24 to 1, (December 31, 2010 – 1.63 to 1) within the range established by the Company. There were no changes in the Company's approach to capital management during the period.

	June 30, 2011	December 31, 2010
Net debt:		
Accounts receivable (including assets held for sale)	**$ 42,252**	$ 60,038
Accounts payable and accrued liabilities	**(82,429)**	(100,745)
Working capital deficiency	**$ (40,177)**	$ (40,707)
Bank loan	**(102,591)**	(138,700)
Net debt	**$ (142,768)**	$ (179,407)
Annualized funds from operations:		
Cash provided by operating activities	**$ 32,896**	$ 20,225
Decommissioning obligations settled	**132**	606
Transportation liability charge	**103**	120
Acquisition costs	**2,150**	-
Change in non-cash working capital	**(6,390)**	6,498
Funds from operations	**28,891**	27,449
Annualized	**$ 115,564**	$ 109,796
Net debt to annualized funds from operations	**1.24**	1.63

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

11. Supplemental cash flow information:

Changes in non-cash working capital is comprised of:

	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Changes in non-cash working capital:				
Accounts receivable	**$ 5,559**	$ 10,134	**$ 2,670**	$ 7,940
Accounts payable and accrued liabilities	**(5,855)**	(13,511)	**(18,316)**	(19,708)
	$ (296)	$ (3,377)	**$ (15,646)**	$ (11,768)
Operating activities	**$ 6,390**	$ 3,739	**$ 8,838**	$ 8,639
Investing activities	**(6,686)**	(7,116)	**(24,484)**	(20,407)
	$ (296)	$ (3,377)	**$ (15,646)**	$ (11,768)
Interest paid	**$ (1,534)**	$ (1,472)	**$ (2,495)**	$ (2,562)

12. Financing:

	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Accretion of decommissioning obligations	**$ 529**	$ 477	**$ 1,006**	$ 1,009
Interest expense	**1,231**	1,225	**2,726**	3,182
Acquisition costs	**2,150**	-	**2,150**	-
	$ 3,910	$ 1,702	**$ 5,882**	$ 4,191

Acquisition costs relate to the Company's acquisition of Caltex Energy Inc. (note 14).

13. Commitments:

	Total	2011	2012	2013	2014	2015	Thereafter
Operating Leases	$ 2,188	$ 879	$ 1,309	$ -	$ -	$ -	$ -
Capital commitments	1,000	1,000	-	-	-	-	-
Firm transportation agreements	20,018	2,000	1,535	1,535	2,110	2,110	10,728
Firm processing agreement	74,700	3,290	6,526	6,526	8,239	8,239	41,880
Total	$ 97,906	$ 7,169	$ 9,370	$ 8,061	$10,349	$10,349	$ 52,608

The transportation agreements include an $18.8 million commitment to a third party to transport natural gas from a gas processing facility in the Septimus 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. 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 committed to process a minimum monthly volume of gas through the facility commencing on December 1, 2009 and continuing through November 30, 2019.

13. Commitments (continued):

In the fourth quarter of 2010, the Company amended the agreement with the owner of this facility. Under the terms of the amended agreement, Crew constructed a facility expansion during the fourth quarter of 2010 and subsequently closed the sale of the Septimus facility expansion in the first quarter of 2011. Upon completion of the expansion, Crew was reimbursed for the cost of the facility expansion of $16.9 million in return for an expanded processing commitment that will extend to December 2020. As part of the amended agreement, 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. If the Company re-purchases a 50% interest on January 1, 2014 for approximately $18.0 million, the remaining commitment would be reduced by approximately $29.0 million.

14. Subsequent event:

On July 1, 2011, the Company acquired all of the issued and outstanding shares of Caltex Energy Inc. ("Caltex"), a Canadian private oil and gas company with operations in Saskatchewan and Alberta (the "Transaction"). Under the terms of the Transaction, Caltex shareholders received 0.38 of a Crew common share for each Caltex share held or an aggregate of approximately 33.6 million Crew shares and Crew assumed approximately $65 million of Caltex's net debt as estimated at closing. Upon completion of the Transaction, Caltex became a wholly owned subsidiary of Crew under the name "Caltex Energy Inc.".

The acquisition is consistent with Crew's strategy to focus on large hydrocarbon in place reservoirs, oil production growth and less capital intensive completion projects.

The acquisition will be accounted for under IFRS 3, "Business Combinations", by the acquisition method based on the fair value of assets acquired. The initial accounting for the business combination is incomplete as the Company is in the process of evaluating the fair value of the assets acquired under IFRS in order to complete the purchase price equation for recognition, measurement and presentation in the Company's financial results for the three month interim period ended September 30, 2011.

Upon closing of the Caltex acquisition on July 1, 2011, the Company completed an update to its bank facility with a syndicate of banks. The Company's lenders have increased the Company's total bank facility to $400 million. The credit Facility includes a revolving line of credit of $370 million and an operating line of credit of $30 million. The applicable pricing grid associated with the updated facility remained as outlined in note 6.

15. Reconciliation of equity and income from previous GAAP to IFRS:

These interim consolidated financial statements are the Company's second under IFRS.

The adoption of IFRS requires the application of IFRS 1. IFRS 1 generally requires that an entity retrospectively apply all IFRS effective at the end of its first IFRS reporting period; however IFRS 1 provides certain mandatory exceptions and permits limited optional exemptions. Certain IFRS 1 optional exemptions have been applied including:

- Deemed cost exemption for full cost oil and gas entities whereby exploration and evaluation assets were classified from the full cost pool to intangible exploration assets at the amount that was recorded under previous GAAP and the remaining full cost pool was allocated to the development assets and components pro rata using reserve values.
- Decommissioning obligation exemption that allows any changes in decommissioning obligations on transition to IFRS to be adjusted through opening retained earnings.
- Stock-based compensation exemption that allows a company to only evaluate share based compensation awards that were unvested as of the date of transition and that were issued subsequent to November 7, 2002.
- Business combinations exemption that allows a company to not restate any business combinations that occurred prior to the date of transition.

The accounting policies in note 3 of the interim consolidated financial statements for the three months ended March 31, 2011 have been applied in preparing the interim consolidated financial statements for the three and six months ended June 30, 2011 and the comparative information for the three and six months ended June 30, 2010.

In preparing comparative information for the three and six months ended June 30, 2010, the Company adjusted amounts previously reported in financial statements prepared in accordance with previous GAAP. An explanation of how the transition from previous GAAP to IFRS has affected the Company's financial position, financial performance and cash flows is set out in the following tables and the notes accompanying the tables.

15. Reconciliation of equity and income from previous GAAP to IFRS (continued):

As at June 30, 2010:

	Previous GAAP	Effect of transition to IFRS	Note	IFRS
Assets				
Current Assets:				
Accounts receivable	**$ 29,634**	$ -		$ 29,634
Fair value of financial instruments	**9,698**	-		9,698
	39,332	-		39,332
Exploration and evaluation assets	**-**	71,111	B	71,111
Property, plant and equipment	**859,248**	(7,975)	B,C,F	851,273
	$ 898,580	$ 63,136		$ 961,716
Liabilities and Shareholders' Equity				
Current Liabilities:				
Accounts payable and accrued liabilities	**$ 64,520**	$ -		$ 64,520
Deferred tax liability	**2,306**	(2,306)	A	-
Current portion of other long-term obligations	**619**	-		619
	67,445	(2,306)		65,139
Bank loan	**71,845**	-		71,845
Decommissioning obligations	**33,582**	16,053	D	49,635
Deferred tax liability	**99,341**	13,049	E	112,390
Shareholders' Equity				
Share capital	**642,208**	3,383	E	645,591
Contributed surplus	**20,502**	2,747	G	23,249
Deficit	**(36,343)**	30,210		(6,133)
	626,367	36,340		662,707
	$ 898,580	$ 63,136		$ 961,716

15. Reconciliation of equity and income from previous GAAP to IFRS (continued):

Reconciliation of consolidated statement of income (loss) for the three months ended June 30, 2010:

	Previous GAAP	Effect of transition to IFRS	Note	IFRS
Revenue				
Gross petroleum and natural gas sales	**$ 43,027**	$ -		$ 43,027
Royalties	**(8,419)**	-		(8,419)
Realized gain on financial instruments	**3,756**	-		3,756
Unrealized gain on financial instruments	**2,334**	-		2,334
	40,698	-		40,698
Expenses				
Operating	**12,663**	-		12,663
Transportation	**2,143**	-		2,143
General and administrative	**1,640**	727	H	2,367
Stock-based compensation	**1,070**	178		1,248
Depletion and depreciation	**24,995**	(7,489)	C	17,506
	42,511	(6,584)		35,927
Income (loss) from operations	**(1,813)**	6,584		4,771
Financing	**(1,877)**	175	D	(1,702)
Gain on divestitures	**-**	38,360	F	38,360
Net income (loss) before taxes	**(3,690)**	45,119		41,429
Deferred tax expense (reduction)	**(999)**	10,884	E	9,885
Net income (loss) and comprehensive income (loss)	**$ (2,691)**	$ 34,235		$ 31,544
Net income (loss) per share				
Basic	**$ (0.03)**			$ 0.39
Diluted	**$ (0.03)**			$ 0.39

15. Reconciliation of equity and income from previous GAAP to IFRS (continued):

Reconciliation of consolidated statement of income (loss) for the six months ended June 30, 2010:

	Previous GAAP	Effect of transition to IFRS	Note	IFRS
Revenue				
Gross petroleum and natural gas sales	**$ 104,799**	$ -		$ 104,799
Royalties	**(21,568)**	-		(21,568)
Realized gain on financial instruments	**4,684**	-		4,684
Unrealized gain on financial instruments	**10,532**	-		10,532
	98,447	-		98,447
Expenses				
Operating	**27,649**	-		27,649
Transportation	**4,520**	-		4,520
General and administrative	**3,310**	1,617	H	4,927
Stock-based compensation	**2,390**	197		2,587
Depletion and depreciation	**56,406**	(18,819)	C	37,587
	94,275	(17,005)		77,270
Income from operations	**4,172**	17,005		21,177
Financing	**(4,543)**	352	D	(4,191)
Gain on divestitures	**-**	48,242	F	48,242
Net income (loss) before taxes	**(371)**	65,599		65,228
Deferred tax expense (reduction)	**(122)**	16,036	E	15,914
Net income (loss) and comprehensive income (loss)	$ **(249)**	$ 49,563		$ 49,314
Net income (loss) per share				
Basic	**$ (0.00)**			$ 0.62
Diluted	**$ (0.00)**			$ 0.61

15. Reconciliation of equity and income from previous GAAP to IFRS (continued):

Impact of Transition to IFRS on 2010 Results:

(A) Under IFRS, all deferred tax assets and liabilities are classified as long-term. Under previous GAAP, deferred tax assets and liabilities were presented according to the classification of the underlying asset or liability that created the difference in the deferred tax amount.

(B) Exploration and Evaluation assets – As required under IFRS 6, the Company reclassified $71.1 million at June 30, 2010.

(C) Depletion and depreciation expense – Under IFRS, Crew has chosen to calculate depletion expense based on proved plus probable reserves as opposed to proved reserves under previous GAAP. This has resulted in a reduction of depletion and depreciation expense of approximately $7.5 million for the three months ended June 30, 2010 and $18.8 million for the six months ended June 30, 2010.

(D) Decommissioning obligations – Under previous GAAP, Crew's decommissioning obligations were discounted based on a credit adjusted risk-free rate which was 8-10% at December 31, 2009. Under IFRS, the Company is required to revalue its obligation at each balance sheet date using a current liability-specific discount rate. At transition, Crew revalued the obligation based on a risk-free rate of 4%, resulting in a $17.7 million increase (net of tax) to the liability, with the offset charged to retained earnings.

As a result of the change in the discount rate applied, accretion of decommissioning obligation expense decreased by $174,000 for the three months ended June 30, 2010 and $352,000 for the six months ended June 30, 2010.

(E) Under previous GAAP, the deferred tax liability associated with the renouncement of tax deductions from the issuance of flow through shares was recorded as a reduction in share capital at the time of renouncement. Under IFRS, the difference between the deferred tax liability associated with the renouncement of the tax deductions and the premium price received on the issuance of flow through shares over the market value of the Company's common shares at the time of issue is recorded as a deferred tax expense as the expenditures are incurred. This deferred tax expense effectively represents the net loss on the distribution of the tax deductions to investors. The transitional adjustment resulted in an increase of $3.4 million to share capital with a resulting offset being charged to retained earnings.

An additional deferred tax expense of $10.9 million for the three months ended June 30, 2010 and $16.0 million was recognized as a result of changes in the temporary difference between the net book value and the tax basis of the assets and liabilities due to other adjustments discussed.

(F) Divestitures – Under previous GAAP, proceeds from divestitures were deducted from the full cost pool without recognition of a gain or loss unless the divestiture resulted in a change in the depletion rate of 20% or greater in which case, a gain or loss was recorded. Under IFRS, gains and losses are recorded on divestitures and are calculated as the difference between the proceeds and the net book value of the asset disposed of. A gain on disposition of oil and gas properties of $38.4 million for the three months ended June 30, 2010 and $48.2 million for the six months ended June 30, 2010 was recorded under IFRS compared to nil under previous GAAP.

15. Reconciliation of equity and income from previous GAAP to IFRS (continued):

Impact of Transition to IFRS on 2010 Results (continued):

(G) Under previous GAAP, Crew expensed stock-based compensation on a straight-line basis. Under IFRS, share-based payments are expensed based on a graded vesting schedule. Crew also incorporated a forfeiture multiplier rather than accounting for forfeitures as they occur as practiced under previous GAAP. The adjustment to contributed surplus to account for the graded vesting and forfeitures was an increase of $2.7 million with the offset being charged to retained earnings.

(H) Under IFRS, the criteria for which general and administrative expenses ("G&A") can be capitalized is different than previous GAAP and as a result a greater portion of G&A costs have been expensed. This resulted in an additional $0.7 million of G&A expenses being recorded for the three months ended June 30, 2010 and $1.6 million for the six months ended June 30, 2010.