Crew Energy Inc. of Calgary, Alberta is pleased to present its financial and operating results for the three month period ended March 31, 2011

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HIGHLIGHTS

- First quarter average production of 15,608 boe per day represents a 7% increase over the fourth quarter 2010;
- Net debt decreased 37% to $120 million from the first quarter 2010;
- The expansion of the Septimus gas processing facility was completed in the first quarter doubling its capacity to 50 mmcf per day;
- Two Princess Pekisko wells drilled in the first quarter are currently producing at 425 and 420 bbls of oil equivalent per day with a number of wells ramping up production;
- Three Montney gas wells at Septimus were completed and flowed at rates after five days of 7.8 mmcf per day, 7.6 mmcf per day, and 12.7 mmcf per day at flowing casing pressures of 1,566 psi, 1,522 psi, and 1,508 psi, respectively;
- On March 2, 2011 Crew closed the previously announced equity offering for aggregate total gross proceeds of $100 million;
- On April 1, 2011, Crew disposed of 140 boe per day of production for gross proceeds of $12.6 million;
- On May 2, 2011, announced the proposed acquisition of Caltex Energy Inc. ("Caltex"), a private oil and gas company with approximately 10,500 boe per day of production in Alberta and Saskatchewan.

FINANCIAL *($ thousands, except per share amounts)*	**Three months ended Mar. 31, 2011**	Three months ended Mar. 31, 2010
Petroleum and natural gas sales	**61,148**	61,772
Funds from operations (1)	**24,111**	27,327
Per share - basic	**0.29**	0.35
- diluted	**0.29**	0.34
Net income (loss)	**(10,126)**	17,770
Per share - basic	**(0.12)**	0.23
- diluted	**(0.12)**	0.22
Capital expenditures	**75,165**	58,185
Property acquisitions (net of dispositions)	**361**	(10,916)
Net capital expenditures	**75,526**	47,269
CAPITAL STRUCTURE *($ thousands)*	**As at Mar. 31, 2011**	As at Dec. 31, 2010
Working capital deficiency (2)	**31,522**	40,707
Bank loan	**88,462**	138,700
Net debt	**119,984**	179,407
Current bank facility	**240,000**	240,000
Common Shares Outstanding *(thousands)*	**85,963**	80,368

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

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

OPERATIONS

	Three months ended Mar. 31, 2011	Three months ended Mar. 31, 2010
Daily production		
Natural gas (mcf/d)	**52,109**	55,732
Oil (bbl/d)	**5,794**	4,261
Natural gas liquids (bbl/d)	**1,129**	1,451
Oil equivalent (boe/d @ 6:1)	**15,608**	15,001
Average prices (1)		
Natural gas ($/mcf)	**4.00**	5.38
Oil ($/bbl)	**69.68**	72.10
Natural gas liquids ($/bbl)	**59.71**	54.66
Oil equivalent ($/boe)	**43.53**	45.75
Netback		
Operating netback ($/boe) (2)	**20.20**	23.54
Realized loss (gain) on financial instruments ($/boe)	**(0.01)**	(0.19)
G&A ($/boe)	**1.98**	1.94
Interest on bank debt ($/boe)	**1.06**	1.45
Funds from operations ($/boe)	**17.17**	20.19
Drilling Activity		
Gross wells	**40**	22
Working interest wells	**39.3**	20.2
Success rate, net wells	**100%**	100%

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

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

OVERVIEW

Operations for the first quarter were highlighted by the drilling of a record 40 (39.3 net) wells with 100% success. At Princess, Alberta Crew drilled 20 (20.0 net) horizontal wells targeting oil, 14 (14.0 net) vertical exploration wells, and two (2.0 net) water disposal wells. The Company drilled four (3.33 net) wells at Septimus, British Columbia targeting liquids rich Montney gas and oil. Of the 34 potential producers drilled at Princess, only ten were placed on production due to surface access restrictions related to cold weather and heavy winter snowfall then quickly followed by an early spring breakup. Three wells drilled at Septimus were completed and all were placed on production by the end of April due to their location on pre-existing pad sites. One (0.33 net) non-operated well drilled at Tower (Septimus) targeting Montney oil is expected to be completed post spring breakup. In addition, a partner operated Falher well at Kakwa (0.25 net) flowed at an average first month rate of approximately 12 mmcf per day (500 boe per day net to Crew).

Average production for the first quarter was 15,608 boe per day which is a 7% increase over the fourth quarter of 2010. Production for the first quarter was slightly lower than the Company's expectations due to the Septimus gas plant being offline for six additional unplanned days to complete the plant expansion to 50 mmcf per day and the previously noted weather related delays at Princess. As a result, capital expenditures in the first quarter were $10 million less than budgeted.

OPERATIONS UPDATE

Pekisko Play - Princess, Alberta

During the first quarter, Crew drilled 20 (20.0 net) horizontal wells targeting oil, 14 (14.0 net) vertical exploration wells, and two (2.0 net) water disposal wells. The Company placed seven horizontal and three vertical wells on production by the end of the quarter. Highlights include the 15-5 well at Alderson currently producing at 420 boe per day and the

5-36 North Alderson well currently producing at 425 boe per day (both 93% oil). Eleven wells placed on production in December, 2010 continue to produce in excess of expectations, producing on average 189 boe per day four months after being placed on production. Current production at Princess is approximately 6,200 boe per day based on field estimates with an estimated 2,800 boe per day shut in due to restricted access or awaiting tie in. The Company completed two three-dimensional seismic programs in the first quarter to identify opportunities over approximately 81 square miles of land.

Crew drilled two (2.0 net) water disposal wells during the quarter. One was drilled vertically and cored in the Leduc formation and displayed high permeability. Injectivity tests on this well exceeded 9,000 bbls of water per day in the Leduc formation with similar results encountered in the Nisku formation.

For the remainder of 2011, Crew plans to drill 51 horizontal, 20 vertical and 15 water disposal wells in the Princess area.

Montney Play - Northeast British Columbia

Crew drilled four (3.33 net) wells in the Montney formation in the first quarter of 2011. Three (3.0 net) wells were drilled at Septimus for liquids rich gas and had production rates after five days of flow of 7.8 mmcf per day (1,482 boe per day) at a flowing casing pressure of 1,566 psi, 7.6 mmcf per day (1,444 boe per day) at a flowing casing pressure of 1,522 psi, and 12.7 mmcf per day (2,415 boe per day) at a flowing casing pressure of 1,508 psi. The Company continues to refine its drilling and completion practices resulting in improved efficiencies. One non-operated well (0.33 net) drilled at Tower targeting Montney oil is expected to be completed post spring breakup. Current production at Septimus exceeds 6,000 boe per day based on field estimates.

Also in the first quarter, Crew completed the expansion and start-up of the Septimus gas processing facility doubling its capacity to approximately 50 mmcf per day.

Crew plans to drill four (4.0 net) more wells at Septimus for the remainder of 2011.

In addition to this activity, Crew is also active in the Montney play at Kobes, British Columbia. The Company participated in a large three dimensional seismic shoot in the first quarter, and plans to drill its first horizontal well into this play in the third quarter offsetting a Crew well that tested 2.5 mmcf per day and 125 bbls per day of condensate. The Company owns 23 net sections on this play which may ultimately require eight to twelve wells per section to adequately deplete the 1,000 feet of gas saturated rock in this area.

Other Exploration Plays – Central Alberta

Crew owns land on several resource exploration plays in Alberta which the Company plans to test in 2011 using horizontal drilling technology.

At Pine Creek, Alberta, Crew plans to drill two exploration wells targeting Cardium light oil. The Company also plans to drill three horizontal wells targeting liquids rich natural gas in the Mannville group at Pine Creek. At Killam, Alberta, Crew plans to drill two dual leg horizontal wells targeting oil in the Mannville offsetting Crew production and recent industry activity. In addition, at Provost, Alberta, Crew plans to drill two dual leg horizontal wells targeting oil in the Viking formation.

If any of these plays prove successful, Crew has numerous offset drilling locations which have the potential to develop into significant core producing properties.

Proposed Acquisition of Caltex Energy Inc.

On May 2, 2011 Crew announced the proposed acquisition (the "Transaction") of Caltex Energy Inc. ("Caltex"). This Transaction augments Crew's strategy to acquire, explore and exploit large hydrocarbon in place reservoirs. The assets to be acquired have the potential to significantly add reserves through the large drilling and recompletion inventory and improved recoveries from current and emerging technologies. The Caltex assets include the following attributes:

- 10,500 boe per day of estimated production (68% oil and liquids);

- 23.8 million boe of proved reserves and 43.0 million boe of proved plus probable reserves;
- 137,000 net undeveloped acres of land;
- Over 900 estimated future drilling, recompletion and reactivation opportunities;
- Current operating netback in excess of $33.00 per boe

The Caltex assets are anticipated to provide a source of stable free cash flow with significant opportunities for growth. They are consistent with Crew's strategy to focus on oil growth and less capital intensive completion techniques using proven technologies and avoiding the use of many of the services driving industry wide inflation. Numerous opportunities exist to improve the produced and booked 4% recovery factor on oil and the produced and booked 27% recovery factor on liquids rich natural gas through infill drilling, recompletions, and secondary recovery programs. In addition, Crew's operating netback per boe is forecasted to increase by 15% while the corporate production decline rate is forecast to be reduced by approximately 15%.

Subject to completion of the Transaction, in the last six months of 2011, Crew plans to drill 26 wells in Lloydminster area of Saskatchewan and five wells in the Greater Wapiti area of west central Alberta. This program is forecast to result in the Caltex assets delivering an exit 2011 production rate of greater than 12,000 boe per day. The transaction is expected to close on July 1st, 2011 and remains subject to the satisfaction of customary conditions including, without limitation, the approval of Caltex and Crew shareholders.

Outlook

Dry weather conditions in Crew's operating areas have led to improved access with the Company now utilizing five drilling rigs at Princess, Killam and Septimus. Although surface conditions are dry, the water table in the Princess area remains high. Pipelining and tie-in operations are not expected to begin until June. Current production is approximately 16,300 boe per day based on field estimates and the Company has approximately 4,000 boe per day of production that is shut in or tested and awaiting tie-in. The Company is in a position to exceed first quarter average production in the second quarter despite the sale of approximately 140 boe per day for $12.6 million effective April 1, 2011 and the shut-in of 1,000 boe per day for two weeks as a result of the planned June 2011 Spectra McMahon, British Columbia gas facility turnaround.

Subject to closing of the Caltex Transaction, Crew forecasts production to average 23,000 to 24,000 boe per day in 2011 resulting in an estimated exit rate of 32,500 to 34,500 boe per day (55 to 60% liquids). Subject to completion of the Transaction, Crew's Board of Directors have approved a $330 million exploration and development capital budget. This level of capital spending is projected to result in yearend net debt of approximately 0.9x debt to annualized estimated fourth quarter funds from operations.

Crew is well positioned to continue its growth strategy for many years with an inventory of over thirteen years of opportunities at the current pace of development. The acquisition of Caltex is complementary to our growth strategy and capital efficiency objectives providing a solid foundation for profitable growth. In addition to being highly accretive in all key metrics, this acquisition positions Crew to post forecasted production per share growth of over 20% in 2011 and 2012.

The focus in the near term will be the successful integration of the Caltex staff and properties as well as the efficient execution of our capital program. With closing of the Transaction, Crew will have sizeable production and future growth opportunities in two of the highest rate of return plays in North America. We look forward to reporting our progress in these initiatives in our second quarter report.

On behalf of the Board,

Dale Shwed
President and C.E.O.

May 18, 2011

ADVISORIES

Management's discussion and analysis ("MD&A") is the Company's explanation of its financial performance for the period covered by the financial statements along with an analysis of the Company's financial position. Comments relate to and should be read in conjunction with the unaudited interim consolidated financial statements of the Company for the three month periods ended March 31, 2011 and 2010 and the audited consolidated financial statements and Management Discussion and Analysis for the year ended December 31, 2010. In 2010, the CICA Handbook was revised to incorporate International 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 and the impact on Crew, future operating costs, future transportation costs, expected royalty rates, general and administrative expenses, interest rates, debt levels, funds from operations and the timing of and impact of implementing accounting policies, the completion and timing of completion of the Caltex Transaction, estimated production associated with the properties of Caltex, estimates regarding undeveloped land position and estimated future drilling, recompletion or reactivation locations and operation netbacks associated with the Caltex properties, the complementary nature of the Caltex assets and anticipated growth opportunities associated therewith and ability to improve upon historical recovery factors, anticipated benefits from the Transaction and anticipated impact upon Crew's forecasts in respect of production and cash flow for 2011 and resulting yearend 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 ability to access sufficient capital from internal and external sources. As a consequence, the Company's actual results may differ materially from those expressed in, or implied by, the forward looking statements. Included herein is an estimate of Crew's year-end net debt based on assumptions as to cash flow, capital spending in 2011 and the other assumptions utilized in arriving at Crew's 2011 capital budget, including without limitation assumptions regarding completion and timing of the completion of the Caltex Transaction and the impact of same upon 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

One of the benchmarks Crew uses to evaluate its performance is funds from operations. Funds from operations is a measure not defined in IFRS that is commonly used in the oil and gas industry. It represents cash provided by operating activities before changes in non-cash working capital, decommissioning obligation expenditures and the transportation liability charge. The Company considers it a key measure as it demonstrates the ability of the business to generate the cash flow necessary to fund future growth through capital investment and to repay debt. Funds from operations should not be considered as an alternative to, or more meaningful than cash provided by operating activities as determined in accordance with 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 Mar. 31, 2011**	Three months ended Mar. 31, 2010
Cash provided by operating activities	**26,469**	31,323
Decommissioning obligation expenditures	**(11)**	576
Transportation liability charge [(1)]	**101**	328
Change in non-cash working capital	**(2,448)**	(4,900)
Funds from operations	**24,111**	27,327

(1) The amount for the three months ended March 31, 2010 does not include the transportation liability write-down of $344,000 as shown in the transportation costs section.

Management uses certain industry benchmarks such as operating netback to analyze financial and operating performance. This benchmark as presented does not have any standardized meaning prescribed by 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 contracts less royalties, operating costs and transportation costs calculated on a boe basis. Management considers operating netback an important measure to evaluate its operational performance as it demonstrates its field level profitability relative to current commodity prices.

RESULTS OF OPERATIONS

Proposed Acquisition

On May 2, 2011, Crew announced it has entered into an arrangement agreement (the "Arrangement Agreement") whereby, subject to satisfaction of certain conditions, Crew will acquire 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 Arrangement Agreement, Caltex shareholders will receive 0.38 of a Crew common share for each Caltex share held or an estimated aggregate of approximately 33.2 million Crew shares based upon certain assumptions concerning the exercise of Caltex convertible securities.

Upon completion of the Transaction, Caltex will become a wholly owned subsidiary of Crew and current Caltex shareholders and rights holders of Caltex convertible securities that are exercised prior to the effective date of the Transaction will own approximately 28% of the combined entity. The Transaction is expected to be completed by way of Plan of Arrangement and is subject to customary conditions including, without limitation, Toronto Stock Exchange, court and regulatory approval and the requisite approval of Crew and Caltex shareholders. The Board of Directors of each of Crew and Caltex have unanimously approved the Transaction and resolved to recommend that their respective shareholders vote in favour of the Transaction. Closing of the Transaction is expected to occur on or about July 1, 2011. The Arrangement Agreement provides for a mutual $20 million non-completion fee payable to Crew or Caltex, as the case may be, in certain circumstances if the Transaction is not completed.

Crew believes the Transaction represents the successful continuation of our strategy of exploiting high netback assets with significant resource potential. Conditional on the successful completion of the transaction the Company has increased its 2011 production guidance to 23,000 to 24,000 boe per day (50% liquids) with an anticipated exit rate of 32,500 to 34,500 boe per day (55% to 60% liquids).

Production

	Three months ended March 31, 2011				Three months ended March 31, 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	**5,677**	**361**	**22,471**	**9,783**	4,138	805	30,881	10,090
British Columbia	**117**	**768**	**29,638**	**5,825**	123	646	24,851	4,911
Total	**5,794**	**1,129**	**52,109**	**15,608**	4,261	1,451	55,732	15,001

In the first quarter of 2011, oil production increased 36% compared to the same period in 2010 as a result of production additions from the successful drilling program in late 2010 in the Princess, Alberta area. Natural gas and associated liquids production decreased in the first quarter of 2011 compared with the first quarter of 2010 due to the disposition of approximately 1,700 boe per day (21% liquids and 79% natural gas) in the Edson, Alberta area which closed on April 1, 2010. This disposition was offset by a successful drilling program which added natural gas liquids ("ngl") rich natural gas production in the Septimus, British Columbia area. Production for the quarter was slightly lower than the Company's expectations due to the Septimus gas plant being offline for six additional unplanned days to complete the plant expansion to 50 mmcf per day and weather delays impacting the tie-in of first quarter oil wells drilled at Princess.

Revenue

	Three months ended Mar. 31, 2011	Three months ended Mar. 31, 2010
Revenue ($ thousands)		
Natural gas	**18,751**	26,984
Oil	**36,331**	27,648
Natural gas liquids	**6,066**	7,140
Total	**61,148**	61,772
Crew average prices		
Natural gas ($/mcf)	**4.00**	5.38
Oil ($/bbl)	**69.68**	72.10
Natural gas liquids ($/bbl)	**59.71**	54.66
Oil equivalent ($/boe)	**43.53**	45.75
Benchmark pricing		
Natural Gas – AECO C daily index (Cdn $/mcf)	**3.82**	5.03
Oil – Bow River Crude Oil (Cdn $/bbl)	**80.70**	81.99
Oil and ngl – Cdn$ West Texas Intermediate (Cdn $/bbl)	**92.74**	81.91

Crew's first quarter 2011 revenue was consistent with the first quarter of 2010 as increased production of higher valued oil in the Princess area was offset by lower realized oil and natural gas prices and a decrease in production of lower valued natural gas and associated liquids production from the disposition of the Edson properties.

In the first quarter of 2011, the Company's average natural gas price decreased 26% over the same period in 2010 which is comparable with the 24% decrease in the Company's natural gas benchmark during the same period. The Company's realized oil price decreased 3% which was comparable with the decrease in the Bow River Crude benchmark of 2% for the same period. In the first quarter of 2011, the Company's ngl price increased in a similar proportion to the increase in the Company's benchmark Cdn$ West Texas Intermediate price compared with the same period in 2010.

Royalties

($ thousands, except per boe)	**Three months ended Mar. 31, 2011**	Three months ended Mar. 31, 2010
Royalties	**14,356**	13,149
Per boe	**$10.22**	$9.74
Percentage of revenue	**23.5%**	21.3%

Royalties as a percentage of revenue increased in the quarter compared to the same quarter in 2010. In the first quarter of 2011, increased production in the Princess Area, which attracts a higher effective royalty rate as compared to the corporate average royalty rate, increased the Company's overall corporate royalty rate. Crew continues to forecast an annual 2011 royalty rate of between 23% and 25% as the Company forecasts an increase in its oil sales in the Princess area in 2011. If the Caltex Transaction is completed in early July, the Company expects its corporate royalty rate will remain consistent averaging 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 operations:

($ thousands)	**Three months ended Mar. 31, 2011**	Three months ended Mar. 31, 2010
Realized gain on financial instruments	**1,016**	928
Unrealized gain/(loss) on financial instruments	**(16,033)**	8,198

As at March 31, 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)	778
Natural Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.90	Swap (1)	809
Natural Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.95	Swap (1)	843
Natural Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.965	Swap (1)	965
Natural Gas	7,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$5.00	Swap (1)	2,770
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	US$ WTI	US$80.15	Swap	(3,706)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$86.00	Swap	(1,410)
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$88.00	Swap	(2,460)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$88.50	Swap	(1,261)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$90.00	Swap	(1,023)
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$90.20	Swap	(2,029)
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$93.00	Swap	(646)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$80.00 - $95.45	Collar	(867)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$82.00 - $94.62	Collar	(891)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$85.00 - $100.50	Collar	(543)
Oil	500 bbl/day	January 1, 2011 – June 30, 2011	CDN$ WCS – WTI diff	($18.00)	Swap	42
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$85.00	Call (1)	(4,796)
Oil	750 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$90.00	Call (1)	(5,473)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	US$ WTI	US$90.00	Call (1)	(4,010)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$101.00	Swap	(631)
Oil	250 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$100.45	Swap	(357)
Oil	250 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$100.50	Swap	(351)
Total						(24,247)

(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 Mar. 31, 2011	Three months ended Mar. 31, 2010
Operating costs	**16,418**	14,986
Per boe	**$11.69**	$11.10

In the first quarter of 2011, the Company's operating costs per unit increased over the same period in 2010 due to the disposition of lower cost production in the Edson area and the additional higher operating cost production from the Company's Princess area. Princess currently realizes higher operating costs due to increased fluid handling costs. The Company expects inflationary pressures on operating costs due to higher fuel, chemical and labor costs will be partially offset by increased forecasted production and lower water handling costs at Princess. As such, the Company forecasts total corporate operating costs to decrease from the current level to average approximately $11.00 per boe for 2011. If the Caltex Transaction closes in early July, the Company expects operating costs for 2011 to range between $11.00 and $12.00 per boe.

Transportation Costs

($ thousands, except per boe)	Three months ended Mar. 31, 2011	Three months ended Mar. 31, 2010
Transportation costs including liability write-down	**2,996**	2,377
Transportation liability write-down	**–**	344
Transportation costs	**2,996**	2,721
Per boe	**$2.13**	$2.02

In the first quarter of 2011, the Company's transportation costs per unit increased compared to the same period in 2010 due to an increase in the per unit transportation cost for oil trucking in the Princess area and additional condensate transportation costs in the Septimus area. In late 2010, in order to receive enhanced pricing, the Company started delivering a portion of the Princess area oil volumes to an alternative truck terminal which added to the cost of clean oil trucking. The Company continues to forecast transportation costs to range between $1.90 and $2.15 per boe for 2011. If the Caltex Transaction is completed in early July, the Company expects transportation costs for 2011 to range between $1.70 and $1.90 per boe.

Operating Netbacks

	Three months ended March 31, 2011				Three months ended March 31, 2010			
	Oil ($/bbl)	**Ngl ($/bbl)**	**Nat. gas ($/mcf)**	**Total ($/boe)**	Oil ($/bbl)	Ngl ($/bbl)	Nat. gas ($/mcf)	Total ($/boe)
Revenue	**69.68**	**59.71**	**4.00**	**43.53**	72.10	54.66	5.38	45.75
Realized commodity hedging gain (loss)	**(2.24)**	**–**	**0.46**	**0.72**	(0.05)	–	0.18	0.65
Royalties	**(22.35)**	**(11.14)**	**(0.33)**	**(10.22)**	(21.05)	(13.51)	(0.65)	(9.74)
Operating costs	**(14.76)**	**(8.37)**	**(1.68)**	**(11.69)**	(13.15)	(9.08)	(1.75)	(11.10)
Transportation costs	**(1.71)**	**(1.89)**	**(0.41)**	**(2.13)**	(0.94)	(1.40)	(0.43)	(2.02)
Operating netbacks	**28.62**	**38.31**	**2.04**	**20.21**	36.91	30.67	2.73	23.54

General and Administrative Costs

($ thousands, except per boe)	**Three months ended Mar. 31, 2011**	Three months ended Mar. 31, 2010
Gross costs	**4,197**	4,172
Operator's recoveries	**(113)**	(176)
Capitalized costs	**(1,296)**	(1,436)
General and administrative expenses	**2,788**	2,560
Per boe	**1.98**	1.89

Increased general and administrative costs after recoveries and capitalization were mainly the result of decreased capitalized general and administrative costs in the first quarter of 2011 compared with the same period in 2010. The Company added employees whose salaries are not capitalized in accordance with the Company's capitalized general and administrative policies during 2010 and early in 2011. 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 months ended March 31, 2010, increased to $2.6 million from $1.9 million as reported under previous GAAP. The Company expects general and administrative expenses to average between $1.50 and $2.00 per boe for the year with higher amounts incurred in the first half of the year due to the payment of annual costs associated with annual regulatory filings. If the Caltex Transaction is completed in early July, the Company expects general and administrative costs to average between $1.30 and $1.80 per boe.

Finance Expenses

($ thousands, except per boe)	**Three months ended Mar. 31, 2011**	Three months ended Mar. 31, 2010
Interest on bank debt	**1,495**	1,957
Accretion of the decommissioning obligation	**477**	532
Total finance expense	**1,972**	2,489
Average debt level	**116,003**	135,842
Effective interest rate on bank debt	**5.2%**	5.8%
Interest on bank debt per boe	**$1.06**	$1.45

In 2011, lower average debt levels combined with lower margins on the Company's bank facility decreased the Company's interest expense for the period. Accretion of the decommissioning obligation was lower in the first quarter of 2011 compared with the same period in 2010 due to the sale of the Edson assets in the second quarter of 2010. The Company expects its effective interest rate on bank debt will average approximately 5.0% to 5.5% in 2011 and does not expect this to change conditional upon completion of the Caltex Transaction.

Stock-Based Compensation

($ thousands)	**Three months ended Mar. 31, 2011**	Three months ended Mar. 31, 2010
Gross costs	**1,544**	2,480
Capitalized costs	**(710)**	(1,141)
Total stock-based compensation	**834**	1,339

The Company's stock-based compensation expense has decreased in 2011 compared with 2010 due to a decrease in the number of 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 Mar. 31, 2011	Three months ended Mar. 31, 2010
Depletion and depreciation	**20,965**	20,081
Per boe	**14.92**	14.87

Total depletion, depreciation and accretion costs per boe have remained consistent in the first quarter of 2011 as compared with the same period in 2010. 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.

Deferred Income Taxes

In the first quarter of 2011, the provision for deferred income taxes was a recovery of $4.1 million compared to an expense of $6.0 million in the first quarter of 2010. The decrease in deferred taxes was a result of the Company having pre-tax earnings in 2010 compared to a loss in the first quarter of 2011.

Cash and Funds from Operations and Net Income (loss)

($ thousands, except per share amounts)	Three months ended Mar. 31, 2011	Three months ended Mar. 31, 2010
Cash provided by operating activities	**26,469**	31,323
Funds from operations	**24,111**	27,327
Per share - basic	**0.29**	0.35
- diluted	**0.29**	0.34
Net income (loss)	**(10,126)**	17,770
Per share - basic	**(0.12)**	0.23
- diluted	**(0.12)**	0.22

The first quarter 2011 decrease in cash provided by operating activities and funds from operations was the result of decreased commodity pricing and higher royalties and costs associated with the Company's oil properties. The first quarter 2011 net loss was a result of a $16.0 million unrealized loss on the Company's risk management program compared with an $8.2 million unrealized gain on the program for the same period in 2010. The Company also experienced a $9.9 million gain on the disposition of undeveloped land in the first quarter of 2010.

Capital Expenditures, Acquisitions and Dispositions

During the first quarter, the Company drilled a total of 40 (39.3 net) wells resulting in thirty-four (34.0 net) oil wells, four (3.3 net) natural gas wells and two (2.0 net) service wells. In addition, the Company completed 29 (29.0 net) wells and recompleted four (4.0 net) wells in the quarter. The Company continued to add to its infrastructure spending $16.1 million on pipelines and upgrading its batteries predominantly in the Princess area. The Company also continued to evaluate land in the Princess area completing a seismic shoot during the first quarter of 2011. During the quarter, the Company also closed the sale of the Septimus facility expansion which had been reclassified as an asset held for sale at December 31, 2010.

Total net capital expenditures for the quarter are detailed below:

($ thousands)	Three months ended Mar. 31, 2011	Three months ended Mar. 31, 2010
Land	**411**	7,717
Seismic	**7,344**	4,931
Drilling and completions	**50,029**	39,697
Facilities, equipment and pipelines	**16,012**	4,280
Other	**1,369**	1,560
Total exploration and development	**75,165**	58,185
Property acquisitions (dispositions)	**361**	(10,916)
Total	**75,526**	47,269

LIQUIDITY AND CAPITAL RESOURCES

Capital Funding

The Company is in the process of completing the extension of its credit facility with a syndicate of banks (the "Syndicate"). The Company's lenders have indicated their willingness to increase the Company's borrowing base to $275 million subject to final credit approval. This increase has been deferred pending a review of the Caltex assets and a determination of the borrowing base associated with the combined assets.

The credit facility currently includes a revolving line of credit of $220 million and an operating line of credit of $20 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 13, 2011. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 percent and all outstanding balances under the Facility will become repayable in one year. 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 June 13, 2011. At March 31, 2011, the Company had drawings of $88.5 million on the Facility and had issued letters of credit totaling $2.1 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 quarter of 2011, the Company received proceeds of $7.2 million upon the exercise of 774,900 employee stock options.

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

Working Capital

The capital intensive nature of Crew's activities generally results in the Company carrying a working capital deficit. Working capital deficiency includes accounts receivable less accounts payable and accrued liabilities. The Company maintains sufficient unused bank credit lines to satisfy working capital deficiencies. At March 31, 2011, the Company's working capital deficiency totaled $31.5 million which, when combined with the drawings on its bank line, represented 50% of its bank facility at March 31, 2011.

Share Capital

As at May 18, 2011, Crew had 85,983,334 Common Shares and 6,724,600 options to acquire Common Shares of the Company issued and outstanding.

Capital Structure

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

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

The Company monitors this ratio and endeavours to maintain it at or below 2.0 to 1.0. This ratio may increase at certain times as a result of acquisitions or low commodity prices. As shown below, as at March 31, 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)	**Mar. 31, 2011**	Dec. 31, 2010
Accounts receivable (including assets held for sale)	**56,762**	60,038
Accounts payable and accrued liabilities	**(88,284)**	(100,745)
Working capital deficiency	**(31,522)**	(40,707)
Bank loan	**(88,462)**	(138,700)
Net debt	**(119,984)**	(179,407)
Funds from operations	**24,111**	27,449
Annualized	**96,444**	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 (1)	$ 88,462	$ –	$ 88,462	$ –	$ –	$ –	$ –
Operating Leases	2,622	1,313	1,309	–	–	–	–
Capital commitments	1,000	1,000	–	–	–	–	–
Firm transportation agreements	21,320	3,302	1,535	1,535	2,110	2,110	10,728
Firm processing agreement	76,327	4,917	6,526	6,526	8,239	8,239	41,880
Total	$ 189,731	$ 10,532	$ 97,832	$ 8,061	$ 10,349	$ 10,349	$ 52,608

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

The transportation agreements include a $19.2 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 has committed to process a minimum monthly volume of gas through the facility commencing on December 1, 2009 and continuing through November 30, 2019. The commitment is included in the above table.

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 full 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

Dry weather conditions in Crew's operating areas have led to improved access with the Company now utilizing five drilling rigs at Princess, Killam and Septimus. Although surface conditions are dry, the water table in the Princess area remains high. Pipelining and tie-in operations are not expected to begin until June. Current production is approximately 16,300 boe per day based on field estimates and the Company has approximately 4,000 boe of production that is shut in or tested and awaiting tie-in. The Company is in a position to exceed first quarter average production in the second quarter despite the sale of approximately 140 boe per day for $12.6 million effective April 1, 2011 and the shut-in of 1,000 boe per day for two weeks as a result of the planned June 2011 Spectra McMahon, British Columbia gas facility turnaround.

Subject to closing of the Caltex Transaction, Crew forecasts production to average 23,000 to 24,000 boe per day in 2011 resulting in an estimated exit rate of 32,500 to 34,500 boe per day (55 to 60% liquids). Subject to completion of the Transaction, Crew's Board of Directors have approved a $330 million exploration and development capital budget. This level of capital spending is projected to result in yearend net debt of approximately 0.9x debt to annualized fourth quarter funds from operations.

ADDITIONAL DISCLOSURES

Quarterly Analysis

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

($ thousands, except per share amounts)	**Mar. 31 2011**	Dec. 31 2010	Sept. 30 2010	June 30 2010	Mar. 31 2010	Dec. 31 2009	Sept. 30 2009	June 30 2009
Total daily production (boe/d)	**15,607**	14,654	13,061	12,048	15,001	14,470	13,065	13,466
Average wellhead price ($/boe)	**43.53**	42.00	37.39	39.25	45.75	43.30	32.04	32.10
Petroleum and natural gas sales	**61,148**	56,620	44,924	43,027	61,772	57,646	38,510	39,331
Cash provided by operations	**26,469**	20,225	18,956	23,422	31,323	16,734	24,902	21,517
Funds from operations	**24,111**	27,449	23,464	19,966	27,327	27,256	19,640	20,036
Per share – basic	**0.29**	0.34	0.29	0.25	0.35	0.35	0.25	0.27
– diluted	**0.29**	0.34	0.29	0.24	0.34	0.35	0.25	0.27
Net income (loss)	**(10,126)**	(14,214)	(17,280)	31,543	17,770	(9,154)	(7,376)	(12,267)
Per share – basic	**(0.12)**	(0.18)	(0.22)	0.39	0.23	(0.12)	(0.10)	(0.17)
– diluted	**(0.12)**	(0.18)	(0.22)	0.39	0.22	(0.12)	(0.10)	(0.17)

(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 quarter of 2009 and 2010 was negatively impacted by scheduled and unscheduled third party facility shutdowns and poor weather experienced in southern Alberta during the second and third quarters 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.

- In 2009 and 2010, the Company sold assets with approximately 2,970 boe per day of production for $182.9 million. The major dispositions closed as follows:
    - First quarter 2009 – 130 boe per day for $10.7 million
    - Second quarter 2009 – 540 boe per day for $22.5 million
    - Fourth quarter 2009 – 600 boe per day for $25.3 million
    - Second quarter 2010 – 1,700 boe per day for $123.3 million

- The 2010 dispositions of assets in the Ferrier and Edson areas resulted in gains on sale of assets of $9.9 million and $37.0 million in the first and second quarters of 2010, 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. The Company's IFRS accounting policies are provided in note 3 to the interim consolidated financial statements. In addition, note 17 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 January 1, 2010, March 31, 2010 and December 31, 2010 and consolidated statements of income and comprehensive income and cash flows for the three months ended March 31, 2010 and year ended December 31, 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 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 are 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 on 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 on 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 Reconciliation

	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	174	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)	34,234	15,328
Net earnings/(loss) - IFRS	17,819	(14,214)	(17,280)	31,543	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.

New standards and interpretations not yet adopted:

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.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

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

The Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on January 1, 2011 and ended on March 31, 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.

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

Dated as of May 18, 2011

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited) (thousands)	**March 31, 2011**	December 31, 2010	January 1, 2010
		(note 17)	(note 17)
ASSETS			
Current Assets:			
Accounts receivable	**$ 47,811**	$ 44,922	$ 37,574
Fair value of financial instruments (note 12)	**–**	982	–
Assets held for sale (note 6)	**8,951**	15,116	–
	56,762	61,020	37,574
Exploration and evaluation assets (note 5)	**78,282**	72,281	35,591
Property, plant and equipment (note 6)	**953,659**	912,640	889,541
	$ 1,088,703	$ 1,045,941	$ 962,706
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities:			
Accounts payable and accrued liabilities	**$ 88,284**	$ 100,745	$ 84,228
Fair value of financial instruments (note 12)	**24,247**	–	834
Current portion of other long-term obligations (note 9)	**242**	343	1,313
Decommissioning obligations on assets held for sale (note 6)	**1,022**	–	–
	113,795	101,088	86,375
Fair value of financial instruments (note 12)	**–**	9,196	–
Bank loan (note 8)	**88,462**	138,700	135,601
Other long-term obligations (note 9)	**–**	–	132
Decommissioning obligations (note 10)	**54,994**	54,828	53,063
Deferred tax liability	**97,093**	102,479	96,488
Shareholders' Equity			
Share capital (note 11)	**755,992**	649,768	620,988
Contributed surplus (note 11)	**26,122**	27,511	25,506
Deficit	**(47,755)**	(37,629)	(55,447)
	734,359	639,650	591,047
Commitments (note 15)			
Subsequent event (note 16)			
	$ 1,088,703	$ 1,045,941	$ 962,706

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

(unaudited) (thousands, except per share amounts)	**Three months ended March 31, 2011**	Three months ended March 31, 2010
		(note 17)
Revenue		
Petroleum and natural gas sales	**$ 61,148**	$ 61,772
Royalties	**(14,356)**	(13,149)
Realized gain on financial instruments (note 12)	**1,016**	928
Unrealized gain (loss) on financial instruments (note 12)	**(16,033)**	8,198
	31,775	57,749
Expenses		
Operating	**16,418**	14,986
Transportation (note 9)	**2,996**	2,377
General and administrative	**2,788**	2,560
Stock-based compensation	**834**	1,339
Financing (note 14)	**1,972**	2,489
Depletion and depreciation	**20,965**	20,081
Gain on divestitures	**–**	(9,882)
	45,973	33,950
Income (loss) before income taxes	**(14,198)**	23,799
Deferred tax expense (reduction)	**(4,072)**	6,029
Net income (loss) and comprehensive income (loss)	**$ (10,126)**	$ 17,770
Net income (loss) per share (note 11)		
Basic	**$ (0.12)**	$ 0.23
Diluted	**$ (0.12)**	$ 0.22

See accompanying notes to the consolidated financial statements.

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 loss for the period	–	–	–	(10,126)	(10,126)
Issue of shares (net of issue costs)	4,820	96,111	–	–	96,111
Stock-based compensation expensed	–	–	834	–	834
Stock-based compensation capitalized	–	–	710	–	710
Transfer of stock-based compensation on exercises	–	2,933	(2,933)	–	–
Issued on exercise of options	775	7,180	–	–	7,180
Balance March 31, 2011	**85,963**	**$ 755,992**	**$ 26,122**	**$ (47,755)**	**$ 734,359**

	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	–	–	–	17,770	17,770
Stock-based compensation expensed	–	–	1,339	–	1,339
Stock-based compensation capitalized	–	–	1,141	–	1,141
Transfer of stock-based compensation on exercises	–	4,506	(4,506)	–	–
Issued on exercise of options	1,269	11,237	–	–	11,237
Balance March 31, 2010	79,421	$ 636,731	$ 23,480	$ (37,677)	$ 622,534

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited) (thousands)	**Three months ended March 31, 2011**	Three months ended March 31, 2010
		(note 17)
Cash provided by (used in):		
Operating activities:		
Net income (loss)	**$ (10,126)**	$ 17,770
Adjustments:		
Depletion and depreciation	**20,965**	20,081
Financing expenses (note 14)	**1,972**	2,489
Interest expense (note 14)	**(1,495)**	(1,957)
Stock-based compensation	**834**	1,339
Deferred tax expense (reduction)	**(4,072)**	6,029
Unrealized (gain) loss on financial instruments	**16,033**	(8,198)
Gain on divestitures	**–**	(9,882)
Transportation liability charge (note 9)	**(101)**	(672)
Decommissioning obligations settled (note 10)	**11**	(576)
Change in non-cash working capital (note 13)	**2,448**	4,900
	26,469	31,323
Financing activities:		
Increase (decrease) in bank loan	**(50,238)**	18,000
Issue of common shares	**100,015**	–
Proceeds from exercise of share options	**7,180**	11,237
Share issue costs	**(5,218)**	–
	51,739	29,237
Investing activities:		
Exploration and evaluation asset expenditures	**(7,213)**	(11,471)
Property, plant and equipment expenditures	**(67,952)**	(46,714)
Property (acquisitions) divestitures	**(361)**	10,916
Proceeds on sale of asset held for sale	**15,116**	–
Change in non-cash working capital (note 13)	**(17,798)**	(13,291)
	(78,208)	(60,560)
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.

For the three months ended March 31, 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 months ended March 31, 2011 and 2010 comprise the Company and its wholly owned subsidiary, Crew Resources Inc., and a partnership, Crew Energy Partnership which are incorporated in Canada. The Company conducts many of its activities jointly with others; these financial statements reflect only the Company's proportionate interest in such activities.

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"). These financial statements are the Company's first IFRS interim consolidated financial statements after its transition to reporting in accordance with IFRS and before the issuance of its first publicly issued annual consolidated IFRS financial statements. IFRS 1 – First-time adoption of International Financial Reporting Standards ("IFRS 1") has been applied to these interim consolidated financial statements. These interim consolidated financial statements use the accounting policies which 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.

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 17. The note includes reconciliations of equity and net loss for comparative periods from former Canadian GAAP ("previous GAAP") to IFRS.

The consolidated financial statements were authorized for issue by the Board of Directors on May 18, 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 4.

(c) Functional and presentation currency:

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

(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. SIGNIFICANT ACCOUNTING POLICIES:

The accounting policies set out below have been applied consistently to all periods presented in these consolidated financial statements, and have been applied consistently by the Company and its subsidiaries.

Certain comparative amounts have been reclassified to conform with the current period's presentation.

(a) Basis of consolidation:

(i) Subsidiaries:

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that currently are exercisable are taken into account. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

The purchase method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in the statement of income.

(ii) Jointly controlled operations and jointly controlled assets:

Many of the Company's oil and natural gas activities involve jointly controlled assets. The consolidated financial statements include the Company's share of these jointly controlled assets and a proportionate share of the relevant revenue and related costs.

(iii) Transactions eliminated on consolidation:

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

(b) Financial instruments:

(i) Non-derivative financial instruments:

Non-derivative financial instruments comprise accounts receivable, cash and cash equivalents, bank loan, and accounts payable. Non-derivative financial instruments are recognized initially at fair value plus, for instruments not at fair value through profit or loss, any directly attributable transaction costs. Subsequent to initial recognition non-derivative financial instruments are measured as described below.

Cash and cash equivalents comprise cash on hand, term deposits held with banks, other short-term highly liquid investments with original maturities of three months or less. Bank overdrafts that are repayable on demand and form an integral part of the Company's cash management, whereby management has the ability and intent to net bank overdrafts against cash, are included as a component of cash and cash equivalents for the purpose of the statement of cash flows.

Other non-derivative financial instruments, such as accounts receivable, bank loan, and accounts payable, are measured at amortized cost using the effective interest method, less any impairment losses.

(ii) Derivative financial instruments:

The Company enters into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices, interest rates and the exchange rate between Canadian and United States dollars. These instruments are not used for trading or speculative purposes. The Company has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though the Company considers all commodity contracts to be economic hedges. As a result, all financial derivative contracts are classified as fair value through profit or loss and are recorded on the balance sheet at fair value. Transaction costs are recognized in profit or loss when incurred.

(iii) Share capital:

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares and share options are recognized as a deduction from equity, net of any tax effects.

(c) Property, plant and equipment and exploration and evaluation assets:

(i) Recognition and measurement:

Exploration and evaluation expenditures:

Pre-licence costs are recognized in the statement of income as incurred.

Exploration and evaluation costs, including the costs of acquiring licences and directly attributable general and administrative costs, initially are capitalized as exploration and evaluation assets. The costs are accumulated in cost centres by well, field or exploration area pending determination of technical feasibility and commercial viability.

Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are allocated to cash-generating units.

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proven and/or probable reserves are determined to exist. A review of each exploration license or field is carried out, at least annually, to ascertain whether proven and/or probable reserves have been discovered. Upon determination of proven and/or probable reserves, intangible exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation assets to a separate category within tangible assets referred to as oil and natural gas interests.

Development and production costs:

Items of property, plant and equipment, which include oil and gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development and production assets are grouped into Cash Generating Units ("CGUs") for impairment testing. The Company allocated its historical property, plant and equipment cost at January 1, 2010, the date of IFRS transition, to the CGUs, based on a pro ration using December 31, 2009 externally determined reserve values underlying each of the CGUs. When significant parts of an item of property, plant and equipment, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (major components).

Gains and losses on disposal of an item of property, plant and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of property, plant and equipment and are recognized in profit or loss.

(ii) Subsequent costs:

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred.

(iii) Depletion and depreciation:

The net carrying value of development or production assets is depleted using the unit of production method by reference to the ratio of production in the year to the related proven and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually.

The estimated useful lives for certain production assets for the current and comparative years are as follows:

Gas processing plant	Unit of production
Pipeline facilities	Unit of production
Turnaround costs	2 years

For other assets, depreciation is recognized in profit or loss on a straight-line basis over the estimated useful lives of each part of an item of property, plant and equipment. Leased assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that the Company will obtain ownership by the end of the lease term. Land is not depreciated.

The estimated useful lives for other assets for the current and comparative years are as follows:

Office equipment	5 years

Depreciation methods, useful lives and residual values are reviewed at each reporting date.

(iv) Assets held for sale:
Non-current assets, or disposal groups consisting of assets and liabilities, are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is met when the sale is highly probable and the asset is available for immediate sale in its present condition.

Non-current assets classified as held for sale are measured at the lower of the carrying amount and fair value less costs to sell, with impairments recognized in net earnings in the period measured. Non-current assets and disposal groups held for sale are presented in current assets and liabilities on the statement of financial position.

(e) Leased assets:
Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases. Upon initial recognition the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

Minimum lease payments made under finance leases are apportioned between the finance expenses and the reduction of the outstanding liability. The finance expenses are allocated to each year during the lease term so as to produce a constant periodic rate of interest on the remaining balance of the liability.

Other leases are operating leases, which are not recognized on the Company's statement of financial position.

Payments made under operating leases are recognized in profit or loss on a straight-line basis over the term of the lease. Lease incentives received are recognized as an integral part of the total lease expense, over the term of the lease.

(f) Impairment:
(i) Financial assets:
A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in profit or loss.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in profit or loss.

(ii) Non-financial assets:
The carrying amounts of the Company's non-financial assets, other than E&E assets and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. For goodwill, an

impairment test is completed each year. E&E assets are assessed for impairment when they are reclassified to property, plant and equipment, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or "CGU"). The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proven and probable reserves.

The goodwill acquired in an acquisition, for the purpose of impairment testing, is allocated to the CGUs that are expected to benefit from the synergies of the combination. E&E assets are allocated to related CGUs when they are assessed for impairment, both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to property, plant and equipment.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the unit (group of units) on a pro rata basis.

An impairment loss in respect of property, plant and equipment and exploration and evaluation assets, recognized in prior years, is assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized. An impairment loss in respect of goodwill is not reversed.

(g) Share based payments:

The grant date fair value of options granted to employees is recognized as compensation expense, within general and administrative expenses, with a corresponding increase in contributed surplus over the vesting period. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest.

(h) Provisions:

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

(i) Decommissioning obligations:

The Company's activities give rise to dismantling, decommissioning and site disturbance re-mediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of expenditure required to settle the present obligation at the balance sheet date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

(i) Revenue:
Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer which is usually when legal title passes to the external party. This is generally at the time product enters the pipeline.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

(j) Finance income and expenses:
Finance expense comprises interest expense on borrowings, accretion of the discount on provisions and impairment losses recognized on financial assets.

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. All other borrowing costs are recognized in profit or loss using the effective interest method. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Company's outstanding borrowings during the period.

Interest income is recognized as it accrues in profit or loss, using the effective interest method.

(k) Income tax:
Income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(l) Earnings per share:
Basic earnings per share is calculated by dividing the profit or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted earnings per share is determined by adjusting the profit or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options granted to employees.

(m) Flow-through shares:

The resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. On issuance the premium received on the flow-through shares, being the difference in price over a common share with no tax attributes, is recognized on the statement of financial position. As expenditures are incurred the deferred tax liability associated with the renounced tax deductions are recognized through profit and loss along with a pro-rata portion of the deferred premium.

(n) New standards and interpretations not yet adopted:

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.

4. 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.

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 March 31, 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).

5. 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	7,213
Transfer to property, plant and equipment	(1,212)
Balance, March 31, 2011	**$ 78,282**

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

(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.

(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 CGUs. The CGU includes both the E&E CGU and CGUs related to oil and natural gas interests for that area, but not larger than a segment.

6. 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	68,313
Transfer from exploration and evaluation assets	1,212
Asset held for sale	(8,951)
Change in decommissioning obligations	700
Capitalized stock-based compensation	710
Balance, March 31, 2011	**$ 1,080,249**

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
Depletion and depreciation expense	20,965
Balance, March 31, 2011	**$ 126,590**

Net book value	Total
Balance, January 1, 2010	$ 889,541
Balance, December 31, 2010	$ 912,640
Balance, March 31, 2011	**$ 953,659**

The calculation of depletion for the three months ended March 31, 2011 included estimated future development costs of $282.5 million (December 31, 2010 - $297.4 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $52.8 million (December 31, 2010 - $51.1 million) and undeveloped land of $100.5 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.

In April 2011 the Company disposed of oil and gas assets in the Gilby area for gross proceeds of $12.7 million. The assets had a net book value of $9.0 million which has been classified as "assets held for sale" at March 31, 2011. Associated decommissioning liabilities of $1.0 million have also been reclassified to current liabilities on assets held for sale.

7. IMPAIRMENT LOSS:

During 2010, as a result of decreasing natural gas prices, Crew recognized a $29.1 million impairment relating to several of the Company's CGUs. An impairment charge was taken at September 30, 2010 ($18.7 million) and December 31, 2010 ($10.4 million) and recorded as additional depletion and depreciation expense. The impairments were based on the difference between the period end net book value of the assets and the recoverable amount. The recoverable amount was determined using fair value less costs to sell, based on discounted cash flows of proved plus probable reserves using forecast prices and costs and a discount rate of 10%.

8. BANK LOAN:

The Company's bank facility consists of a revolving line of credit of $220 million and an operating line of credit of $20 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 13, 2011. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 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 June 13, 2011.

Advances under the Facility are available by way of prime rate loans with interest rates between 1.25 percent and 2.75 percent over the bank's prime lending rate and bankers' acceptances and LIBOR loans, which are subject to stamping fees and margins ranging from 2.25 percent to 3.75 percent depending upon the debt to EBITDA ratio of the Company calculated at the Company's previous quarter end. Standby fees are charged on the undrawn facility at rates ranging from 0.56 percent to 0.94 percent depending upon the debt to EBITDA ratio.

As at March 31, 2011, the Company's applicable pricing included a 1.5 percent margin on prime lending and a 2.5 percent stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.625 percent per annum standby fee on the portion of the facility that is not drawn. Borrowing margins and fees are reviewed annually as part of the bank syndicate's annual renewal. At March 31, 2011, the Company had issued letters of credit totaling $2.1 million (December 31, 2010 - $1.1 million). The effective interest rate on the Company's borrowings under its bank facility for the period ended March 31, 2011 was 5.2% (2010 – 5.8%).

9. 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 period ended March 31, 2011 was $0.1 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.

10. DECOMMISSIONING OBLIGATIONS:

	As at March 31, 2011	As at December 31, 2010
Decommissioning obligations, beginning of year	**$ 54,828**	$ 53,063
Obligations incurred	**1,481**	3,383
Obligations settled	**11**	(1,512)
Obligations divested	**–**	(5,212)
Change in estimated future cash outflows	**(781)**	3,141
Accretion of decommissioning liabilities	**477**	1,965
Decommissioning obligations, end of period	**$ 56,016**	$ 54,828

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 $56.0 million as at March 31, 2011 (December 31, 2010 - $54.8 million) based on an undiscounted total future liability of $65.4 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 3.70% (2010 – 3.50%).

11. SHARE CAPITAL:

At March 31, 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	309	$ 19.62
Exercised	(775)	$ 9.27
Forfeited	(67)	$ 16.03
Balance at March 31, 2011	4,797	$ 11.53
Exercisable at March 31, 2011	2,343	$ 9.14

The following table summarizes information about the stock options outstanding at March 31, 2011:

Range of exercise prices	Outstanding at March 31, 2011	Weighted average remaining life (years)	Weighted average exercise price	Exercisable at March 31, 2011	Weighted average exercise price
$ 3.43 to $ 7.01	1,054	1.8	$ 5.16	597	$ 5.17
$ 7.02 to $ 9.94	1,055	0.9	$ 7.48	999	$ 7.38
$ 9.95 to $14.63	209	1.3	$ 12.81	113	$ 12.46
$14.64 to $18.70	2,197	2.7	$ 15.35	634	$ 15.02
$18.71 to $21.19	282	3.9	$ 19.75	–	$ –
	4,797	2.1	$ 11.53	2,343	$ 9.14

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

Assumptions	**Three months ended March 31, 2011**	Three months ended March 31 2010
Risk free interest rate (%)	**2.3**	2.3
Expected life (years)	**4.0**	4.0
Expected volatility (%)	**60**	61
Forfeiture rate (%)	**16**	17
Weighted average fair value of options	**$ 9.28**	$ 7.07

Earnings (Loss) per share:

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average shares outstanding for the period ended March 31, 2011 was 82,221,000 (2010 – 78,649,000).

In computing diluted earnings per share for the period ended March 31, 2011, nil (2010 – 2,082,000) shares were added to the weighted average Common Shares outstanding to account for the dilution of stock options. There were 4,797,000 (2010 – 2,104,000) stock options that were not included in the diluted earnings per share calculation because they were anti-dilutive.

12. DERIVATIVE CONTRACTS AND CAPITAL MANAGEMENT:

Derivative contracts:

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

At March 31, 2011 the following derivative contracts were outstanding and recorded at estimated fair value:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Commodity contracts						
Natural Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.85	Swap(1)	778
Natural Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.90	Swap(1)	809
Natural Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.95	Swap(1)	843
Natural Gas	2,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$4.965	Swap(1)	965
Natural Gas	7,500 gj/day	January 1, 2011 – December 31, 2011	AECO C Monthly Index	$5.00	Swap(1)	2,770
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	US$ WTI	US$80.15	Swap	(3,706)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$86.00	Swap	(1,410)
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$88.00	Swap	(2,460)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$88.50	Swap	(1,261)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$90.00	Swap	(1,023)
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$90.20	Swap	(2,029)
Oil	500 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$93.00	Swap	(646)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$80.00 - $95.45	Collar	(867)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$82.00 - $94.62	Collar	(891)
Oil	250 bbl/day	January 1, 2011 – December 31, 2011	CDN$ WTI	$85.00 - $100.50	Collar	(543)
Oil	500 bbl/day	January 1, 2011 – June 30, 2011	CDN$ WCS – WTI diff	($18.00)	Swap	42
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$85.00	Call(1)	(4,796)
Oil	750 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$90.00	Call(1)	(5,473)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	US$ WTI	US$90.00	Call(1)	(4,010)
Oil	250 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$100.45	Swap	(357)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$101.00	Swap	(631)
Oil	250 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$100.50	Swap	(351)
Total commodity contracts						**(24,247)**

(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.

(b) Capital management:

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 March 31, 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.

	March 31, 2011	December 31, 2010
Net debt:		
Accounts receivable (including assets held for sale)	**$ 56,762**	$ 60,038
Accounts payable and accrued liabilities	**(88,284)**	(100,745)
Working capital deficiency	**$ (31,522)**	$ (40,707)
Bank loan	**(88,462)**	(138,700)
Net debt	**$ (119,984)**	$ (179,407)
Annualized funds from operations:		
Cash provided by operating activities	**$ 26,469**	$ 20,225
Decommissioning obligations settled	**(11)**	606
Transportation liability charge	**101**	120
Change in non-cash working capital	**(2,448)**	6,498
Funds from operations	**24,111**	27,449
Annualized	**$ 96,444**	$ 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.

13. SUPPLEMENTAL CASH FLOW INFORMATION:

Changes in non-cash working capital is comprised of:

	Three months ended March 31, 2011	Three months ended March 31, 2010
Changes in non-cash working capital		
Accounts receivable	$ (2,889)	$ (2,194)
Accounts payable and accrued liabilities	(12,461)	(6,197)
	$ (15,350)	$ (8,391)
Operating activities	$ 2,448	$ 4,900
Investing activities	(17,798)	(13,291)
	$ (15,350)	$ (8,391)
Interest paid	$ (961)	$ (1,090)

14. FINANCING:

	Three months ended March 31, 2011	Three months ended March 31, 2010
Accretion of decommissioning obligations	$ 477	$ 532
Interest expense	1,495	1,957
	$ 1,972	$ 2,489

15. COMMITMENTS:

($ thousands)	Total	2011	2012	2013	2014	2015	Thereafter
Operating Leases	$ 2,622	$ 1,313	$ 1,309	$ –	$ –	$ –	$ –
Capital commitments	1,000	1,000	–	–	–	–	–
Firm transportation agreements	21,320	3,302	1,535	1,535	2,110	2,110	10,728
Firm processing agreement	76,327	4,917	6,526	6,526	8,239	8,239	41,880
Total	$ 101,269	$ 10,532	$ 9,370	$ 8,061	$ 10,349	$ 10,349	$ 52,608

The transportation agreements include a $19.2 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 has committed to process a minimum monthly volume of gas through the facility commencing on December 1, 2009 and continuing through November 30, 2019. The commitment is included in the above table.

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 full 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.

16. SUBSEQUENT EVENT:

On May 2, 2011, Crew announced that it has entered into an arrangement agreement ("Arrangement Agreement") whereby, subject to satisfaction of certain conditions, Crew will acquire 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 Arrangement Agreement, Caltex shareholders will receive 0.38 of a Crew common share for each Caltex share held or an estimated aggregate of approximately 33.2 million Crew shares based upon certain assumptions concerning the exercise of Caltex convertible securities.

Upon completion of the Transaction, Caltex will become a wholly owned subsidiary of Crew and current Caltex shareholders and holders of Caltex convertible securities that are exercised prior to the effective date of the Transaction will own approximately 28% of the combined entity. The Transaction is expected to be completed by way of Plan of Arrangement and is subject to customary conditions including, without limitation, Toronto Stock Exchange, court and regulatory approval and the requisite approval of Crew and Caltex shareholders. The Board of Directors of each of Crew and Caltex has unanimously approved the Transaction and resolved to recommend that their respective shareholders vote in favour of the Transaction. Closing of the Transaction is expected to occur on or about July 1, 2011. The Arrangement Agreement provides for a mutual $20 million non-completion fee payable to Crew or Caltex, as the case may be, in certain circumstances if the Transaction is not completed.

17. RECONCILIATION OF EQUITY AND INCOME FROM PREVIOUS GAAP TO IFRS:

These interim consolidated financial statements are the Company's first 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 have to 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 have to restate any business combinations that occurred prior to the date of transition.

The accounting policies in note 2 have been applied in preparing the interim consolidated financial statements for the three months ended March 31, 2011, the comparative information for the three months ended March 31, 2010, the financial statements for the year ended December 31, 2010 and the preparation of the opening IFRS balance sheet at January 1, 2010, the Company's date of transition to IFRS.

In preparing its opening IFRS balance sheet, comparative information for the three months ended March 31, 2010 and financial statements for the year ended December 31, 2010, the Company adjusted amounts previously reported in financial statements prepared in accordance with former previous GAAP. An explanation of how the transition from former 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.

At the date of IFRS transition – January 1, 2010:

	Previous GAAP	Effect of transition to IFRS	Note	IFRS
Assets				
Current Assets:				
Accounts receivable	**$ 37,574**	$ –		$ 37,574
Deferred tax asset	**542**	(542)	A	–
	38,116	(542)		37,574
Exploration and evaluation assets	**–**	35,591	B	35,591
Property, plant and equipment	**925,132**	(35,591)	B	889,541
	$ 963,248	$ (542)		$ 962,706
Liabilities and Shareholders' Equity				
Current Liabilities:				
Accounts payable and accrued liabilities	**$ 84,228**	$ –		$ 84,228
Fair value of financial instruments	**834**	–		834
Current portion of other long-term obligations	**1,313**	–		1,313
	86,375	–		86,375
Bank loan	**135,601**	–		135,601
Other long-term obligations	**132**	–		132
Decommissioning obligations	**35,341**	17,722	E	53,063
Deferred tax liability	**101,519**	(5,031)	A,E,F	96,488
Shareholders' Equity				
Share capital	**617,605**	3,383	F	620,988
Contributed surplus	**22,769**	2,737	G	25,506
Deficit	**(36,094)**	(19,353)		(55,447)
	604,280	(13,233)		591,047
	$ 963,248	$ (542)		$ 962,706

As at March 31, 2010

	Previous GAAP	Effect of transition to IFRS	Note	IFRS
Assets				
Current Assets:				
Accounts receivable	**$ 39,768**	$ –		$ 39,768
Fair value of financial instruments	**7,364**	–		7,364
Assets held for sale	**–**	91,396	H	91,396
	47,132	91,396		138,528
Exploration and evaluation assets	**–**	47,062	B	47,062
Property, plant and equipment	**943,880**	(118,173)	B,D,E,H	825,707
	$ 991,012	$ 20,285		$ 1,011,297
Liabilities and Shareholders' Equity				
Current Liabilities:				
Accounts payable and accrued liabilities	**$ 78,031**	$ –		$ 78,031
Deferred tax liability	**1,740**	(1,740)	A	–
Current portion of other long-term obligations	**773**	–		773
Decommissioning liability on asset held for sale	**–**	5,212	E	5,212
	80,544	3,472		84,016
Bank loan	**153,601**	–		153,601
Decommissioning obligations	**35,709**	12,919	E	48,628
Deferred tax liability	**100,559**	1,959	F	102,518
Shareholders' Equity				
Share capital	**633,348**	3,383	F	636,731
Contributed surplus	**20,903**	2,577	G	23,480
Deficit	**(33,652)**	(4,025)		(37,677)
	620,599	1,935		622,534
	$ 991,012	$ 20,285		$ 1,011,297

At the end of the last reporting year under previous GAAP – December 31, 2010:

	Previous GAAP	Effect of transition to IFRS	Note	IFRS
Assets				
Current Assets:				
Accounts receivable	**$ 44,922**	$ –		$ 44,922
Fair value of financial instruments	**982**	–		982
Assets held for sale	**15,116**	–		15,116
	61,020	–		61,020
Exploration and evaluation assets	**–**	72,281	B	72,281
Property, plant and equipment	**937,050**	(24,410)	B,C,D,E,H	912,640
	$ 998,070	$ 47,871		$ 1,045,941
Liabilities and Shareholders' Equity				
Current Liabilities:				
Accounts payable and accrued liabilities	**$ 100,745**	$ –		$ 100,745
Current portion of other long-term obligations	**343**	–		343
	101,088	–		101,088
Fair value of financial instruments	**9,196**	–		9,196
Bank loan	**138,700**	–		138,700
Decommissioning obligations	**36,073**	18,755	E	54,828
Deferred tax liability	**96,330**	6,149	F	102,479
Shareholders' Equity				
Share capital	**646,385**	3,383	F	649,768
Contributed surplus	**23,553**	3,958	G	27,511
Deficit	**(53,255)**	15,626		(37,629)
	616,683	22,967		639,650
	$ 998,070	$ 47,871		$ 1,045,941

Reconciliation of consolidated statement of income for the period ended March 31, 2010:

	Previous GAAP	Effect of transition to IFRS	Note	IFRS
Revenue				
Gross petroleum and natural gas sales	**$ 61,772**	$ –		$ 61,772
Royalties	**(13,149)**	–		(13,149)
Realized gain on financial instruments	**928**	–		928
Unrealized gain on financial instruments	**8,198**	–		8,198
	57,749	–		57,749
Expenses				
Operating	**14,986**	–		14,986
Transportation	**2,377**	–		2,377
General and administrative	**1,670**	890	I	2,560
Stock-based compensation	**1,320**	19	G	1,339
Financing	**2,667**	(178)	E	2,489
Depletion and depreciation	**31,410**	(11,329)	C,D	20,081
Gain on divestitures	**–**	(9,882)	H	(9,882)
	54,430	(20,480)		33,950
Net income before taxes	**3,319**	20,480		23,799
Deferred tax expense	**877**	5,152	F	6,029
Net income and comprehensive income	**$ 2,442**	$ 15,328		$ 17,770
Net income per share				
Basic	**$ 0.03**			$ 0.23
Diluted	**$ 0.03**			$ 0.22

Reconciliation of consolidated statement of income (loss) for the year ended December 31, 2010:

	Previous GAAP	Effect of transition to IFRS	Note	IFRS
Revenue				
Gross petroleum and natural gas sales	**$ 206,343**	$ –		$ 206,343
Royalties	**(41,799)**	–		(41,799)
Realized gain on financial instruments	**13,082**	–		13,082
Unrealized loss on financial instruments	**(7,380)**	–		(7,380)
	170,246	–		170,246
Expenses				
Operating	**53,976**	–		53,976
Transportation	**9,582**	–		9,582
General and administrative	**6,479**	3,244	I	9,723
Stock-based compensation	**4,517**	1,020	G	5,537
Financing	**8,434**	(674)	E	7,760
Depletion and depreciation	**110,575**	(2,487)	C,D	108,088
Gain on divestitures	**–**	(48,242)	H	(48,242)
	193,563	(47,139)		146,424
Net income (loss) before tax	**(23,317)**	47,139		23,822
Deferred tax expense (reduction)	**(6,156)**	12,159	F	6,003
Net income (loss) and comprehensive income (loss)	**$ (17,161)**	$ 34,980		$ 17,819
Net income (loss) per share				
Basic	**$ (0.22)**			$ 0.22
Diluted	**$ (0.22)**			$ 0.22

Reconciliation of cash flow statement for the period ended March 31, 2010:

	Previous GAAP	Effect of transition to IFRS	Note	IFRS
Cash provided by (used in):				
Operating activities:				
Net income	**$ 2,442**	$ 15,328		$ 17,770
Adjustments:				
Depletion and depreciation	**31,410**	(11,329)	D	20,081
Financing expenses	**2,667**	(178)	E	2,489
Interest expense	**(1,957)**	–		1,957
Stock-based compensation	**1,320**	19	G	1,339
Deferred tax expense	**877**	5,152		6,029
Unrealized gain on financial instruments	**(8,198)**	–		(8,198)
Gain on divestitures	–	(9,882)	H	(9,882)
Transportation liability charge	**(672)**	–		(672)
Decommissioning obligation settled	**(576)**	–		(576)
Change in non-cash working capital	**4,900**	–		4,900
	32,213	(890)		31,323
Financing activities:				
Increase in bank loan	**18,000**	–		18,000
Proceeds from exercise of share options	**11,237**	–		11,237
	29,237	–		29,237
Investing activities:				
Exploration and evaluation asset expenditures	–	(11,471)	B	(11,471)
Property, plant and equipment expenditures	**(59,075)**	12,361	B,G,I	(46,714)
Property dispositions	**10,916**	–		10,916
Change in non-cash working capital	**(13,291)**	–		(13,291)
	(61,450)	890		(60,560)
Change in cash and cash equivalents	–	–		–
Cash and cash equivalents, beginning of period	–	–		–
Cash and cash equivalents, end of period	**$ –**	$ –		$ –

Reconciliation of cash flow statement for the year ended December 31, 2010:

	Previous GAAP	Effect of transition to IFRS	Note	IFRS
Cash provided by (used in):				
Operating activities:				
Net income (loss)	**$ (17,161)**	$ 34,980		$ 17,819
Adjustments:				
Depletion and depreciation	**110,575**	(2,487)	C,D	108,088
Financing expenses	**8,434**	(674)	E	7,760
Interest expense	**(5,795)**	–		(5,795)
Stock-based compensation	**4,517**	1,020	G	5,537
Deferred tax expense (reduction)	**(6,156)**	12,159	F	6,003
Unrealized gain on financial instruments	**7,380**	–		7,380
Gain on divestitures	–	(48,242)	H	(48,242)
Transportation liability charge	**(1,102)**	–		(1,102)
Decommissioning obligation settled	**(1,512)**	–		(1,512)
Change in non-cash working capital	**(2,010)**	–		(2,010)
	97,170	(3,244)		93,926
Financing activities:				
Increase in bank loan	**3,099**	–		3,099
Issue of common shares	**20,566**	–		20,566
Share issue costs	**(48)**	–		(48)
	23,617	–		23,617
Investing activities:				
Exploration and evaluation asset expenditures	–	(37,234)	B	(37,234)
Property, plant and equipment expenditures	**(248,870)**	40,478	B, I	(208,392)
Property acquisitions	**(1,223)**	–		(1,223)
Property dispositions	**133,243**	–		133,243
Cost incurred on asset held for sale	**(15,116)**	–		(15,116)
Change in non-cash working capital	**11,179**	–		11,179
	(120,787)	3,244		(117,543)
Change in cash and cash equivalents	**–**	–		–
Cash and cash equivalents, beginning of year	**–**	–		–
Cash and cash equivalents, end of year	**$ –**	$ –		$ –

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 ("E&E") – As required under IFRS 6, upon transition to IFRS, Crew reclassified $35.6 million from Property, Plant and Equipment ("PP&E") to E&E, which primarily consisted of undeveloped exploration lands. The Company reclassified $72.3 million at December 31, 2010 (March 31, 2010 - $47.1 million).

(C) Under IFRS, impairment tests for PP&E are performed at a CGU level as opposed to the entire Company's PP&E balance being subjected to 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 the greater of the fair value less costs to sell based on discounted future cash flows of proved plus probable reserves using forecast prices and costs, and the value in use.

As a result of decreased forward natural gas prices which impacted the fair value less costs to sell derived from the Company's reserves, Crew recognized a $29.1 million impairment for the year ended December 31, 2010. This resulted in a reduction of PP&E with the offset charged to depletion and depreciation expense.

(D) 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 $33.2 million in 2010 (March 31, 2010 - $11.3 million).

(E) 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. A further change in the discount rate at December 31, 2010 resulted in a revaluation to increase the liability by $3.1 million.

As a result of the change in the discount rate applied, accretion of decommissioning obligation expense decreased by $674,000 for the year ended December 31, 2010 (March 31, 2010 - $178,000).

(F) 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.

For the year ended December 31, 2010, a deferred tax expense of $12.6 million (March 31, 2010 - $5.2 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.

(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 currently 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. This resulted in less than a $0.1 million change for the three month ended March 31, 2010 and a $1.0 million increase to stock-based compensation expense for the year ended December 31, 2010.

(H) 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. For the year ended December 31, 2010, the Company recorded a $48.2 million

(March 31, 2010 - $9.9 million) gain on disposition of oil and gas properties for IFRS as compared to nil under previous GAAP.

On April 1, 2010, the Company disposed of oil and gas properties in the Edson area with a net book value of $91.5 million. This amount was classified as an asset held for sale at March 31, 2010.

(l) 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 $3.2 million of G&A expenses for the year ended December 31, 2010 (March 31, 2010 - $0.9 million).

CAUTIONARY STATEMENTS

Forward-looking information and statements

This report contains certain forward–looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "project", "should", "believe", "plans", "intends" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this report contains forward-looking information and statements pertaining to the following: the volume and product mix of Crew's oil and gas production; production estimates; anticipated disposal rates on water disposal wells; future oil and natural gas prices and Crew's commodity risk management programs; future liquidity and financial capacity; future results from operations and operating metrics; anticipated reductions in operating costs; future costs, expenses and royalty rates; future interest costs; the exchange rate between the $US and $Cdn; future development, exploration, acquisition and development activities and related capital expenditures and the timing thereof; the number of wells to be drilled, completed and tied-in and the timing thereof; the amount and timing of capital projects; operating costs; the total future capital associated with development of reserves and resources; 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; the completion and timing of completion of the Caltex Transaction, estimated production associated with the properties of Caltex, estimates regarding undeveloped land position and estimated future drilling, recompletion or reactivation locations and operation netbacks associated with the Caltex properties, the complementary nature of the Caltex assets and anticipated growth opportunities associated therewith and ability to improve upon historical recovery factors, anticipated benefits from the Transaction and anticipated impact upon Crew's forecasts in respect of production and cash flow for 2011 and resulting yearend net debt. Included herein is an estimate of Crew's year-end net debt based on assumptions as to the completion and timing of completion of the Caltex Transaction, 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 report are not guarantees of future performance and should not be unduly relied upon. Such information and statements, including the assumptions made in respect thereof, involve known and unknown risks, uncertainties and other factors that may cause actual results or events to defer materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; changes in the demand for or supply of Crew's products; unanticipated operating results or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in development plans of Crew or by third party operators of Crew's properties, increased debt levels or debt service requirements; inaccurate estimation of Crew's oil and gas reserve and resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; and certain other risks detailed from time-to-time in Crew's public disclosure documents (including, without limitation, those risks identified in this report and Crew's Annual Information Form).

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

BOE equivalent

Barrel of oil equivalents or BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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

CORPORATE INFORMATION

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BANKERS

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Canadian Imperial Bank of Commerce

Union Bank

Bank of Montreal

Bank of Nova Scotia

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVE ENGINEERS

GLJ Petroleum Consultants

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
Stock Symbol: **CR**

BOARD OF DIRECTORS

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Independent Director

Jeffery E. Errico
Independent Director

Dennis L. Nerland
Independent Director

Dale O. Shwed
President, Crew Energy Inc.

David G. Smith
Independent Director

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and Divestitures

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Vice President, Finance
and Controller

Michael D. Sandrelli
Secretary
Partner, Burnet, Duckworth
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ABBREVIATIONS

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

crew
energy inc.