crew energy inc.

RESOURCE FOCUS → OPPORTUNITY → SUSTAINABILITY

2012 FINANCIAL REVIEW

www.crewenergy.com

CORPORATE PROFILE

Crew Energy Inc. ("Crew") or ("the Company") is a growth-oriented oil and natural gas producer, committed to the pursuit of sustainable per share growth through a balanced mix of financially responsible exploration and development, complemented by strategic acquisitions.

Crew's activities are concentrated in Alberta, northeast British Columbia and Saskatchewan and focus on the development and expansion of its core oil and liquids rich natural gas properties and exploration of its large undeveloped land base.

ANNUAL GENERAL MEETING

The Annual Meeting of Shareholders of Crew Energy Inc. will be held at 3:00 p.m. (MDT) on Thursday, May 23, 2013, in the Bow River Room of Centennial Place – West Tower, Suite 300, 250 - 5th Street SW., Calgary, Alberta.

CONTENTS

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

MANAGEMENT'S DISCUSSION AND ANALYSIS

Years ended December 31, 2012 and December 31, 2011

HIGHLIGHTS

Financial *($ thousands, except per share amounts)*	**Year ended December 31, 2012**	Year ended December 31, 2011
Petroleum and natural gas sales	**417,763**	388,166
Cash provided by operations	**213,591**	153,429
Funds from operations (1)	**186,604**	172,103
Per share – basic	**1.54**	1.69
– diluted	**1.54**	1.67
Net income (loss)	**21,542**	(130,162)
Per share – basic	**0.18**	(1.28)
– diluted	**0.18**	(1.28)
Capital expenditures	**258,791**	375,874
Property acquisitions (net of dispositions)	**(96,557)**	(25,492)
Net capital expenditures	**162,234**	350,382
Capital Structure *($ thousands)*	**As at December 31, 2012**	As at December 31, 2011
Working capital deficiency (2)	**48,522**	92,452
Bank loan	**242,834**	230,676
Net debt	**291,356**	323,128
Bank facility	**400,000**	430,000
Common Shares Outstanding *(thousands)*	**121,620**	119,993
Operations	**Year ended December 31, 2012**	Year ended December 31, 2011
Daily production		
Conventional oil (bbl/d)	**5,792**	5,737
Heavy oil (bbl/d)	**5,765**	3,221
Natural gas liquids (bbl/d)	**3,091**	2,035
Natural gas (mcf/d)	**79,889**	68,756
Oil equivalent (boe/d @ 6:1)	**27,963**	22,452
Average prices (3)		
Conventional oil ($/bbl)	**72.66**	78.05
Heavy oil ($/bbl)	**62.93**	70.30
Natural gas liquids ($/bbl)	**50.06**	62.68
Natural gas ($/mcf)	**2.54**	3.81
Oil equivalent ($/boe)	**40.82**	47.37
Netback ($/boe)		
Operating netback (4)	**21.35**	23.61
G&A	**1.79**	1.72
Interest on bank debt	**1.31**	0.88
Funds from operations	**18.25**	21.01
Drilling Activity		
Gross wells	**112**	158
Working interest wells	**107.2**	154.5
Success rate, net wells	**98%**	99%

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

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

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

(4) 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.

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 audited consolidated financial statements of the Company for the years ended December 31, 2012 and 2011. The consolidated financial statements for the year ended December 31, 2012 have been prepared in accordance with International Financial Reporting Standards ("IFRS"). All figures provided herein and in the December 31, 2012 audited consolidated financial statements are reported in Canadian dollars.

Forward Looking Statements

This MD&A contains forward looking statements. Management's assessment of future plans and operations, drilling plans and the timing thereof, plans for the tie-in and completion of wells and the timing thereof, capital expenditures, timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, production estimates, expected commodity mix and prices, future operating costs, future transportation costs, expected royalty rates, expected general and administrative expenses, expected interest rates, debt levels, funds from operations and the timing of and impact of implementing accounting policies, estimates regarding undeveloped land position and estimated future drilling, recompletion or reactivation locations and anticipated impact upon Crew's forecasts in respect of production and cash flow for 2013 and resulting year-end net debt may constitute forward looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, the inability to fully realize the benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and inability to access sufficient capital from internal and external sources. As a consequence, the Company's actual results may differ materially from those expressed in, or implied by, the forward looking statements. Forward looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Crew believes that the expectations reflected in such forward looking statements or information are reasonable, undue reliance should not be placed on forward looking statements because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document and other documents filed by the Company, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Company has an interest in to operate the field in a safe, efficient and effective manner; Crew's ability to obtain financing on acceptable terms; changes in the Company's banking facility; field production rates and decline rates; the ability to reduce operating costs; the ability to replace and expand oil and natural gas reserves through acquisition, development or exploration; the timing and costs of pipeline, storage and facility construction and expansion; the ability of the Company to secure adequate product transportation; future petroleum and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company operates; and Crew's ability to successfully market its petroleum and natural gas products. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) or at the Company's website (www.crewenergy.com). Furthermore, the forward looking statements contained in this document are made as at the date of this document and the Company does not undertake any obligation to update publicly or to revise any of the included forward looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Conversions

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

Throughout this MD&A, Crew has used the 6:1 boe measure which is the approximate energy equivalency of the two commodities at the burner tip. Boe does not represent a value equivalency at the wellhead nor at the plant gate which is where Crew sells its production volumes and therefore may be a misleading measure, particularly if used in isolation. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a 6:1 conversion may be misleading as an indication of value.

Non-IFRS Measures

Funds from Operations

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

	Three months ended December 31,		Year ended December 31,	
($ thousands)	**2012**	2011	**2012**	2011
Cash provided by operating activities	**50,873**	39,969	**213,591**	153,429
Decommissioning obligation expenditures	**1,160**	483	**2,460**	1,144
Transportation liability charge	–	35	–	343
Acquisition costs [(1)]	–	–	–	2,605
Change in operating non-cash working capital	**(4,923)**	24,354	**(29,447)**	14,582
Funds from operations	**47,110**	64,841	**186,604**	172,103

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

Operating Netback

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

Working Capital and Net Debt

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

($ thousands)	**December 31, 2012**	December 31, 2011
Current assets	**46,405**	79,117
Current liabilities	**(102,097)**	(192,744)
Fair value of financial instruments	**7,170**	21,175
Working capital deficit	**(48,522)**	(92,452)

($ thousands)	**December 31, 2012**	December 31, 2011
Bank loan	**(242,834)**	(230,676)
Working capital deficit	**(48,522)**	(92,452)
Net debt	**(291,356)**	(323,128)

RESULTS OF OPERATIONS

Overview

Crew's results in 2012 were impacted by an extremely volatile commodity price environment. The year began optimistically with Canadian oil and natural gas markets at a level that would allow Crew to aggressively pursue a significant production growth profile with a $300 million budgeted capital program. However, commodity prices declined dramatically in the first quarter with natural gas prices down 43% and the Company's benchmark crude prices declining 20% over the quarter. This resulted in the Company shutting in approximately 1,200 boe per day of uneconomic natural gas production early in the second quarter and, more importantly, the cutting of Company's overall 2012 capital spending by 25% with a corresponding reduction in the projected production by 14%.

Despite the challenging environment, the Company's 2012 production averaged 27,963 boe per day (52% liquids), a 25% increase over 2011. Production per share averaged 231 boe per day per million shares outstanding a 5% increase over the 220 boe per day per million shares in 2011. First half 2012 production averaged 29,286 boe per day (53% liquids) while second half production decreased over the first half to 26,654 boe per day (52% liquids) a 9% decrease resulting mainly from the shut-in of 4% of production due to low natural gas prices, as noted above, and the reduced capital spending.

North American oil prices started the year strong driven by economic indicators showing signs of a recovery in the U.S. and other developing world economies. West Texas Intermediate ("WTI") oil prices started the year strong averaging $99 per bbl in the first half of the year. However, as the first half drew to a close, prices began softening as continued concerns over European sovereign debt levels crept back into the headlines. WTI pricing in the second half averaged $90 per bbl a 10% drop over the first half to average $94 per bbl for the year.

More importantly, in North America, increasing supplies of oil from "shale oil" plays began to impact North American pricing as limited pipeline space began restricting the movement of Canadian and US crude supplies to the North American refining complex. This resulted in a widening of the differential between North American Crudes and other world crude prices. In particular, limited pipeline capacity to take growing Canadian crude supplies to the U.S. refining complex has created significant volatility in Canadian crude prices. Crew's benchmark Western Canadian Select ("WCS") opened the year strong, averaging $82 per bbl in the first quarter but dropped 20% from the beginning of the first quarter to the end of the same quarter. Volatility was the theme for the remainder of the year with WCS swinging from a low of $65 per bbl in July to a high of $79 per bbl in October while averaging approximately $70 per bbl for all three of the remaining quarters to average of $73 per bbl for the year.

Natural gas prices continued to be pressured by an over supplied market and were dramatically impacted in early 2012 by the North American winter that never happened. With North America experiencing one of the warmest winters on record, natural gas inventories were at record levels going into the spring. Prices for natural gas sold in Canada finished 2011 above the $3.00 per mcf but began softening in December 2011 and fell quickly to a low of $1.71 per mcf in April 2012. Prices averaged $1.93 per mcf in the first half of 2012. As we entered the second half of the year sentiment was low and there were concerns that the worst was still ahead. However, the warm weather remained and an unusually hot North American summer drove increased cooling demand for electricity and the demand for more natural gas generated electricity replaced more expensive coal generated electricity. With increased demand for natural gas throughout the summer prices recovered to a second half high of $3.45 mcf in November and a second half average of $2.79 per mcf resulting in a year's average of $2.43 per mcf.

Crew's 2012 financial results were aided by increased levels of production added through the exploration and development drilling program and the 2011 Caltex acquisition. The Company's revenue increased 8% over 2011 to $418 million and funds from operations increased 8% over 2011 to $187 million or $1.54 per fully diluted share. In addition, the Company recorded earnings of $21.2 million as a result of realized gains earned on the Company's commodity related financial instruments and a large gain earned on the sale of natural gas assets. Crew's financial position remains strong with net debt at year end of $292 million or 1.55 times annualized fourth quarter funds from operations.

Crew's financial position was strengthened in the fourth quarter with the sale of the Company's Kobes Montney asset, for $108 million for a net financial gain to the Company of $70.8 million. A portion of the proceeds, $22 million, were re-invested in a follow-up purchase of 56 net sections of Montney lands in the Groundbirch/Septimus area which is adjacent to the Company's existing Septimus operations.

During the year, exploration and development capital expenditures totaled $259 million including 60% towards continued growth of its oil plays, drilling 91 net oil wells and one service well in the Company's oil prone areas. Crew also continued to develop its liquids rich natural gas development into the Montney formation at Septimus. During the year, the Company directed 27% of its total exploration and development budget toward Septimus drilling a total of six wells in the area. Crew also successfully drilled its first Montney oil development wells at Tower, British Columbia with production from the new wells averaging over 350 bbl per day of 45 API oil and associated natural gas and natural gas liquids production.

During 2012, the Company continued its program of minor divesting of non-core properties to help fund development of its core properties. This program resulted in several minor property sales for total proceeds of $11 million. These properties comprised production of approximately 105 boe per day and proven plus probable reserves of 650 mboe.

Production

	Three months ended December 31, 2012					Three months ended December 31, 2011				
	Conv. Oil (bbl/d)	**Heavy Oil (bbl/d)**	**Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Conv. Oil (bbl/d)	Heavy Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
Alberta	**5,050**	**12**	**2,003**	**36,929**	**13,220**	6,634	17	1,970	49,776	16,917
British Columbia	**208**	**–**	**1,291**	**39,560**	**8,092**	150	–	1,025	34,263	6,886
Saskatchewan	**–**	**5,632**	**–**	**494**	**5,715**	–	6,128	–	618	6,231
Total	**5,258**	**5,644**	**3,294**	**76,983**	**27,027**	6,784	6,145	2,995	84,657	30,034

The Company's fourth quarter 2012 production decreased 10% compared with the same period in 2011. The decrease was the result of declines in conventional and heavy oil production and shut-in uneconomic natural gas production. The conventional oil declines were the result of reduced capital spending in Princess, Alberta while the heavy oil declines were related to reduced pressure in the Waseca formation at Low Lake. The Company has initiated pressure maintenance schemes to offset these declines both at Princess and Low Lake. In the first half of 2012, the Company also shut-in approximately 1,200 boe per day of uneconomic dry natural gas production in Alberta which partially accounts for the decrease in natural gas production in the fourth quarter of 2012 as compared to the fourth quarter of 2011. The remainder is a result of declines at Princess resulting from reduced capital spending. These decreases in production were partially offset by increased liquids rich natural gas production due to a successful drilling program at Septimus, British Columbia and Kakwa, Alberta.

	Year ended December 31, 2012					Year ended December 31, 2011				
	Conv. Oil (bbl/d)	**Heavy Oil (bbl/d)**	**Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Conv. Oil (bbl/d)	Heavy Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
Alberta	**5,502**	**11**	**1,798**	**40,242**	**14,018**	5,614	6	1,101	34,038	12,394
British Columbia	**290**	**–**	**1,293**	**38,900**	**8,066**	123	–	934	34,427	6,795
Saskatchewan	**–**	**5,754**	**–**	**747**	**5,879**	–	3,215	–	291	3,263
Total	**5,792**	**5,765**	**3,091**	**79,889**	**27,963**	5,737	3,221	2,035	68,756	22,452

In 2012, Crew's production increased 25% over 2011 due to the acquisition of Caltex Energy Inc. ("Caltex") in July 2011 which added heavy oil production in Saskatchewan and liquids rich natural gas in central Alberta for the last six months of 2011 as compared with a full year of production in 2012. The increase in production from the acquisition was partially offset by declines in conventional and heavy oil production as well as the shut-in of uneconomic natural gas production.

Revenue

	Three months ended December 31,		Year ended December 31,	
	2012	2011	**2012**	2011
Revenue *($ thousands)*				
Conventional oil	**33,117**	53,889	**154,024**	163,427
Heavy oil	**31,153**	43,791	**132,796**	82,639
Natural gas liquids	**14,286**	17,676	**56,636**	46,560
Natural gas	**23,917**	26,707	**74,307**	95,540
Total	**102,473**	142,063	**417,763**	388,166
Crew average prices				
Conventional oil ($/bbl)	**68.46**	86.34	**72.66**	78.05
Heavy oil ($/bbl)	**60.00**	77.47	**62.93**	70.30
Natural gas liquids ($/bbl)	**47.14**	64.15	**50.06**	62.68
Natural gas ($/mcf)	**3.38**	3.43	**2.54**	3.81
Oil equivalent ($/boe)	**41.21**	51.41	**40.82**	47.37
Benchmark pricing				
Conv. and heavy oil – WCS (Cdn $/bbl)	**69.43**	85.48	**73.08**	77.10
Oil and ngl – Cdn$ WTI (Cdn $/bbl)	**87.41**	96.24	**94.11**	94.02
Natural Gas – AECO C daily index (Cdn $/mcf)	**3.26**	3.25	**2.43**	3.68

The Company's fourth quarter revenue decreased 28% as compared to the same period in 2011 as a result of the 10% decrease in production combined with a 20% decrease in average commodity prices. In the fourth quarter of 2012, the price received for the Company's conventional oil decreased 21% which was comparable to the 19% decrease in the Company's WCS benchmark. Crew's fourth quarter heavy oil price decreased 23% as compared to the same period in 2011 due to a 19% drop in the benchmark WCS oil price combined with increased winter blending costs relative to the price received for the Company's heavy oil production. The Company's ngl price decreased 27% as compared with a 9% decrease in the Cdn$ West Texas Intermediate ("WTI") benchmark price due to the inclusion of lower valued ethane and propane production in ngl revenue which is not factored into the Company's benchmark comparison. The Company's natural gas price decreased 1% in the fourth quarter of 2012 compared with the same period in 2011 which was comparable to the change in the Company's natural gas AECO C benchmark.

Crew's revenue for 2012 increased 8% over the same period in 2011 as a result of a full year of production from the Caltex acquisition partially offset by a 14% decrease in commodity pricing. Crew's realized conventional oil price for the year decreased proportionately to the WCS benchmark while the Company's realized heavy oil price decreased by 10% as compared with a 5% decrease in the WCS benchmark due to the increased blending costs required to get heavy oil production to pipeline specifications. The Company's ngl price decreased 20% for 2012 as compared with 2011 primarily due to a decrease in ethane and propane pricing. In 2012, the price received for the Company's natural gas decreased 33% as compared with 2011 which was comparable to the decline in the benchmark AECO C index.

Royalties

	Three months ended December 31,		Year ended December 31,	
($ thousands, except per boe)	**2012**	2011	**2012**	2011
Royalties	**19,042**	35,055	**90,794**	91,882
Per boe	**7.66**	12.69	**8.87**	11.21
Percentage of revenue	**18.6%**	24.7%	**21.7%**	23.7%

Royalties and royalties as a percentage of revenue decreased in the fourth quarter of 2012 as compared with the same period in 2011 due to lower oil royalty rates as a result of decreased oil pricing and decreased average production per well combined with new liquids rich natural gas production from new wells which initially attract a lower royalty rate. Royalties as a percentage of revenue decreased in 2012 as compared with 2011 due to lower oil prices, lower average production per well and lower natural gas prices with a relatively fixed gas cost allowance ("GCA") provision. In addition, the Company also recovered prior period GCA during 2012 which lowered Crew's royalty rate. Crew projects royalty rates to average between 20% and 23% for 2013.

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, differentials, interest rates and foreign exchange rates while allowing for participation in commodity price increases. The Company's financial derivative trading activities are conducted pursuant to the Company's Risk Management Policy approved by the Board of Directors. In 2012, these contracts had the following impact on the consolidated statement of income:

	Three months ended December 31,		Year ended December 31,	
($ thousands)	**2012**	2011	**2012**	2011
Realized gain/(loss) on financial instruments	**3,415**	(9)	**23,728**	2,186
Unrealized gain/(loss) on financial instruments	**3,278**	(27,199)	**14,005**	(10,437)

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

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Oil	4,500 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$91.20	Swap	(3,259)
Oil	750 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$92.60	Call	(1,693)
Oil	1,000 bbl/day	January 1, 2013 – December 31, 2013	US$ WTI	$89.84	Call	(3,189)
Oil	250 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$85.00 - $100.00	Collar (1)	312
Natural Gas	5,000 gj/day	January 1, 2013 – December 31, 2013	AECO C Monthly Index	$2.65 - $3.50	Collar	12
Natural Gas	35,000 gj/day	January 1, 2013 – December 31, 2013	AECO C Monthly Index	$3.03	Swap	647
Total						(7,170)

(1) The referenced contract is a fade-in collar whereby the price is fixed at $100/bbl unless the market price falls below $85/bbl in which case the price received will be $85/bbl.

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

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded
Natural Gas	2,500 gj/day	April 1, 2013 – October 31, 2013	AECO C Monthly Index	$2.93	Swap
Oil	500 bbl/day	April 1, 2013 – December 31, 2013	CDN$ WCS – WTI Diff	$25.00	Swap
Oil	750 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$85.00 – $95.00	Collar (3)
Oil	1,000 bbl/day	January 1, 2014 – December 31, 2014	CDN$ WCS – WTI Diff	$23.25	Swap
Oil	1,500 bbl/day	January 1, 2014 – December 31, 2014	CDN$ WTI	$95.68	Swap
Oil	250 bbl/day	January 1, 2014 – December 31, 2014	CDN$ WTI	$92.20	Call (1)(2)
Oil	1,000 bbl/day	January 1, 2014 – December 31, 2014	USD$ WTI	$92.40	Call (2)
Oil	500 bbl/day	January 1, 2014 – December 31, 2014	CDN$ WTI	$96.05	Call
Oil	250 bbl/day	January 1, 2014 – December 31, 2014	US$ WTI	$95.75	Swaption
Natural Gas	12,500 gj/day	January 1, 2014 – December 31, 2014	AECO C Monthly Index	$3.52	Swap

(1) This is a structured call which is only triggered if the average CDN$ WTI trades above $100 per bbl for a given month during the term.

(2) Crew funded the buy-out of the 2013 oil calls with the proceeds from the sale of these calls.

(3) The referenced contract is a fade-in collar whereby the price is fixed at $95/bbl unless the market price falls below $85/bbl in which case the price received will be $85/bbl.

Operating Costs

	Three months ended December 31,		Year ended December 31,	
($ thousands, except per boe)	**2012**	2011	**2012**	2011
Operating costs	**28,363**	31,101	**118,105**	91,855
Per boe	**11.41**	11.26	**11.54**	11.21

In the fourth quarter of 2012, the Company's operating costs per unit slightly increased over the same period in 2011 due to lower production to offset fixed costs combined with higher heavy oil well servicing costs in the Lloydminster area. Increased lower cost production at Septimus partially offset the increase in Company operating costs per unit.

Operating costs and operating costs per boe increased in 2012 as compared with 2011 due to a full year of higher operating cost production from the properties acquired in the Caltex acquisition. Partially offsetting this increase were several initiatives across the Company including decreased fluid handling, rental and fuel costs in the Princess area where costs per unit have decreased approximately 8% in 2012. In addition, increased production at Septimus, where operating costs per unit are approximately 44% below the Company average, has partially offset the increase in annual costs per unit.

The Company forecasts operating costs to average $11.00 to $11.50 per boe for 2013.

Transportation Costs

	Three months ended December 31,		Year ended December 31,	
($ thousands, except per boe)	**2012**	2011	**2012**	2011
Transportation costs	**3,404**	3,957	**14,167**	13,222
Per boe	**1.37**	1.43	**1.38**	1.61

In the fourth quarter and year ended December 31, 2012, the Company's transportation costs per boe decreased compared to the same periods in 2011 due to a new Princess oil sales pipeline becoming operational in the first quarter of 2012 combined with the addition of lower transportation cost per unit production from the Caltex acquisition. The Company expects transportation costs per boe to range between $1.25 and $1.50 per boe for 2013.

Operating Netbacks

	Three months ended December 31,		Year ended December 31,	
($/boe)	**2012**	2011	**2012**	2011
Revenue	**41.21**	51.41	**40.82**	47.37
Realized commodity hedging gain	**1.37**	–	**2.32**	0.27
Royalties	**(7.66)**	(12.69)	**(8.87)**	(11.21)
Operating costs	**(11.41)**	(11.26)	**(11.54)**	(11.21)
Transportation costs	**(1.37)**	(1.43)	**(1.38)**	(1.61)
Operating netbacks	**22.14**	26.03	**21.35**	23.61

General and Administrative Costs

	Three months ended December 31,		Year ended December 31,	
($ thousands, except per boe)	**2012**	2011	**2012**	2011
Gross costs	**6,944**	7,782	**29,862**	22,353
Operator's recoveries	**(236)**	(474)	**(1,313)**	(844)
Capitalized costs	**(2,168)**	(2,609)	**(10,181)**	(7,395)
General and administrative expenses	**4,540**	4,699	**18,368**	14,114
Per boe	**1.83**	1.70	**1.79**	1.72

General and administrative costs after recoveries and capitalization slightly decreased in the fourth quarter of 2012 as compared with the same period in 2011 due to reduced staffing costs as a result of reduced activity during the period. Gross general and administrative costs and net costs after recoveries and capitalization have increased in 2012 due to increased staff levels and additional office space to accommodate the Company's acquisition of Caltex in July 2011. The Company expects general and administrative expenses to average between $1.70 and $1.90 per boe for 2013.

Share-Based Compensation

	Three months ended December 31,		Year ended December 31,	
($ thousands)	**2012**	2011	**2012**	2011
Gross costs	**8,886**	3,845	**21,977**	12,772
Capitalized costs	**(4,505)**	(1,556)	**(11,168)**	(5,747)
Total share-based compensation	**4,381**	2,289	**10,809**	7,025

In the fourth quarter and year ended December 31, 2012, the Company's share-based compensation expense has increased compared with the same periods in 2011 due to an increase in outstanding options during the period combined with the accelerated expensing of surrendered options which occurred in the fourth quarter of 2012. During the fourth quarter of 2012, certain employees voluntarily surrendered 2.3 million stock options for which the Company accelerated approximately $4.5 million of share-based compensation expense into 2012.

Depletion and Depreciation

	Three months ended December 31,		Year ended December 31,	
($ thousands, except per boe)	**2012**	2011	**2012**	2011
Depletion and depreciation	**56,534**	59,996	**202,604**	155,789
Per boe	**22.74**	21.71	**19.80**	19.01

Depletion and depreciation costs per boe have increased in the fourth quarter and for the year ended December 31, 2012 compared to the same periods in 2011 due to the expiry of $7.9 million of non-core undeveloped lands which was recorded as additional depletion in the period. During the fourth quarter, Crew also disposed of the Kobes property which was a lower depletion rate property which resulted in an increase in Crew's corporate depletion rate in the quarter.

Impairment

At December 31, 2012, the recoverable amounts for the Company's CGU's were estimated at their fair values based on the net present value of the before tax cash flows from oil and gas proved plus probable reserves as estimated by the Company's third party reserve evaluators discounted at a rate of 10% and the internally estimated fair value of undeveloped lands based on recent crown land sales in the areas. It was determined that the net book value of certain CGUs exceeded the recoverable amount and Crew has recognized a $122.8 million (2011 – $181.9 million) impairment charge. The impairment charges primarily relate to the weakening of the third party reserve evaluator's future oil and natural gas price forecasts. Offsetting this impairment was a reversal of a prior period impairment charge of $93.6 million resulting from the recognition of additional reserves due to improved performance associated with assets that were previously recognized in prior year's proved plus probable reserves at lower amounts. As the recoverable amount of the CGUs are sensitive to a decrease in commodity prices, further impairment charges could be recorded in future periods. Alternatively, an improvement of commodity prices could reverse any impairment charges recorded to date, less applicable depletion and depreciation charges.

Finance Expenses

	Three months ended December 31,		Year ended December 31,	
($ thousands, except per boe)	**2012**	2011	**2012**	2011
Interest on bank debt	**3,429**	2,401	**13,453**	7,176
Accretion of the decommissioning obligation	**686**	657	**2,677**	2,400
Acquisition costs	**–**	–	**–**	2,605
Total finance expense	**4,115**	3,058	**16,130**	12,181
Average debt level	**322,428**	200,233	**319,982**	138,973
Effective interest rate on bank debt	**4.2%**	4.8%	**4.2%**	5.2%
Interest on bank debt per boe	**1.38**	0.87	**1.31**	0.88

In the fourth quarter of 2012, interest on bank debt increased 43% over the same period in 2011 as higher average debt levels from increased spending in prior periods and reduced funds from operations were partially offset by lower margins on the Company's bank facility. The Company's effective interest rate decreased in the fourth quarter of 2012 compared with the same period in 2011 due to lower stamping fees combined with decreased stand-by fees on the Company's unutilized borrowing facility. For 2012, the Company's interest on bank debt increased due to higher average debt levels from the acquisition of Caltex in July 2011. Higher average debt levels were partially offset by a lower effective interest rate due to a lower prime rate and lower margins on the Company's bank facility. The Company expects its effective interest rate on bank debt will average 4.25% to 4.75% in 2013.

The accretion of the decommissioning obligation slightly increased in the fourth quarter and for 2012 compared to the same periods in 2011 due to additional accretion on new wells drilled and additional accretion on the Caltex decommissioning obligation.

Deferred Income Taxes

In the fourth quarter of 2012, the provision for deferred income taxes was $9.1 million compared to a $51.3 million recovery for the same period in 2011 due to higher pre-tax earnings in the fourth quarter of 2012. For 2012, the provision for deferred incomes taxes was $12.2 million compared to a recovery of $45.8 million for the same period in 2011 due to higher pre-tax earnings in 2012.

A summary of the Company's estimated income tax pools at December 31, 2012 is outlined below:

($ thousands)	**December 31, 2012**	December 31, 2011
Cumulative Canadian Exploration Expense	**163,000**	140,900
Cumulative Canadian Development Expense	**491,500**	454,600
Cumulative Canadian Oil and Gas Property Expense	**50,300**	106,100
Undepreciated Capital Cost	**167,500**	154,400
Share issue costs	**4,200**	2,500
Non-capital loss	**–**	36,800
	876,500	895,300

The estimated income tax pools for 2012 have been reduced by the estimated deferred partnership income for 2012. The Company did not pay cash taxes in 2012 and estimates it has sufficient tax pools to shelter estimated income until 2014 or beyond.

Cash and Funds from Operations and Net Income

	Three months ended December 31,		Year ended December 31,	
($ thousands, except per share amounts)	**2012**	2011	**2012**	2011
Cash provided by operating activities	**50,873**	39,969	**213,591**	153,429
Funds from operations	**47,110**	64,841	**186,604**	172,103
Per share – basic	**0.39**	0.54	**1.54**	1.69
– diluted	**0.39**	0.54	**1.54**	1.67
Net income/(loss)	**21,453**	(148,529)	**21,542**	(130,162)
Per share – basic	**0.18**	(1.24)	**0.18**	(1.28)
– diluted	**0.18**	(1.24)	**0.18**	(1.28)

The fourth quarter decrease in funds from operations was predominantly a result of decreased production and decreased commodity pricing. The increase in 2012 cash provided by operating activities and funds from operations was a result of a full year of production from the Caltex properties in 2012. The increase in net income in the fourth quarter and for the year ended December 31, 2012 was a result of the gain on sale of the Kobes property of $70.8 million in the fourth quarter of 2012.

Capital Expenditures, Property Acquisitions and Dispositions

During the fourth quarter of 2012, the Company drilled a total of 24 (24.0 net) wells resulting in 21 (21.0 net) oil wells and three (3.0 net) natural gas wells. In addition, the Company completed 26 (26.0 net) wells and recompleted 24 (22.8 net) wells in the quarter. Infrastructure spending comprised approximately 19% of the Company's exploration and development expenditures during the fourth quarter as the Company added to its infrastructure incurring $10.5 million on pipelines and upgrading its facilities predominantly in Princess, Lloydminster and at its Deep Basin and northeast British Columbia properties. During the fourth quarter, the Company closed a disposition of approximately 15,800 net acres of Montney land with current production of approximately 625 boe per day at Kobes, British Columbia for net proceeds of approximately $108.1 million. The Company also completed an acquisition of approximately 36,000 net acres of Montney land with current production of 52 boe per day for $22 million in the fourth quarter.

In 2012, the Company drilled a total of 112 (107.2 net) wells resulting in 94 (91.1 net) oil wells, 15 (13.1 net) gas wells, one (1.0 net) service wells and two (2.0 net) dry and abandoned wells. During the year, the Company completed 105 (103.2 net) wells and recompleted 84 (80.5 net) wells. Crew continued to add to its undeveloped land base spending $13.1 million on land sales and lease retention. In addition, Crew spent $60.1 million on facility upgrades and pipeline infrastructure primarily in Princess, Lloydminster, Septimus and Kakwa, Alberta. During the year, the Company closed dispositions at Kobes and Kakwa for net proceeds of $118.7 million which was partially offset by the Septimus/Groundbirch area acquisition of $22.0 million.

Total net capital expenditures for the quarter and year are detailed below:

	Three months ended December 31,		Year ended December 31,	
($ thousands)	**2012**	2011	**2012**	2011
Land	**3,914**	1,191	**13,150**	4,906
Seismic	**(322)**	1,114	**3,909**	11,792
Drilling and completions	**38,737**	73,341	**170,161**	263,778
Facilities, equipment and pipelines	**10,535**	30,348	**60,079**	86,508
Other	**2,309**	2,860	**11,492**	8,890
Total exploration and development	**55,173**	108,854	**258,791**	375,874
Property acquisitions (dispositions)	**(86,395)**	(13,203)	**(96,557)**	(25,492)
Total	**(31,222)**	95,651	**162,234**	350,382

The Company's Board of Directors has approved a $219 million exploration and development budget for 2013.

LIQUIDITY AND CAPITAL RESOURCES

Capital Funding

The Company has a credit facility with a syndicate of lending banks (the "Syndicate") that includes a revolving line of credit of $370 million and an operating line of credit of $30 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 10, 2013. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 percent and all outstanding balances under the Facility will become repayable in one year from the extension date. The available lending limits of the Facility are reviewed semi-annually and are based on the Syndicate's interpretation of the Company's reserves and future commodity prices. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled borrowing base review on or before June 10, 2013. At December 31, 2012, the Company had drawings of $242.8 million on the Facility and had issued letters of credit totaling $10.3 million. During the fourth quarter, the Company's Facility was reduced to $400 million due to the sale of the Kobes property.

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

Working Capital

The capital intensive nature of Crew's activities generally results in the Company carrying a working capital deficit. Working capital deficit includes accounts receivable less accounts payable and accrued liabilities. The Company maintains sufficient unused bank credit lines to satisfy working capital deficits. At December 31, 2012, the Company's working capital deficiency totaled $48.5 million which, when combined with the drawings on its bank line at December 31, 2012, represented approximately 73% of its $400 million bank facility.

Share Capital

As at March 6, 2013, Crew had 121,619,344 Common Shares and options to acquire 6,167,400 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 financial position in order to continue to fund the future growth of the Company. Crew monitors its capital structure and makes adjustments on an on-going basis in order to maintain the flexibility needed to achieve the Company's long-term objectives. To manage the capital structure the Company may adjust capital spending, hedge future revenue and costs, issue new equity, issue new debt or repay existing debt through asset sales.

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

The Company monitors this ratio and endeavours to maintain it at or below 2.0 to 1. This ratio may increase at certain times as a result of acquisitions or low commodity prices. As shown below, as at December 31, 2012, the Company's ratio of net debt to annualized funds from operations was 1.55 to 1 (December 31, 2011 – 1.25 to 1).

($ thousands, except ratio)	**December 31, 2012**	December 31, 2011
Working capital deficit	**(48,522)**	(92,452)
Bank loan	**(242,834)**	(230,676)
Net debt	**(291,356)**	(323,128)
Fourth quarter funds from operations	**47,110**	64,841
Annualized	**188,440**	259,364
Net debt to annualized funds from operations ratio	**1.55**	1.25

Contractual Obligations

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

($ thousands)	Total	2013	2014	2015	2016	2017	Thereafter
Bank Loan [(1)]	242,834	–	242,834	–	–	–	–
Operating leases	9,713	2,231	2,363	2,494	2,625	–	–
Firm transportation agreements	23,618	3,364	3,980	4,021	3,636	2,110	6,507
Firm processing agreements	66,348	8,031	8,926	8,961	8,783	7,740	23,907
Total	342,513	13,626	258,103	15,476	15,044	9,850	30,414

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

The operating leases include the Company's contractual obligation to a third party for its five year lease of additional office space.

The transportation agreements include a commitment to a third party to transport natural gas from a gas processing facility in the Septimus area to the Alliance pipeline system.

The firm processing agreements include a commitment to process natural gas through a third party owned gas processing facility in the Septimus area until 2019. Crew has retained the option to re-purchase a 50% interest in the facility at certain dates prior to January 1, 2014, at a cost of 50% of the total expanded facility's construction cost. If the Company repurchases a 50% interest on January 1, 2014 for approximately $20 million, the remaining commitment would be reduced by approximately $27 million.

GUIDANCE

Crew is maintaining its forecasted average production of 27,500 to 28,500 boe per day in 2013. The first quarter has been very active with the Company operating up to six drilling rigs and expecting to drill 35 wells. Crew will continue to invest in projects that provide near term funds flow with the highest rates of return in addition to resource capture initiatives at a reasonable cost. As a result, approximately 87% of the wells planned in 2013 are targeting oil while acquisition targets have focused on scalable resource.

Crew expects to spend approximately $70 million on exploration and development activities in the first quarter out of an approved $219 million annual exploration and development capital budget. With the recent acquisition of 59 sections of land in northeast British Columbia on the regional Montney resource complex for $20 million, estimated net debt at the end of the first quarter is expected to be $340 to $350 million or 1.8 times annualized fourth quarter 2012 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)	**Dec. 31 2012**	Sept. 30 2012	June 30 2012	Mar. 31 2012	Dec. 31 2011	Sept. 30 2011	June 30 2011	Mar. 31 2011
Total daily production (boe/d)	**27,027**	26,281	28,192	30,380	30,034	27,510	16,443	15,607
Average wellhead price ($/boe)	**41.21**	38.16	38.96	44.52	51.41	45.33	46.94	43.53
Petroleum and natural gas sales	**102,473**	92,269	99,946	123,075	142,063	114,719	70,236	61,148
Cash provided by operations	**50,873**	46,935	49,557	66,226	39,969	54,095	32,896	26,469
Funds from operations	**47,110**	39,410	52,027	48,057	64,841	54,260	28,891	24,111
Per share – basic	**0.39**	0.33	0.43	0.40	0.54	0.45	0.34	0.29
– diluted	**0.39**	0.33	0.43	0.40	0.54	0.45	0.33	0.29
Net income (loss)	**21,812**	(17,947)	24,107	(6,430)	(148,529)	12,232	16,261	(10,126)
Per share – basic	**0.18**	(0.15)	0.20	(0.05)	(1.24)	0.10	0.19	(0.12)
– diluted	**0.18**	(0.15)	0.20	(0.05)	(1.24)	0.10	0.19	(0.12)

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. The Company reduced capital expenditures in the second and third quarters of 2012 in order to maintain financial strength during a period of commodity price volatility. This impacted production as new production additions were not sufficient to replace corporate declines during this period.

- Production was negatively impacted by scheduled and unscheduled third party facility shutdowns in the second quarters of 2011 and 2012 and poor weather experienced in southern Alberta during the second quarter of 2011. The Company also shut-in approximately 1,200 boe per day of uneconomic natural gas production in the second quarter of 2012.

- Revenue and royalties are significantly impacted by underlying commodity prices. The Company utilizes derivative contracts and forward sales contracts to reduce the exposure to commodity price fluctuations. These contracts can cause volatility in net income as a result of unrealized gains and losses on commodity derivative contracts held for risk management purposes. The Company also monetized certain 2012 WTI to WCS differential hedges in the first quarter of 2012 and certain 2013 WTI hedges in the second quarter of 2012 resulting in realized gains of $3.7 million and $12.1 million, respectively.

- The Company acquired Caltex Energy on July 1, 2011 adding approximately 10,500 boe per day of production at the time of acquisition.

- During 2011 and 2012, the Company has sold assets for proceeds of approximately $144 million. These dispositions in central Alberta and northeast British Columbia resulted in gains on sale of assets of $4.7 million, $7.4 million, $3.5 million, $3.6 million and $70.8 million in the second and fourth quarters of 2011 and the second, third and fourth quarters of 2012, respectively.

- The Company incurred an impairment charge of $122.8 million on certain CGUs in the fourth quarter of 2012 which was offset by the reversal of $93.6 million of impairment charges taken on certain CGUs in 2011. In the fourth quarter of 2011, the Company recorded an impairment charge of $181.9 million on certain CGUs.

The following table summarizes Crew's key financial results over the past three years:

($ thousands, except per share amounts)	**Year ended Dec. 31, 2012**	Year ended Dec. 31, 2011	Year ended Dec. 31, 2010
Petroleum and natural gas sales	**417,763**	388,166	206,343
Cash provided by operations	**213,591**	153,429	93,926
Funds from operations	**186,604**	172,103	98,206
Per share – basic	**1.54**	1.69	1.23
– diluted	**1.54**	1.67	1.20
Net income (loss)	**21,542**	(130,162)	17,818
Per share – basic	**0.18**	(1.28)	0.22
– diluted	**0.18**	(1.28)	0.22
Daily production (boe/d)	**27,963**	22,452	13,689
Crew average sales price ($/boe)	**40.82**	47.37	41.30
Total assets	**1,833,802**	1,842,719	1,045,941
Working capital deficiency (1)	**48,522**	92,452	40,707
Bank loan	**242,834**	230,676	138,700
Total other long-term liabilities	**305,308**	289,117	157,307

(1) Working capital includes accounts receivable, assets held for sale and accounts payable and accrued liabilities.

Crew's petroleum and natural gas sales, cash provided by operations, funds from operations and net income are all impacted by production levels and commodity pricing. These performance measures have all fluctuated throughout 2010 to 2012 as a result of volatile oil and natural gas prices combined with the increased cost of the Company's operations. In 2011, the Company acquired Caltex which added 10,500 boe per day of production. In 2012, the Company incurred $122.8 million of impairment charges on certain CGUs. In 2011, the Company also incurred impairment charges on its natural gas weighted CGUs of $181.9 million of which $93.6 million were reversed in 2012 as a result of additional reserves from existing wells outperforming the previous year's type curve.

New Accounting Pronouncements

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

(a) IFRS-9 *Financial Instruments:*

As of January 1, 2015, the Company will be required to adopt IFRS-9 *Financial Instruments*, which is the result of the first phase of the IASB project to replace IAS-39 *Financial Instruments: Recognition and Measurement*. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has two classification categories: amortized cost and fair value. Portions of the standard remain in development and the full impact of the standard on the Company's financial statements will not be known until the project is complete.

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

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

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

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

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

Crew is still determining the impact that the adoption of these standards will have on its financial statements.

Application of Critical Accounting Estimates

Crew's significant accounting policies are disclosed in note 3 to the December 31, 2012 consolidated financial statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Crew continuously refines its management and reporting systems to ensure that accurate, timely and useful information is gathered and disseminated. Crew's financial and operating results incorporate certain estimates including the following:

- Estimated accruals for revenues, royalties and operating costs where actual revenues and costs have not been received;
- Estimated capital expenditures where actual costs have not been received or for projects that are in progress;
- Estimated depletion, depreciation and amortization charges are based on estimates of oil and gas reserves that Crew expects to recover in the future. As a key component in the DD&A calculation, the reserve estimates have a significant impact on net earnings and the Company's financial results could differ if there is a revision in our estimate of reserve quantities;
- Estimated future recoverable value of property, plant and equipment and any related impairment charges or recoveries are assessed for impairment when circumstances suggest the carrying amount may exceed its recoverable amount. The recoverable amount calculation requires the use of estimates which are subject to change as new information becomes available. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets;
- Estimated fair values of derivative contracts which are used to manage commodity price, foreign currency and interest rate swaps are determined using valuation models which require assumptions regarding the amount and timing of future cash flows and discount rates. As the Company's assumptions rely on external market data, the resulting fair value estimates may not be indicative of the amounts realized or settled and are therefore subject to market uncertainty;
- Decommissioning obligations are based on assumptions which take into consideration current economic factors and experience to date which we believe are reasonable. The actual cost of the Company's decommissioning obligations may change in response to numerous factors.
- Estimated deferred income tax assets and liabilities are based on current tax interpretations, regulations and legislation which are subject to change. As a result, there are usually a number of tax matters under review and therefore income taxes are subject to measurement uncertainty.

Crew hires employees and engages consultants who have the expertise to ensure these estimates are accurate and ensures departments with the most knowledge of the activity are responsible for the estimates. Past estimates are reviewed and analyzed regularly to ensure future estimates continue to track actuals. The emergence of new information and changed circumstances may result in actual results or changes to estimate amounts that differ materially from current estimates.

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. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's disclosure controls and procedures at the financial year end of the Company and have concluded that the Company's disclosure controls and procedures are effective at the financial year end of the Company for the foregoing purposes.

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. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal controls over financial reporting at the financial year end of the Company and concluded that the Company's internal controls over financial reporting are effective, at the financial year end of the Company, for the foregoing purpose. 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 October 1, 2012 and ended on December 31, 2012 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

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

Dated as of March 6, 2013

MANAGEMENT'S REPORT

Management, in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, has prepared the accompanying consolidated financial statements of Crew Energy Inc. Financial and operating information presented throughout this report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

KPMG LLP were appointed by the Company's Board of Directors to conduct an audit of the consolidated financial statements. Their examination included a review and evaluation of Crew's internal control systems as they considered necessary and included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with International Financial Reporting Standards.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual evaluation of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the independent auditors to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of the external auditors and reviews their fees. The external auditors have access to the Audit Committee without the presence of management.

(signed)

Dale O. Shwed
President and CEO

(signed)

John G. Leach
Senior Vice-President and CFO

March 6, 2013

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Crew Energy Inc.

We have audited the accompanying consolidated financial statements of Crew Energy Inc., which comprise the consolidated statements of financial position as at December 31, 2012 and December 31, 2011, the consolidated statements of income (loss) and comprehensive income (loss), changes in shareholders' equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Crew Energy Inc. as at December 31, 2012 and December 31, 2011, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

(signed)

KPMG
Chartered Accountants

Calgary, Canada
March 6, 2013

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(thousands)	**December 31, 2012**	December 31, 2011
ASSETS		
Current Assets:		
Accounts receivable	**$ 46,405**	$ 79,117
Exploration and evaluation assets (note 7)	**60,651**	56,197
Property, plant and equipment (note 8)	**1,726,746**	1,707,405
	$ 1,833,802	$ 1,842,719
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 94,927**	$ 171,569
Fair value of financial instruments (note 14)	**7,170**	21,175
	102,097	192,744
Bank loan (note 11)	**242,834**	230,676
Decommissioning obligations (note 12)	**108,787**	104,836
Deferred tax liability (note 15)	**196,521**	184,281
Shareholders' Equity		
Share capital (note 13)	**1,275,777**	1,261,884
Contributed surplus	**54,035**	36,089
Deficit	**(146,249)**	(167,791)
	1,183,563	1,130,182
Commitments (note 18)		
Subsequent event (note 14)		
	$ 1,833,802	$ 1,842,719

See accompanying notes to the consolidated financial statements.

On behalf of the Board

(signed)

David G. Smith
Director

(signed)

Dennis L. Nerland
Director

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

(thousands, except per share amounts)	**Year ended December 31, 2012**	Year ended December 31, 2011
Revenue		
Petroleum and natural gas sales	**$ 417,763**	$ 388,166
Royalties	**(90,794)**	(91,882)
Realized gain on financial instruments (note 14)	**23,728**	2,186
Unrealized gain (loss) on financial instruments (note 14)	**14,005**	(10,437)
	364,702	288,033
Expenses		
Operating	**118,105**	91,855
Transportation (note 10)	**14,167**	13,222
General and administrative	**18,368**	14,114
Share-based compensation	**10,809**	7,025
Depletion and depreciation	**202,604**	155,789
	364,053	282,005
Income from operations	**649**	6,028
Financing (note 17)	**(16,130)**	(12,181)
Gain on divestitures (note 8)	**78,517**	12,115
Net impairment of property, plant and equipment (note 9)	**(29,254)**	(181,941)
Income (loss) before income taxes	**33,782**	(175,979)
Deferred tax expense (benefit) (note 15)	**12,240**	(45,817)
Net income (loss) and comprehensive income (loss)	**$ 21,542**	$ (130,162)
Net income (loss) per share (note 13)		
Basic	**$ 0.18**	$ (1.28)
Diluted	**$ 0.18**	$ (1.28)

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(thousands)	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 2012	119,993	$ 1,261,884	$ 36,089	$ (167,791)	$ 1,130,182
Net income	–	–	–	21,542	21,542
Share-based compensation expensed	–	–	10,809	–	10,809
Share-based compensation capitalized	–	–	11,168	–	11,168
Transfer of share-based compensation on exercises	–	4,031	(4,031)	–	–
Issued on exercise of options	1,627	9,862	–	–	9,862
Balance December 31, 2012	**121,620**	**$ 1,275,777**	**$ 54,035**	**$ (146,249)**	**$ 1,183,563**

	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	–	–	–	(130,162)	(130,162)
Issue of shares	4,820	100,015			100,015
Share issue costs, net of tax of $1,453	–	(4,277)	–	–	(4,277)
Shares issued on acquisition (note 6)	33,606	501,911	–	–	501,911
Share-based compensation expensed	–	–	7,025	–	7,025
Share-based compensation capitalized	–	–	5,747	–	5,747
Transfer of share-based compensation on exercises	–	4,194	(4,194)	–	–
Issued on exercise of options	1,199	10,273	–	–	10,273
Balance December 31, 2011	119,993	$ 1,261,884	$ 36,089	$ (167,791)	$ 1,130,182

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands)	**Year ended December 31, 2012**	Year ended December 31, 2011
Cash provided by (used in):		
Operating activities:		
Net income (loss)	**$ 21,542**	$ (130,162)
Adjustments:		
Depletion and depreciation	**202,604**	155,789
Financing expenses (note 17)	**16,130**	12,181
Interest expense (note 17)	**(13,453)**	(7,176)
Acquisition costs (note 17)	**–**	(2,605)
Share-based compensation	**10,809**	7,025
Deferred tax expense (benefit)	**12,240**	(45,817)
Unrealized loss (gain) on financial instruments	**(14,005)**	10,437
Gain on divestitures	**(78,517)**	(12,115)
Net impairment of property, plant and equipment	**29,254**	181,941
Transportation liability charge (note 10)	**–**	(343)
Decommissioning obligations settled (note 12)	**(2,460)**	(1,144)
Change in non-cash working capital (note 16)	**29,447**	(14,582)
	213,591	153,429
Financing activities:		
Increase in bank loan	**12,158**	40,738
Issue of common shares	**–**	100,015
Proceeds from exercise of options	**9,862**	10,273
Share issue costs	**–**	(5,730)
	22,020	145,296
Investing activities:		
Exploration and evaluation asset expenditures	**(7,821)**	(9,864)
Property, plant and equipment expenditures	**(250,970)**	(366,010)
Property acquisitions	**(22,178)**	–
Property divestitures	**118,735**	25,492
Asset held for sale	**–**	15,116
Change in non-cash working capital (note 16)	**(73,377)**	36,541
	(235,611)	(298,725)
Change in cash and cash equivalents	**–**	–
Cash and cash equivalents, beginning of year	**–**	–
Cash and cash equivalents, end of year	**$ –**	$ –

See accompanying notes to the consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2012 and 2011

(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, British Columbia and Saskatchewan. The consolidated financial statements (the "financial statements") of the Company are comprised of the accounts of Crew and its wholly owned subsidiary, Crew Oil and Gas Inc. which is incorporated in Canada, and three partnerships, Crew Energy Partnership, Crew Heavy Oil Partnership and Crew Conventional Partnership. The Company conducts many of its activities jointly with others; these financial statements reflect only the Company's proportionate interest in such activities. Crew's principal place of business is located at Suite 800, 250 – 5th Street SW, Calgary, Alberta, Canada, T2P 0R4.

2. BASIS OF PREPARATION:

These financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. A summary of the significant accounting policies and method of computation is presented in note 3.

The financial statements have been prepared on the historical cost basis except for derivative financial instruments which are measured at fair value. The methods used to measure fair values are discussed in note 5.

These financial statements are presented in Canadian dollars, which is the Company's and its subsidiaries and partnerships functional currency.

Operating expenses in the statement of income are presented as a combination of function and nature in conformity with industry practice. Depletion and depreciation are presented on a separate line by their nature, while operating expenses and net general and administrative expenses are presented on a functional basis. Significant expenses such as salaries, wages and fees and share-based compensation are presented by their nature in the notes to the financial statements.

The financial statements were authorized for issue by the Board of Directors on March 6, 2013.

3. SIGNIFICANT ACCOUNTING POLICIES:

The accounting policies set out below have been applied consistently to all years presented in these financial statements.

Certain comparative amounts have been reclassified to conform with the current year'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 financial statements from the date that control commences until the date that control ceases. The acquisition 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 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 financial statements.

(b) Foreign currency:

Transactions in foreign currencies are translated to Canadian dollars at exchange rates at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at the period end exchange rate. Non-monetary assets and liabilities denominated in foreign currencies that are measured at fair value are translated to the functional currency at the exchange rate at the date that the fair value was determined. Foreign currency differences arising on translation are recognized in profit or loss.

(c) Financial instruments:

(i) Non-derivative financial instruments:

Non-derivative financial instruments comprise accounts receivable, cash and cash equivalents, the 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, the 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 financial derivative contracts to be economic hedges. As a result, all financial derivative contracts are classified at fair value through profit or loss and are recorded on the statement of financial position 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 stock options are recognized as a deduction from equity, net of any tax effects.

(d) Property, plant and equipment and intangible exploration 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 leases and licenses 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 related cash-generating units ("CGUs").

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 CGUs for impairment testing. 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 property, plant and equipment, property swaps and farm-outs, are determined by comparing the proceeds or fair value of the asset received or given up 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 on 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. Relative volumes of reserves and production are converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil. 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 straight line

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 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, 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 remediation 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 statement of financial position 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 a finance cost 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.

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, impairment losses recognized on financial assets and corporate acquisition costs.

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) Critical accounting judgments and key sources of estimation uncertainty:

The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, 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 period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of these financial statements are outlined below.

Critical judgments in applying accounting policies:

The following are the critical judgments that management has made in the process of applying the Company's accounting policies and that have the most significant effect on the amounts recognized in these consolidated financial statements:

(i) Identification of cash-generating units

Crew's assets are aggregated into cash-generating units, for the purpose of calculating impairment, based on their ability to generate largely independent cash flows. By their nature, these estimates and assumptions are subject to measurement uncertainty and may impact the carrying value of the Company's assets in future periods.

(ii) Impairment of petroleum and natural gas assets

Judgments are required to assess when impairment indicators, or reversal indicators, exist and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future oil and natural gas prices, future costs, discount rates, market value of land and other relevant assumptions.

(iii) E&E assets

The application of the Company's accounting policy for exploration and evaluation assets requires management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found in assessing economic and technical feasibility.

(iv) Deferred income taxes

Judgments are made by management to determine the likelihood of whether deferred income tax assets at the end of the reporting period will be realized from future taxable earnings. To the extent that assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in profit or loss in the period in which the change occurs.

Key sources of estimation uncertainty:

The following are the key assumptions concerning the sources of estimation uncertainty at the end of the reporting period, that have a significant risk of causing adjustments to the carrying amounts of assets and liabilities.

(i) Reserves

The assessment of reported recoverable quantities of proved and probable reserves include estimates regarding production profile, commodity prices, exchange rates, remediation costs, timing and amount of future development costs, and production, transportation and marketing costs for future cash flows. It also requires interpretation of geological and geophysical models in anticipated recoveries. The economical, geological and technical factors used to estimate reserves may change from period to period. Changes in reported reserves can impact the carrying values of the Company's petroleum and natural gas properties and equipment, the calculation of depletion and depreciation, the provision for decommissioning obligations, and the recognition of deferred tax assets due to changes in expected future cash flows. The recoverable quantities of reserves and estimated cash flows from Crew's petroleum and natural gas interests are independently evaluated by reserve engineers at least annually.

The Company's petroleum and natural gas reserves represent the estimated quantities of petroleum, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be economically recoverable in future years from known reservoirs and which are considered commercially producible. Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon (i) a reasonable assessment of the future economics of such production; (ii) a reasonable expectation that there is a market for all or substantially all the expected petroleum and natural gas production; and (iii) evidence that the necessary production, transmission and transportation facilities are available or can be made available. Reserves may only be considered proven and probable if producibility is supported by either production or conclusive formation tests. Crew's petroleum and gas reserves are determined pursuant to National Instrument 51-101, Standard of Disclosures for Oil and Gas Activities.

(ii) Decommissioning obligations

The Company estimates future remediation costs of production facilities, wells and pipelines at different stages of development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires assumptions regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

(iii) Business combinations

In a business combination, management makes estimates of the fair value of assets acquired and liabilities assumed which includes assessing the value of oil and gas properties based upon the estimation of recoverable quantities of proven and probable reserves being acquired.

(iv) Share-based payments

All equity-settled, share-based awards issued by the Company are recorded at fair value using the Black-Scholes option-pricing model. In assessing the fair value of equity-based compensation, estimates have to be made regarding the expected volatility in share price, option life, dividend yield, risk-free rate and estimated forfeitures at the initial grant date.

(v) Income taxes

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in profit or loss both in the period of change, which would include any impact on cumulative provisions, and in future periods. Deferred tax assets (if any) are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse.

(vi) Derivatives

The Company's estimate of the fair value of derivative financial instruments is dependent on estimate forward prices and volatility in those prices.

4. FUTURE ACCOUNTING POLICIES:

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

(a) IFRS-9 Financial Instruments:

As of January 1, 2015, the Company will be required to adopt IFRS-9 *Financial Instruments*, which is the result of the first phase of the IASB project to replace IAS-39 *Financial Instruments: Recognition and Measurement*. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has two classification categories: amortized cost and fair value. Portions of the standard remain in development and the full impact of the standard on the Company's financial statements will not be known until the project is complete.

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

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

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

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

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

As of December 31, 2012 Crew is still determining the impact that the adoption of these standards will have on its financial statements.

5. 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 December 31, 2012 and December 31, 2011, the fair value of accounts receivable and accounts payable 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 statement of financial position date, using the remaining contracted volumes and a credit adjusted interest rate. 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), 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).

6. CORPORATE ACQUISITION

On July 1, 2011, Crew Energy Inc. acquired all of the issued and outstanding shares of Caltex Energy Inc. ("Caltex Energy"), a private exploration and development company pursuing petroleum and natural gas production and reserves in western Canada for total consideration of $501.9 million. The Company issued 33,606,410 shares at $14.93 per share based on the Company's trading price on June 30, 2011, the last date of trading before Crew acquired control. On December 31, 2011, Caltex Energy was amalgamated with the Company. Acquisition related costs of approximately $2.6 million have been expensed as period costs in the statement of income for the year ending December 31, 2011.

The Company believes that the acquisition of Caltex Energy will allow its shareholders to participate in the benefits of increased access to lower geological risk plays with large resources in place which include multi-zone, medium depth natural gas opportunities and multi-zone, shallow heavy oil opportunities.

The acquisition has been accounted for using the acquisition method with the results of Caltex Energy's operations included in the Company's financial and operating results commencing July 1, 2011. The following table presents the allocation of the purchase price based on estimated fair values:

Consideration:	
Issue of 33,606,410 common shares	$ 501,911
Net assets acquired:	
Property, plant and equipment	730,302
Accounts receivable and other current assets	24,258
Accounts payable and other current liabilities	(38,928)
Risk management contract	(2,524)
Bank loan	(51,238)
Deferred tax liability	(129,072)
Decommissioning obligations	(30,887)
	$ 501,911

The value attributed to the property, plant and equipment acquired was determined in reference to an engineering report prepared by Caltex Energy's third party reserve evaluators using proved plus probable reserves discounted at a rate of 10%. Accounts receivable and payable are recognized at the contractual amount.

7. EXPLORATION AND EVALUATION ASSETS:

Cost or deemed cost	Total
Balance, January 1, 2011	$ 72,281
Additions	9,864
Transfer to property, plant and equipment	(25,948)
Balance, December 31, 2011	$ 56,197
Additions	7,821
Transfer to property, plant and equipment	(3,367)
Balance, December 31, 2012	**$ 60,651**

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

8. PROPERTY, PLANT AND EQUIPMENT:

Cost or deemed cost	Total
Balance, January 1, 2011	$ 1,018,265
Additions	366,010
Transfer from exploration and evaluation assets	25,948
Corporate acquisition (note 6)	730,302
Divestitures	(17,921)
Change in decommissioning obligations	20,363
Capitalized share-based compensation	5,747
Balance, December 31, 2011	$ 2,148,714
Additions	250,970
Transfer from exploration and evaluation assets	3,367
Acquisitions	22,178
Divestitures	(43,837)
Change in decommissioning obligations	4,882
Capitalized share-based compensation	11,168
Balance, December 31, 2012	**$ 2,397,442**

Accumulated depletion and depreciation	Total
Balance, January 1, 2011	$ 105,625
Depletion and depreciation expense	155,789
Divestitures	(2,046)
Impairment	181,941
Balance, December 31, 2011	$ 441,309
Depletion and depreciation expense	202,604
Divestitures	(2,471)
Impairment	29,254
Balance, December 31, 2012	**$ 670,696**

Net book value	Total
Balance, December 31, 2011	$ 1,707,405
Balance, December 31, 2012	**$ 1,726,746**

The calculation of depletion for the three months ended December 31, 2012 included estimated future development costs of $731.1 million (December 31, 2011 – $681.4 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $91.5 million (December 31, 2011 – $87.0 million) and undeveloped land of $165.8 million (December 31, 2011 – $154.6 million) related to development acreage.

During 2012, the Company disposed of non-core oil and gas assets in central Alberta and northern BC for gross proceeds of $118.7 million. The assets had a net book value of $41.3 million and associated decommissioning liabilities of $1.1 million.

In 2011, the Company disposed of non-core oil and gas assets in central Alberta for gross proceeds of $25.5 million. The assets had a net book value of $15.9 million and associated decommissioning liabilities of $2.5 million.

9. IMPAIRMENT LOSS (RECOVERY):

	Year ended December 31, 2012	Year ended December 31, 2011
Impairment losses:		
E&E Assets	**$ –**	$ –
PP&E	**122,848**	181,941
	$ 122,848	$ 181,941
Impairment reversals:		
E&E Assets	**$ –**	$ –
PP&E	**(93,594)**	–
	$ (93,594)	–
	$ 29,254	$ 181,941

(a) Assessment:

At December 31, 2012, and 2011, due to declining forward natural gas and oil prices, reserve revisions and adjustments to future costs, the Company tested its CGUs for impairment as well as the potential reversal of prior period impairments. The recoverable amounts of the Company's CGUs were estimated as the fair value less costs to sell based on the net present value of the before tax cash flows from oil and gas proved plus probable reserves estimated by the Company's third party reserve evaluators discounted at a rate of 10% (2011 – 10% to 12%) and the internally estimated fair value of undeveloped lands based on recent crown land sales in the area.

Impairment reversals are recognized to the extent of the original impairment recorded, but are limited to the net book value that would exist had the original impairment never been recorded, including estimates for depletion. In determining the appropriate discount rate the Company considered the acquisition metrics of recent transactions completed on assets similar to those in the specific CGU.

(b) Results of 2012 assessment:

The following estimates were used in determining whether an impairment to the carrying value of the CGUs existed at December 31, 2012:

	WTI Oil (US$/bbl)	WCS ($Cdn/bbl)	AECO Gas ($Cdn/mmbtu)	$Cdn/$US
2013	89.63	69.33	3.31	1.00
2014	89.63	74.57	3.72	1.00
2015	88.29	73.21	3.91	1.00
2016	95.52	80.17	4.70	1.00
2017	96.96	81.37	5.32	1.00
2018	98.41	82.59	5.40	1.00
2019	99.89	83.83	5.49	1.00
2020	101.38	85.08	5.58	1.00
2021	102.91	86.36	5.67	1.00
2022	104.45	87.66	5.76	1.00
2023	106.02	88.97	5.85	1.00
Remainder	+1.5%/yr	+1.5%/yr	+1.5%/yr	1.00 thereafter

At December 31, 2012 it was determined that the net book value of certain CGUs exceeded the recoverable amount and Crew recognized $122.8 million in impairment charges. Offsetting this impairment was a reversal of prior period impairment charges of $93.6 million resulting from the recognition of additional reserves due to improved performance associated with assets that were previously recognized in prior year's proved plus probable reserves at lower amounts.

A one per cent increase in the assumed discount rate would result in an additional impairment of $69.0 million.

(c) Results of 2011 assessment:

The following estimates were used in determining whether an impairment to the carrying value of the CGUs existed at December 31, 2011:

	WTI Oil (US$/bbl)	WCS ($Cdn/bbl)	AECO Gas ($Cdn/mmbtu)	$Cdn/$US
2012	97.00	81.61	3.49	0.98
2013	100.00	82.63	4.13	0.98
2014	100.00	82.63	4.59	0.98
2015	100.00	82.63	5.05	0.98
2016	100.00	82.63	5.51	0.98
2017	100.00	82.63	5.97	0.98
2018	101.35	83.75	6.21	0.98
2019	103.38	85.44	6.33	0.98
2020	105.45	87.16	6.46	0.98
2021	107.56	88.92	6.58	0.98
Remainder	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.98 thereafter

At December 31, 2011 it was determined that the net book value of certain CGUs exceeded the recoverable amount and Crew recognized a $181.9 million impairment charge.

10. 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 the acquisition of a $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 Company amortised the final $0.3 million in 2011.

11. BANK LOAN:

The Company's bank facility as at December 31, 2012 consisted of a revolving line of credit of $370 million and an operating line of credit of $30 million (the "Facility") provided by a syndicate of seven banks. The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 10, 2013. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 per cent and all outstanding advances thereunder will become repayable in one year from the extension date. 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 10, 2013. The Facility is secured by a floating charge debenture and a general securities agreement on the assets of the Company.

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

As at December 31, 2012, 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 December 31, 2012, the Company had issued letters of credit totaling $10.3 million (December 31, 2011 – $10.2 million). The effective interest rate on the Company's borrowings under its bank facility for the year ended December 31, 2012 was 4.2% (2011 – 5.2%).

12. DECOMMISSIONING OBLIGATIONS:

	As at December 31, 2012	As at December 31, 2011
Decommissioning obligations, beginning of year	**$ 104,836**	$ 54,828
Obligations incurred	**8,254**	7,781
Obligations settled	**(2,460)**	(1,144)
Obligations divested	**(1,148)**	(2,498)
Obligations acquired (note 6)	**–**	30,887
Change in estimated future cash outflows	**(3,372)**	12,582
Accretion of decommissioning obligations	**2,677**	2,400
Decommissioning obligations, end of year	**$ 108,787**	$ 104,836

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning obligations to be $108.8 million as at December 31, 2012 (December 31, 2011 – $104.8 million) based on an undiscounted total future liability of $113.4 million (December 31, 2011 – $107.2 million). These payments are expected to be made over the next 25 years with the majority of costs to be incurred between 2015 and 2036. The discount factor, being the risk-free rate related to the liability, is 2.55% (December 31, 2011 – 2.40%).

13. SHARE CAPITAL:

At December 31, 2012, the Company was authorized to issue an unlimited number of common shares with the holders of common shares entitled to one vote per share.

The Company has received approval for the commencement of a Normal Course Issuer Bid from the Toronto Stock Exchange ("TSX"). Under the bid, the Company may purchase for cancellation up to 6,038,492 of its Common Shares, representing approximately 5% of the public float of issued and outstanding shares. Purchases under the bid can be made between May 14, 2012 and May 13, 2013. Purchases will be made on the open market through the facilities of the TSX in accordance with its policies and the price which the Company will pay for any common shares purchased will be the prevailing market price of the common shares on the TSX at the time of such purchase. As of December 31, 2012, no share re-purchases have been made.

Share based payments:

The Company has a stock 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 stock options are as follows:

	Number of options	Weighted average exercise price
Balance January 1, 2011	5,330	$ 10.79
Granted	5,178	$ 15.03
Exercised	(1,199)	$ 8.58
Forfeited	(1,085)	$ 17.27
Balance December 31, 2011	8,224	$ 12.93
Granted	3,297	$ 6.71
Exercised	(1,627)	$ 6.06
Forfeited	(832)	$ 13.05
Cancelled	(2,330)	$ 16.84
Expired	(312)	$ 14.97
Balance December 31, 2012	**6,420**	**$ 9.94**

The weighted average trading price of the Company's common shares was $8.13 during the year ended December 31, 2012 (December 31, 2011 – $14.55).

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

Range of exercise prices	Outstanding at December 31, 2012	Weighted average remaining life (years)	Weighted average exercise price	Exercisable at December 31, 2012	Weighted average exercise price
$ 5.16 to $ 7.01	2,580	3.4	$ 5.68	–	$ –
$ 7.02 to $ 9.94	194	3.3	$ 7.73	29	$ 9.16
$ 9.95 to $14.63	1,795	2.9	$ 11.34	463	$ 11.06
$ 14.64 to $ 18.29	1,851	1.2	$ 14.74	1,127	$ 14.72
	6,420	2.6	$ 9.94	1,619	$ 13.57

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

Assumptions	**Year ended December 31, 2012**	Year ended, December 31, 2011
Risk free interest rate (%)	**1.3**	2.0
Expected life (years)	**4.0**	4.0
Expected volatility (%)	**61**	58
Forfeiture rate (%)	**16.5**	16.4
Weighted average fair value of options	**$ 3.16**	$ 7.11

Net income (loss) per share:

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average shares outstanding for the year ended December 31, 2012 was 120,815,000 (2011 – 102,034,000).

In computing diluted earnings per share for the year ended December 31, 2012, 378,000 (2011 – NIL) shares were added to the weighted average Common Shares outstanding to account for the dilution of stock options. There were 3,995,000 (2011 – 8,224,000) stock options that were not included in the diluted earnings per share calculation because they were anti-dilutive.

14. FINANCIAL RISK MANAGEMENT:

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities such as:

- credit risk;
- market risk; and
- liquidity risk.

This note presents information about the Company's exposure to each of the above risks, the Company's objectives, policies and processes for measuring and managing risk, and the Company's management of capital. Further quantitative disclosures are included throughout these financial statements.

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

(a) Credit risk:

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from joint venture partners and oil and natural gas marketers. The maximum exposure to credit risk at year-end is as follows:

	December 31, 2012	December 31, 2011
Trade and other receivables	**$ 46,405**	$ 79,117

Trade and other receivables:

Substantially all of the Company's petroleum and natural gas production is marketed under standard industry terms. Receivables from petroleum and natural gas marketers are normally collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large credit worthy purchasers and to sell through multiple purchasers. During 2012, two third party purchasers marketed at least 40% of the Company's total revenues. The Company historically has not experienced any collection issues with its petroleum and natural gas marketers. Joint venture receivables are typically collected within one to three months of the joint venture bill being issued to the partner. The Company attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to the expenditure.

However, the receivables are from participants in the petroleum and natural gas sector, and collection of the outstanding balances can be impacted by industry factors such as commodity price fluctuations, limited capital availability and unsuccessful drilling programs. The Company does not typically obtain collateral from petroleum and natural gas marketers or joint venture partners; however the Company can cash call for major projects and does have the ability, in most cases, to withhold production from joint venture partners in the event of non-payment.

Derivative assets can consist of commodity, interest rate and foreign exchange contracts used to manage the Company's exposure to fluctuations in commodity prices, interest rates and the exchange rate between United States and Canadian dollars. The Company manages the credit risk exposure related to derivative assets by selecting investment grade counterparties and by not entering into contracts for trading or speculative purposes.

The carrying amount of accounts receivable and derivative assets, when outstanding, represents the maximum credit exposure. As at December 31, 2012 the Company's receivables consisted of $32.8 (2011 – $50.8) million of receivables from petroleum and natural gas marketers which has subsequently been collected,

$4.1 (2011 – $15.4) million from joint venture partners of which $1.9 million has been subsequently collected, and $9.5 (2011 – $12.9) million of Crown incentives, deposits, prepaids and other accounts receivable. The Company does not consider any receivables to be past due.

(b) Market risk:

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

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

Foreign currency exchange rate risk:

Foreign currency exchange rate risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. Substantially all of the Company's petroleum and natural gas sales are conducted in Canada and are denominated in Canadian dollars. Canadian commodity prices are influenced by fluctuations in the Canadian to U.S. dollar exchange rate.

Interest rate risk:

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its bank loan which bears a floating rate of interest. Average bank debt outstanding during the year ending December 31, 2012 was $320.0 million (2011 $138.9 million). For the year ended December 31, 2012, a 1.0 percent change to the effective interest rate would have a $2.4 million impact on net income (2011 – $1.0 million).

Commodity price risk:

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by not only the relationship between the Canadian and United States dollar, as outlined below, but also North American and global economic events that dictate the levels of supply and demand. The Company has attempted to mitigate a portion of the commodity price risk through the use of various financial derivative and physical delivery sales contracts as outlined below. The Company's policy is to enter into commodity price contracts when considered appropriate to a maximum of 50% of forecasted gross production volumes for a period of not more than two years. Any contracts for volumes greater than 50% of forecasted gross production or extending beyond two years require Board approval.

Derivatives are recorded on the statement of financial position at fair value at each reporting period with the change in fair value being recognized as an unrealized gain or loss on the statement of income.

The Company's derivatives are measured in accordance with a three level hierarchy. The hierarchy groups financial assets and liabilities into three levels based on the significance of inputs used in measuring the fair value of the financial assets and liabilities. The fair value hierarchy has the following levels:

a) Level 1: fair value is based on quoted prices (unadjusted) in active markets for identical assets or liabilities;

b) Level 2: fair value is based on inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (ie. as prices) or indirectly (ie. derived from prices); and

c) Level 3: fair value is based on inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The Company's derivative contracts are valued using Level 2 of the hierarchy.

At December 31, 2012, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Oil	4,500 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$91.20	Swap	(3,259)
Oil	750 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$92.60	Call	(1,693)
Oil	1,000 bbl/day	January 1, 2013 – December 31, 2013	US$ WTI	$89.84	Call	(3,189)
Oil	250 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$85.00 - $100.00	Collar (1)	312
Natural Gas	5,000 gj/day	January 1, 2013 – December 31, 2013	AECO C Monthly Index	$2.65 - $3.50	Collar	12
Natural Gas	35,000 gj/day	January 1, 2013 – December 31, 2013	AECO C Monthly Index	$3.03	Swap	647
Total						(7,170)

(1) The referenced contract is a fade-in collar whereby the price is fixed at $100/bbl unless the market price falls below $85/bbl in which case the price received will be $85/bbl.

As at December 31, 2012, a 10% decrease to the price outlined in the contracts above would result in a $15.9 million increase in net income.

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

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded
Natural Gas	2,500 gj/day	April 1, 2013 – October 31, 2013	AECO C Monthly Index	$2.93	Swap
Oil	500 bbl/day	April 1, 2013 – December 31, 2013	CDN$ WCS - WTI Diff	$25.00	Swap
Oil	750 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$85.00 - $95.00	Collar (3)
Oil	1,000 bbl/day	January 1, 2014 – December 31, 2014	CDN$ WCS - WTI Diff	$23.25	Swap
Oil	1,500 bbl/day	January 1, 2014 – December 31, 2014	CDN$ WTI	$95.68	Swap
Oil	250 bbl/day	January 1, 2014 – December 31, 2014	CDN$ WTI	$92.20	Call (1) (2)
Oil	1,000 bbl/day	January 1, 2014 – December 31, 2014	USD$ WTI	$92.40	Call (2)
Oil	500 bbl/day	January 1, 2014 – December 31, 2014	CDN$ WTI	$96.05	Call (2)
Oil	250 bbl/day	January 1, 2014 – December 31, 2014	USD$ WTI	$95.75	Swaption
Natural Gas	12,500 gj/day	January 1, 2014 – December 31, 2014	AECO C Monthly Index	$3.52	Swap

(1) This is a structured call which is only triggered if the average CDN$ WTI trades above $100 per bbl for a given month during the term.

(2) Crew funded the buy-out of the 2013 oil calls with the proceeds from the sale of these calls.

(3) The referenced contract is a fade-in collar whereby the price is fixed at $95/bbl unless the market price falls below $85/bbl in which case the price received will be $85/bbl.

(c) Liquidity risk:

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with the financial liabilities. The Company's financial liabilities consist of accounts payable, financial instruments and the bank loan. Accounts payable consists of invoices payable to trade suppliers for office, field operating activities and capital expenditures. The Company processes invoices within a normal payment period. Accounts payable and financial instruments have contractual maturities of less than one year. The Company maintains a revolving credit facility, as outlined in note 11, that is subject to renewal annually by the lenders and has a contractual maturity in 2014. The Company also maintains and monitors a certain level of cash flow which is used to partially finance all operating and capital expenditures as the Company does not pay dividends.

Capital management:

The Company's objective when managing capital is to maintain a flexible capital structure which will allow it to execute on its capital expenditure program, which includes expenditures on oil and gas activities which may or may not be successful. Therefore, the Company monitors the level of risk incurred in its capital expenditures to balance the proportion of debt and equity in its capital structure.

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

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

The Company monitors this ratio and endeavours to maintain it at or below 2.0 to 1.0 in a normalized commodity price environment. This ratio may increase at certain times as a result of acquisitions or low commodity prices. As shown below, as at December 31, 2012, the Company's ratio of net debt to annualized funds from operations was 1.55 to 1 (December 31, 2011 – 1.25 to 1).

	December 31, 2012	December 31, 2011
Net debt:		
Accounts receivable	**$ 46,405**	$ 79,117
Accounts payable and accrued liabilities	**(94,927)**	(171,569)
Working capital deficiency	**$ (48,522)**	$ (92,452)
Bank loan	**(242,834)**	(230,676)
Net debt	**$ (291,356)**	$ (323,128)
Fourth Quarter Annualized funds from operations:		
Cash provided by operating activities	**$ 50,873**	$ 39,969
Decommissioning obligations settled	**1,160**	483
Transportation liability charge	**–**	35
Change in non-cash working capital	**(4,923)**	24,354
Fourth Quarter Funds from operations	**47,110**	64,841
Annualized	**$ 188,440**	$ 259,364
Net debt to annualized funds from operations	**1.55**	1.25

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

15. INCOME TAXES:

(a) Deferred income tax expense:

The provision for income tax expense in the financial statements differs from the result which would have been obtained by applying the combined federal and provincial income tax rate to the Company's income (loss) before income taxes. This difference results from the following items:

	Year ended Dec. 31, 2012	Year ended Dec. 31, 2011
Income (loss) before income taxes	**$ 33,782**	$ (175,979)
Combined federal and provincial income tax rate	**25.3%**	26.7%
Computed "expected" income tax expense (reduction)	**$ 8,547**	$ (46,986)
Increase (decrease) in income taxes resulting from:		
Non-deductible share-based compensation	**2,737**	1,889
Change in income tax rates	**800**	(634)
Other	**156**	(86)
Deferred income tax (recovery) expense	**$ 12,240**	$ (45,817)

The income tax rate change is due to a change in the statutory federal income tax rates.

(b) Deferred income tax liability:

The components of the Company's deferred income tax liability are as follows:

	December 31, 2012	December 31, 2011
Deferred tax liabilities:		
Property, plant and equipment	**$ 212,027**	$ 185,697
Partnership deferral	**14,992**	41,361
Deferred tax assets:		
Decommissioning obligations	**$ (27,545)**	$ (26,429)
Fair value of financial instruments	**(1,815)**	(5,338)
Non-capital losses	**–**	(9,277)
Other	**(1,138)**	(1,733)
Deferred income tax liability	**$ 196,521**	$ 184,281

The Company's assets have an approximate tax basis of $876.5 million at December 31, 2012 (December 31, 2011 – $895.3 million) available for deduction against future taxable income. The following table summarizes the tax pools:

	December 31, 2012	December 31, 2011
Cumulative Canadian Exploration Expense	**$ 163,000**	$ 140,900
Cumulative Canadian Development Expense	**491,500**	454,600
Cumulative Canadian Oil and Gas Property Expense	**50,300**	106,100
Undepreciated Capital Costs	**167,500**	154,400
Share issue costs	**4,200**	2,500
Non-capital losses	**–**	36,800
Estimated tax basis	**$ 876,500**	$ 895,300

The estimated income tax pools for 2012 have been reduced by the estimated deferred partnership income for 2012.

The following tables provide a continuity of the deferred income tax liability (asset):

	December 31, 2010	Recognized in profit or loss	Acquired in business combination	Recognized in equity	December 31, 2011
Property, plant and equipment	$ 105,824	$ (51,842)	$ 131,715	$ –	$ 185,697
Partnership deferral	22,161	11,572	7,628	–	41,361
Decommissioning obligations	(13,784)	(4,185)	(8,460)	–	(26,429)
Fair value of financial instruments	(2,068)	(2,580)	(690)	–	(5,338)
Non-capital losses	(8,156)	–	(1,121)	–	(9,277)
Other	(1,498)	1,218	–	(1,453)	(1,733)
	$ 102,479	$ (45,817)	$ 129,072	$ (1,453)	$ 184,281

	December 31, 2011	Recognized in profit or loss	Acquired in business combination	Recognized in equity	December 31, 2012
Property, plant and equipment	$ 185,697	$ 26,330	$ –	$ –	$ 212,027
Partnership deferral	41,361	(26,369)	–	–	14,992
Decommissioning obligations	(26,429)	(1,116)	–	–	(27,545)
Fair value of financial instruments	(5,338)	3,523	–	–	(1,815)
Non-capital losses	(9,277)	9,277	–	–	–
Other	(1,733)	595	–	–	(1,138)
	$ 184,281	$ 12,240	$ –	$ –	$ 196,521

16. SUPPLEMENTAL CASH FLOW INFORMATION:

Changes in non-cash working capital is comprised of:

	Year ended December 31, 2012	Year ended December 31, 2011
Changes in non-cash working capital:		
Accounts receivable	$ 32,712	$ (34,195)
Accounts payable and accrued liabilities	(76,642)	70,824
Non-cash working capital acquired (note 6)	–	(14,670)
	$ (43,930)	$ 21,959
Operating activities	$ 29,447	$ (14,582)
Investing activities	(73,377)	36,541
	$ (43,930)	$ 21,959
Interest paid	$ (13,016)	$ (6,689)

17. FINANCING:

	Year ended December 31, 2012	Year ended December 31, 2011
Interest expense	$ 13,453	$ 7,176
Accretion of decommissioning obligations	2,677	2,400
Acquisition costs	–	2,605
	$ 16,130	$ 12,181

Acquisition costs relate to the Company's acquisition of Caltex Energy (note 6).

18. COMMITMENTS:

	Total	2013	2014	2015	2016	2017	Thereafter
Operating leases	$ 9,713	$ 2,231	$ 2,363	$ 2,494	$ 2,625	$ –	$ –
Firm transportation agreements	23,618	3,364	3,980	4,021	3,636	2,110	6,507
Firm processing agreement	66,348	8,031	8,926	8,961	8,783	7,740	23,907
Total	$ 99,679	$ 13,626	$ 15,269	$ 15,476	$ 15,044	$ 9,850	$ 30,414

The operating leases include the Company's contractual obligation to a third party for its five year lease of office space.

The transportation agreements include a commitment to a third party to transport natural gas from a gas processing facility in the Septimus area to the Alliance pipeline system.

The firm processing agreements include a commitment to process natural gas through a third party owned gas processing facility in the Septimus area until 2019. Crew has retained the option to re-purchase a 50% interest in the facility at certain dates prior to January 1, 2014, at a cost of 50% of the total expanded facility's construction cost. If the Company re-purchases a 50% interest on January 1, 2014 for approximately $20 million, the remaining commitment would be reduced by approximately $27 million.

19. PERSONNEL EXPENSES:

The aggregate payroll expense of employees and executive management was as follows:

	Year ended December 31, 2012	Year ended December 31, 2011
Salary, wages and fees	**$ 19,947**	$ 15,129
Share-based compensation	**21,977**	12,772
	$ 41,924	$ 27,901
Capitalized portion of total remuneration	**(21,348)**	(13,142)
	$ 20,576	$ 14,759

The Company has determined that the key management personnel consists of its officers and directors. In addition to the salaries and directors fees paid both groups participate in the stock option plan. The total compensation expense, including salaries, wages, fees and share-based compensation, relating to key management personnel for the year was $9.4 million (2011 – $9.2 million).

CORPORATE INFORMATION

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National Bank of Canada

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RESERVE ENGINEERS

Sproule Associates Ltd.

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
Stock Symbol: **CR**

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Independent Director

Jeffery E. Errico
Independent Director

Dennis L. Nerland
Independent Director

Dale O. Shwed
President, Crew Energy Inc.

David G. Smith
Independent Director

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Chief Financial Officer

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