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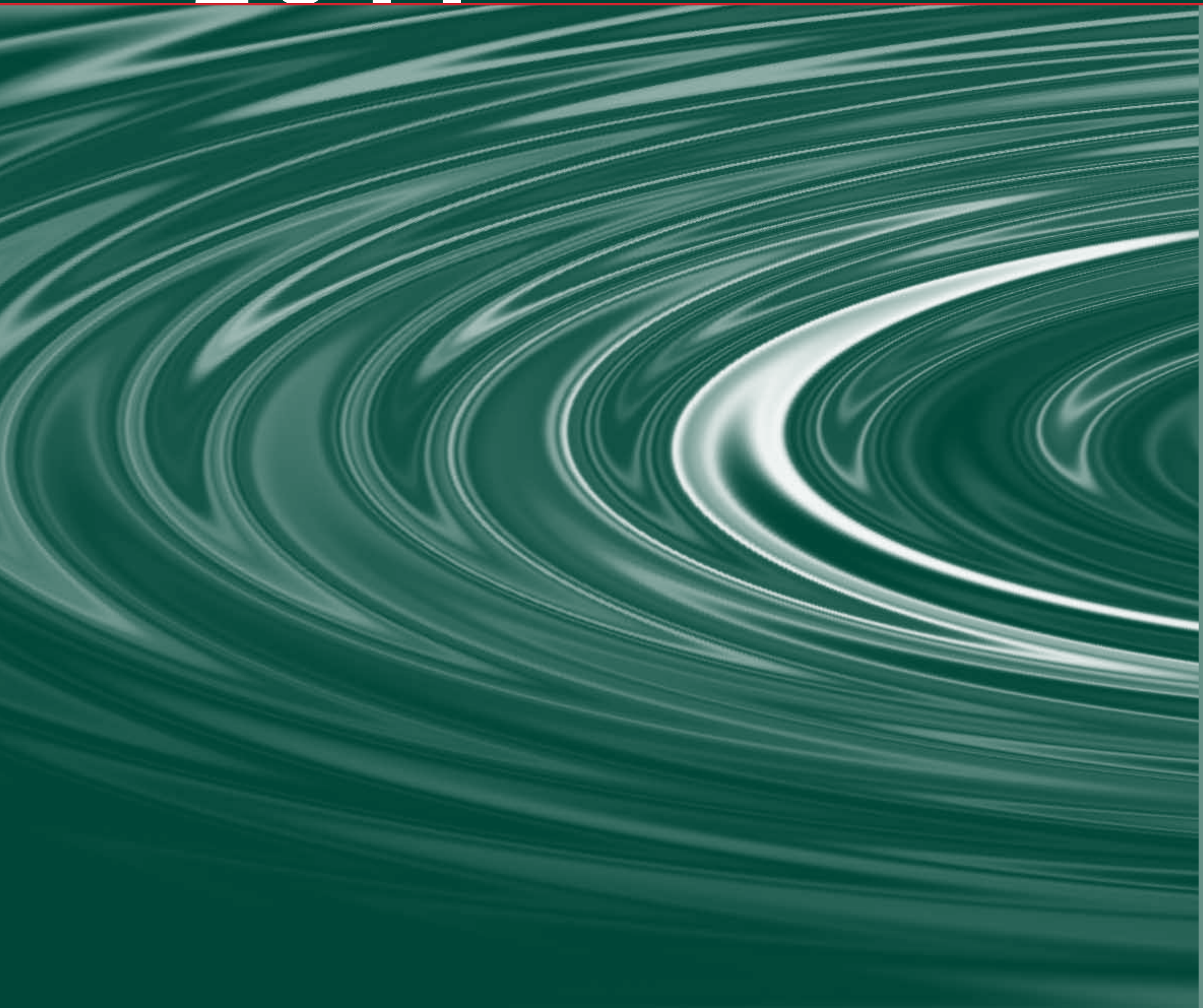
FINANCIAL REVIEW 2011



RESOURCE FOCUS > OPPORTUNITY > SUSTAINABILITY

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 24, 2012, 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, 2011 and December 31, 2010

HIGHLIGHTS

Financial *($ thousands, except per share amounts)*	Year ended December 31, 2011	Year ended December 31, 2010
Petroleum and natural gas sales	**388,166**	206,343
Cash provided by operations	**153,429**	93,926
Funds from operations (1)	**172,103**	98,206
Per share - basic	**1.69**	1.23
- diluted	**1.67**	1.20
Net income (loss)	**(130,162)**	17,818
Per share - basic	**(1.28)**	0.22
- diluted	**(1.28)**	0.22
Capital expenditures	**375,874**	245,626
Property acquisitions (net of dispositions)	**(25,492)**	(132,020)
Net capital expenditures	**350,382**	113,606
Capital Structure *($ thousands)*	As at December 31, 2011	As at December 31, 2010
Working capital deficiency (2)	**92,452**	40,707
Bank loan	**230,676**	138,700
Net debt	**323,128**	179,407
Bank facility	**430,000**	240,000
Common Shares Outstanding *(thousands)*	**119,993**	80,368
Operations	Year ended December 31, 2011	Year ended December 31, 2010
Daily production		
Conventional oil (bbl/d)	**5,737**	4,175
Heavy oil (bbl/d)	**3,221**	–
Natural gas liquids (bbl/d)	**2,035**	1,235
Natural gas (mcf/d)	**68,756**	49,672
Oil equivalent (boe/d @ 6:1)	**22,452**	13,689
Average prices (3)		
Conventional oil ($/bbl)	**78.05**	67.48
Heavy oil ($/bbl)	**70.30**	–
Natural gas liquids ($/bbl)	**62.68**	50.70
Natural gas ($/mcf)	**3.81**	4.45
Oil equivalent ($/boe)	**47.37**	41.30
Netback ($/boe)		
Operating netback (4)	**23.61**	22.86
Realized (gain)/loss on financial instruments	**–**	0.10
G&A	**1.72**	1.95
Interest on bank debt	**0.88**	1.16
Funds from operations	**21.01**	19.65
Drilling Activity		
Gross wells	**158**	80
Working interest wells	**154.5**	75.2
Success rate, net wells	**99%**	99%

Notes:

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

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

(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, 2011 and 2010. In 2010, the CICA Handbook was revised to incorporate International Financial Reporting Standards ("IFRS"), and require publicly accountable enterprises to apply such standards effective for years beginning on or after January 1, 2011. Previously, the Company prepared its interim and annual consolidated financial statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). The comparative 2010 amounts have been restated to conform to IFRS however the financial information contained within this MD&A that relates to periods prior to January 1, 2010 has been prepared under previous GAAP and has not be restated. The consolidated financial statements for the year ended December 31, 2011 have been prepared in accordance with IFRS and all figures provided herein and in the December 31, 2010 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, general and administrative expenses, 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 2012 and resulting year-end net debt may constitute forward looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, the inability to fully realize the benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and inability to access sufficient capital from internal and external sources. As a consequence, the Company's actual results may differ materially from those expressed in, or implied by, the forward looking statements. Forward looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Crew believes that the expectations reflected in such forward looking statements or information are reasonable, undue reliance should not be placed on forward looking statements because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document and other documents filed by the Company, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Company has an interest in to operate the field in a safe, efficient and effective manner; Crew's ability to obtain financing on acceptable terms; the anticipated increase to 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 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)	**2011**	2010	**2011**	2010
Cash provided by operating activities	**39,969**	20,225	**153,429**	93,926
Decommissioning obligation expenditures	**483**	606	**1,144**	1,512
Transportation liability charge (1)	**35**	120	**343**	758
Acquisition costs (2)	**–**	–	**2,605**	–
Change in non-cash working capital	**24,354**	6,498	**14,582**	2,010
Funds from operations	**64,841**	27,449	**172,103**	98,206

Notes:

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

(2) This amount relates to costs incurred for the Caltex acquisition that closed on July 1, 2011. See Finance Expenses section for further details.

Operating Netback

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

Working Capital and Net Debt

The Company closely monitors its capital structure with a goal of maintaining a strong 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, 2011**	December 31, 2010
Current assets	**79,117**	61,020
Current liabilities	**(192,744)**	(101,088)
Fair value of financial instruments	**21,175**	(982)
Current portion of other long-term obligations	**–**	343
Working capital deficit	**(92,452)**	(40,707)

($ thousands)	**December 31, 2011**	December 31, 2010
Bank loan	**(230,676)**	(138,700)
Working capital deficit	**(92,452)**	(40,707)
Net debt	**(323,128)**	(179,407)

RESULTS OF OPERATIONS

Overview

Crew's past year was highlighted by the July 1st acquisition of Caltex Energy Inc. ("Caltex"). The Caltex acquisition was consistent with Crew's strategy to explore, exploit and acquire large hydrocarbon in place reservoirs. The transaction provided Crew with exposure to a significant heavy oil development in the Lloydminster area of Saskatchewan and liquids rich natural gas assets in the Greater Wapiti area of Alberta. The integration of the Caltex assets into Crew added 10,500 boe per day of new production that was 68% weighted towards liquids production and 41.0 mmboe of proved plus probable reserves that were 48% liquids weighted. The Caltex acquisition was funded through the issuance of 33.6 million Crew shares and the assumption of $66 million of Caltex net debt for a total cost of $568 million.

The acquisition of Caltex has significantly strengthened Crew's asset base by providing two additional platforms for growth with over 900 new potential drilling locations. The added liquids weighted production increased Crew's corporate netbacks from $21.14 per boe in the first half of 2011 to $24.53 per boe in the second half and provides free cash flow to help fund the development of Crew's premier oil development in the Princess area of Alberta and the liquids rich Montney natural gas play in northeast British Columbia.

Crew's 2011 production was enhanced by the Caltex acquisition along with added production from the Company's successful drilling programs at Princess and Wapiti, Alberta and at Septimus in northeast British Columbia. The Company's production averaged 22,452 boe per day (49% liquids) which is a 64% increase over 2010. Production per share averaged 220 boe per day per million shares which is a 28% increase over the 172 boe per day per million shares produced in 2010. First half 2011 production averaged 16,028 boe per day (43% liquids) or 191 boe per day per million shares outstanding. Second half production increased 80% over the first half to 28,771 boe per day (52% liquids) or a 26% increase to 240 boe per day per million shares outstanding.

Strong world oil prices opened the year benefiting from positive economic growth indicators out of the US and China. West Texas Intermediate ("WTI") oil prices averaged US$98.30 per bbl during the first half of the year ranging from US$92 per bbl in January to a peak of US $110 per bbl in April. First half optimism gave way to mid-year concerns over European sovereign debt. This concern led to considerable second half market volatility. Oil prices retreated quickly from the first half highs to average US$91.90 per bbl in the second half of 2011 hitting a low of US$85 per bbl in September and eventually recovering back to US$99 per bbl at year end.

Natural gas prices continued to wilt under the weight of increasing supply from aggressive development of unconventional natural gas resource plays throughout North America. Prices for natural gas sold in Canada opened 2011 just above $4.00 per million cubic feet in January and held in that area averaging $3.88 per million cubic feet for the first half of the year. Prices moved slowly lower throughout the second half of the year due to the global economic uncertainty, reduced demand due to moderate weather patterns and a continued increase in supply. Prices averaged $3.48 per million cubic feet in the second half of the year with the year's lowest price realized in December at $3.01 per million cubic feet.

Crew's 2011 financial results were bolstered by increased levels of liquids production added through the drill bit and the Caltex acquisition combined with the strong oil price environment. The Company's revenue increased 88% over 2010 to $388 million and funds from operations increased 75% over 2010 to $172 million or $1.67 per fully diluted share, a 39% increase over 2010. The Company's financial position remains strong with net debt at year end of $323 million or 1.25 times annualized fourth quarter funds from operations borrowed on a bank facility with a total lending capacity of $430 million.

Continued weakness in natural gas pricing resulted in Crew directing its 2011 capital program primarily towards development of its oil plays in the Princess area of Southern Alberta and the newly acquired heavy oil play in the Lloydminster area of west central Saskatchewan. Capital expenditures during the year totaled $350 million net of $25.5 million of non-core asset divestitures. The Company directed 65% of its spending towards continued growth of its top tier oil plays, drilling 120.5 net oil wells and 13 service wells in the Company's oil prone areas. The Company also advanced the development of the infrastructure at Princess spending 18% of total expenditures on the expansion of facilities and gathering systems in the area.

Crew continued to develop its Montney assets in northeast British Columbia in 2011. The primary focus of the Company's efforts was the continued development of liquids rich natural gas development at Septimus. During the year the Company directed 21% of its total exploration and development budget toward Septimus, drilling a total of 11 wells. In addition, Crew successfully drilled its first two Montney development wells at Kobes, British Columbia.

During 2011 the Company continued its program of divesting of non-core properties to help fund development of its core properties. This program resulted in two minor property sales for total proceeds of $25.5 million. These properties had production of approximately 280 boe per day and proven plus probable reserves of 1.0 mmboe as at December 31, 2010.

Acquisition of Caltex

On July 1, 2011, Crew closed an acquisition whereby the Company acquired all of the issued and outstanding shares of Caltex, a Canadian private oil and gas company with operations in Saskatchewan and Alberta (the "Transaction"). Caltex shareholders received 0.38 of a Crew common share for each Caltex share held or an aggregate of approximately 33.6 million Crew shares. Upon closing of the Transaction, Caltex became a wholly owned subsidiary of Crew and immediately following closing, former Caltex shareholders owned approximately 28% of the combined entity. Caltex was amalgamated into Crew effective December 31, 2011.

The business combination has been accounted for using the acquisition method with the results of operations of Caltex included in the Company's financial and operating results commencing July 1, 2011. The allocation of the purchase price was based on estimated fair values as described in note 6 of the consolidated financial statements of the Company for the year ended December 31, 2011.

Production

	Three months ended December 31, 2011					Three months ended December 31, 2010				
	Conv. Oil (bbl/d)	**Heavy Oil (bbl/d)**	**Ngl (bbl/d)**	**Nat. gas (mcf/d)**	**Total (boe/d)**	Conv. Oil (bbl/d)	Heavy Oil (bbl/d)	Ngl (bbl/d)	Nat. gas (mcf/d)	Total (boe/d)
Alberta	**6,634**	**17**	**1,970**	**49,776**	**16,917**	5,172	–	393	23,358	9,458
British Columbia	**150**	**–**	**1,025**	**34,263**	**6,886**	149	–	756	25,746	5,196
Saskatchewan	**–**	**6,128**	**–**	**618**	**6,231**	–	–	–	–	–
Total	**6,784**	**6,145**	**2,995**	**84,657**	**30,034**	5,321	–	1,149	49,104	14,654

The Company's fourth quarter 2011 production increased 105% compared with the same period in 2010. The increase was the result of the acquisition of Caltex on July 1, 2011 which added approximately 10,500 boe per day of production combined with production increases from the Company's successful drilling program in Princess, Alberta and Septimus, British Columbia. Light/medium ("conventional") oil production increased 27% over the fourth quarter of 2010 due to increased production at Princess. Heavy oil production was added due to the acquisition of Caltex. Fourth quarter natural gas and associated liquids production increased in Alberta due to the Caltex acquisition and increased 33% in northeastern British Columbia due to the Company's successful drilling program.

	Year ended December 31, 2011					Year ended December 31, 2010				
	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	**5,614**	**6**	**1,101**	**34,038**	**12,394**	4,043	–	500	24,502	8,627
British Columbia	**123**	**–**	**934**	**34,427**	**6,795**	132	–	735	25,170	5,062
Saskatchewan	**–**	**3,215**	**–**	**291**	**3,263**	–	–	–	–	–
Total	**5,737**	**3,221**	**2,035**	**68,756**	**22,452**	4,175	–	1,235	49,672	13,689

In 2011, Crew's production increased 64% over 2010 due to the acquisition of Caltex in July, 2011 which added heavy oil production in Saskatchewan and liquids rich natural gas in central Alberta. The Company also increased oil production due to the successful drilling program targeting oil in the Pekisko formation at Princess and increased liquids rich natural gas production from the Montney formation at Septimus. These production additions were partially offset by the disposition of approximately 280 boe per day of non-core production in the second and fourth quarters of 2011 in central Alberta.

Revenue

	Three months ended December 31		Year ended December 31	
	2011	2010	**2011**	2010
Revenue *($ thousands)*				
Conventional oil	**53,889**	33,373	**163,427**	102,824
Heavy oil	**43,791**	–	**82,639**	–
Natural gas liquids	**17,676**	5,556	**46,560**	22,863
Natural gas	**26,707**	17,691	**95,540**	80,656
Total	**142,063**	56,620	**388,166**	206,343
Crew average prices				
Conventional oil ($/bbl)	**86.34**	68.17	**78.05**	67.48
Heavy oil ($/bbl)	**77.47**	–	**70.30**	–
Natural gas liquids ($/bbl)	**64.15**	52.57	**62.68**	50.70
Natural gas ($/mcf)	**3.43**	3.92	**3.81**	4.45
Oil equivalent ($/boe)	**51.41**	42.00	**47.37**	41.30
Benchmark pricing				
Conv. and heavy oil – WCS (Cdn $/bbl)	**85.48**	67.86	**77.10**	67.23
Oil and ngl – Cdn$ WTI (Cdn $/bbl)	**96.24**	86.25	**94.02**	81.86
Natural Gas – AECO C daily index (Cdn $/mcf)	**3.25**	3.68	**3.68**	4.06

The Company's fourth quarter revenue increased 151% as compared to the same period in 2010 as a result of the 105% increase in production and a higher weighting to higher valued oil and liquids production. The Company's conventional oil price increase was comparable with the 26% increase in the Western Canadian Select ("WCS") benchmark. During the fourth quarter, the Company's natural gas price decreased 13% over the same period in 2010 which was comparable to the 12% decrease in the AECO C benchmark. The Company's realized ngl price increase was greater than the Company's Cdn$ WTI benchmark price increase due to increased production of higher priced condensate in the Septimus area in 2011 and the addition of higher priced ngl volumes from the Caltex conventional assets in west central Alberta.

Crew's revenue for 2011 increased 88% over the same period in 2010 as a result of the Caltex acquisition, incremental organic production growth and the increase in realized oil and natural gas liquid prices. Crew's realized conventional oil price for the year increased proportionately to the WCS benchmark while the Company's realized natural gas liquids price increased by 24% compared to a 15% increase in the Cdn$ WTI benchmark due to the previously mentioned addition of higher priced natural gas liquids production at Septimus and in west central Alberta. In 2011, the Company's natural gas price decreased 14% compared to a 9% decrease in the benchmark due to the expiration of a $5.85 per gj fixed price physical gas sales contract which increased the Company's realized gas price in 2010. This contract expired in October 2010.

Heavy oil production was added July 1, 2011 as part of the Caltex acquisition. Crew's realized heavy oil pricing was approximately $8.00 below the benchmark WCS pricing which reflects the Company's current quarter cost of diluent used to blend its heavy oil production to pipeline specifications.

Royalties

	Three months ended December 31		Year ended December 31	
($ thousands, except per boe)	**2011**	2010	**2011**	2010
Royalties	**35,055**	11,311	**91,882**	41,799
Per boe	**12.69**	8.39	**11.21**	8.37
Percentage of revenue	**24.7%**	20.0%	**23.7%**	20.3%

Royalties as a percentage of revenue increased in the fourth quarter and for the year ended December 31, 2011 compared to the same periods in 2010 due to the addition of heavy oil and liquids rich natural gas production from the Caltex acquisition which on average attracts a higher royalty rate than the Company's pre-acquisition production. In addition, the Company increased production in the Princess area which also attracts a higher royalty rate than Crew's other producing areas. Crew projects royalty rates to average between 24% and 26% for 2012.

Financial Instruments

Commodities

The Company enters into derivative and physical risk management contracts in order to reduce volatility in financial results, to protect acquisition economics and to ensure a certain level of cash flow to fund planned capital projects. Crew's strategy focuses on the use of puts, costless collars, swaps and fixed price contracts to limit exposure to fluctuations in commodity prices, 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 2011, these contracts had the following impact on the consolidated statement of income:

	Three months ended December 31		Year ended December 31	
($ thousands)	**2011**	2010	**2011**	2010
Realized gain/(loss) on financial instruments	**(9)**	3,284	**2,186**	13,082
Unrealized loss on financial instruments	**(27,199)**	(12,586)	**(10,437)**	(7,380)

As at December 31, 2011, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$98.00	Swap	(549)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$98.15	Swap	(477)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$98.60	Swap	(403)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$95.00 – $106.15	Collar	23
Oil	1,000 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$94.00	Swap	(2,457)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	US$ WTI	US$85.00	Call (1)(2)	(3,306)
Oil	750 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$90.00	Call (1)(2)	(4,053)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	US$ WTI	US$90.00	Call (1)(2)	(2,638)
Oil	250 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$100.45	Swap	(52)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$101.00	Swap	20
Oil	250 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$100.50	Swap	(29)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	USD$ WTI	$85.00 – $93.55	Collar	(1,674)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$85.00 – $93.25	Collar	(1,713)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$85.00 – $94.50	Collar	(1,553)
Oil	1,000 bbl/day	January 1, 2012 – December 31, 2012	USD$ WTI	$85.00 – $95.00	Collar	(3,035)
Oil	1,500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WCS – WTI Diff	$15.50	Swap (3)	587
Oil	1,000 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WCS – WTI Diff	$15.75	Swap	326
Oil	1,000 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WCS – WTI Diff	$17.50	Swap	(384)
US$ / CAD$ exchange	Sell US $1.0 mm per month	January 1, 2012 – December 31, 2012	CDN$/US$	1.047	Swap	192
Total						(21,175)

Notes:

(1) These derivative contracts are part of a paired transaction in which the proceeds from the original sale of 2012 oil calls were used to fund enhanced 2011 natural gas swaps for which the Company realized $9.4 million in 2011.

(2) In 2012, Crew rolled these 2012 calls into 2013 and increased the strike prices as shown in the table below.

(3) In 2012, the Company unwound 500 bbl per day of this derivative commodity contract from March to December 2012 for proceeds of $1.6 million.

Subsequent to December 31, 2011, the Company entered into the following derivative commodity contracts:

Subject of Contract	Volume	Term	Reference	Strike Price (per bbl)	Option Traded
Oil	500 bbl/day	February 1, 2012 – February 29, 2012	CDN$ WTI	$100.15	Swap
Oil	500 bbl/day	February 1, 2012 – February 29, 2012	CDN$ WTI	$100.20	Swap
Oil	1,000 bbl/day	March 1, 2012 – April 30, 2012	CDN$ WTI	$106.30	Swap
Oil	500 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$100.25	Swap
Oil	500 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$100.37	Swap
Oil	500 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$101.25	Swap
Oil	500 bbl/day	January 1, 2013 – December 31, 2013	USD$ WTI	$86.30 (1)	Call
Oil	250 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$92.20 (1)	Call
Oil	500 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$92.80 (1)	Call
Oil	250 bbl/day	January 1, 2013 – December 31, 2013	USD$ WTI	$93.25 (1)	Call
Oil	250 bbl/day	January 1, 2013 – December 31, 2013	USD$ WTI	$93.50 (1)	Call

Notes:

(1) In 2012, Crew entered into these calls by swapping existing 2012 calls into 2013 and increasing the strike prices.

Operating Costs

	Three months ended December 31		Year ended December 31	
($ thousands, except per boe)	**2011**	2010	**2011**	2010
Operating costs	**31,101**	14,009	**91,855**	53,976
Per boe	**11.26**	10.39	**11.21**	10.80

In the fourth quarter of 2011, the Company's operating costs per unit increased over the same period in 2010 due to the higher cost production added as part of the Caltex acquisition and increased higher cost production from the Princess area. This was partially offset by increased production in the Septimus area which has a lower cost per unit than the Company's average operating cost per boe. During the quarter, the Company reduced its fluid handling costs in Princess as regulatory approval for Crew owned injection/disposal wells was received. This cost reduction was partially offset by higher fuel and electricity costs.

For 2011, the Company's operating costs per unit increased as compared to 2010 due to the second quarter 2010 sale of the Edson properties which had a lower cost per boe and the addition of the higher cost Caltex production on July 1, 2011 and Princess production throughout 2011. The Company forecasts operating costs to average $11.00 to $11.50 per boe for 2012.

Transportation Costs

	Three months ended December 31		Year ended December 31	
($ thousands, except per boe)	**2011**	2010	**2011**	2010
Transportation costs including liability write-down	**3,957**	2,819	**13,222**	9,582
Transportation liability write-down	**–**	–	**–**	344
Transportation costs	**3,957**	2,819	**13,222**	9,926
Per boe	**1.43**	2.09	**1.61**	1.99

In the fourth quarter and year ended December 31, 2011, the Company's transportation costs per boe decreased compared to the same periods in 2010 due to additional production at Princess and Septimus combined with production from the acquisition of Caltex which all attract a lower transportation cost per boe compared with the Company's other producing areas. The Company expects transportation costs per boe to range between $1.40 and $1.60 per boe for 2012.

Operating Netbacks

	Three months ended December 31, 2011			Three months ended December 31, 2010		
	Oil and ngl ($/bbl)	**Natural gas ($/mcf)**	**Total ($/boe)**	Oil and ngl ($/bbl)	Natural gas ($/mcf)	Total ($/boe)
Revenue	**78.74**	**3.43**	**51.41**	65.40	3.92	42.00
Realized commodity hedging gain (loss)	**(1.87)**	**0.35**	**–**	(0.31)	0.87	2.42
Royalties	**(21.54)**	**(0.45)**	**(12.69)**	(17.98)	(0.14)	(8.39)
Operating costs	**(13.93)**	**(1.37)**	**(11.26)**	(12.34)	(1.47)	(10.39)
Transportation costs	**(1.11)**	**(0.30)**	**(1.43)**	(1.63)	(0.41)	(2.09)
Operating netbacks	**40.29**	**1.66**	**26.03**	33.14	2.77	23.55

	Year ended December 31, 2011			Year ended December 31, 2010		
	Oil and ngl ($/bbl)	**Natural gas ($/mcf)**	**Total ($/boe)**	Oil and ngl ($/bbl)	Natural gas ($/mcf)	Total ($/boe)
Revenue	**72.93**	**3.81**	**47.37**	63.65	4.45	41.30
Realized commodity hedging gain (loss)	**(1.81)**	**0.38**	**0.27**	0.34	0.71	2.72
Royalties	**(20.48)**	**(0.39)**	**(11.21)**	(17.46)	(0.40)	(8.37)
Operating costs	**(13.83)**	**(1.45)**	**(11.21)**	(12.58)	(1.61)	(10.80)
Transportation costs	**(1.30)**	**(0.32)**	**(1.61)**	(1.45)	(0.37)	(1.99)
Operating netbacks	**35.51**	**2.03**	**23.61**	32.50	2.78	22.86

General and Administrative Costs

	Three months ended December 31,		Year ended December 31,	
($ thousands, except per boe)	**2011**	2010	**2011**	2010
Gross costs	**7,782**	4,697	**22,353**	16,420
Operator's recoveries	**(474)**	(92)	**(844)**	(702)
Capitalized costs	**(2,609)**	(1,714)	**(7,395)**	(5,995)
General and administrative expenses	**4,699**	2,891	**14,114**	9,723
Per boe	**1.70**	2.14	**1.72**	1.95

Increased general and administrative costs after recoveries and capitalization for the fourth quarter and year ended December 31, 2011 were the result of increased staff levels to accommodate the Company's increased production levels and the acquisition of Caltex. The Company's general and administrative costs per boe have decreased in the fourth quarter and for the year ended December 31, 2011 due to the increased production levels over the same periods in 2010. The introduction of IFRS has resulted in the Company altering the recoveries and the capitalization of some general and administrative costs. As such, net general and administrative expenses for the three and twelve months ended December 31, 2010, increased to $2.9 million and $9.7 million from $1.9 million and $6.5 million as reported under previous GAAP. The Company expects general and administrative expenses to average between $1.60 and $1.80 per boe for 2012.

Share-Based Compensation

	Three months ended December 31		Year ended December 31	
($ thousands)	**2011**	2010	**2011**	2010
Gross costs	**3,845**	2,951	**12,772**	10,255
Capitalized costs	**(1,556)**	(1,357)	**(5,747)**	(4,717)
Total share-based compensation	**2,289**	1,594	**7,025**	5,538

In the fourth quarter and year ended December 31, 2011, the Company's share-based compensation expense has increased compared with the same period in 2010 due to an increase in the number of stock options outstanding combined with the Company incurring higher share-based compensation costs in the first year of the option grants due to a graded vesting schedule under IFRS. As a result of the introduction of IFRS, the Company has altered the percentage of share-based compensation expense it capitalizes. As such, the Company capitalized $1.4 million and $4.7 million for the three and twelve month periods ended December 31, 2010 as compared to $1.1 million and $4.5 million as reported under previous GAAP.

Depletion and Depreciation

	Three months ended December 31		Year ended December 31	
($ thousands, except per boe)	**2011**	2010	**2011**	2010
Depletion and depreciation	**59,996**	21,097	**155,789**	79,016
Per boe	**21.71**	15.65	**19.01**	15.81

Depletion and depreciation costs per boe have increased in the fourth quarter and for the year ended December 31, 2011 compared to the same periods in 2010 due to the addition of the fair market value of the Caltex assets at July 1, 2011 which was higher than the Company's pre-acquisition book value per boe for proved plus probable reserves. This was partially offset by successful lower cost reserve additions from the Company's drilling program over the past year. Under IFRS, Crew depletes its assets on a component basis utilizing total proved plus probable reserves including future development capital as opposed to depleting using total proved reserves under previous GAAP.

Impairment loss

At December 31, 2011, 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 rates of between 10% and 12% and the internally estimated fair value of undeveloped lands. It was determined that the net book value of certain CGUs exceeded the recoverable amount and Crew has recognized a $181.9 million (2010 – $29.1 million) impairment charge. When the Company acquired Caltex, the acquired assets were recorded at the fair value on July 1, 2011. Subsequent to July 1, the fair value of the assets has decreased mainly due to reduced forward natural gas pricing. In addition, the current fair value of the Company's natural gas weighted CGUs have decreased due to reduced forward natural gas pricing. 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)	**2011**	2010	**2011**	2010
Interest on bank debt	**2,401**	1,425	**7,176**	5,795
Accretion of the decommissioning obligation	**657**	477	**2,400**	1,965
Acquisition costs	**–**	–	**2,605**	–
Total finance expense	**3,058**	1,902	**12,181**	7,760
Average debt level	**200,233**	120,596	**138,973**	96,538
Effective interest rate on bank debt	**4.8%**	4.7%	**5.2%**	6.0%
Interest on bank debt per boe	**0.87**	1.06	**0.88**	1.16

In the fourth quarter of 2011, interest on bank debt increased 68% over the same period in 2010 as higher average debt levels from the acquisition of Caltex and increased capital spending were partially offset by lower margins on the Company's bank facility. The Company's effective interest rate slightly increased in the fourth quarter of 2011 compared with the same period in 2010 due to increased stand-by fees on the Company's unutilized borrowing facility which were partially offset by lower margins on the Company's bank facility. For 2011, the Company's effective interest rate on bank debt was lower than the same period in 2010 due to lower margins on the Company's bank facility combined with reduced deferred financing costs. The Company projects its effective interest rate on bank debt will average 4.5% to 5.0% in 2012.

The accretion of the decommissioning obligation increased in the fourth quarter and for 2011 compared to the same periods in 2010 due to additional accretion on the Caltex decommissioning obligation which was acquired on July 1, 2011. Acquisition costs are those expenditures incurred by Crew during the year ended December 31, 2011 related to the acquisition of Caltex. Under IFRS, costs such as legal, accounting and regulatory fees associated with the acquisition of a business are expensed in the period in which they are incurred.

Deferred Income Taxes

In the fourth quarter of 2011, the provision for deferred income taxes was a recovery of $51.3 million compared to a $4.4 million recovery for the same period in 2010 due to a higher pre-tax loss in the fourth quarter of 2011. For 2011, the provision for deferred incomes taxes was a recovery of $45.8 million compared to a tax expense of $6.0 million for the same period in 2010 due to a pre-tax loss incurred in 2011 associated with the Company's impairment loss.

A summary of the Company's estimated income tax pools at December 31, 2011 is outlined below:

($ thousands)	**December 31, 2011**	December 31, 2010
Cumulative Canadian Exploration Expense	**140,900**	120,600
Cumulative Canadian Development Expense	**454,600**	223,800
Cumulative Canadian Oil and Gas Property Expense	**106,100**	23,000
Undepreciated Capital Cost	**154,400**	109,700
Share issue costs	**2,500**	1,300
Non-capital loss	**36,800**	31,400
	895,300	509,800

The estimated income tax pools for 2011 have been reduced by the estimated deferred partnership income for 2011. The Company did not pay cash taxes in 2011 and estimates it has sufficient tax pools to shelter estimated income until 2013 or beyond.

Cash and Funds from Operations and Net Income

	Three months ended December 31		Year ended December 31	
($ thousands, except per share amounts)	**2011**	2010	**2011**	2010
Cash provided by operating activities	**39,969**	20,225	**153,429**	93,926
Funds from operations	**64,841**	27,449	**172,103**	98,206
Per share – basic	**0.54**	0.34	**1.69**	1.23
– diluted	**0.54**	0.34	**1.67**	1.20
Net income/(loss)	**(148,529)**	(14,215)	**(130,162)**	17,818
Per share – basic	**(1.24)**	(0.18)	**(1.28)**	0.22
– diluted	**(1.24)**	(0.18)	**(1.28)**	0.22

The fourth quarter and year ended December 31, 2011 increase in cash provided by operating activities and funds from operations was the result of increased oil and ngl pricing combined with higher production levels. The fourth quarter and 2011 loss was a result of an impairment loss of $181.9 million recorded in the fourth quarter of 2011.

Capital Expenditures, Property Acquisitions and Dispositions

During the fourth quarter, the Company drilled a total of 37 (35.0 net) wells resulting in 28 (26.1 net) oil wells, six (5.9 net) natural gas wells, two (2.0 net) service wells and one (1.0 net) dry and abandoned well. In addition, the Company completed 39 (36.9 net) wells and recompleted 14 (13.1 net) wells in the quarter. Infrastructure spending comprised approximately 28% of the Company's capital expenditures during the fourth quarter as the Company added to its infrastructure incurring $30.3 million on pipelines and upgrading its batteries and facilities predominantly in Princess and northeast British

Columbia. During the fourth quarter, the Company closed a disposition of non-core properties in central Alberta for proceeds of $13.2 million.

In 2011, the Company drilled a total of 158 (154.5 net) wells resulting in 123 (120.9 net) oil wells, 20 (18.6 net) gas wells, 13 (13.0 net) service wells and two (2.0 net) dry and abandoned wells. During the year, the Company completed 142 (139.2 net) wells and recompleted 60 (56.7 net) wells. Crew continued to evaluate its undeveloped land base spending $11.8 million shooting seismic primarily in the Princess area. In addition, Crew spent $86.5 million on facility upgrades and pipeline infrastructure primarily in Princess, Lloydminster and northeastern British Columbia. During the year, the Company closed non-core asset dispositions of approximately 280 boe per day of production for proceeds of $25.5 million.

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

	Three months ended December 31		Year ended December 31	
($ thousands)	**2011**	2010	**2011**	2010
Land	**1,191**	1,098	**4,906**	38,835
Seismic	**1,114**	194	**11,792**	5,471
Drilling and completions	**73,341**	47,419	**263,778**	163,992
Facilities, equipment and pipelines	**30,348**	10,605	**86,508**	33,679
Other	**2,860**	1,045	**8,890**	3,649
Total exploration and development	**108,854**	60,361	**375,874**	245,626
Property acquisitions (dispositions)	**(13,203)**	620	**(25,492)**	(132,020)
Total	**95,651**	60,981	**350,382**	113,606

The Company's Board of Directors has approved a $300 million exploration and development budget for 2012.

LIQUIDITY AND CAPITAL RESOURCES

Capital Funding

The Company has a credit facility with its syndicate of lending banks (the "Syndicate") that includes a revolving line of credit of $400 million and an operating line of credit of $30 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 11, 2012. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 percent and all outstanding balances under the Facility will become repayable in one year. The available lending limits of the Facility are reviewed semi-annually and are based on the Syndicate's interpretation of the Company's reserves and future commodity prices. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled borrowing base review on or before June 11, 2012. At December 31, 2011, the Company had drawings of $230.7 million on the Facility and had issued letters of credit totaling $10.2 million.

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

During 2011, the Company received proceeds of $10.3 million upon the exercise of 1,197,800 employee stock options.

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

Working Capital

The capital intensive nature of Crew's activities generally results in the Company carrying a working capital deficit. Working capital deficit includes accounts receivable less accounts payable and accrued liabilities. The Company maintains sufficient unused bank credit lines to satisfy working capital deficits. At December 31, 2011, the Company's working capital deficiency totaled $92.5 million which, when combined with the drawings on its bank line at December 31, 2011, represented approximately 75% of its $430 million bank facility.

Share Capital

As at March 5, 2012, Crew had 120,759,844 Common Shares and options to acquire 7,727,600 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, 2011, the Company's ratio of net debt to annualized funds from operations was 1.25 to 1 (December 31, 2010 – 1.63 to 1).

($ thousands, except ratio)	**December 31, 2011**	December 31, 2010
Working capital deficit	**(92,452)**	(40,707)
Bank loan	**(230,676)**	(138,700)
Net debt	**(323,128)**	(179,407)
Funds from operations	**64,841**	27,449
Annualized	**259,364**	109,796
Net debt to annualized funds from operations ratio	**1.25**	1.63

Contractual Obligations

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

($ thousands)	Total	2012	2013	2014	2015	2016	Thereafter
Bank Loan (1)	230,676	–	230,676	–	–	–	–
Operating leases	12,221	2,508	2,231	2,363	2,494	2,625	–
Capital commitments	1,100	1,100	–	–	–	–	–
Firm transportation agreements	27,284	3,665	3,364	3,980	4,021	3,636	8,618
Firm processing agreement	75,353	9,005	8,031	8,926	8,961	8,783	31,647
Total	346,634	16,278	244,302	15,269	15,476	15,044	40,265

Note

(1) Based on the existing terms of the Company's bank facility the first possible repayment date may come in 2013. However, it is expected that the revolving bank facility will be extended and no repayment will be required in the near term.

The 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.

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

In the fourth quarter of 2010, the Company amended the agreement with the owner of this facility. Under the terms of the amended agreement, Crew constructed a facility expansion during the fourth quarter of 2010 and subsequently closed the sale of the Septimus facility expansion in the first quarter of 2011. Upon completion of the expansion, Crew was reimbursed for the cost of the facility expansion of $19.0 million in return for an expanded processing commitment that will extend to December 2020. As part of the amended agreement, Crew has also retained the option to re-purchase a 50% interest in the facility at certain dates prior to January 1, 2014, at a cost of 50% of the total expanded facility's construction cost. If the Company re-purchases a 50% interest on January 1, 2014 for approximately $20 million, the remaining commitment would be reduced by approximately $27 million.

GUIDANCE

For 2012, the Company has a $300 million capital expenditure budget approved by the Board of Directors. It is designed to approximate funds from operations and will concentrate on oil and liquids production at Princess, Lloydminster and Tower in order to capitalize on strong oil prices. The 2012 capital program will also advance seven of our secondary oil recovery schemes and will continue to advance and de-risk oil/liquids plays in British Columbia and the Deep Basin of Alberta. The $300 million capital program will be funded mainly by funds from operations and bank debt with priority given to maintaining our strong balance sheet.

Our 2012 budget and guidance is a best estimate based on certain assumptions including operating results and commodity prices and will be regularly monitored by management. Our priority is to proactively manage our capital program as it relates to operational success and fluctuating commodity prices with a goal to maintain financial flexibility and achieve our production guidance between 32,500 and 33,500 boe per day.

ADDITIONAL DISCLOSURES

Quarterly Analysis

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

($ thousands, except per share amounts)	**Dec. 31 2011**	Sept. 30 2011	June 30 2011	Mar. 31 2011	Dec. 31 2010	Sept. 30 2010	June 30 2010	Mar. 31 2010
Total daily production (boe/d)	**30,034**	27,510	16,443	15,607	14,654	13,061	12,048	15,001
Average wellhead price ($/boe)	**51.41**	45.33	46.94	43.53	42.00	37.39	39.25	45.75
Petroleum and natural gas sales	**142,063**	114,719	70,236	61,148	56,620	44,924	43,027	61,772
Cash provided by operations	**39,969**	54,095	32,896	26,469	20,225	18,956	23,422	31,323
Funds from operations	**64,841**	54,260	28,891	24,111	27,449	23,464	19,966	27,327
Per share – basic	**0.54**	0.45	0.34	0.29	0.34	0.29	0.25	0.35
– diluted	**0.54**	0.45	0.33	0.29	0.34	0.29	0.24	0.34
Net income (loss)	**(148,529)**	12,232	16,261	(10,126)	(14,214)	(17,281)	31,544	17,770
Per share – basic	**(1.24)**	0.10	0.19	(0.12)	(0.18)	(0.22)	0.39	0.23
– diluted	**(1.24)**	0.10	0.19	(0.12)	(0.18)	(0.22)	0.39	0.22

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

- Revenue is directly impacted by the Company's ability to replace existing declining production and add incremental production through its on-going capital expenditure program.
- Over the past few years, the price of natural gas has been negatively impacted by an increasing supply of natural gas coming from new technology tapping into abundant supplies of tight shale gas reservoirs in North America. With depressed natural gas prices, Crew has focused its capital expenditures towards oil development with higher netbacks.

This has resulted in the commodity mix moving towards more oil and the Company's overall netbacks improving increasing revenues and funds from operations.

- Production in the second quarters of 2010 and 2011 was negatively impacted by scheduled and unscheduled third party facility shutdowns and poor weather experienced in southern Alberta during the second quarters of 2010 and 2011 and third quarter of 2010.
- Revenue and royalties are significantly impacted by underlying commodity prices. The Company utilizes derivative contracts and forward sales contracts to reduce the exposure to commodity price fluctuations. These contracts can cause volatility in net income as a result of unrealized gains and losses on commodity derivative contracts held for risk management purposes.
- During 2010 and 2011, the Company sold assets with approximately 1,980 boe per day of production for $149.1 million. The major dispositions closed as follows:
  - Second quarter 2010 – 1,700 boe per day for $123.3 million
  - Second quarter 2011 – 140 boe per day for $12.3 million
  - Fourth quarter 2011 – 140 boe per day for $13.2 million
- These dispositions of assets in the Ferrier, Edson and Provost areas resulted in gains on sale of assets of $37.0 million, $4.7 million and $7.4 million in the second quarter of 2010 and the second and fourth quarters of 2011, respectively.
- The Company acquired Caltex Energy on July 1, 2011 adding approximately 10,500 boe per day of production and the results of operations of Caltex are included in the Company's financial and operating results commencing July 1, 2011.
- The Company incurred an impairment charge of $181.9 million on certain CGUs in the fourth quarter of 2011 and incurred impairment charges of $18.7 million and $10.4 million on two of its natural gas weighted CGUs in the third and fourth quarters of 2010, respectively.

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

($ thousands, except per share amounts)	**Year ended Dec. 31, 2011**	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009
Petroleum and natural gas sales	**388,166**	206,343	181,829
Cash provided by operations	**153,429**	93,926	82,660
Funds from operations	**172,103**	98,206	83,453
Per share – basic	**1.69**	1.23	1.11
– diluted	**1.67**	1.20	1.11
Net income (loss)	**(130,162)**	17,818	(37,815)
Per share – basic	**(1.28)**	0.22	(0.50)
– diluted	**(1.28)**	0.22	(0.50)
Daily production (boe/d)	**22,452**	13,689	14,002
Crew average sales price ($/boe)	**47.37**	41.30	35.58
Total assets	**1,842,719**	1,045,941	963,248
Working capital deficiency (1)	**92,452**	40,707	46,654
Bank loan	**230,676**	138,700	135,601
Total other long-term liabilities	**289,117**	157,307	136,992

Notes:

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

(2) The 2010 comparatives have been adjusted to conform to IFRS whereas the 2009 results have not been adjusted and reflect the results in accordance with previous GAAP.

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 2009 to 2011 as a result of volatile oil and natural gas prices combined with the increased cost of the Company's operations. The Company disposed of assets with production of 1,700 boe per day for $123.3 million in 2010. In 2011, the Company acquired Caltex which added 10,500 boe per day of production. In 2011, the Company also incurred impairment charges on its natural gas weighted CGUs of $181.9 million.

New Accounting Pronouncements

International Financial Reporting Standards

Effective January 1, 2011, Canadian public companies adopted International Financial Reporting Standards ("IFRS") which will include comparatives for 2010. Note 20 to the consolidated financial statements provides reconciliations between the Company's 2010 previous GAAP results and its 2010 results under IFRS. The reconciliations include the consolidated statement of financial position as at December 31, 2010, and consolidated statements of income and comprehensive income for the year ended December 31, 2010.

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

Summary Statement of Financial Position Reconciliations

As at Date of IFRS Transition – January 1, 2010

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

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

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

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

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

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

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

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

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

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

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

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

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

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

- Impairment testing – estimates of reserves, future commodity prices, future costs, production profiles, discount rates, market value of land.

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

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

Summary Statement of Financial Position Reconciliations
As at December 31, 2010

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

(1) The PP&E adjustment includes the impact of the reclassification of E&E assets ($72.3 million decrease in PP&E), lower depletion as a result of using proved plus probable reserves to calculate depletion ($31.6 million increase in PP&E), gains on sale of assets and gains on farmout of assets ($48.2 million increase in PP&E), impairment on the Company's gas focused CGUs ($29.1 million decrease in PP&E), reduction of capitalized G&A, capital recoveries and associated deferred tax impact ($2.8 million decrease in PP&E).

(2) Includes the adjustment to revalue the liability to a risk free interest rate of 3.50% at December 31, 2010 and the related deferred tax impact.

(3) Includes recalculation of stock based compensation incorporating graded vesting and a forfeiture multiplier.

Summary Net Earnings Reconciliations

($ thousands)	Annual	Q4	Q3	Q2	Q1
Net earnings/(loss) – previous GAAP	(17,161)	(9,525)	(7,387)	(2,691)	2,442
Addition/(deduction):					
General and administrative	(3,244)	(987)	(640)	(727)	(890)
Share-based compensation	(1,021)	(501)	(322)	(178)	(20)
Depletion and depreciation	31,559	6,002	6,739	7,489	11,329
Decommissioning obligation accretion	674	160	161	175	178
Gain on divestitures and farmouts	48,242	–	–	38,360	9,882
Property, plant and equipment impairment	(29,072)	(10,336)	(18,736)	–	–
Deferred income tax	(12,159)	973	2,904	(10,884)	(5,152)
	34,979	(4,689)	(9,894)	34,235	15,327
Net earnings/(loss) - IFRS	17,818	(14,214)	(17,281)	31,544	17,769

Impact of Transition to IFRS on 2010 Results:

- Exploration and Evaluation ("E&E") – In 2010, Crew incurred $37.2 million of E&E expenditures acquiring undeveloped land and evaluating its undeveloped land with seismic acquisitions. This amount was reclassified from PP&E, under previous GAAP, to E&E under IFRS.
- Divestitures and farmouts – Under previous GAAP, proceeds from divestitures were deducted from the full cost pool without recognition of a gain or loss unless the divestiture resulted in a change in the depletion rate of 20% or greater in which case a gain or loss was recorded. Under IFRS, gains and losses are recorded on divestitures and farmouts and are calculated as the difference between the proceeds and the net book value of the asset disposed of. For the year ended December 31, 2010, the Company recorded a $46.9 million gain on disposition of oil and gas properties and an additional $1.3 million gain on farmouts for IFRS as compared to nil under previous GAAP.
- Impairment of PP&E – Under IFRS, impairment tests of PP&E are performed at a CGU level as opposed to the entire Company's PP&E balance with a full cost ceiling test under previous GAAP. Impairment is recognized if the carrying value exceeds the recoverable amount for a CGU. The recoverable amount is determined using fair value less costs to sell based on discounted future cash flows of proved plus probable reserves using forecast prices and costs. In the third quarter of 2010, as a result of decreased natural gas prices and a subsequent decrease in the Company's future natural gas prices used in the Company's reserves, Crew incurred an $18.7 million impairment charge in certain CGUs. Further deterioration in future natural gas pricing in the fourth quarter of 2010 resulted in the Company incurring an additional $10.4 million impairment charge on the same natural gas weighted CGUs. PP&E impairments can be reversed in the future if the recoverable amount increases.
- Depletion and depreciation expense – Under IFRS, Crew has chosen to calculate the depletion expense utilizing proved plus probable reserves as opposed to proved reserves under previous GAAP. This has resulted in a reduction of depletion and depreciation expense of approximately $31.6 million in 2010.

Future Accounting Changes

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

(a) IFRS-9 Financial Instruments:

As of January 1, 2013, the Company will be required to adopt IFRS-9 Financial Instruments, which is the result of the first phase of the IASB project to replace IAS-39 Financial Instruments: Recognition and Measurement. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has two classification categories: amortized cost and fair value. Portions of the standard remain in development and the full impact of the standard on the Company's financial statements will not be known until the project is complete.

(b) In May, 2011, the IASB released the following new standards which are effective for fiscal years beginning January 1, 2013 with earlier adoption permitted.

(i) IFRS-10 Consolidated Financial Statements, 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 currently assessing the expected impact, if any, 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, 2011 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, 2011 and ended on December 31, 2011 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting. There were no changes to internal controls over financial reporting as a result of the transition to IFRS or the acquisition of Caltex.

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 5, 2012

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 and included such test 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 5, 2012

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, 2011, December 31, 2010 and January 1, 2010, the consolidated statements of income (loss) and comprehensive income (loss), changes in shareholders' equity and cash flows for the years ended December 31, 2011 and December 31, 2010, 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 as at December 31, 2011, December 31, 2010 and January 1, 2010, and its consolidated financial performance and its consolidated cash flows for the years ended December 31, 2011 and December 31, 2010 in accordance with International Financial Reporting Standards.

(signed)

KPMG LLP
Chartered Accountants

Calgary, Canada
March 5, 2012

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(thousands)	December 31, 2011	December 31, 2010	January 1, 2010
		(note 20)	(note 20)
ASSETS			
Current Assets:			
Accounts receivable	**$ 79,117**	$ 44,922	$ 37,574
Fair value of financial instruments (note 14)	**–**	982	–
Assets held for sale	**–**	15,116	–
	79,117	61,020	37,574
Exploration and evaluation assets (note 7)	**56,197**	72,281	35,591
Property, plant and equipment (note 8)	**1,707,405**	912,640	889,541
	$ 1,842,719	$ 1,045,941	$ 962,706
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities:			
Accounts payable and accrued liabilities	**$ 171,569**	$ 100,745	$ 84,228
Fair value of financial instruments (note 14)	**21,175**	–	834
Current portion of other long-term obligations (note 10)	**–**	343	1,313
	192,744	101,088	86,375
Fair value of financial instruments (note 14)	**–**	9,196	–
Bank loan (note 11)	**230,676**	138,700	135,601
Other long-term obligations (note 10)	**–**	–	132
Decommissioning obligations (note 12)	**104,836**	54,828	53,063
Deferred tax liability (note 15)	**184,281**	102,479	96,488
Shareholders' Equity:			
Share capital (note 13)	**1,261,884**	649,768	620,988
Contributed surplus	**36,089**	27,511	25,506
Deficit	**(167,791)**	(37,629)	(55,447)
	1,130,182	639,650	591,047
Commitments (note 18)			
Subsequent event (note 14)			
	$ 1,842,719	$ 1,045,941	$ 962,706

See accompanying notes to the consolidated financial statements.

(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, 2011**	Year ended December 31, 2010
		(note 20)
Revenue		
Petroleum and natural gas sales	**$ 388,166**	$ 206,343
Royalties	**(91,882)**	(41,799)
Realized gain on financial instruments (note 14)	**2,186**	13,082
Unrealized loss on financial instruments (note 14)	**(10,437)**	(7,380)
	288,033	170,246
Expenses		
Operating	**91,855**	53,976
Transportation (note 10)	**13,222**	9,582
General and administrative	**14,114**	9,723
Share-based compensation	**7,025**	5,538
Depletion and depreciation	**155,789**	79,016
	282,005	157,835
Income from operations	**6,028**	12,411
Financing (note 17)	**(12,181)**	(7,760)
Gain on divestitures (note 8)	**12,115**	48,242
Impairment of property, plant and equipment (note 9)	**(181,941)**	(29,072)
Income (loss) before income taxes	**(175,979)**	23,821
Deferred tax expense (recovery) (note 15)	**(45,817)**	6,003
Net income (loss) and comprehensive income (loss)	**$ (130,162)**	$ 17,818
Net income (loss) per share (note 13)		
Basic	**$ (1.28)**	$ 0.22
Diluted	**$ (1.28)**	$ 0.22

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, 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**

	Number of shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance January 1, 2010	78,152	$ 620,988	$ 25,506	$ (55,447)	$ 591,047
Net income	–	–	–	17,818	17,818
Share issue costs, net of tax of $12	–	(36)	–	–	(36)
Share-based compensation expensed	–	–	5,538	–	5,538
Share-based compensation capitalized	–	–	4,717	–	4,717
Transfer of share-based compensation on exercises	–	8,250	(8,250)	–	–
Issued on exercise of options	2,216	20,566	–	–	20,566
Balance December 31, 2010	80,368	$ 649,768	$ 27,511	$ (37,629)	$ 639,650

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands)	Year ended December 31, 2011	Year ended December 31, 2010
		(note 20)
Cash provided by (used in):		
Operating activities:		
Net income (loss)	**$ (130,162)**	$ 17,818
Adjustments:		
Depletion and depreciation	**155,789**	79,016
Financing expenses (note 17)	**12,181**	7,760
Interest expense (note 17)	**(7,176)**	(5,795)
Acquisition costs (note 17)	**(2,605)**	–
Share-based compensation	**7,025**	5,538
Deferred tax expense (recovery)	**(45,817)**	6,003
Unrealized loss on financial instruments	**10,437**	7,380
Gain on divestitures	**(12,115)**	(48,242)
Impairment of property, plant and equipment	**181,941**	29,072
Transportation liability charge (note 10)	**(343)**	(1,102)
Decommissioning obligations settled	**(1,144)**	(1,512)
Change in non-cash working capital (note 16)	**(14,582)**	(2,010)
	153,429	93,926
Financing activities:		
Increase in bank loan	**40,738**	3,099
Issue of common shares	**100,015**	–
Proceeds from exercise of options	**10,273**	20,566
Share issue costs	**(5,730)**	(48)
	145,296	23,617
Investing activities:		
Exploration and evaluation asset expenditures	**(9,864)**	(37,234)
Property, plant and equipment expenditures	**(366,010)**	(208,392)
Property divestitures	**25,492**	132,020
Asset held for sale	**15,116**	(15,116)
Change in non-cash working capital (note 16)	**36,541**	11,179
	(298,725)	(117,543)
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, 2011 and 2010

(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 to the financial statements. These policies have been retrospectively and consistently applied except where specific exemptions permitted an alternative treatment on transition to IFRS in accordance with IFRS 1 – First-time adoption of International Financial Reporting Standards ("IFRS-1"). An explanation of how the transition to IFRS has affected the reported financial position, financial performance and cash flows of the Company is provided in note 20 and includes reconciliations of equity and net loss for comparative periods from former Canadian GAAP ("previous GAAP") to IFRS.

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 5, 2012.

3. SIGNIFICANT ACCOUNTING POLICIES:

The accounting policies set out below have been applied consistently to all years presented in these financial statements, except where specific exemptions permitted an alternative treatment on transition to IFRS in accordance with IFRS-1, and have been applied consistently by the Company and its subsidiaries.

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 commodity contracts to be economic hedges. As a result, all financial derivative contracts are classified as fair value through profit or loss and are recorded on the 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 licences 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. The Company allocated its historical property, plant and equipment cost at January 1, 2010, the date of IFRS transition, to the CGUs, based on a pro ration using December 31, 2009 externally determined reserve values underlying each of the CGUs. When significant parts of an item of property, plant and equipment, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (major components).

Gains and losses on disposal of 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 in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The

carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred.

(iii) Depletion and depreciation:

The net carrying value of development or production assets is depleted using the unit of production method by reference to the ratio of production in the year to the related proven and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. 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 finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

(i) Revenue:

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

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

(j) Finance income and expenses:

Finance expense comprises interest expense on borrowings, accretion of the discount on provisions, 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, apart from those involving estimations (see below), 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 interim condensed financial statements:

(i) Reserves

Estimation of reported recoverable quantities of proved and probable reserves include judgmental assumptions 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) 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.

(iii) 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.

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) 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 judgment 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.

(ii) Impairment of petroleum and natural gas assets

For the purposes of determining whether impairment of petroleum and natural gas assets has occurred, and the extent of any impairment or its reversal, the key assumptions the Company uses in estimating future cash flows are future petroleum and natural gas prices, expected production volumes and anticipated recoverable quantities of proved and probable reserves. These assumptions are subject to change as new information becomes available. Changes in economic conditions can also affect the rate used to discount future cash flow estimates. Changes in the aforementioned assumptions could affect the carrying amounts of assets, and impairment charges and reversal will affect profit or loss.

(iii) 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 and a judgment as to whether or not there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. To the extent 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.

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, 2013, the Company will be required to adopt IFRS-9 Financial Instruments, which is the result of the first phase of the IASB project to replace IAS-39 Financial Instruments: Recognition and Measurement. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has two classification categories: amortized cost and fair value. Portions of the standard remain in development and the full impact of the standard on the Company's financial statements will not be known until the project is complete.

(b) In May, 2011, the IASB released the following new standards which are effective for fiscal years beginning January 1, 2013 with earlier adoption permitted.

(i) IFRS-10 Consolidated Financial Statements, 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 currently assessing the expected impact, if any, 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, 2011 and December 31, 2010, the fair value of these balances approximated their carrying value due to their short term to maturity. Bank loans bear a floating rate of interest and therefore carrying value approximates fair value.

(iii) Derivatives:

The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and published forward price curves as at the 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 adjusted for changes expected due to publicly available information), weighted average expected life of the instruments (based on historical experience and general option holder behaviour), expected dividends, and the risk-free interest rate (based on government bonds).

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 and are expected to be collected and paid.

Included in the consolidated statements of income (loss) and comprehensive income (loss) are the following amounts:

Caltex Energy amounts since acquisition	
Petroleum and natural gas revenue	$ 113,001
Loss and comprehensive loss	(90,705)

If Caltex Energy had been acquired on January 1, 2011, the incremental petroleum and natural gas revenue and income recognized for the period ended December 31, 2011 and the pro forma results would have been as follows:

Year ended December 31, 2011	As stated	Caltex Energy prior to acquisition	Pro Forma
Petroleum and natural gas revenue	$ 388,166	$ 108,150	$ 496,316
Loss and comprehensive loss	(130,162)	8,396	(121,766)

7. EXPLORATION AND EVALUATION ASSETS:

Cost or deemed cost	Total
Balance, January 1, 2010	$ 35,591
Additions	37,234
Transfer to property, plant and equipment	(544)
Balance, December 31, 2010	$ 72,281
Additions	9,864
Transfer to property, plant and equipment	(25,948)
Balance, December 31, 2011	**$ 56,197**

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

8. PROPERTY, PLANT AND EQUIPMENT:

Cost or deemed cost	Total
Balance, January 1, 2010	$ 889,541
Additions	223,508
Transfer from exploration and evaluation assets	544
Divestitures	(91,453)
Asset held for sale	(15,116)
Change in decommissioning obligations	6,524
Capitalized share-based compensation	4,717
Balance, December 31, 2010	$ 1,018,265
Additions	366,010
Transfer from exploration and evaluation assets	25,948
Divestitures	(17,921)
Corporate acquisition (note 6)	730,302
Change in decommissioning obligations	20,363
Capitalized share-based compensation	5,747
Balance, December 31, 2011	**$ 2,148,714**

Accumulated depletion and depreciation	Total
Balance, January 1, 2010	$ –
Depletion and depreciation expense	79,016
Divestitures	(2,463)
Impairment	29,072
Balance, December 31, 2010	$ 105,625
Depletion and depreciation expense	155,789
Divestitures	(2,046)
Impairment	181,941
Balance, December 31, 2011	**$ 441,309**

Net book value	Total
Balance, January 1, 2010	$ 889,541
Balance, December 31, 2010	$ 912,640
Balance, December 31, 2011	**$ 1,707,405**

The calculation of depletion for the three months ended December 31, 2011 included estimated future development costs of $681.4 million (December 31, 2010 - $297.4 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $87.0 million (December 31, 2010 - $51.1 million) and undeveloped land of $154.6 million (December 31, 2010 - $110.6 million) related to development acreage.

During 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.

In 2010, the Company disposed of oil and gas assets in the Edson area for proceeds of $132.0 million. The assets had a net book value of $89.0 million and associated decommissioning liabilities of $5.2 million.

9. IMPAIRMENT LOSS:

At December 31, 2011, due to declining forward natural gas prices, reserve revisions and adjustments to future costs, the Company tested certain natural gas and oil CGUs for impairment. 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% to 12% and the internally estimated fair value of undeveloped lands. 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.

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.

A one per cent increase in the assumed discount rate would result in an additional impairment of $48.9 million while a ten percent decrease to the forward commodity price estimate would result in an additional impairment of $179.9 million.

During the year ended December 31, 2010, due to declining forward natural gas prices, the Company tested certain natural gas CGUs for impairment. The recoverable amounts of the Company's CGUs were estimated as the fair value less cost 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% and the internally estimated fair value of undeveloped lands. 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.

The following estimates were used in determining whether an impairment to the carrying value of the CGUs existed at December 31, 2010:

	WTI Oil (US$/bbl)	WCS ($Cdn/bbl)	AECO Gas ($Cdn/mmbtu)	$Cdn/$US
2011	88.00	74.98	4.16	0.98
2012	89.00	74.95	4.74	0.98
2013	90.00	74.13	5.31	0.98
2014	92.00	75.23	5.77	0.98
2015	95.17	77.84	6.22	0.98
2016	97.55	79.79	6.53	0.98
2017	100.26	82.02	6.76	0.98
2018	102.74	84.05	6.90	0.98
2019	105.45	86.28	7.06	0.98
2020	107.56	88.01	7.21	0.98
Remainder	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.98 thereafter

During 2010, the Company recognized a $29.1 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 charge for the year ended December 31, 2011 was $0.3 million (2010 - $1.1 million).

11. BANK LOAN:

The Company's bank facility as at December 31, 2011 consisted of a revolving line of credit of $400 million and an operating line of credit of $30 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by June 11, 2012. If not extended, the Facility will cease to revolve, the margins thereunder will increase by 0.50 per cent and all outstanding advances thereunder will become repayable in one year. The available lending limits of the Facility are reviewed semi-annually and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. There can be no assurance that the amount of the available Facility will not be adjusted at the next scheduled borrowing base review on or before June 11, 2012.

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

As at December 31, 2011, the Company's applicable pricing included a 1.25 percent margin on prime lending and a 2.25 percent stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.563 percent per annum standby fee on the portion of the facility that is not drawn. Borrowing margins and fees are reviewed annually as part of the bank syndicate's annual renewal. At December 31, 2011, the Company had issued letters of credit totaling $10.2 million (December 31, 2010 - $1.1 million). The effective interest rate on the Company's borrowings under its bank facility for the year ended December 31, 2011 was 5.2% (2010 - 6.0%).

12. DECOMMISSIONING OBLIGATIONS:

	As at December 31, 2011	As at December 31, 2010
Decommissioning obligations, beginning of year	**$ 54,828**	$ 53,063
Obligations incurred	**7,781**	3,383
Obligations settled	**(1,144)**	(1,512)
Obligations divested	**(2,498)**	(5,212)
Obligations acquired (note 6)	**30,887**	–
Change in estimated future cash outflows	**12,582**	3,141
Accretion of decommissioning obligations	**2,400**	1,965
Decommissioning obligations, end of year	**$ 104,836**	$ 54,828

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 $104.8 million as at December 31, 2011 (December 31, 2010 - $54.8 million) based on an undiscounted total future liability of $107.2 million (December 31, 2010 - $63.4 million). These payments are expected to be made over the next 25 years with the majority of costs to be incurred between 2012 and 2036. The discount factor, being the risk-free rate related to the liability, is 2.40% (December 31, 2010 – 3.50%).

13. SHARE CAPITAL:

At December 31, 2011, the Company was authorized to issue an unlimited number of common shares with the holders of common shares entitled to one vote per share.

Share based payments:

The Company has 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, 2010	5,751	$ 8.33
Granted	2,237	$ 15.18
Exercised	(2,216)	$ 9.28
Forfeited	(442)	$ 8.50
Balance December 31, 2010	5,330	$ 10.79
Granted	5,178	$ 15.03
Exercised	(1,199)	$ 8.58
Forfeited	(1,085)	$ 17.27
Balance at December 31, 2011	**8,224**	**$ 12.93**

The weighted average trading price of the Company's common shares was $14.55 during the year ended December 31, 2011 (December 31, 2010 - $16.83).

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

Range of exercise prices	Outstanding at December 31, 2011	Weighted average remaining life (years)	Weighted average exercise price	Exercisable at December 31, 2011	Weighted average exercise price
$ 3.43 to $ 7.01	989	1.0	$ 5.15	574	$ 5.18
$ 7.02 to $ 9.94	672	0.1	$ 7.53	658	$ 7.49
$ 9.95 to $14.63	1,749	3.5	$ 11.17	159	$ 12.84
$14.64 to $19.40	4,814	2.8	$ 15.92	732	$ 15.36
	8,224	2.5	$ 12.93	2,123	$ 9.98

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

Assumptions	**Year ended December 31, 2011**	Year ended, December 31, 2010
Risk free interest rate (%)	**2.0**	2.3
Expected life (years)	**4.0**	4.0
Expected volatility (%)	**58**	61
Forfeiture rate (%)	**16.4**	17.3
Weighted average fair value of options	**$ 7.11**	$ 7.32

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, 2011 was 102,034,000 (2010 – 79,747,000).

In computing diluted earnings per share for the year ended December 31, 2011, no (2010 – 1,953,000) shares were added to the weighted average Common Shares outstanding to account for the dilution of stock options. There were 8,224,000 (2010 – 5,330,000) 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, 2011	December 31, 2010
Trade and other receivables	**$ 79,117**	$ 44,922
Derivatives	–	982
	$ 79,117	$ 45,904

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 2011, two third party purchasers marketed at least 10% 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, 2011 the Company's receivables consisted of $50.8 (2010 - $22.5) million of receivables from petroleum and natural gas marketers which has subsequently been collected, $15.4 (2010 - $6.7) million from joint venture partners of which $4.6 million has been subsequently collected, and $12.9 (2010 - $15.7) 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 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. 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, 2011 was $138.9 million (2010 $96.5 million). For the year ended December 31, 2011, a 1.0 percent change to the effective interest rate would have a $1.0 million impact on net income (2010 - $1.1 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 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 production volumes for a period of not more than two years. Any contracts 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.

At December 31, 2011, the Company held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value ($000s)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$98.00	Swap	(549)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$98.15	Swap	(477)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$98.60	Swap	(403)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$95.00 - $106.15	Collar	23
Oil	1,000 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$94.00	Swap	(2,457)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	US$ WTI	US$85.00	Call (1)(2)	(3,306)
Oil	750 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$90.00	Call (1)(2)	(4,053)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	US$ WTI	US$90.00	Call (1)(2)	(2,638)
Oil	250 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$100.45	Swap	(52)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$101.00	Swap	20
Oil	250 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$100.50	Swap	(29)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	USD$ WTI	$85.00 - $93.55	Collar	(1,674)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$85.00 - $93.25	Collar	(1,713)
Oil	500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WTI	$85.00 - $94.50	Collar	(1,553)
Oil	1,000 bbl/day	January 1, 2012 – December 31, 2012	USD$ WTI	$85.00 - $95.00	Collar	(3,035)
Oil	1,500 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WCS – WTI Diff	$15.50	Swap (3)	587
Oil	1,000 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WCS – WTI Diff	$15.75	Swap	326
Oil	1,000 bbl/day	January 1, 2012 – December 31, 2012	CDN$ WCS – WTI Diff	$17.50	Swap	(384)
US$ / CAD$ exchange	Sell US $1.0 mm per month	January 1, 2012 – December 31, 2012	CDN$/US$	1.047	Swap	192
Total						(21,175)

(1) These derivative contracts are part of a paired transaction in which the proceeds from the sale of 2012 oil calls were used to fund 2011 natural gas swaps for which the Company realized $9.4 million in 2011.

(2) In 2012, Crew rolled these 2012 calls into 2013 and increased the strike prices.

(3) In 2012, the Company unwound 500 bbl per day of this derivative commodity contract from March to December 2012 for proceeds of $1.6 million.

As at December 31, 2011, a 10% decrease to the price outlined in the contracts above would result in a $5.7 million increase in net income.

Subsequent to December 31, 2011, the Company entered into the following derivative commodity contracts:

Subject of Contract	Volume	Term	Reference	Strike Price (per bbl)	Option Traded
Oil	500 bbl/day	February 1, 2012 – February 29, 2012	CDN$ WTI	$100.15	Swap
Oil	500 bbl/day	February 1, 2012 – February 29, 2012	CDN$ WTI	$100.20	Swap
Oil	1,000 bbl/day	March 1, 2012 – April 30, 2012	CDN$ WTI	$106.30	Swap
Oil	500 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$100.25	Swap
Oil	500 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$100.37	Swap
Oil	500 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$101.25	Swap
Oil	500 bbl/day	January 1, 2013 – December 31, 2013	USD$ WTI	$86.30 (1)	Call
Oil	250 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$92.20 (1)	Call
Oil	500 bbl/day	January 1, 2013 – December 31, 2013	CDN$ WTI	$92.80 (1)	Call
Oil	250 bbl/day	January 1, 2013 – December 31, 2013	USD$ WTI	$93.25 (1)	Call
Oil	250 bbl/day	January 1, 2013 – December 31, 2013	USD$ WTI	$93.50 (1)	Call

(1) Crew funded these 2013 contracts by closing out of 2012 calls.

(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 2013. 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, 2011, the Company's ratio of net debt to annualized funds from operations was 1.25 to 1 (December 31, 2010 – 1.63 to 1).

	December 31, 2011	December 31, 2010
Net debt:		
Accounts receivable (including assets held for sale)	**$ 79,117**	$ 60,038
Accounts payable and accrued liabilities	**(171,569)**	(100,745)
Working capital deficiency	**$ (92,452)**	$ (40,707)
Bank loan	**(230,676)**	(138,700)
Net debt	**$ (323,128)**	$ (179,407)
Fourth Quarter Annualized funds from operations:		
Cash provided by operating activities	**$ 39,969**	$ 20,225
Decommissioning obligations settled	**483**	606
Transportation liability charge	**35**	120
Change in non-cash working capital	**24,354**	6,498
Fourth Quarter Funds from operations	**64,841**	27,449
Annualized	**$ 259,364**	$ 109,796
Net debt to annualized funds from operations	**1.25**	1.63

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

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, 2011	Year ended Dec. 31, 2010
Income (loss) before income taxes	**$ (175,979)**	$ 23,821
Combined federal and provincial income tax rate	**26.7%**	28.1%
Computed "expected" income tax reduction	**$ (46,986)**	$ 6,694
Increase (decrease) in income taxes resulting from:		
Non-deductible share-based compensation	**1,889**	1,446
Benefits relating to change in income tax rates	**(634)**	(2,038)
Other	**(86)**	(99)
Deferred income tax (recovery) expense	**$ (45,817)**	$ 6,003

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, 2011	December 31, 2010
Deferred tax liabilities:		
Property, plant and equipment	**$ 185,697**	$ 105,824
Partnership deferral	**41,361**	22,161
Deferred tax assets:		
Decommissioning obligations	**$ (26,429)**	$ (13,784)
Fair value of financial instruments	**(5,338)**	(2,068)
Non-capital losses	**(9,277)**	(8,156)
Other	**(1,733)**	(1,498)
Deferred income tax liability	**$ 184,281**	$ 102,479

The Company's assets have an approximate tax basis of $895.3 million at December 31, 2011 (December 31, 2010 - $509.8 million) available for deduction against future taxable income. The non-capital loss carryforwards of $36.8 million (December 31, 2010 - $31.5 million) expire between 2027 and 2029. The following table summarizes the tax pools:

	December 31, 2011	December 31, 2010
Cumulative Canadian Exploration Expense	**$ 140,900**	$ 120,600
Cumulative Canadian Development Expense	**454,600**	223,800
Cumulative Canadian Oil and Gas Property Expense	**106,100**	23,000
Undepreciated Capital Costs	**154,400**	109,700
Share issue costs	**2,500**	1,300
Non-capital losses	**36,800**	31,400
Estimated tax basis	**$ 895,300**	$ 509,800

The estimated income tax pools for 2011 have been reduced by the estimated deferred partnership income for 2011.

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

	January 1, 2010	Recognized in profit or loss	Acquired in business combination	Recognized in equity	December 31, 2010
Property, plant and equipment	$ 106,846	$ (1,022)	$ –	$ –	$ 105,824
Partnership deferral	14,436	7,725	–	–	22,161
Decommissioning obligations	(13,442)	(342)	–	–	(13,784)
Fair value of financial instruments	(213)	(1,855)	–	–	(2,068)
Non-capital losses	(8,287)	131	–	–	(8,156)
Other	(2,852)	1,366	–	(12)	(1,498)
	$ 96,488	$ 6,003	$ –	$ (12)	$ 102,479

	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

16. SUPPLEMENTAL CASH FLOW INFORMATION:

Changes in non-cash working capital is comprised of:

	Year ended December 31, 2011	Year ended December 31, 2010
Changes in non-cash working capital:		
Accounts receivable	**$ (34,195)**	$ (7,348)
Accounts payable and accrued liabilities	**70,824**	16,517
Non-cash working capital acquired (note 6)	**(14,670)**	–
	$ 21,959	$ 9,169
Operating activities	**$ (14,582)**	$ (2,010)
Investing activities	**36,541**	11,179
	$ 21,959	$ 9,169
Interest paid	**$ (6,689)**	$ (5,415)

17. FINANCING:

	Year ended December 31, 2011	Year ended December 31, 2010
Interest Expense	**$ 7,176**	$ 5,795
Accretion of decommissioning obligations	**2,400**	1,965
Acquisition costs	**2,605**	–
	$ 12,181	$ 7,760

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

18. COMMITMENTS:

	Total	2012	2013	2014	2015	2016	Thereafter
Operating Leases	$ 12,221	$ 2,508	$ 2,231	$ 2,363	$ 2,494	$ 2,625	$ –
Capital commitments	1,100	1,100	–	–	–	–	–
Firm transportation agreements	27,284	3,665	3,364	3,980	4,021	3,636	8,618
Firm processing agreement	75,353	9,005	8,031	8,926	8,961	8,783	31,647
Total	$ 115,958	$ 16,278	$ 13,626	$ 15,269	$ 15,476	$ 15,044	$ 40,265

The transportation agreements include an $18.0 million commitment to a third party to transport natural gas from a gas processing facility in the Septimus area to the Alliance pipeline system.

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

In the fourth quarter of 2010, the Company amended the agreement with the owner of this facility. Under the terms of the amended agreement, Crew constructed a facility expansion during the fourth quarter of 2010 and subsequently closed the sale of the Septimus facility expansion in the first quarter of 2011. Upon completion of the expansion, Crew was reimbursed for the cost of the facility expansion of $19.0 million in return for an expanded processing commitment that will extend to December 2020. As part of the amended agreement, Crew has also retained the option to re-purchase a 50% interest in the facility at certain dates prior to January 1, 2014, at a cost of 50% of the total expanded facility's construction cost. If the Company re-purchases a 50% interest on January 1, 2014 for approximately $20.0 million, the remaining commitment would be reduced by approximately $27.0 million.

19. PERSONNEL EXPENSES:

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

	Year ended December 31, 2011	Year ended December 31, 2010
Salary, wages and fees	**$ 15,129**	$ 11,390
Share based compensation	**12,772**	10,254
	$ 27,901	$ 21,644
Capitalized portion of total remuneration	**(13,142)**	(10,712)
	$ 14,759	$ 10,932

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 $9.2 million (2010 - $8.3 million).

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

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

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

The accounting policies in note 3 have been applied in preparing the financial statements for the year ended December 31, 2011 and the comparative information as at and for year ended December 31, 2010, the financial statements for the year ended December 31, 2010 and the preparation of the opening IFRS statement of financial position at January 1, 2010, the Company's date of transition to IFRS.

In preparing its opening IFRS statement of financial position and comparative information for the year ended December 31, 2010, the Company adjusted amounts previously reported in financial statements prepared in accordance with previous GAAP. An explanation of how the transition from previous GAAP to IFRS has affected the Company's financial position, financial performance and cash flows is set out in the following tables and the notes accompanying the tables.

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

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

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

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

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

	Previous GAAP	Effect of transition to IFRS	Note	IFRS
Revenue				
Petroleum and natural gas sales	**$ 206,343**	$ –		$ 206,343
Royalties	**(41,799)**	–		(41,799)
Realized gain on financial instruments	**13,082**	–		13,082
Unrealized loss on financial instruments	**(7,380)**	–		(7,380)
	170,246	–		170,246
Expenses				
Operating	**53,976**	–		53,976
Transportation	**9,582**	–		9,582
General and administrative	**6,479**	3,244	I	9,723
Share-based compensation	**4,517**	1,021	G	5,538
Depletion and depreciation	**110,575**	(31,559)	D	79,016
	185,129	(27,294)		157,835
Income (loss) from operations	**(14,883)**	(27,294)		12,411
Financing	**8,434**	(674)	E	7,760
Gain on divestitures	–	48,242	H	48,242
Impairment of property, plant and equipment	–	(29,072)	C	(29,072)
Net income (loss) before income taxes	**(23,317)**	47,138		23,821
Deferred tax expense (recovery)	**(6,156)**	12,159	F	6,003
Net income (loss) and comprehensive income (loss)	**$ (17,161)**	$ 34,979		$ 17,818
Net income (loss) per share				
Basic	**$ (0.22)**			$ 0.22
Diluted	**$ (0.22)**			$ 0.22

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

	Previous GAAP	Effect of transition to IFRS	Note	IFRS
Cash provided by (used in):				
Operating activities:				
Net income (loss)	$ (17,161)	$ 34,979		$ 17,818
Adjustments:				
Depletion and depreciation	110,575	(31,559)	D	79,016
Financing expenses	8,434	(674)	E	7,760
Interest expense	(5,795)	–		(5,795)
Share-based compensation	4,517	1,021	G	5,538
Deferred tax expense (recovery)	(6,156)	12,159	F	6,003
Unrealized loss on financial instruments	7,380	–		7,380
Gain on divestitures	–	(48,242)	H	(48,242)
Impairment of property, plant and equipment	–	29,072	C	29,072
Transportation liability charge	(1,102)	–		(1,102)
Decommissioning obligations settled	(1,512)	–		(1,512)
Change in non-cash working capital	(2,010)	–		(2,010)
	97,170	(3,244)		93,926
Financing activities:				
Increase in bank loan	3,099	–		3,099
Issue of common shares	20,566	–		20,566
Share issue costs	(48)	–		(48)
	23,617	–		23,617
Investing activities:				
Exploration and evaluation asset expenditures	–	(37,234)	B	(37,234)
Property, plant and equipment expenditures	(248,870)	40,478	B, I	(208,392)
Property dispositions	132,020	–		132,020
Cost incurred on asset held for sale	(15,116)	–		(15,116)
Change in non-cash working capital	11,179	–		11,179
	(120,787)	3,244		(117,543)
Change in cash and cash equivalents	–	–		–
Cash and cash equivalents, beginning of year	–	–		–
Cash and cash equivalents, end of year	$ –	$ –		$ –

Impact of Transition to IFRS on 2010 Results:

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

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

(c) Under IFRS, impairment tests for PP&E are performed at a CGU level as opposed to the entire Company's PP&E balance being subjected to a full cost ceiling test under previous GAAP. Impairment is recognized if the carrying value exceeds the recoverable amount for a CGU. The recoverable amount is determined using the greater of the fair value less costs to sell based on discounted future cash flows of proved plus probable reserves using forecast prices and costs, and the value in use.

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

(d) Depletion and depreciation expense – Under IFRS, Crew has chosen to calculate depletion expense based on proved plus probable reserves as opposed to proved reserves under previous GAAP. This has resulted in a reduction of depletion and depreciation expense of approximately $31.6 million in 2010.

(e) Decommissioning obligations – Under previous GAAP, Crew's decommissioning obligations were discounted based on a credit adjusted risk-free rate which was 8-10% at December 31, 2009. Under IFRS, the Company is required to revalue its obligation at each statement of financial position date using a current liability-specific discount rate. At transition, Crew revalued the obligation based on a risk-free rate of 4% resulting in a $17.7 million increase (net $4.5 million of tax) to the liability with the offset charged to retained earnings. A further change in the discount rate at December 31, 2010 resulted in a revaluation to increase the liability by $1.0 million.

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

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

For the year ended December 31, 2010, a deferred tax expense of $12.2 million was recognized as a result of changes in the temporary difference between the net book value and the tax basis of the assets and liabilities due to other adjustments discussed.

(g) Under previous GAAP, Crew expensed share-based compensation on a straight-line basis. Under IFRS, share-based payments are expensed based on a graded vesting schedule. Crew also incorporated a forfeiture multiplier rather than accounting for forfeitures as they occur as currently practiced under previous GAAP. The adjustment to contributed surplus to account for the graded vesting and forfeitures was an increase of $2.7 million with the offset being charged to retained earnings. This resulted in a $1.0 million increase to share-based compensation expense for the year ended December 31, 2010.

(h) Divestitures – Under previous GAAP, proceeds from divestitures were deducted from the full cost pool without recognition of a gain or loss unless the divestiture resulted in a change in the depletion rate of 20% or greater in which case, a gain or loss was recorded. Under IFRS, gains and losses are recorded on divestitures and are calculated as the difference between the proceeds and the net book value of the asset disposed of. For the year ended December 31, 2010, the Company recorded a $48.2 million gain on disposition of oil and gas properties for IFRS as compared to nil under previous GAAP.

(i) Under IFRS, the criteria for which general and administrative expenses ("G&A") can be capitalized is different than previous GAAP and as a result a greater portion of G&A costs have been expensed. This resulted in an additional $3.2 million of G&A expenses for the year ended December 31, 2010.

HEAD OFFICE

Suite 800, 250 - 5th Street S.W.
Calgary, Alberta T2P 0R4
Phone: (403) 266-2088
Fax: (403) 266-6259
www.crewenergy.com

TSX: CR

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