crew
energy inc.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2011

March 23, 2012

TABLE OF CONTENTS

ABBREVIATIONS ii
CONVERSIONS ii
FORWARD-LOOKING STATEMENTS iii
CERTAIN DEFINITIONS iv

CORPORATE STRUCTURE 1
DESCRIPTION AND GENERAL DEVELOPMENT OF THE BUSINESS 1
SIGNIFICANT ACQUISITIONS 4
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION 4
  Disclosure of Reserves Data 4
    Reserves Data (Forecast Prices and Costs) 5
    Reconciliation of Changes in Reserves 10
  Additional Information Relating to Reserves Data 11
    Undeveloped Reserves 11
    Significant Factors or Uncertainties 12
    Future Development Costs 12
  Other Oil and Gas Information 12
    Principal Properties 12
    Overview 13
    Oil and Gas Wells 15
    Land Holdings Including Properties With No Attributed Reserves 16
    Forward Contracts and Marketing 16
    Additional Information Concerning Abandonment and Reclamation Costs 17
    Tax Horizon 18
    Capital Expenditures 18
    Exploration and Development Activities 19
    Production Estimates 19
    Production History 20
DIVIDEND POLICY 21
DESCRIPTION OF CAPITAL STRUCTURE 21
MARKET FOR SECURITIES 22
ESCROWED SECURITIES 22
DIRECTORS AND OFFICERS 23
AUDIT COMMITTEE INFORMATION 25
HUMAN RESOURCES 26
INDUSTRY CONDITIONS 26
RISK FACTORS 37
LEGAL PROCEEDINGS AND REGULATORY ACTIONS 46
INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS 46
TRANSFER AGENT AND REGISTRAR 46
MATERIAL CONTRACTS 46
INTERESTS OF EXPERTS 47
ADDITIONAL INFORMATION 47

APPENDIX "A" – FORM 51-101F3 – REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE
APPENDIX "B" – FORM 51-101F2 – REPORT ON RESERVES DATA
APPENDIX "C" – AUDIT COMMITTEE MANDATE

ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrel
Mbbl	thousand barrels
Mmbbl	million barrels
bbl/d	barrels per day
BOPD	barrels of oil per day
NGLs or ngls	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
Mmcf	million cubic feet
Mcf/d	thousand cubic feet per day
Mmcf/d	million cubic feet per day
Mmbtu	million British Thermal Units
Bcf	billion cubic feet
GJ	Gigajoule
Tcf	trillion cubic feet

Other

AECO	the natural gas storage facility located at Suffield, Alberta.
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale.
BOE or boe	barrel of oil equivalent on the basis of 6 Mcf/BOE for natural gas and 1 bbl/BOE for crude oil and natural gas liquids
BOE/d or Boe/d	barrel of oil equivalent per day
CSA	Canadian Securities Administrators
m^3	cubic metres
Mboe	1,000 barrels of oil equivalent
M$	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

Measurements expressed in Boe or Mcfe may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf:1 Bbl and an Mcfe conversion ratio of 1 bbl:6 Mcf are based on an approximate energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. 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 conversion on a 6:1 basis may be misleading as an indication of value.

Where any disclosure of reserves data is made in this annual information form that does not reflect all reserves of Crew, the reader should note that the estimates of reserves and future net revenue for individual properties or groups of properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

CONVERSIONS

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
bbl	Cubic metres	0.159
Cubic metres	bbl oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres (Alberta)	Hectares	0.400
Hectares (Alberta)	Acres	2.500
Acres (British Columbia)	Hectares	0.405
Hectares (British Columbia)	Acres	2.471

FORWARD LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, financial and business prospects and financial outlook, reserves and production estimates, drilling, testing, tie-in and re-completion plans, timing of drilling, re-completion and tie in of wells, productive capacity of wells and capital expenditures and the timing and funding thereof, the effect of government announcements, proposals and legislation, plans regarding hedging, expected or anticipated production rates, timing of expected production increases, weighting of production between different commodities, forecast commodity prices, exchange rates, production expenses, transportations costs and other costs and expenses, timing and completion of new facilities, expected land expiries and plans with respect thereto, well abandonment costs, expectation as to non-taxable status, and expected volatility in commodity prices and stock markets, may be forward looking statements. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserves 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, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserves estimates of Crew's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in 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 Crew 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, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Crew operates; the timely receipt of any required regulatory approvals; the ability of Crew to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which Crew has an interest in to operate the field in a safe, efficient and effective manner; the ability of Crew to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Crew to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Crew operates; and the ability of Crew to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could effect Crew'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 on Crew's website (www.Crewenergy.com). Although the forward looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward looking statements. Investors should not place undue reliance on forward looking statements. These forward looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward looking statements and other information contained herein concerning the oil and gas industry and the Corporation's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserves reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Corporation believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Corporation is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires:

"**ABCA**" means *Business Corporations Act* (Alberta);

"**Caltex**" means Caltex Energy Inc., a corporation amalgamated pursuant to the ABCA;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**Common Shares**" means the common shares in the capital of the Corporation;

"**Crew**" or the "**Corporation**" means Crew Energy Inc., a corporation incorporated pursuant to the ABCA;

"**Crew Conventional Partnership**" means Crew Conventional Partnership, a general partnership formed under the laws of Alberta, the partners of which are Crew and Crew Oil & Gas;

"**Crew Energy Partnership**" means Crew Energy Partnership, a general partnership formed under the laws of Alberta, the partners of which are Crew and Crew Oil & Gas;

"**Crew Heavy Oil Partnership**" means Crew Heavy Oil Partnership, a general partnership formed under the laws of Alberta, the partners of which are Crew and Crew Oil & Gas;

"**Crew Oil & Gas**" means Crew Oil & Gas Inc., a corporation amalgamated under the ABCA;

"**Edson Disposition**" means the Corporation's April, 2010 disposition of assets in the Edson area as more particularly described under the heading "*Description and General Development of the Business*";

"**GLJ**" means GLJ Petroleum Consultants Ltd.;

"**GLJ Report**" means the report of GLJ dated March 1, 2012 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2011;

"**Gross**" or "**gross**" means:

(a) in relation to the Corporation's interest in production and reserves, its "company gross reserves", which are the Corporation's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;

(b) in relation to wells, the total number of wells in which the Corporation has an interest; and

(c) in relation to properties, the total area of properties in which the Corporation has an interest.

"**Net**" or "**net**" means:

(a) in relation to the Corporation's interest in production and reserves, the Corporation's working interest (operating and non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interests in production or reserves;

(b) in relation to wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and

(c) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

"**NI 51-101**" means National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities;

"**Subsidiary**" means, with respect to any Person, a subsidiary (as that term is defined in the ABCA (for such purposes, if such person is not a corporation, as if such person were a corporation)) of such Person and includes any partnership, joint venture, trust, limited liability company, unlimited liability company or other entity, whether or not having legal status, that would constitute a subsidiary (as described above) if such entity were a corporation; and

"**TSX**" means the Toronto Stock Exchange.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2011.

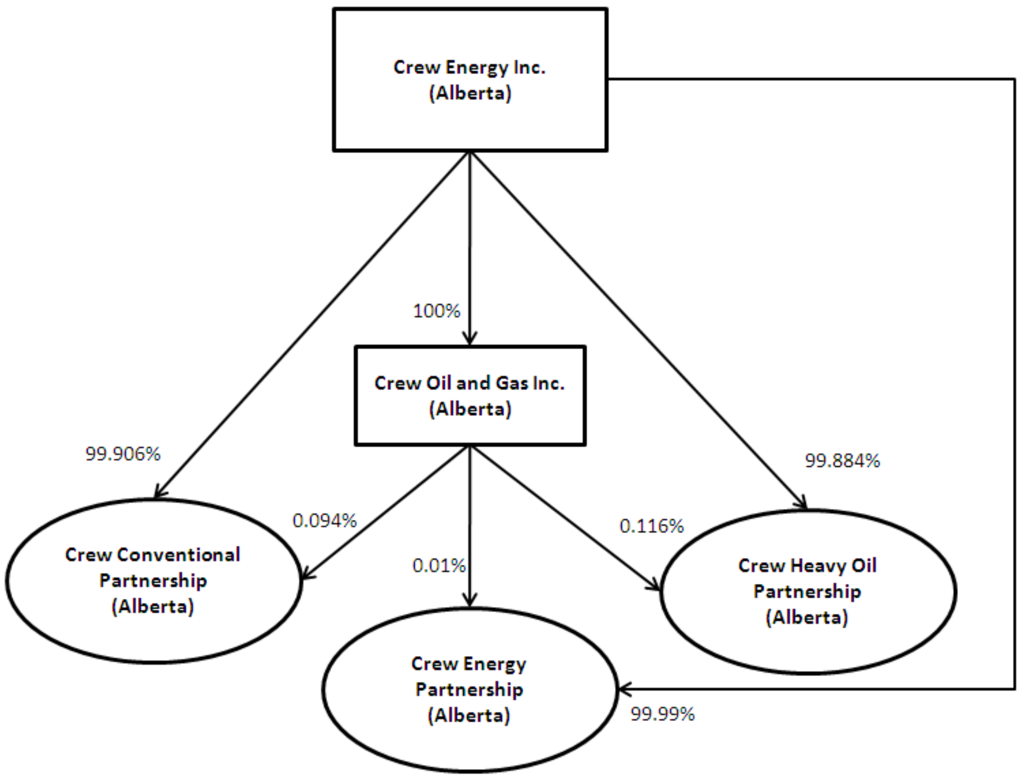
All dollar amounts herein are in Canadian dollars, unless otherwise stated.

CORPORATE STRUCTURE

Crew was originally incorporated pursuant to the provisions of the ABCA as 1046546 Alberta Ltd. on May 12, 2003. On June 27, 2003, Crew filed Articles of Amendment to change its name to "Crew Energy Inc."

On December 31, 2011 Crew completed a short form amalgamation under the ABCA with its then wholly-owned subsidiaries, Crew Resources Inc. and Caltex Energy Inc. to form "Crew Energy Inc."

The following diagram describes the inter-corporate relationships among Crew and its material Subsidiaries.



Crew's head office is located at Suite 800, 250 - 5th Street S.W., Calgary, Alberta, T2P 0R4 and its registered office is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

The Common Shares of Crew trade on the TSX under the symbol "CR".

Unless the context otherwise requires, reference herein to "Crew" or the "Corporation" means Crew Energy Inc. together with its Subsidiaries.

DESCRIPTION AND GENERAL DEVELOPMENT OF THE BUSINESS

Business Plan and Growth Strategies

Crew has been engaged in the business of exploring for, developing, producing and acquiring crude oil and natural gas in western Canada since it began active operations on September 2, 2003 following completion of the plan of arrangement among the Corporation, Baytex Energy Ltd. and Baytex Energy Trust.

The business plan of Crew is to create sustainable and profitable growth in the oil and gas industry in western Canada. To accomplish this, Crew has focused and continues to focus on enhancing its asset base through land acquisition and exploratory and development drilling within its core project areas in Alberta, Saskatchewan and northeast British Columbia. In addition, Crew also evaluates strategic acquisition opportunities of producing oil and natural gas properties where it views further exploration, exploitation and development opportunities exist. Crew will continue to target areas and prospects that it believes could result in meaningful reserve and production additions.

To achieve sustainable and profitable growth, management of Crew believes in controlling the timing and costs of its projects wherever possible. To minimize competition within its geographic areas of interest, Crew strives to maximize its working interest ownership in its properties where reasonably possible. While Crew believes that it has the skills and resources necessary to achieve its objectives, participation in the exploration and development of oil and natural gas has a number of inherent risks. See "*Risk Factors*".

In reviewing potential drilling or acquisition opportunities, Crew gives consideration to the following criteria: (i) the at risk capital required to secure or evaluate the investment opportunity; (ii) if successful, the potential return on the project; (iii) the likelihood of success; (iv) the risked return versus cost of capital; (v) the strategic benefits to Crew; and (iv) Crew's technical expertise in the opportunity.

In general, Crew uses a portfolio approach in developing a number of opportunities with a balance of risk profiles and commodity exposure, in an attempt to generate sustainable high levels of profitable production and financial growth.

Crew's management team has a demonstrated track record of bringing together all of the key components to a successful intermediate exploration and production company: strong technical skills, expertise in planning and financial controls, ability to execute on business development opportunities and an entrepreneurial spirit that will allow Crew to effectively identify, evaluate and execute on value added initiatives.

Crew has executed its growth strategy through exploration and development programs combined with both corporate and property acquisitions. Financing for these programs has been obtained through a combination of cash flow from operations, various equity issues of common shares and common shares issued on a "flow-through basis", property dispositions and bank credit facilities.

Crew may pursue asset or corporate acquisitions or investments that do not conform to the guidelines discussed above based upon its consideration of the qualitative aspects of the subject properties, including risk profile, technical upside, reserve life and asset quality.

Corporate History

The following is a description of significant events over the last number of completed financial years that have influenced the general development of the Corporation's business.

On November 21, 2006 Crew completed the acquisition (the "**Gladius Acquisition**") of all of the outstanding shares of Gladius Energy Inc. ("**Gladius**"), a private oil and gas company. Gladius held certain producing oil and natural gas properties and undeveloped land primarily in Crew's Ferrier area in west central Alberta. At the time of closing of the Gladius Acquisition, the principal properties of Gladius were producing approximately 1,000 Boe/d, comprised of approximately 59% natural gas and 41% natural gas liquids and light oil. The Gladius assets also included approximately 10,730 net acres of undeveloped land. The shares of Gladius were acquired by Crew on the basis of 0.47875 of a Common Share of Crew for each share of Gladius. The former shareholders of Gladius received an aggregate of approximately 5.32 million Common Shares of Crew in exchange for all of the outstanding shares of Gladius. Following the Gladius Acquisition, the producing properties of Gladius were transferred into the Crew Energy Partnership and Gladius was amalgamated with Crew effective January 17, 2007.

On April 30, 2007, the Corporation completed a short form prospectus offering of 5,750,000 subscription receipts at an issue price of $10.30 per subscription receipt for aggregate gross proceeds of approximately $59.2 million. The gross proceeds of this offering were used to partially fund the Corporation's acquisition (the "**Enco Acquisition**") of all of the outstanding shares of ENCO Gas, Ltd. ("**Enco**"), a private oil and gas company. Each subscription receipt issued in connection with the Enco Acquisition entitled the holder thereof to receive, without payment of additional consideration or further action, one Common Share of the Corporation upon closing of the Enco Acquisition. The remainder of the purchase price for the Enco Acquisition was provided by a newly arranged credit facility.

On May 3, 2007 Crew completed the Enco Acquisition. Enco held certain producing oil and natural gas properties and undeveloped land located primarily in northeast British Columbia. At the time of closing the Enco Acquisition, the principal properties of Enco were producing approximately 3,100 boe/d, comprised of approximately 95% natural gas and 5% natural gas liquids and light oil. The Enco assets also included approximately 33,410 net acres of undeveloped land. Following the Enco Acquisition, the producing properties of Enco were transferred into the Crew Energy Partnership and Enco was amalgamated with Crew effective January 1, 2008.

On October 25, 2007, the Corporation completed a bought deal short form prospectus offering of 4,181,860 Common Shares at an issue price of $8.25 per share, and 1,860,500 Common Shares issued on a "flow-through" basis at an issue price of $10.75 per share, for aggregate gross proceeds of approximately $54.5 million.

On May 1, 2008, the Corporation completed a bought deal short form prospectus offering of 5,000,000 Common Shares at an issue price of $13.35 per share for aggregate gross proceeds of approximately $66.8 million. The gross proceeds of this offering were used to partially fund the Corporation's acquisition (the "**Montney Acquisition**") of Crown leasehold interests in approximately 102.2 net sections of undeveloped Montney formation rights located in the Corporation's core operating area in Northeast British Columbia for approximately $63 million in cash pursuant to the terms of a purchase and such agreement dated April 14, 2008. The Montney Acquisition was completed by Crew on May 12, 2008.

On August 22, 2008 Crew completed the acquisition of all of the outstanding shares of Gentry Resources Ltd. pursuant to a plan of arrangement under the ABCA (the "**Gentry Acquisition**"). Prior to completion of the Gentry Acquisition, Gentry was a reporting issuer in certain provinces of Canada and its common shares were listed for trading on the TSX under the symbol "GNY". Pursuant to the terms of the arrangement agreement dated June 23, 2008 among Crew and Gentry (the "**Gentry Acquisition Agreement**"), shareholders of Gentry received, for each outstanding share of Gentry held by them, 0.22 of a Common Share of Crew. The former shareholders of Gentry received in the aggregate approximately 12.28 million Common Shares of Crew in exchange for all of the outstanding shares of Gentry. Crew also assumed approximately $73.6 million of Gentry net debt upon closing of the Gentry Acquisition. Following completion of the Gentry Acquisition, the common shares of Gentry were delisted from trading on the TSX and Gentry ceased to be a reporting issuer.

Gentry was a junior oil and natural gas company with its principal and head office located in Calgary, Alberta and carried on the business of acquiring crude oil and natural gas properties and exploring for, developing and producing crude oil and natural gas in Alberta and Saskatchewan. At the time of closing of the Gentry Acquisition, the principal properties of Gentry were producing approximately 4,000 Boe/d, comprising approximately 50% natural gas, 45% oil and 5% natural gas liquids. The Gentry assets also included approximately 280,000 net acres of undeveloped land.

Following the Gentry Acquisition, the producing properties of Gentry were transferred into the Crew Energy Partnership and Gentry was amalgamated with Crew effective January 1, 2009.

On May 28, 2009, the Corporation completed a bought deal short form prospectus offering of 7,000,000 Common Shares at an issue price of $6.20 per share for aggregate gross proceeds of approximately $43.4 million.

On March 10, 2010, Crew entered into an agreement (the "**Edson Disposition Agreement**") for the divestiture of a portion of its oil and natural gas assets (the "**Edson Disposed Assets**") in the Edson area of west central Alberta for gross proceeds of $126 million, before closing adjustments. The Edson Disposition was completed on April 1, 2010. The Edson Disposed Assets comprised Crew's interests in 72 gross (50 net) sections, excluding the Cardium formation rights on 32 net sections. Production attributed to the Edson Disposed Assets, estimated at the time of entering into of the Edson Disposition Agreement, was approximately 1,700 Boe/d (79% natural gas and 21% liquids).

On March 2, 2011, the Corporation completed a bought deal short form prospectus offering of 4,820,000 Common Shares at an issue price of $20.75 per share for aggregate gross proceeds of approximately $100 million.

On July 1, 2011 Crew completed the acquisition of Caltex Energy Inc. (the "**Caltex Acquisition**"). See "*Significant Acquisitions – Acquisition of Caltex Energy Inc*."

Competitive Conditions

The oil and natural gas industry is intensely competitive in all its phases. Crew competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Crew's competitors include resource companies which have greater financial resources, staff and facilities than those of Crew. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Crew believes that its competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development.

SIGNIFICANT ACQUISITIONS

Other than the Caltex Acquisition, there were no significant acquisitions completed by Crew during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102.

Acquisition of Caltex Energy Inc.

On July 1, 2011, Crew completed the acquisition of all of the outstanding shares of Caltex pursuant to a plan of arrangement under the ABCA.

Caltex was a private company with its principal and head office located in Calgary, Alberta, engaged in the business of acquiring crude oil and natural gas properties and exploring for, developing and producing crude oil and natural gas in the provinces of Alberta and Saskatchewan. The principal properties of Caltex included producing heavy oil properties in the Lloydminster area of Saskatchewan and Alberta and liquids rich natural gas assets in the greater Wapiti area of Alberta.

Pursuant to the Caltex Acquisition, shareholders of Caltex received, for each outstanding share of Caltex held by them, 0.38 of a Common Share of Crew. The former shareholders of Caltex received in the aggregate approximately 33.6 million Common Shares of Crew in exchange for all of the outstanding shares of Caltex. Crew also assumed approximately $65.9 million of Caltex's net debt upon closing of the Caltex Acquisition.

Immediately following completion of the Caltex Acquisition, Crew's revolving line of credit was increased to $370 million which, together with a $30 million operating line of credit, represented aggregate available credit facilities of $400 million.

Following the Caltex Acquisition, Caltex Energy Inc. was amalgamated with Crew and its other wholly-owned subsidiary, Crew Resources Inc., and the two previously wholly-owned subsidiaries of Caltex Energy Inc. were amalgamated to form Crew Oil & Gas Inc, all effective December 31, 2011.

The Corporation's Business Acquisition Report dated July 27, 2011 in respect of the Caltex Acquisition is filed and can be located under Crew's profile on Sedar at www.sedar.com.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated March 2, 2012. The effective date of the Statement is December 31, 2011 and the preparation date of the Statement was March 1, 2012.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by GLJ with an effective date of December 31, 2011 and is contained in the GLJ Report. The Reserves Data summarizes the crude oil, natural gas liquids, natural gas and coal bed methane reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs prior to the provision for interest, general and administrative expenses, the impact of hedging activities, certain well abandonment costs and all reclamation costs, which were not deducted by GLJ in estimating future net revenue. The GLJ Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The Corporation engaged GLJ to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Corporation's reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia and Saskatchewan.

The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 and the Report on Reserves Data by the Independent Qualified Reserves Evaluator in Form 51-101F2 are attached at Appendices A and B hereto, respectively.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and cost assumptions will be attained and variances could be material. The recovery and reserves estimates of the Corporation's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2011

	RESERVES SUMMARY											
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS LIQUIDS		CONVENTIONAL NATURAL GAS		COAL BED METHANE		TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mmcf)	Net (Mmcf)	Gross (Mmcf)	Net (Mmcf)	Gross (Mboe)	Net (Mboe)
PROVED												
Developed Producing	8,298	6,338	3,159	2,700	4,427	3,275	125,046	100,767	1,459	1,399	36,968	29,341
Developed Non-Producing	670	531	1,537	1,333	745	607	28,335	24,007	574	538	7,770	6,561
Undeveloped	5,353	4,034	814	709	4,967	3,924	111,797	91,406	6,715	5,804	30,886	24,869
TOTAL PROVED	14,320	10,902	5,510	4,742	10,139	7,806	265,179	216,180	8,749	7,741	75,624	60,770
TOTAL PROBABLE	10,542	7,985	4,845	4,164	9,538	7,526	210,971	173,576	9,380	8,285	61,650	49,986
TOTAL PROVED PLUS PROBABLE	24,863	18,887	10,355	8,906	19,676	15,332	476,150	389,756	18,128	16,025	137,274	110,756

	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
PROVED										
Developed Producing	882,117	726,706	626,687	556,188	503,448	882,117	726,706	626,687	556,188	503,448
Developed Non-Producing	191,380	151,149	124,494	105,647	91,669	146,540	123,107	105,912	92,783	82,454
Undeveloped	610,358	385,065	262,080	186,568	136,361	457,752	282,711	186,836	127,992	88,999
TOTAL PROVED	1,683,856	1,262,920	1,013,261	848,404	731,479	1,486,409	1,132,525	919,435	776,964	674,901
TOTAL PROBABLE	1,569,415	930,051	628,399	458,320	351,137	1,117,180	688,938	457,818	327,536	245,716
TOTAL PROVED PLUS PROBABLE	3,253,271	2,192,971	1,641,660	1,306,724	1,082,616	2,663,589	1,821,463	1,377,253	1,104,500	920,618

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2011

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	WELL ABANDONMENT COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Total Proved	3,922,775	804,286	1,078,484	320,772	35,376	1,683,856	197,447	1,486,409
Total Proved Plus Probable	7,526,072	1,515,698	2,026,416	681,447	49,240	3,253,271	589,682	2,663,589

FUTURE NET REVENUE BY PRODUCTION GROUP AS OF DECEMBER 31, 2011

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES(3) (discounted at 10%/year) (M$)	UNIT VALUE BEFORE INCOME TAXES(4) (discounted at 10%/year) (Units as noted)
Proved Producing	Light and Medium Crude Oil (1)	250,897	$31.95 per boe
	Heavy Oil(1)	102,605	$37.90 per boe
	Natural Gas (2)	271,220	$2.44 per mcfe
	Coal Bed Methane	1,965	$1.40 per mcf
Total Proved	Light and Medium Crude Oil (1)	368,240	$28.11 per boe
	Heavy Oil(1)	159,171	$33.50 per boe
	Natural Gas (2)	479,983	$1.92 per mcfe
	Coal Bed Methane	5,867	$0.76 per mcf
Total Proved Plus Probable	Light and Medium Crude Oil (1)	568,077	$25.72 per boe
	Heavy Oil(1)	284,007	$31.82 per boe
	Natural Gas (2)	778,573	$1.68 per mcfe
	Coal Bed Methane	11,004	$0.69 per mcf

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products but excluding solution gas.
(3) Other company revenue and costs not related to specific production group have been allocated proportionately to production groups.
(4) Unit values are based on Net reserves.

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids, natural gas and non-conventional natural gas reserves estimates presented in the GLJ Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

Reserves Categories

Reserves are estimated remaining quantities of crude oil, natural gas, non-conventional natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions which are generally accepted as reasonable.

Reserves are classified according to the degree of certainty associated with the estimates.

(a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories.

(c) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

   (i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainly.

   (ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(d) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserve estimates are prepared). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

3. Forecast Prices and Costs

GLJ has prepared its January 1, 2012, price and market forecasts as summarized in the tables below after a comprehensive review of information. Information sources include numerous government agencies, industry publications, Canadian oil refiners and natural gas marketers. The forecasts presented herein are based on an informed interpretation of currently available data. While these forecasts are considered reasonable at this time, users of these forecasts should understand the inherent high uncertainty in forecasting any commodity or market. These forecasts will be revised periodically as market, economic and political conditions change. These future revisions may be significant.

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, as at January 1, 2012, inflation and exchange rates utilized by GLJ in the GLJ Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF JANUARY 1, 2012
FORECAST PRICES AND COSTS

	OIL			ALBERTA NGLS			NATURAL GAS			
Year	WTI Cushing @ Oklahoma ($US/bbl)	LIGHT, SWEET OIL @ Edmonton (40 API, 0.3% S) ($Cdn/bbl)	Bow River Medium Crude @ Hardisty ($Cdn/bbl)	EDMONTON PROPANE ($Cdn/bbl)	EDMONTON BUTANE ($Cdn/bbl)	EDMONTON PENTANES PLUS ($Cdn/bbl)	NATURAL GAS AECO/NIT Spot Gas Price ($Cdn/MmBtu)	NATURAL GAS Westcoast Station 2 Spot Gas Price ($Cdn/MmBtu)	INFLATION RATE(1) %/Year	EXCHANGE RATE(2) ($US/$Cdn)
Forecast										
2012	97.00	97.96	83.27	58.78	76.41	107.76	3.49	3.29	2.0	0.98
2013	100.00	101.02	84.35	60.61	78.80	108.09	4.13	3.93	2.0	0.98
2014	100.00	101.02	84.35	60.61	78.80	105.06	4.59	4.39	2.0	0.98
2015	100.00	101.02	84.35	60.61	78.80	105.06	5.05	4.85	2.0	0.98
2016	100.00	101.02	84.35	60.61	78.80	105.06	5.51	5.31	2.0	0.98
2017	100.00	101.02	84.35	60.61	78.80	105.06	5.97	5.77	2.0	0.98
2018	101.35	102.40	85.50	61.44	79.87	106.49	6.21	6.01	2.0	0.98
2019	103.38	104.47	87.23	62.68	81.49	108.65	6.33	6.13	2.0	0.98
2020	105.45	106.58	89.00	63.95	83.13	110.84	6.46	6.26	2.0	0.98
2021	107.56	108.73	90.79	65.24	84.81	113.08	6.58	6.38	2.0	0.98
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.98

Notes:
(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by the Corporation for the year ended December 31, 2011, were $3.81/mcf for natural gas, $78.05/bbl for light/medium oil, $70.30/bbl for heavy oil and $62.68/bbl for natural gas liquids.

4. Well abandonment costs for wells with reserves have been included at the property level. Additional abandonment costs associated with non-reserves wells, lease reclamation costs and facility abandonment and reclamation expenses have not been included in this analysis.

5. The forecast price and cost assumptions assume the continuance of current laws and regulations.

6. The extent and character of all factual data supplied to GLJ were accepted by GLJ as represented. No field inspection was conducted.

7. The after-tax net present value of the Corporation's properties here reflects the tax burden on the properties on a stand-alone basis and utilizing the Corporation's tax pools. It does not consider the business-entity-level tax situation, or tax planning. It does not provide an estimate of the value at the level of the business entity, which may be significantly different. The financial statements and the management's discussion and analysis of the Corporation should be consulted for information at the level of the business entity. Furthermore, the tax methodology used assumes that all tax pools are utilized to the maximum depreciation rate as currently permitted.

Reconciliation of Changes in Reserves

CURRENT YEAR
RECONCILIATION OF
GROSS RESERVES BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			HEAVY OIL			NATURAL GAS LIQUIDS		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2010	11,774	10,387	22,161	19	4	23	4,324	2,381	6,705
Discoveries	261	222	483	0	0	0	247	128	375
Extensions and Improved Recovery	4,557	773	5,329	816	144	960	1,283	1,704	2,987
Infill Drilling	205	0	205	0	0	0	940	1,262	2,202
Technical Revisions	(672)	(1,061)	(1,733)	547	(471)	76	149	338	487
Acquisitions	363	241	604	5,304	5,168	10,472	4,233	3,633	7,866
Dispositions	(74)	(20)	(94)	0	0	0	(107)	(27)	(134)
Economic Factors	0	0	0	0	0	0	(188)	119	(69)
Production	(2,093)	0	(2,093)	(1,175)	0	(1,175)	(742)	0	(742)
December 31, 2011	14,320	10,542	24,863	5,510	4,845	10,355	10,139	9,538	19,677

	CONVENTIONAL NATURAL GAS			COAL BED METHANE			OIL EQUIVALENT		
FACTORS	Proved (Mmcf)	Probable (Mmcf)	Proved Plus Probable (Mmcf)	Proved (Mmcf)	Probable (Mmcf)	Proved Plus Probable (Mmcf)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2010	165,873	89,677	255,551	10,231	8,246	18,477	45,467	29,093	74,560
Discoveries	3,753	1,943	5,696	0	0	0	1,134	673	1,807
Extensions and Improved Recovery	29,934	27,388	57,322	85	(85)	0	11,659	7,171	18,830
Infill Drilling	31,792	27,911	59,703	0	0	0	6,444	5,914	12,358
Technical Revisions	(4,983)	2,775	(2,208)	(788)	672	(115)	(939)	(619)	(1,558)
Acquisitions	71,044	61,343	132,387	0	0	0	21,741	19,266	41,007
Dispositions	(3,658)	(1,076)	(4,735)	0	0	0	(791)	(226)	(1,017)
Economic Factors	(3,709)	1,011	(2,698)	(616)	547	(69)	(909)	378	(531)
Production	(24,868)	0	(24,868)	(164)	0	(164)	(8,182)	0	(8,182)
December 31, 2011	265,179	210,971	476,150	8,749	9,380	18,128	75,624	61,650	137,274

Note:

(1) Gross Reserves in the tables above are the Corporation's interest share before deduction of royalties and without including any royalty interests of the Corporation.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to Crew's assets for the years ended December 31, 2011, 2010 and 2009 and, in the aggregate, before that time based on forecast prices and costs. These reserves are included in the "Summary of Oil and Gas Reserves" table on page 6.

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Conventional Natural Gas (Mmcf)		Coal Bed Methane (Mmcf)		NGLs (Mbbl)	
	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
Prior thereto	1,278	1,278	120	120	25,870	25,870	6,490	6,490	585	585
2009	2,097	2,644	0	0	40,943	57,320	686	7,474	963	1,394
2010	3,854	4,736	0	0	29,597	56,780	0	8,169	748	1,495
2011	3,672	5,353	814	814	81,906	111,797	0	6,715	4,178	4,967

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Conventional Natural Gas (Mmcf)		Coal Bed Methane (Mmcf)		NGLs (Mbbl)	
	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
Prior thereto	2,133	2,133	30	30	47,006	47,006	6,710	6,710	1,238	1,238
2009	5,427	6,451	0	0	32,985	48,749	0	6,035	819	1,377
2010	4,031	6,966	0	0	30,539	51,352	0	7,917	755	1,416
2011	3,078	5,924	1,314	1,314	111,687	155,025	797	8,954	6,380	7,690

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook. The majority of undeveloped reserves are scheduled to be developed within the next three years. Crew has areas where multiple zones have been assigned reserves in a well. Once the producing zones are depleted, capital may be spent re-completing the well in another zone. Some of these expenditures are planned to occur in 2012 and beyond, the timing dictated by the predicted reserve life for the currently producing zones.

A number of factors that could result in delayed or cancelled development of the Corporation's undeveloped reserves are as follows:

- changing economic conditions (due to pricing, royalty structure, operating and capital expenditure fluctuations);
- changing technical conditions (production anomalies (such as water breakthrough and accelerated depletion);
- multi-zone developments (such as production from a prospective formation completion may be delayed until the initial completion is no longer economic);
- a larger development program may need to be spread out over several years to optimize capital allocation and/or facility utilization; and
- surface access issues (landowners, weather conditions, regulatory approvals).

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

The Corporation does not anticipate any significant economic factors or significant uncertainties that may affect any particular components of the reserves data. However, the reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond the Corporation's control (see "*Risk Factors*").

Future Development Costs

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserves categories noted below.

	Forecast Prices and Costs	
Year	**Proved Reserves (M$)**	**Proved Plus Probable Reserves (M$)**
2012	95,758	144,820
2013	164,395	270,063
2014	52,226	213,202
2015	2,830	45,869
2016	3,363	5,014
Thereafter	2,200	2,479
Total Undiscounted	320,772	681,447

The Corporation currently expects that the capital listed in the preceding table will be funded through internally generated cash flows and, as required, available credit facilities and will not have any significant associated funding costs. Therefore, the cost of funding is not expected to have any significant effect on the disclosed reserves or future net revenue.

Other Oil and Gas Information

Principal Properties

The following is a description of Crew's important oil and natural gas properties as at December 31, 2011. Production stated is production before deduction of royalties and includes royalty interests to Crew and, unless otherwise stated, is average production for 2011. Reserves amounts are total proved plus probable reserves based on forecast prices and costs, stated before deduction of royalties and include royalty interests as at December 31, 2011 based on forecast prices and costs as evaluated in the GLJ Report (see "*Reserves Data*"). **The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.** Unless otherwise specified, gross and net acres and well count information are as at December 31, 2011.

Overview

Crew's operations are divided into six main operating areas: Princess, Pine Creek/Edson and Deep Basin in Alberta, Septimus and Inga in northeast British Columbia, and Lloydminster, Saskatchewan. Crew also has a number of minor operating areas primarily in central Alberta. Crew will focus on the development of its main operating areas in 2012 and has budgeted capital expenditures of $300 million towards the continued growth of these core areas. This development will be the foundation upon which the Corporation will continue to grow its base production and includes the drilling of an estimated 130 net wells in 2012.

Princess, Alberta

The Princess area comprises 442 contiguous sections of Crew controlled freehold and Crown land directly south of Brooks, Alberta. The area lies in a unique geographic position in Alberta where the structural effects of the Sweetgrass Arch and the regional dip of the Western Canadian Sedimentary Basin intersect to form an area where the subsurface structure is essentially flat. Numerous northwest trending Mannville channels have eroded the Mississippian Pekisko formation forming hydrocarbon traps on the subcrop edge (Tilley and West Tide Lake) and in elongated outliers (Alderson). These outliers can be two to three miles wide and up to 12 miles long. Crew has three dimensional seismic control over the block and has in excess of 900 drilling locations identified. At December 31, 2011 the Corporation owned 38 (34.4 net) producing gas wells, 202 (201.7 net) producing oil wells and 36 (35.1 net) service wells in the area along with three 100% owned oil batteries and associated fluid gathering infrastructure. In 2011, Crew drilled 119 (119.0 net) wells in this area resulting in 104 (104.0 net) oil wells and 13 (13.0 net) service wells. In 2011, production for Princess averaged 6,688 boe/d weighted 80% towards medium gravity (23° to 26° API) oil and associated liquids.

As at December 31, 2011, the GLJ Report showed the Princess area to have proved plus probable reserves of 22,290 Mbbl of oil and ngls and 25,162 Mmcf of natural gas. At year-end, the Corporation owned 299,973 net acres of land with an average working interest of 90% in the area. Crew plans to drill approximately 75 oil wells in 2012 in the Princess area.

Pine Creek/Edson, Alberta

The greater Pine Creek area is in west central Alberta including Crew's operations west of Edmonton. Production from this area is mainly characterized by high heat content natural gas with associated natural gas liquids produced from several Cretaceous, Jurassic and Devonian formations. At December 31, 2011 the Corporation had 49 (35.9 net) producing gas wells and four (3.3 net) producing oil wells in the area. In 2011, the Corporation drilled five (5.0 net) wells resulting in two (2.0 net) oil wells and three (3.0 net) gas wells. Production in 2011 averaged 1,332 boe/d weighted 80% to natural gas.

As at December 31, 2011, the GLJ Report showed the greater Pine Creek/Edson area to have proved plus probable reserves of 1,354 Mbbl of oil and ngls and 26,533 Mmcf of natural gas. At year-end, the Corporation owned 116,922 net acres of land with an average working interest of 71% in the area.

Crew lands in the Pine Creek area include 27 net sections of land that have been identified as prospective for the Cardium resource play. Crew has no immediate drilling plans for 2012 in the Pine Creek/Edson area.

Deep Basin, Alberta

The Deep Basin area is located in northwest Alberta near the British Columbia border and was acquired by Crew on July 1, 2011 through the acquisition of Caltex. Production from this area is characterized by liquids rich natural gas from the Cretaceous aged Cardium and Falher formations. Reserves from both of these zones are accessed through long reach horizontal wells with multi-stage propane or water based fracture stimulations. Crew's production from this area in 2011 averaged 2,505 boe/d weighted 71% to natural gas. At December 31, 2011 the Corporation had 57

(48.4 net) producing gas wells and 16 (11.7 net) producing oil wells in the area which included the drilling of three (2.4 net) wells over the last half of the year resulting in three (2.4 net) gas wells.

As at December 31, 2011, the GLJ Report showed the Deep Basin area to have proved plus probable reserves of 8,855 Mbbl of oil and ngls and 132,943 Mmcf of natural gas. At year-end, the Corporation owned 106,430 net acres of land with an average working interest of 86% in the area.

Development plans in 2012 include the drilling of five (4.6 net) horizontal wells and expansion of the Corporation's operated compression facilities in the area.

Septimus, British Columbia

The Septimus area is located 15 kilometers south of Fort St. John, British Columbia. The Corporation's operations at Septimus include natural gas production from the Montney formation. The Montney formation in the Septimus area is a tight siltstone formation that is approximately 300 meters thick which is accessed with long reach horizontal wells that are currently completed with up to ten multi-stage water-based fracture stimulations. At December 31, 2011 the Corporation had an interest in 29 (28.6 net) natural gas wells in the area. Production averaged 5,282 boe/d weighted 86% to natural gas. The Corporation drilled a total of 12 (11.3 net) wells in the Septimus area in 2011 resulting in 11 (11.0 net) gas wells and one (0.3 net) oil well.

As at December 31, 2011, the GLJ Report showed Crew's Septimus area to have total proved plus probable reserves of 4,928 Mbbl of oil and ngls along with 174,568 Mmcf of natural gas. At year-end 2011, the Corporation owned 82,255 net acres of land with an average working interest of 86% in this area.

In 2009, Crew constructed a 25 mmcf per day Septimus gas plant which became operational on October 1, 2009 allowing the Company to increase production volumes. In December 2009, Crew completed the sale of the Septimus gas processing facility to a third party for the as built cost of approximately $19.1 million. 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 undertook construction of the facility expansion to double the capacity to 50 Mmcf/d during the fourth quarter of 2010 and then subsequently sold the Septimus facility expansion upon its completion in February, 2011. Upon completion of the expansion, Crew was reimbursed for the full cost of the facility expansion of $19.0 million in return for an expanded processing commitment that will extend to December 2020. Crew has also retained the option to re-purchase a 50% interest in the facility at certain dates prior to January 1, 2014, at a cost of 50% of the total expanded facility's construction cost.

Current plans for 2012 are to drill 13 (11.0 net) wells at Septimus with eight (6.0 net) targeting oil in the Montney formation and five (5.0 net) targeting liquids rich natural gas.

Inga, British Columbia

The greater Inga area includes Crew's other operations situated in northeast British Columbia between Fort St. John and Fort Nelson. At December 31, 2011 the Corporation had 93 (36.7 net) producing gas wells and 11 (4.6 net) producing oil wells in the area. Production averaged 933 boe/d from this area weighted 66% towards natural gas. Production from this area is mainly characterized by high heat content natural gas with associated natural gas liquids produced from several Cretaceous and Triassic age reservoirs. In 2011, the Corporation drilled two (1.9 net) gas wells in the Inga area.

As at December 31, 2011, the GLJ Report showed Crew's greater Inga area to have total proved plus probable reserves of 4,588 Mbbl of oil and ngls along with 70,874 Mmcf of natural gas. At year end, the Corporation owned 114,340 net acres of land with an average working interest of 48% in this area. Current plans for 2012 are to drill one well targeting the Montney formation in the Inga area.

Lloydminster, Saskatchewan/Alberta

The Lloydminster area includes Crew's operations situated in the Saskatchewan/Alberta border region near the city of Lloydminster, Saskatchewan and was acquired on July 1, 2011 through the acquisition of Caltex. The Corporation's production comprises 12 to 14 degree API oil from several stacked Cretaceous aged reservoirs in stratigraphic and structural traps, along with Devonian aged carbonate units that are trapped along the subcrop edge. Most of the producing wells are vertical, although the Corporation drilled three horizontal wells in 2011. Due to the high porosity and permeability of the reservoir zones, no fracture stimulations are needed. At December 31, 2011 the Corporation owned 231 (196.4 net) producing oil wells, seven (6.1 net) producing natural gas wells and 11 (9.6 net) service wells along with one 100% owned oil battery. In 2011, the Corporation drilled 14 (11.9 net) oil wells in the area and production averaged 3,263 boe/d weighted 98% to oil and liquids.

As at December 31, 2011, the GLJ Report showed the Lloydminster area to have proved plus probable reserves of 10,322 Mbbl of oil and ngls and 1,639 Mmcf of natural gas. At year-end, the Corporation owned 71,163 net acres of land with an average working interest of 89% in the area.

Minor Properties

In addition to the foregoing, Crew has an interest in other minor properties that contributed, in the aggregate, 2,449 boe/d of production in 2011. In 2011, Crew drilled three (3.0 net) oil wells on its minor properties.

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Corporation has a working interest as at December 31, 2011.

	Oil Wells				**Natural Gas Wells**			
	Producing		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	256	238.4	94	63.2	371	256.2	248	178.7
British Columbia	11	4.6	7	4.0	133	71.5	38	22.2
Saskatchewan	231	196.3	150	127.5	7	6.1	18	16.6
Total	498	439.3	251	194.7	511	333.8	304	217.5

Land Holdings Including Properties With No Attributed Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2011.

	Developed Acres		Undeveloped Acres	
	Gross	**Net**	**Gross**	**Net**
Alberta	348,908	219,469	521,192	451,750
British Columbia	113,170	50,959	272,715	182,467
Saskatchewan	24,269	18,294	42,440	38,970
Other Canada	160	-	376,920	37,692
Total	486,507	288,722	1,213,267	710,879

In 2012, the Corporation has a financial commitment which is estimated at approximately $1.1 million for work to be completed in the Edson area.

Of the Corporation's undeveloped land, the rights to explore, develop and exploit 88,445 net acres may expire by December 31, 2012 if the Corporation takes no action to retain the land. Crew plans to drill or submit applications to continue selected portions of this acreage.

In those situations where Crew holds interests in different formations under the same surface area pursuant to separate leases, Crew would consider this to be two separate leases and would calculate them separately. This situation would arise where Crew has purchased rights through Crown land sales and expended funds on the acquisitions of both leases based on the geological risk associated with those rights in each lease.

In the current natural gas price environment Crew may delay certain natural gas exploration and development investment decisions in order to maximize the value of the properties with no attributed reserves but retaining the mineral rights for future development.

Forward Contracts and Marketing

With the exception of the following financial derivative contracts entered into pursuant to the Corporation’s risk management program, as of December 31, 2011, Crew does not have any material commitments to buy or sell natural gas or crude oil production.

As at December 31, 2011, the Corporation 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.

Additional Information Concerning Abandonment and Reclamation Costs

The total net cost to abandon and reclaim Crew's assets was estimated by management and was based on Crew's net ownership interest, the estimated future cost to abandon and reclaim the Corporation's wells and facilities, the estimated future value of salvaged equipment and the estimated timing of when the costs and recoveries will be incurred. As at December 31, 2011, management expected to incur abandonment and reclamation costs on 1,240.8 net wells. The total of such costs, net of estimated salvage value, was $16.3 million ($14.1 million discounted at 10%).

Future net revenues in the GLJ Report include abandonment liabilities only for wells assigned reserves and no salvage values. Reclamation costs of $57.3 million ($25.6 million discounted at 10%) and salvage values of $90.9 million ($33.9 million discounted at 10%) are not considered in future net revenue in the GLJ Report. Within the next three financial years, it is estimated that abandonment and reclamation costs net of estimated salvage value will total approximately $1.9 million ($1.7 million discounted at 10%).

Tax Horizon

The Corporation was not required to pay any cash income taxes for the period ended December 31, 2011. Based on current estimates of the Corporation's future taxable income and levels of tax deductible expenditures, management believes that the Corporation will not be required to pay cash income taxes in 2012 and does not anticipate being in a cash income tax payable situation through 2013 and beyond at the currently anticipated rate of capital expenditures and forecasted commodity prices.

Capital Expenditures

The following tables summarize capital expenditures (net of incentives and net of disposition proceeds and including capitalized general and administrative expenses) related to the Corporation's activities for the year ended December 31, 2011:

	($ thousands)
Property acquisition (disposition) costs	
Proved properties	(25,492)
Undeveloped properties	4,906
Exploration costs	45,708
Development costs	325,260
Corporate acquisition - Caltex	730,302
Total	1,080,684

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated in drilling during the year ended December 31, 2011. **This table does not include wells drilled in Caltex prior to its acquisition by Crew on July 1, 2011.**

	Gross			Net		
	Exploration	**Development**	**Total**	**Exploration**	**Development**	**Total**
Crude Oil	38	85	123	38.0	82.9	120.9
Natural Gas	2	18	20	1.9	16.7	18.6
Dry[(1)]	2	-	2	2.0	-	2.0
Service[(2)]	-	13	13	-	13.0	13.0
Stratagraphic Test	-	-	-	-	-	-
Total:	42	116	158	41.9	112.6	154.5

Notes:

(1) "Dry well" means a well which is not a productive well or a service well. A productive well is a well which is capable of producing oil and gas in commercial quantities or in quantities considered by the operator to be sufficient to justify the costs required to complete, equip and produce the well.

(2) A service well means a well such as a water or gas-injection, water-source or water-disposal well. Such wells do not have marketable reserves of crude oil or natural gas attributed to them but are essential to the production of the crude oil and natural gas reserves.

In 2012, the Corporation intends to continue to concentrate on developing oil and liquids production at its principal properties at Princess, Lloydminster and Tower in order to capitalize on strong oil prices. The 2012 capital program is also anticipated to advance a number of Crew's secondary oil recovery schemes at Princess and continue to advance and de-risk the Corporation's oil and liquids plays in British Columbia and the deep basin of Alberta. The Corporation is currently budgeting for a $300 million capital expenditure program in 2012, which is currently planned to be financed through cash flow from operations and, if required, the Corporation's $430 million bank facility.

For details on Crew's important current and likely exploration and development activities during 2012, see "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Principal Properties*".

Production Estimates

The following table sets out the volume of the Corporation's average estimated daily production for the year ended December 31, 2012 as estimated in the GLJ Report which is reflected in the estimate of gross proved reserves and gross probable reserves disclosed in the tables contained under "*Disclosure of Reserves Data*".

	Light and Medium Oil		Heavy Oil		Natural Gas Liquids		Conventional Natural Gas		Coal Bed Methane		Total Oil Equivalent	
Reserves Category	**Gross (bbl/d)**	**Net (bbl/d)**	**Gross (bbl/d)**	**Net (bbl/d)**	**Gross (bbl/d)**	**Net (bbl/d)**	**Gross (Mcf/d)**	**Net (Mcf/d)**	**Gross (Mcf/d)**	**Net (Mcf/d)**	**Gross (Boe/d)**	**Net (Boe/d)**
Total Proved	7,517	5,470	5,415	4,524	3,220	2,564	86,945	71,744	418	401	30,713	24,583
Total Proved Plus Probable	9,062	6,574	6,696	5,572	3,537	2,834	94,170	77,712	421	404	35,059	27,999

Notes:

(1) The Corporation does not have any fields that individually account for 20% or more of the Corporation's estimated production.

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback associated with Crew's assets for the periods indicated below:

	Quarter Ended			
	2011			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Average Daily Production[1]				
Light and Medium Crude Oil (bbl/d)	6,784	4,910	5,458	5,794
Heavy Oil (bbl/d)	6,145	6,633	-	-
Natural Gas (Mcf/d)	84,270	79,668	57,285	51,721
Coal Bed Methane (Mcf/d)	387	410	413	388
NGLs (bbl/d)	2,995	2,621	1,369	1,129
Combined (BOE/d)	30,034	27,510	16,443	15,608
Average Price Received				
Light and Medium Crude Oil ($/bbl) [3]	86.34	71.36	82.50	69.68
Heavy Oil ($/bbl)	77.47	63.66	-	-
Natural Gas ($/Mcf)[3]	3.43	3.91	4.06	4.00
Coal Bed Methane ($/Mcf)	3.29	3.66	3.77	3.69
NGLs ($/bbl)	64.15	61.69	63.74	59.71
Combined ($/BOE) [3]	51.41	45.33	46.94	43.53
Transportation Expenses				
Light and Medium Crude Oil ($/bbl)	1.39	1.43	1.62	1.71
Heavy Oil ($/bbl)	0.91	1.01	-	-
Natural Gas ($/Mcf)	0.30	0.28	0.32	0.41
Coal Bed Methane ($/Mcf)	0.18	0.18	0.18	0.18
NGLs ($/bbl)	0.67	1.03	1.65	1.89
Combined ($/BOE)	1.43	1.42	1.78	2.13
Royalties Paid				
Light and Medium Crude Oil ($/bbl)	26.10	20.42	27.49	22.35
Heavy Oil ($/bbl)	18.56	16.20	-	-
Natural Gas ($/Mcf)	0.45	0.42	0.29	0.34
Coal Bed Methane ($/Mcf)	0.20	0.21	0.22	0.21
NGLs ($/bbl)	13.32	15.26	11.24	11.13
Combined ($/BOE)	12.69	10.23	11.08	10.22
Operating Expenses				
Light and Medium Crude Oil ($/bbl)	13.61	13.76	15.73	14.76
Heavy Oil ($/bbl)	15.59	16.00	-	-
Natural Gas ($/Mcf)	1.37	1.31	1.55	1.68
Coal Bed Methane ($/Mcf)	1.55	1.54	1.88	1.77
NGLs ($/bbl)	7.92	7.06	8.48	8.37
Combined ($/BOE)	11.26	10.79	11.38	11.69
Netback Received [2]				
Light and Medium Crude Oil ($/bbl)	45.24	35.75	37.66	30.86
Heavy Oil ($/bbl)	42.41	30.45	-	-
Natural Gas ($/Mcf)	1.31	1.90	1.90	1.57
Coal Bed Methane ($/Mcf)	1.36	1.73	1.49	1.53
NGLs ($/bbl)	42.24	38.34	42.37	38.32
Combined ($/BOE)	26.03	22.89	22.70	19.49

Notes:

(1) Before deduction of royalties and including royalty interests.
(2) Netbacks are calculated by subtracting transportation, royalties and operating costs from revenues.
(3) Average price received does not include the impact of the Corporation's realized gains and losses on financial instruments.

The following table indicates the Corporation's average daily production, before deduction of royalties and including royalty interests, from its important fields for the year ended December 31, 2011:

	Light and Medium Crude Oil (bbl/d)	Heavy Oil (bbl/d)	Conventional Natural Gas (Mcf/d)	Coal Bed Methane (Mcf/d)	NGLS (bbl/d)	Oil Equivalent (BOE/d)
Deep Basin	85	-	10,663	-	642	2,505
Princess	5,202		7,931		165	6,688
Edson/Pine Creek	26	-	6,377	-	243	1,332
Other	301	6	8,667	400	51	1,869
Total Alberta	5,614	6	33,638	400	1,101	12,394
Inga/Kobes	120	-	3,703	-	195	932
Septimus	2	-	27,276	-	733	5,282
Other	1	-	3,448	-	6	581
Total British Columbia	123	-	34,427	-	934	6,795
Lloydminster	-	3,215	291	-	-	3,263
Total Saskatchewan	-	3,215	291	-	-	3,263
Total	5,737	3,221	68,356	400	2,035	22,452

For the year ended December 31, 2011, approximately 75% of Crew's gross revenue was derived from crude oil and natural gas liquids production and 25% was derived from natural gas production.

DIVIDEND POLICY

Crew has not paid any dividends on the outstanding Common Shares. The Board of Directors of Crew will determine the actual timing, payment and amount of dividends, if any, that may be paid by Crew from time to time based upon, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other business considerations as the board of directors of Crew considers relevant.

DESCRIPTION OF CAPITAL STRUCTURE

The Corporation is authorized to issue an unlimited number of Common Shares and 1,881,000 Class C performance shares ("**Performance Shares**"). The following is a description of the rights, privileges, restrictions and conditions attaching to the share capital of the Corporation.

Common Shares

The Corporation is authorized to issue an unlimited number of Common Shares without nominal or par value. Holders of Common Shares are entitled to one vote per share at meetings of shareholders of the Corporation and are entitled to dividends if, as and when declared by the board of directors and, upon liquidation, dissolution or winding-up, to receive the remaining property of the Corporation.

Performance Shares

Holders of Performance Shares are not entitled to any voting rights or to receive notice of or to attend any meeting of the shareholders of the Corporation, are not entitled to receive any dividends on the Performance Shares and are not entitled upon any liquidation, dissolution or winding-up of the Corporation to any return of capital other than payment of the redemption price for each Performance Share in preference to the holders of Common Shares.

All of the previously outstanding Performance Shares vested and were converted into Common Shares on or prior to September 3, 2007. No further Performance Shares may be issued by the Corporation.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX and trade under the symbol "CR". The following sets forth trading information for the Common Shares (as reported by the TSX) for the periods indicated.

	Price Range ($)		
Period	**High**	**Low**	**Volume (in 000s)**
2011			
January	21.14	18.46	11,785
February	21.56	18.93	15,493
March	19.59	16.82	26,178
April	17.87	15.84	12,230
May	17.49	13.97	25,310
June	15.97	13.86	10,860
July	15.85	14.05	24,790
August	15.34	10.40	15,327
September	12.45	9.02	19,118
October	11.67	7.95	16,218
November	11.66	10.07	21,003
December	12.29	10.32	19,135
2012			
January	13.71	11.39	21,313
February	14.23	12.63	21,820
March (1-22)	13.44	10.02	13,914

ESCROWED SECURITIES

There are no securities of the Corporation currently held in escrow.

DIRECTORS AND OFFICERS

The name, age, province and country of residence, position with the Corporation and principal occupation of the directors and officers of the Corporation, as applicable, are set out below and in the case of directors, the period each has served as a director of the Corporation.

Name, Age, Province and Country of Residence	Office Held	Date First Elected or Appointed as a Director	Principal Occupation
John A. Brussa(2)(3)(4) Alberta, Canada Age: 55	Chairman	September, 2003	Partner, Burnet, Duckworth & Palmer LLP (a law firm).
Jeffery E. Errico(1)(2)(3) Alberta, Canada Age: 61	Director	September, 2008	Chairman of Insignia Energy Ltd., a public energy company, since 2007; prior thereto, President and Chief Executive Officer of Petrofund Energy Trust, a public oil and gas trust, from April, 2003 to June 2006.
Dennis L. Nerland(1)(3)(4) Alberta, Canada Age: 59	Director	September, 2003	Partner, Shea Nerland Calnan (a law firm).
David G. Smith(1)(2)(4) Alberta, Canada Age: 54	Director	January, 2009	President and Chief Operating Officer of Keyera Corp. since May, 2011; prior thereto, Executive Vice President, Liquids Business Unit, Keyera Corp. since January 1, 2011 and of Keyera Facilities Income Fund since November 2008; prior thereto, Executive Vice President and Chief Financial Officer, Keyera Facilities Income Fund since February 2006; prior thereto, Senior Vice President and Chief Financial Officer, Keyera Facilities Income Fund.
Dale O. Shwed Alberta, Canada Age: 53	President, Chief Executive Officer and Director	June, 2003	President and Chief Executive Officer of the Corporation since June, 2003; prior thereto President and Chief Executive Officer of Baytex.
John G. Leach, CA Alberta, Canada Age: 47	Senior Vice-President and Chief Financial Officer	N/A	Senior Vice-President and Chief Financial Officer of the Corporation since January, 2009; prior thereto, Vice-President and Chief Financial Officer of the Corporation since September, 2003; prior thereto, Vice President, Finance and Administration of Baytex.
Ken Truscott Alberta, Canada Age: 53	Senior Vice-President, Business Development and Land	N/A	Senior Vice-President, Business Development and Land of the Corporation since January, 2009; prior thereto, Vice-President, Land of the Corporation since September, 2007; prior thereto, Independent businessman since May, 2006; prior thereto President and Chief Executive Officer of Morpheus Energy Corporation.

Name, Age, Province and Country of Residence	Office Held	Date First Elected or Appointed as a Director	Principal Occupation
Rob Morgan Alberta, Canada Age: 48	Senior Vice-President and Chief Operating Officer	N/A	Senior Vice-President and Chief Operating Officer of the Corporation since July, 2011; prior thereto, Chief Operating Officer – Upstream of Harvest Operations Corp., a wholly-owned subsidiary of Harvest Energy Trust since February, 2006; prior thereto Vice-President Operations and Corporate Development Viking Energy Royalty Trust since 2004; prior thereto Vice-President Corporate Development, Petrovera Resources since 1999.
Gary Smith **Alberta, Canada** **Age: 53**	Vice-President, Exploration	N/A	Vice-President, Exploration of the Corporation since January, 2009; prior thereto, Exploration Manager of the Corporation since March, 2008; prior thereto, Senior Geologist of the Corporation since October, 2007; prior thereto, Vice-President, Exploration, Greenbank Energy since September, 2004; prior thereto, Senior Geologist, Storm Energy since February, 2002; prior thereto, Senior Geologist, Canadian Hunter.
Shawn A. Van Spankeren Alberta, Canada Age: 39	Vice-President, Finance and Controller	N/A	Vice-President, Finance and Controller of the Corporation since January, 2009; prior thereto, Controller of the Corporation since September, 2003; prior thereto, Controller of Baytex.
Kurtis Fischer Alberta, Canada Age: 44	Vice-President, Production	N/A	Vice-President, Production since July, 2011; prior thereto, Vice-President, Acquisitions and Divestitures of the Corporation since May, 2010; prior thereto, Manager, Acquisitions and Divestitures of the Corporation since April, 2008; prior thereto Senior Engineering Technologist of the Corporation since August, 2004.
Michael D. Sandrelli Alberta, Canada Age: 43	Corporate Secretary	N/A	Partner, Burnet, Duckworth & Palmer LLP (a law firm).

Notes:

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Compensation Committee.
(4) Member of the Corporate Governance Committee.
(5) Crew does not have an Executive Committee of its board of directors.

All of the directors and officers of Crew have been engaged for more than five years in their present principal occupations or executive positions with the same companies except as described above.

The term of office of each director expires at the next annual meeting of shareholders of the Corporation.

As at December 31, 2011, the directors and executive officers of Crew, as a group, beneficially owned, or controlled or directed, directly or indirectly, an aggregate of 4,508,765 Common Shares representing approximately 4% of the issued and outstanding Common Shares.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of Crew will be subject to in connection with the operations of Crew. In particular, certain of the directors and officers of Crew are or may be involved in managerial or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with Crew or with entities which may, from time to time, provide financing to, or make equity investments in, Crew's competitors. In accordance with ABCA, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with Crew are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract.

AUDIT COMMITTEE INFORMATION

The text of the Audit Committee's Mandate and Terms of Reference is attached hereto as Appendix C.

The Audit Committee of Crew is composed of the following members:

Name	Independent	Financially Literate	Relevant Education and Experience
David G. Smith	Yes	Yes	Mr. Smith is President and Chief Operating Officer of Keyera Corp., previously Keyera Facilities Income Fund, a public energy infrastructure company. Prior to that he was Executive Vice President, Liquids Business Unit and prior to that Executive Vice President and Chief Financial Officer and Corporate Secretary of Keyera Facilities Income Fund and its predecessor companies from June 1998 until May, 2011. Previously Mr. Smith was employed with Gulf Canada Resources Limited and Imperial Oil Limited, and he has more than 25 years of experience in the oil and gas industry. Mr. Smith holds a Bachelor of Mathematics degree from the University of Waterloo and a Master of Business Administration degree from Harvard University.
Dennis L. Nerland	Yes	Yes	Mr. Nerland is a lawyer practicing primarily in the area of tax and estate planning. Mr. Nerland has been a partner of Shea Nerland Calnan since 1990 and was a partner at Burnet, Duckworth & Palmer LLP prior thereto. Mr. Nerland is a member of the Law Society of Alberta, the Canadian Tax Foundation, the Calgary Bar Association, and the Society of Trusts and Estates Practitioners. Mr. Nerland is also a director of a number of public and private companies.
Jeffery E. Errico	Yes	Yes	Mr. Errico is the Executive Chairman of Insignia Energy Ltd., a public energy company. Prior to that he was the President and CEO of Petro Fund Corp. from April 2003 to June 2006. He is a professional engineer who received a Bachelor of Science degree in chemical engineering from the University of British Columbia. He has over 30 years of experience in the oil and gas industry, having served as a senior executive for several oil and gas companies.

Pre Approval of Policies and Procedures

Crew has adopted the following policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by KPMG LLP: The Audit Committee approves a schedule which summarizes the services to be provided that the Audit Committee believes to be typical, recurring or otherwise likely to be provided by KPMG LLP. The schedule generally covers the period between the adoption of the schedule and the end of the year, but at the option of the Audit Committee, may cover a shorter or longer period. The list of services is sufficiently detailed as to the particular services to be provided to ensure that (i) the Audit Committee knows precisely what services it is being asked to pre-approve and (ii) it is not necessary for any member of the Corporation's management to make a judgment as to whether a proposed service fits within the pre-approved services. Services that arise that were not contemplated in the schedule must be pre-approved by the Audit Committee chairman or a delegate of the Audit Committee. The full Audit Committee is informed of the services at its next meeting.

Crew has not approved any non-audit services on the basis of the de minimis exemptions. All non-audit services are pre-approved by the Audit Committee in accordance with the pre-approval policy referenced herein.

The following table provides information about the fees billed to Crew and its subsidiaries for professional services rendered by KPMG LLP, the Corporation’s external auditors, during fiscal 2011 and 2010:

	Aggregate fees billed	
	2011	2010
Audit fees	222,000	159,000
Audit-related fees	141,000	12,000
Tax fees	26,815	6,435
All other fees	-	-
	389,815	177,435

Audit Fees. Audit fees consist of fees for the audit of Crew’s annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.

Audit-Related Fees. Audit-related services include audit and review of certain subsidiaries and financial aspects, as well as prospectus review and IFRS consulting for Crew and its Subsidiaries.

Tax Fees. Tax fees included tax planning and various taxation matters.

All Other Fees. Other services provided by Crew’s external auditor other than audit, audit-related, IFRS consulting and tax services.

HUMAN RESOURCES

Crew currently employs 137 full-time employees, of which 105 are located in the head office and 32 are field employees, and 5 part-time consultants. Crew intends to add additional professional and administrative staff as the need arises.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these regulations or controls will affect the Corporation's operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada.

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB.

Natural Gas

The price of the vast majority of natural gas produced in western Canada is now determined through highly liquid market hubs such as the Alberta "NIT" (Nova Inventory Transfer) hub rather than through direct negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

Alberta

Producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework", which was implemented in 2010.

Royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than $\$535/m^3$ compared to the previous royalty curve.

Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 36%. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than $5.25/GJ compared to the previous royalty curve.

Oil sands projects are also subject to the Alberta's royalty regime. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil and Cushing, Oklahoma: rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1-9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher. In addition, concurrently with the implementation of the New Royalty Framework, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the current royalty regime.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold production taxes. The level of the freehold production tax is based on the volume of monthly production and a specified rate of tax for both oil and gas.

The Innovative Energy Technologies Program (the "**IETP**"), which is currently in place, has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

The Government of Alberta currently has in place two royalty programs, both of which commenced in 2008 and are intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a $1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to $3,750 per metre. On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of $875,000 for wells exceeding 4,000 metres that are spudded subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The five-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this program, companies drilling new natural gas or conventional deep oil wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the royalty regime. These options expired on February 15, 2011 and on January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the royalty regime. The revised royalty curves for conventional oil and natural gas will not be applied to production from wells operating under the transitional royalty rates.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. One aspect of the program was a drilling royalty credit program which provided up to a $200 per metre royalty credit for new wells. The drilling credit program applied to wells that were drilled between April 1, 2009 and March 31, 2010 and has not been extended for wells drilled after March 31, 2010. Another aspect of the program was a new well royalty program which provided for a maximum 5% royalty rate for eligible new wells for the first twelve (12) productive months or until the regulated "volume cap" was reached. The *New Well Royalty Regulation*, providing for the permanent implementation of this incentive program, was approved by an Order-in-Council on March 17, 2011.

In addition to the foregoing, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

The Emerging Resource and Technologies Initiative will be reviewed in 2014, and the Government of Alberta has committed to providing industry with three years notice at that time if it decides to discontinue the program.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 ("old oil"), between October 31, 1975 and June 1, 1998 ("new oil"), or after June 1, 1998 ("third-tier oil"). The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas as an incentive for the production and marketing of natural gas which might otherwise have been flared.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. For natural gas, the freehold production tax is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas.

British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity wells. These include both royalty credit and royalty reduction programs, including the following:

- *Summer Royalty Credit Program* providing a royalty credit of 10% of drilling and completion costs up to $100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;

- *Deep Royalty Credit Program* providing a royalty credit equal to approximately 23% of drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 2,300 metres;

- *Deep Re-Entry Royalty Credit Program* providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres and a re-entry date subsequent to December 1, 2003;

- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation with a spud date after November 30, 2003;

- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m^3 as well as a royalty credit for coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land;

- *Marginal Royalty Reduction Program* providing royalty reductions for low productivity natural gas wells with average monthly production under 25,000 m^3 during the first 12 production months and average daily production less than 23 m^3 for every metre of marginal well depth;

- *Ultra-Marginal Royalty Reduction Program* providing additional royalty reductions for low productivity shallow natural gas wells with a true vertical depth of less than 2,500 metres in the case of vertical wells, and a total vertical depth of less than 2,300 metres in the case of a horizontal well, average monthly production under 60,000 m^3 during the first 12 production months and average daily production less than 11.5 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every 100 metres of marginal well depth; and

- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. In 2009, 2010 and 2011, the Government of British Columbia awarded $120 million in royalty credits to oil and gas companies under the Infrastructure Royalty Credit Program.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres. An additional $50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

Saskatchewan

In Saskatchewan, the amount payable as Crown royalty or freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil", "third tier oil", "new oil" and "old oil") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (having a finished drilling date on or after January 1, 1994 and before October 1, 2004), fourth tier oil (having a finished drilling date on or after October 1, 2002) or new oil (not classified as either third tier oil or fourth tier oil). Southwest designated oil uses the same definitions of third and fourth tier oil but new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil. Where average wellhead prices are below the established base prices of $100 per m^3 for third and fourth tier oil and $50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as Crown royalty or freehold production tax in respect of natural gas production is determined by a sliding scale based on the actual price received, the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" or "associated gas" and royalty rates are determined according to the finished drilling date of the respective well. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* replacing the existing *Freehold Oil and Gas Production Tax Act* with the intention to facilitate more efficient payment of freehold production taxes by industry. No regulations have been passed with respect to the calculation of freehold production taxes under the new legislation, although several regulations remain in force under the previous legislation.

As with conventional oil production, base prices are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $50 per thousand m^3 for third and fourth tier gas and $35 per thousand m^3 for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas**.**

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations);

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres or within certain formations);

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for horizontal gas wells;

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* treating incremental production from waterflood projects as fourth tier oil for the purposes of royalty calculation;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing Crown royalty and freehold tax determinations based in part on the profitability of enhanced recovery projects pre- and post-payout;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on enhanced oil recovery projects pre-payout and 20% post-payout and a freehold production tax of 0% on operating income from enhanced oil recovery projects pre-payout and 8% post-payout; and

- *Royalty/Tax Regime for High Water-Cut Oil Wells* granting "third tier oil" royalty/tax rates to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the Government of Canada disallowing Crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to seven years since the Government of Canada's initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan's RTR will be wound down as a result of the Government of Canada's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards which are designed to reduce emissions resulting for the flaring and venting of associated gas (the "**Associated Natural Gas Standards**"). The Associated Natural Gas Standards were jointly developed with industry and the implementation of such standards is set to commence on July 1, 2012 for new wells and facilities licensed on or after such date, and to apply to existing licensed wells and facilities on July 1, 2015.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta, British Columbia and Saskatchewan has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. On March 29, 2007, British Columbia's policy of deep rights reversion was expanded for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. Leases and licences that were granted prior to January 1, 2009 but continued after that date are not subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009. The order in which these agreements will receive reversion notices will depend on their vintage and location, and the Government of Alberta had anticipated that the receipt of reversion notices for older leases and licenses would commence in April 2011. However, on April 14, 2011, the Government of Alberta announced it was deferring serving shallow rights reversion notices and will revisit the decision in spring 2012.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

In December, 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009 and provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA will be deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, leases, licenses, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 29, 2011 the Government of Alberta released a revised draft of the Lower Athabasca Regional Plan (the "**Revised LARP**") updating its prior draft of April 5, 2011 (the "**Draft LARP**"). The Revised LARP, while establishing several conservation areas of the Athabasca region, has changed the boundaries of certain conservation areas outlined in the Draft LARP with the result that fewer oil sands leases appear to be impacted. Consistent with the Draft LARP, as the intention of the Revised LARP is to manage the areas to minimize or prevent new land disturbance, activities associated with oil sands development are considered incompatible with the intent to manage such conservation areas. However, references to the cancellation of existing tenures have been removed from the Revised LARP and the Revised LARP now contemplates that the conservation areas will be created pursuant to existing legislation rather than the previously contemplated regulations. Existing conventional petroleum and natural gas rights will not be affected, although the Revised LARP raises some question as to whether new conventional leases and licenses will be granted in the conservation areas in the future. The planning process is also underway for a regional plan for the South Saskatchewan Region.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas ("**GHG**") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 although on December 12, 2011 Canada formally withdrew from the Kyoto Protocol.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("**CCS**") technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO_2 equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets:

(a) Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 per tonne of CO_2 equivalent for the 2010 to 2012 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce GHG emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

(b) The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either purchase the offset credits for cancellation or banking for future use or sale.

(c) Under the Updated Action Plan, regulated entities were able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations. However, with the recent withdrawal from the Kyoto Protocol, the future use of this mechanism may not occur.

(d) Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

From December 7 to 18, 2009, government leaders and representatives met in Copenhagen, Denmark and agreed to the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Another meeting of government leaders and representatives in 2010 resulted in the Cancun Agreements wherein developed countries committed to additional measures to help developing countries deal with climate change. Neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets. In response to the Copenhagen Accord, the Government of Canada indicated that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020.

Although draft regulations for the implementation of the Updated Action Plan were intended to become binding on January 1, 2010, only draft regulations pertaining to carbon dioxide emissions from coal-fired generation of electricity have been proposed to date. Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent, if any; the proposals contained in the Updated Action Plan will be implemented.

The United States Environmental Protection Agency (the "**EPA**") has indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by specifying that it will issue final regulations by May 26, 2012, and with respect to refineries, specifying that it will issue proposed regulations by December 10, 2011 and finalized regulations by November 10, 2012. The EPA did not meet the December 10, 2011 deadline and it is unclear whether the EPA will also miss the finalized regulations deadline.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on December 4, 2003, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Similar to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity to 88% of their baseline for 2008 and subsequent years, with their baseline being established by the average of the ratio of the total annual emissions to production for the years 2003 to 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of baseline in the fifth year, 6% of baseline in the sixth year, 8% of baseline in the seventh year, and 10% of baseline in the eighth year. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA contains compliance mechanisms that are similar to the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of $15 per tonne of CO_2 equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

British Columbia

In February, 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is $25 per tonne of CO_2 equivalent. It is scheduled to increase to $30 per tonne of CO_2 equivalent on July 31, 2012. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**") which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO_2 equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO_2 equivalents per year are required to have their emissions reports verified by a third party. Regulations pertaining to proposed offsets and emissions trading are currently in the consultation stage. With respect to its operations in British Columbia that may exceed these thresholds, Crew will take all necessary steps to ensure compliance with the new reporting regulations.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. Regulations under the MRGGA have also yet to be proclaimed, but draft versions indicate that Saskatchewan will adopt the goal of a 20% reduction in GHG emissions from 2006 levels by 2020 and permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to both the federal and Alberta climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation therein. Moreover, if such acquisitions or participations are identified, management of the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. Drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including fire, explosion, blowouts, cratering, sour gas releases, spills or other environmental hazards, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In accordance with industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of certain risks is such that liabilities could exceed policy limits or not be covered, in either event the Corporation could incur significant costs.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels have caused significant volatility in commodity prices. These conditions have caused a decrease in confidence in the global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. This volatility may in the future affect the Corporation's ability to obtain equity or debt financing on acceptable terms.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and natural gas acquisition, development and exploration activities. Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States, Canada and Europe, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, and sanctions imposed on certain oil producing nations by other countries and the ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility. This volatility is often based on factors both related and unrelated to the financial performance or prospects of the issuers involved. The market price of the common shares of the Corporation could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. Factors that could affect the market price of the common shares of the Corporation that are unrelated to the Corporation's performance include domestic and global commodity prices and market perceptions of the attractiveness of particular industries. The price at which the common shares of the Corporation will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets may be periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. As a result, the Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others therefore depends upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project Risks

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and within applicable environmental regulations;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;

- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Gathering and Processing Facilities and Pipeline Systems

The Corporation delivers its products through gathering, processing and pipeline systems some of which it does not own. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in the Corporation’s inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation’s production. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation’s financial condition, results of operations and cash flows.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could materially adversely affect the Corporation's ability to process its production and to deliver the same for sale.

Competition

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (oil and natural gas) production. The use of hydraulic fracturing is being used to produce commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs or third party or governmental claims, and could increase the Corporation's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with greenhouse gas emissions legislation in Alberta and British Columbia or that may be enacted in other provinces. The Corporation may also be required comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which regulations are expected to be consistent with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits regulated by the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "Industry Conditions – Climate Change Regulation".

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Corporation's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Corporation's reserves as determined by independent evaluators.

To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Corporation may contract.

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, which could negatively impact the market price of the common shares of the Corporation.

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors, the overall state of the capital markets, the Corporation’s credit rating (if applicable), interest rates, tax burden due to new tax laws and investor appetite for investments in the energy industry and the Corporation's securities in particular. Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. As a result of the global economic volatility, the Corporation, along with many other oil and natural gas entities, may, from time to time, have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited or unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation’s properties.

Credit Facility Arrangements

The Corporation currently has a credit facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under its credit facility which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that the Corporation does not comply therewith the Corporation's access to capital could be restricted or repayment could be required. The failure of the Corporation to comply with such covenants, which may be affected by events beyond the Corporation's control, could result in the default under the Corporation's credit facility which could result in the Corporation being required to repay amounts owing thereunder. Even if the Corporation is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing, the lenders under the credit facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Corporation's credit facility may, from time to time, impose operating and financial restrictions on the Corporation that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The Corporation's borrowing base is determined and re-determined by the Corporation's lenders based on the Corporation's reserves, commodity prices, applicable discount rate and other factors as determined by the

Corporation's lenders. A material decline in commodity prices could reduce the Corporation's borrowing base, therefore reducing the funds available to the Corporation under the credit facility which could result in a portion, or all, of the Corporation's bank indebtedness be required to be repaid.

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation’s hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and natural gas properties the Corporation controls that, if successful or made into law, could impair the Corporation’s activities on them and result in a reduction of the revenue received by the Corporation.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

Insurance

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, North Africa and other areas of the world have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Corporation's net production revenue.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have insurance to protect against the risk from terrorism.

Dilution

The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation which may be dilutive.

Management of Growth

The Corporation may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this growth may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Dividends

The Corporation has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other considerations as the board of directors of the Corporation considers relevant.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation.

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Conflicts of Interest

Certain directors of the Corporation are also directors of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "Directors and Officers – Conflicts of Interest".

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key person insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Crew is not a party to any legal proceeding nor was it a party to, nor is or was any of its property the subject of any legal proceeding, during the financial year ended December 31, 2011, nor is Crew aware of any such contemplated legal proceedings, which involve a claim for damages, exclusive of interest and costs, that may exceed 10% of the current assets of Crew.

During the year ended December 31, 2011, there were no (i) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision, or (iii) settlement agreements the Corporation entered into before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors or executive officers of Crew, any holder of Common Shares who beneficially owns or controls or directs, directly or indirectly, more than 10% of the outstanding Common Shares, or any known associate or affiliate of such persons, in any transactions within the three most recently completed financial years or during the current financial year which has materially affected or is reasonably expected to materially affect Crew.

TRANSFER AGENT AND REGISTRAR

Valiant Trust Company, at its principal offices in Calgary, Alberta and Toronto, Ontario is the transfer agent and registrar of the Common Shares.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business (unless otherwise required by applicable securities requirements to be disclosed), neither the Corporation or its Subsidiaries have entered into any material contracts within the last financial year, or before the last financial year that are still in effect other than the Arrangement Agreement in respect of the Caltex Acquisition, a copy of which has been filed on SEDAR at www.sedar.com.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than GLJ, the Corporation's independent engineering evaluator and KPMG LLP, the Corporation's auditors. As at the date hereof, the designated professionals of GLJ, as a group, beneficially owned, directly or indirectly less than 1% of Crew's outstanding securities, including securities of Crew's associates and affiliates, either at the time it prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them. KPMG LLP is independent in accordance with the auditor's rules of professional conduct of the Institute of Chartered Accountants of Alberta.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans will be contained in the Corporation's information circular for the Corporation's next annual meeting of securityholders to be held on May 24, 2012. Additional financial information is contained in the Corporation's consolidated financial statements and the related management's discussion and analysis for its most recently completed financial year. Alternatively, additional information relating to the Corporation is available on SEDAR at www.sedar.com.

For copies of Crew's information circular, comparative consolidated financial statements, including any interim consolidated comparative financial statements and additional copies of the Annual Information Form please contact:

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

APPENDIX "A"
FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Crew Energy Inc. (the "**Corporation**") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011 estimated using forecast prices and costs:

An independent qualified reserves evaluator has evaluated and reviewed the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the board of directors of the Corporation has

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing the reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

(signed) "*Dale O. Shwed*"
Dale O. Shwed
President and Chief Executive Officer

(signed) "*John G. Leach*"
John G. Leach
Senior Vice-President and Chief Financial Officer

(signed) "*Jeffery E. Errico*"
Jeffery E. Errico
Director and Chairman of the Reserves Committee

(signed) "*John A. Brussa*"
John A. Brussa
Director and Member of the Reserves Committee

March 23, 2012

APPENDIX "B"
FORM 51-101F2
REPORT ON RESERVES DATA

To the board of directors of Crew Energy Inc. (the "**Company**"):

1. We have prepared and evaluation of the Company's reserves data as at December 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011 estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2011, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate, M$)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	March 1, 2012	Canada	-	$1,641,660	-	$1,641,660

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.

7. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after its preparation dates.

8. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

(signed) "*GLJ Petroleum Consultants*"
GLJ Petroleum Consultants

Calgary, Alberta
March 2, 2012

Originally signed by:
John H. Stilling, P. Eng.
Vice President

APPENDIX "C"
CREW ENERGY INC.
AUDIT COMMITTEE
MANDATE AND TERMS OF REFERENCE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Crew Energy Inc. ("**Crew**" or the "**Corporation**") to which the Board has delegated its responsibility for the oversight of the nature and scope of the annual audit, the oversight of management's reporting on internal accounting standards and practices, the review of financial information, accounting systems and procedures, financial reporting and financial statements and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

1. To assist directors in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Crew and related matters;

2. To provide better communication between directors and external auditors;

3. To enhance the external auditor's independence;

4. To increase the credibility and objectivity of financial reports; and

5. To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

1. The Committee will be comprised of at least three (3) directors of Crew or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("**MI 52-110**")) unless the Board determines that the exemption contained in MI 52-110 is available and determines to rely thereon.

2. The Board of Directors may from time to time designate one of the members of the Committee to be the Chair of the Committee.

3. All of the members of the Committee must be "financially literate" (as defined in MI 52-110) unless the Board determines that an exemption under MI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of MI 52-110.

Mandate and Responsibilities of Committee

It is the responsibility of the Committee to:

1. Oversee the work of the external auditors, including the resolution of any disagreements between management and the external auditors regarding financial reporting.

2. Satisfy itself on behalf of the Board with respect to Crew's internal control systems:

   - identifying, monitoring and mitigating business risks; and

   - ensuring compliance with legal, ethical and regulatory requirements.

3. Review the annual and interim financial statements of Crew and related management's discussion and analysis ("**MD&A**") prior to their submission to the Board for approval. The process should include but not be limited to:

    - reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
    - reviewing significant accruals, reserves or other estimates such as the indicators of impairment;
    - reviewing accounting treatment of unusual or non-recurring transactions;
    - ascertaining compliance with covenants under loan agreements;
    - reviewing disclosure requirements for commitments and contingencies;
    - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
    - reviewing unresolved differences between management and the external auditors; and
    - obtain explanations of significant variances with comparative reporting periods.

4. Review the financial statements, prospectuses, MD&A, annual information forms ("**AIF**") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Crew's disclosure of all other financial information and will periodically assess the accuracy of those procedures.

5. With respect to the appointment of external auditors by the Board:

    - recommend to the Board the external auditors to be nominated;
    - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;
    - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;
    - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
    - review and pre-approve any non-audit services to be provided to Crew or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre–approve non–audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre–approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.

6. Review with external auditors (and internal auditor if one is appointed by Crew) their assessment of the internal controls of Crew, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee will also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Crew and its subsidiaries.

7. Review risk management policies and procedures of Crew (i.e. hedging, litigation and insurance).

8. Establish a procedure for:

    - the receipt, retention and treatment of complaints received by Crew regarding accounting, internal accounting controls or auditing matters; and

    - the confidential, anonymous submission by employees of Crew of concerns regarding questionable accounting or auditing matters.

9. Review and approve Crew's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of Crew.

The Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Corporation. The Committee will also have the authority to investigate any financial activity of Crew. All employees of Crew are to cooperate as requested by the Committee.

The Committee may also retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of Crew without any further approval of the Board.

Meetings and Administrative Matters

1. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.

2. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.

3. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board unless otherwise determined by the Committee or the Board.

4. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

5. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.

6. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

7. The Committee may invite such officers, directors and employees of the Corporation as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.

8. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

9. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation.

10. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee, each member will hold such office until the Committee is reconstituted.

11. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chairman of the Board by the Committee Chair.